OTTER TAIL CORP

FORM 10-K
(Annual Report)

Filed 02/26/10 for the Period Ending 12/31/09

Address	215 S CASCADE ST
	PO BOX 496
	FERGUS FALLS, MN 56538-0496
Telephone	8664108780
CIK	0001466593
Symbol	OTTR
SIC Code	4911 - Electric Services
Industry	Electric Utilities
Sector	Utilities
Fiscal Year	12/31

[Table of Contents](#)

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, 2009

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

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

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

Title of each class	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:

CUMULATIVE PREFERRED SHARES, without par value

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 ☐ (Do not check if a smaller reporting company)	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, 2009 was **$767,320,116.**

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: **35,835,553 Common Shares ($5 par value) as of February 15, 2010.**

Documents Incorporated by Reference:

Proxy Statement for the 2010 Annual Meeting-Portions incorporated by reference into Part III

OTTER TAIL CORPORATION
FORM 10-K TABLE OF CONTENTS

Exhibit Index

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 electric and nonelectric 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) (formerly known as Otter Tail Holding 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. See "Holding Company Reorganization" for additional details regarding the reorganization. References in this report to Otter Tail Corporation and the Company refer, for periods prior to July 1, 2009, to the corporation that was the registrant prior to the reorganization, and, for periods after the reorganization, to the new parent holding company, in each case including its consolidated subsidiaries, unless otherwise indicated or the context otherwise requires. 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. Its telephone number is (866) 410-8780.

The Company makes available free of charge at its internet 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 in all 50 states and in international markets. The Company had approximately 3,562 full-time employees at December 31, 2009. The businesses of the Company have been classified into six segments: Electric, Plastics, Manufacturing, Health Services, Food Ingredient Processing and Other Business Operations.

- 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 Midwest Independent Transmission System Operator (MISO) markets. OTP's operations have been our primary business since 1907.

- Plastics consists of businesses producing polyvinyl chloride (PVC) pipe in the Upper Midwest and Southwest regions of the United States.

- Manufacturing consists of businesses in the following manufacturing activities: production of wind towers, contract machining, metal parts stamping and fabrication, and production of waterfront equipment, material and handling trays and horticultural containers. These businesses have manufacturing facilities in Florida, Illinois, Minnesota, Missouri, North Dakota, Oklahoma and Ontario, Canada and sell products primarily in the United States.

- Health Services consists of businesses involved in the sale of diagnostic medical equipment, patient monitoring equipment and related supplies and accessories. These businesses also provide equipment maintenance, diagnostic imaging services and rental of diagnostic medical imaging equipment to various medical institutions located throughout the United States.

- Food Ingredient Processing consists of Idaho Pacific Holdings, Inc. (IPH), which owns and operates potato dehydration plants in Ririe, Idaho; Center, Colorado; and Souris, Prince Edward Island, Canada. IPH produces dehydrated potato products that are sold in the United States, Canada and other countries. Approximately 16% of IPH's sales in 2009 were to customers outside of the United States.

- Other Business Operations consists of businesses in residential, commercial and industrial electric contracting industries, fiber optic and electric distribution systems, water, wastewater and HVAC systems construction, transportation and energy services. These businesses operate primarily in the Central United States, except for the transportation company which operates in 46 states and four Canadian provinces.

The Company's corporate operating costs include items such as corporate staff and overhead costs, the results of the Company's captive insurance company and other items excluded from the measurement of operating segment performance. Corporate assets consist primarily of cash, prepaid expenses, investments and fixed assets. Corporate is not an operating segment. Rather, it is added to operating segment totals to reconcile to totals on the Company's consolidated financial statements.

The Company's electric operations, including wholesale power sales, are operated by its wholly owned subsidiary, OTP, and its energy services operation is operated by a separate wholly owned subsidiary of the Company. All of the Company's other businesses are owned by its wholly owned subsidiary, Varistar Corporation (Varistar).

The Company continues to look for strategic acquisitions of additional businesses with emphasis on adding to existing operating companies and expects continued growth in this area. No acquisitions were completed during 2009.

The Company considers the following guidelines when reviewing potential acquisition candidates:

- Emerging or middle market company;
- Proven entrepreneurial management team that will remain after the acquisition;
- Preference for 100% ownership of the acquired company;
- Products and services intended for commercial rather than retail consumer use; and
- The potential to provide immediate earnings and future growth.

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 40 through 63 of this Annual Report on Form 10-K.

Holding Company Reorganization

On July 1, 2009 Otter Tail Corporation completed a holding company reorganization in accordance with Section 302A.626 of the Minnesota Business Corporation Act (the MBCA) whereby OTP (also referred to as Old Otter Tail), 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 (formerly known as Otter Tail Holding Company).

The new holding company structure was effected on July 1, 2009 pursuant to a Plan of Merger dated as of June 30, 2009 (the Plan of Merger), by and among Old Otter Tail, Otter Tail Holding Company (now known as Otter Tail Corporation), a Minnesota corporation and, prior to the reorganization, a direct subsidiary of Old Otter Tail, and Otter Tail Merger Sub Inc., a Minnesota corporation and indirect subsidiary of Old Otter Tail and direct subsidiary of Otter Tail Holding Company (Merger Sub). The Plan of Merger provided for the merger (the Merger) of Old Otter Tail with Merger Sub, with Old Otter Tail as the surviving corporation. Pursuant to Section 302A.626 (subd. 2) of the MBCA shareholder approval was not required for the Merger. As a result of the Merger, Old Otter Tail is now a wholly owned subsidiary of the Company with the name Otter Tail Power Company. Immediately following the completion of the Merger, the Company changed its name from Otter Tail Holding Company to Otter Tail Corporation.

In the Merger, each issued and outstanding common share of Old Otter Tail was converted into one common share of the Company, par value $5 per share, and each issued and outstanding cumulative preferred share of Old Otter Tail was converted into one cumulative preferred share of the Company having the same designations, rights, powers and preferences. In connection with the Merger, each person that held rights to purchase, or other rights to or interests in, common shares of Old Otter Tail under any stock option, stock purchase or compensation plan or arrangement of Old Otter Tail immediately prior to the Merger holds a corresponding number of rights to purchase, and other rights to or interests in, common shares of the Company, par value $5 per share, immediately following the Merger.

The conversion of the common shares in the Merger occurred without an exchange of certificates. Accordingly, certificates formerly representing outstanding common shares of Old Otter Tail are deemed to represent the same number of common shares of the Company.

Pursuant to Section 302A.626 (subd. 7) of the MBCA, the provisions of the Restated Articles of Incorporation and Restated Bylaws of the Company are consistent with those of Old Otter Tail prior to the Merger. The authorized common shares and cumulative preferred shares of the Company, the designations, rights, powers and preferences of such shares and the qualifications, limitations and restrictions thereof are also consistent with those of Old Otter Tail's common shares and cumulative preferred shares immediately prior to the Merger. The directors and executive officers of the Company are the same individuals who were directors and executive officers, respectively, of Old Otter Tail immediately prior to the Merger.

(b) Financial Information about Industry Segments

The Company is engaged in businesses that have been classified into six segments: Electric, Plastics, Manufacturing, Health Services, Food Ingredient Processing and Other Business Operations. Financial information about the Company's segments and geographic areas is included in note 2 of "Notes to Consolidated Financial Statements" on pages 82 through 84 of this Annual Report on Form 10-K.

(c) Narrative Description of Business

ELECTRIC

General

OTP provides electricity to more than 129,000 customers in a 50,000 square mile area of Minnesota, North Dakota and South Dakota. The Company derived 30%, 26% and 26% of its consolidated operating revenues from the Electric segment for each of the three years ended December 31, 2009, 2008 and 2007, respectively. The Company derived 131%, 95% and 45% of its consolidated net income from the Electric segment for each of the three years ended December 31, 2009, 2008 and 2007, respectively. The breakdown of retail revenues by state is as follows:

State	2009	2008
Minnesota	49.1%	50.2%
North Dakota	41.5	40.4
South Dakota	9.4	9.4
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 423 communities and adjacent rural areas and farms, approximately 130,900 people live in communities having a population of more than 1,000, according to the 2000 census. The only communities served which have a population in excess of 10,000 are Jamestown, North Dakota (15,527); Fergus Falls, Minnesota (13,471); and Bemidji, Minnesota (11,917). As of December 31, 2009, OTP served 129,307 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	2009	2008
Commercial	36.8%	35.9%
Residential	32.8	30.6
Industrial	23.3	23.1
All Other Sources	7.1	10.4
Total	100.0%	100.0%

Wholesale electric energy kilowatt-hour (kwh) sales were 24.9% of total kwh sales for 2009 and 38.7% for 2008. Wholesale electric energy kwh sales decreased by 47.5% between the years while revenue per kwh decreased by 48.6%. 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.

With the inception of the MISO Day 2 markets in April 2005, MISO introduced two new types of contracts, virtual transactions and Financial Transmission Rights (FTR). Virtual transactions are of two types: Virtual Demand Bid, which is a bid to purchase energy in MISO's Day-Ahead Market that is not backed by physical load, and Virtual Supply Offer, which is an offer submitted by a market participant in the Day-Ahead Market to sell energy not supported by a physical injection or reduction in withdrawals in commitment by a resource. An FTR is a financial contract that entitles its holder to a stream of payments, or charges, based on transmission congestion charges calculated in MISO's Day-Ahead Market. A market participant can acquire an FTR from several sources: the annual or monthly FTR auction, the FTR secondary market or a grant of an FTR in conjunction with a transmission service request. An FTR is structured to hedge a market participant's exposure to uncertain cash flows resulting from congestion of the transmission system. In 2009, net revenues from virtual and FTR transactions represented 0.02% of total electric energy revenues compared with 0.3% in 2008. As the MISO markets have evolved and become more efficient, profits from virtual transactions have declined.

Capacity and Demand

As of December 31, 2009 OTP's owned net-plant dependable kilowatt (kW) capacity was:

Baseload Plants	
Big Stone Plant	256,000 kW
Coyote Station	143,000
Hoot Lake Plant	140,466
Total Baseload Net Plant	539,466 kW
Combustion Turbine and Small Diesel Units	116,550 kW
Hydroelectric Facilities	3,765 kW
Owned Wind Facilities (rated at nameplate)	
Langdon Wind Center (27 turbines)	40,500 kW
Luverne Wind Farm (33 turbines)	49,500
Ashtabula Wind Center (32 turbines)	48,000
Total Owned Wind Facilities	138,000 kW

The baseload net plant capacity for Big Stone Plant and Coyote Station constitutes OTP's ownership percentages of 53.9% and 35%, respectively. OTP owns 100% of the Hoot Lake Plant. During 2009, OTP generated about 71% of its retail kwh sales and purchased the balance.

In 2009, OTP constructed 33 wind turbines on its portion of the Luverne Wind Farm in Steele County, North Dakota. OTP's 33 wind turbines, nameplate rated at 1.5 megawatts (MW) each, became commercially operational in September 2009.

In addition to the owned facilities described above OTP had the following purchase power agreements in place on December 31, 2009:

Purchased Wind Agreements (rated at nameplate and greater than 2,000 kW)	
Edgeley	21,000 kW
Langdon	19,500
Total Purchased Wind	40,500 kW

Purchased Power Agreements (in excess of 1 year and 500 kW)	
Manitoba Hydro	50,000 kW
WAPA	5,800
WPPI Energy	40,000
Total Purchased Power	95,800 kW

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.

In May 2009, OTP entered into an agreement for the purchase of 50 MW of capacity and associated energy from a regional power producer from May 1, 2010 through April 30, 2013 to cover a portion of its expected capacity and energy requirements during that period at a cost of approximately $36.5 million over the three-year term of the agreement. In November 2009, OTP exercised its option to cancel the final two years of that agreement. It was replaced with an equivalent purchase from different regional power suppliers at a total savings of approximately $1.4 million. OTP has also entered into a capacity contract with a regional power producer for an additional 35 MW from June 1, 2010 through May 30, 2011.

OTP traditionally experiences its peak system demand during the winter season. For the year ended December 31, 2009 OTP experienced a system peak demand of 800,488 kW on January 13, 2009, which was also the highest all-time system peak demand (as reported to Mid-Continent Area Power Pool (MAPP)). Taking into account additional capacity available to it on January 13, 2009 under purchase power contracts (including short-term arrangements), as well as its own generating capacity, OTP's capability of then meeting system demand, excluding reserve requirements computed in accordance with accepted industry practice, amounted to 1,003,500 kW (878,175 kW if reserve requirements are included).

With the implementation of MISO's resource adequacy program on June 1, 2009, OTP withdrew from participation in MAPP's Generation Reserve Sharing Pool (GRSP). The requirements and structure of the MISO resource adequacy program are significantly different than those of MAPP's GRSP. Future reporting of load and capacity data will be in a MISO format that is not directly comparable to the MAPP GRSP format. OTP's additional capacity available under power purchase contracts (as described above), combined with generating capacity and load management control capabilities, is expected to meet 2010 system demand and MISO reserve requirements.

Big Stone II

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, due to a number of factors. The broad economic downturn, a high level of uncertainty associated with proposed federal climate legislation and existing federal environmental regulations and challenging credit and equity markets made proceeding with Big Stone II and committing to approximately $400 million in capital expenditures untenable for OTP's customers and the Company's shareholders. On November 2, 2009, the remaining Big Stone II participants announced the cancellation of the Big Stone II project.

As of December 31, 2009, OTP had incurred $13.0 million in costs related to this project. OTP believes these incurred costs are probable of recovery in future rates and has deferred recognition of these costs as operating expenses pending determination of recoverability by the state and federal regulatory commissions that approve OTP's rates. In filings made on December 14, 2009, OTP requested from its three state commissions authority to reflect these costs on its books as a regulatory asset through the use of deferred accounting, pending a determination on the recoverability of the costs. The South Dakota Public Utilities Commission (SDPUC) approved OTP's request for deferred accounting treatment on February 9, 2010. If Minnesota or North Dakota denies the requests to use deferred accounting or if any of the three jurisdictions eventually denies recovery of all or any portion of these deferred costs, such costs would be subject to expense in the period they are deemed to be inappropriate for deferral or unrecoverable.

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 and Big Stone plants burn western subbituminous coal.

The following table shows the sources of energy used to generate OTP's net output of electricity for 2009 and 2008:

	2009		2008	
Sources	Net Kilowatt Hours Generated (Thousands)	% of Total Kilowatt Hours Generated	Net Kilowatt Hours Generated (Thousands)	% of Total Kilowatt Hours Generated
Subbituminous Coal	2,186,145	63.0%	2,613,060	67.7%
Lignite Coal	856,359	24.7	1,016,828	26.4
Wind and Hydro	391,032	11.3	177,250	4.6
Natural Gas and Oil	33,017	1.0	48,957	1.3
Total	3,466,553	100.0%	3,856,095	100.0%

OTP has the following primary coal supply agreements:

Plant	Coal Supplier	Type of Coal	Expiration Date
Big Stone Plant	Cloud Peak Energy Resources LLC*	Wyoming subbituminous	December 31, 2010
	COALSALES, LLC	Wyoming subbituminous	December 31, 2010
Hoot Lake Plant	Cloud Peak Energy Resources LLC*	Wyoming subbituminous	December 31, 2011
Coyote Station	Dakota Westmoreland Corporation	North Dakota lignite	May 4, 2016

* *Formerly known as Kennecott Coal Sales Company*

The contract with Dakota Westmoreland Corporation has a 5 to 15-year renewal option subject to certain contingencies. 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 the Coyote Station and Hoot Lake Plant.

In response to a request for proposal, OTP received a proposal from a coal supplier for the supply of additional coal to Big Stone Plant in 2010 and for most of Big Stone Plant's anticipated coal needs in 2011 and 2012. OTP is currently negotiating terms with the supplier but has not entered into a contractual agreement.

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 the Coyote Station due to its location next to a coal mine.

The average cost of coal consumed (including handling charges to the plant sites) per million British Thermal Unit for each of the three years 2009, 2008 and 2007 was $1.726, $1.678 and $1.486, 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:

		2009		2008	
Rates	Regulation	% of Electric Revenues	% of kwh Sales	% of Electric Revenues	% of kwh Sales
MN Retail Sales	MN Public Utilities Commission	42.4%	37.6%	32.6%	31.7%
ND Retail Sales	ND Public Service Commission	35.8	30.2	26.3	23.4
SD retail Sales	SD Public Utilities Commission	8.1	7.3	6.1	6.2
Transmission & Wholesale	Federal Energy Regulatory Commission	13.7	24.9	35.0	38.7
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. Accordingly, OTP has designed its electric system to provide continuous service at times of peak usage. The pattern of electric usage can vary dramatically during a 24-hour period and from season to season. OTP's tariffs provide for continuous electric service and are designed to cover the costs of service during peak times. 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 lower rates for residential demand control, real-time pricing and controlled service and in North Dakota and South Dakota for bulk interruptible rates. Each of these specialized rates is designed to improve efficient use of OTP resources, while giving customers more control over the size of their electric bill. In all three states, OTP has approved tariffs 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. In North Dakota and South Dakota, 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.

The following summarizes 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), SDPUC and the FERC. The Company's nonelectric businesses are not subject to direct regulation by any of these agencies.

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.

The Minnesota Office of Energy Security (MNOES), part of the Minnesota Department of Commerce (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 MNOES is authorized to collect and analyze data on energy and 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 MNOES acts as a state advocate in matters heard before the MPUC. The MNOES 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.

In an order issued by the MPUC on August 1, 2008 OTP was granted an increase in Minnesota retail electric rates of $3.8 million, or approximately 2.9%, which went into effect in February 2009. The MPUC approved a rate of return on equity of 10.43% on a capital structure with 50.0% equity. An interim rate increase of 5.4% was in effect from November 30, 2007 through January 31, 2009. Amounts refundable totaling $4.4 million had been recorded as a liability on the Company's consolidated balance sheet as of January 31, 2009. OTP refunded Minnesota customers the difference between interim and final rates, with interest, in March 2009. In June 2008, OTP deferred recognition of $1.5 million in rate case-related regulatory assessments and fees of outside experts and attorneys that are subject to amortization and recovery over a three-year period beginning in February 2009.

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 Next Generation Energy Act of 2007, passed by the Minnesota legislature in May 2007, transitions from a conservation spending goal to a conservation energy savings goal. A statewide energy conservation goal of 1.5% of the historical three-year weather normalized average megawatt hour (mwh) retail sales was set for 2010. OTP filed its plan to achieve these goals on June 1, 2008 for implementation in 2009 and 2010.

The MNOES 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 MNOES 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. Since 1995, OTP has recovered conservation related costs not included in base rates under Minnesota's Conservation Improvement Programs through the use of an annual recovery mechanism approved by the MPUC.

Minnesota law requires utilities to submit to the MPUC for approval a 15-year advance integrated resource plan (IRP). 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. OTP submitted its most recent IRP on July 1, 2005. On January 15, 2009 the MPUC approved OTP's 2006-2020 IRP in its entirety. On June 2, 2009 the MPUC issued an order denying reconsideration, thus finalizing the IRP. This 2006-2020 IRP includes new renewable wind generation, significant demand-side management including conservation, new baseload (which included the cancelled Big Stone II power plant), natural gas-fired peaking plants and wholesale energy purchases. Capacity additions approved in accordance with Minnesota rules in the 2006-2020 IRP, excluding baseload generation for the cancelled Big Stone II, are as follows:

Resource	Approved MW
Natural gas	200 MW
Wind	280 MW
Demand-Side Management	100 MW

On September 24, 2009 the MPUC issued an order granting OTP's request to extend the next OTP resource plan filing deadline to July 1, 2010.

The Minnesota legislature has enacted a statute that favors conservation over the addition of new resources. In addition, it 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. It has effectively prohibited the building of new nuclear facilities. 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 rate recovery therefrom, and may not approve any nonrenewable energy facility in an integrated resource plan, 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. On October 8, 2009, the MPUC established an estimate of the range of costs of future carbon dioxide (CO_2) regulation to be used in modeling analyses for resource plans. The MPUC updates these estimates as appropriate. The current estimate is $9 to $34/ton of CO_2.

In February 2007, the Minnesota legislature passed a renewable energy standard requiring 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: 12% by 2012; 17% by 2016; 20% by 2020 and 25% by 2025. Additionally, Minnesota law requires utilities to make a good faith effort to generate or procure sufficient renewable generation such that 7% of total retail electric sales to retail customers in Minnesota come from qualifying renewable sources by 2010. Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards. OTP has acquired renewable resources and expects to acquire additional renewable resources in order to maintain compliance with the Minnesota renewable energy standard. OTP has sufficient renewable energy resources available and in service to comply with the required 2016 level of the Minnesota renewable energy standard. 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 standards. 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.

In an order issued on August 15, 2008, the MPUC approved OTP's proposal to implement a Renewable Resource Cost Recovery Rider for its Minnesota jurisdictional portion of investment in qualifying renewable energy facilities. The rider enables OTP to recover from its Minnesota retail customers its investments in owned renewable energy facilities and provides for a return on those investments. The Minnesota Renewable Resource Adjustment (MNRRA) of $0.0019 per kwh was included on Minnesota customers' electric service statements beginning in September 2008, reflecting cost recovery for OTP's twenty-seven 1.5 MW wind turbines and collector system at the Langdon Wind Energy Center, which became fully operational in January 2008.

The MPUC approved OTP's petition for a 2009 MNRRA in July 2009, which increased the MNRRA rate to provide cost recovery for its 32 wind turbines at the Ashtabula Wind Energy Center that became commercially operational in November 2008. This approval increased the 2009 MNRRA to $0.00415 per kwh for the recovery of $6.6 million through March 31, 2010—$4.0 million from August through December 2009 and $2.6 million from January through March 2010. The approval also granted OTP authority to recover, over a 48-month period beginning in April 2010, accrued renewable resource recovery revenues that had not previously been recovered. On January 12, 2010, the MPUC issued an order finding OTP's Luverne Wind Farm project eligible for cost recovery through the MNRRA. The 2010 annual MNRRA cost recovery filing was made on December 31, 2009 with a requested effective date of April 1, 2010.

In addition to the Renewable Resource Cost Recovery Rider, the Minnesota Public Utilities 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 otherwise deemed eligible by the MPUC. Such transmission cost recovery riders allow a return on investments 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 request for approval of a transmission cost recovery rider was granted by the MPUC on January 7, 2010, and became effective February 1, 2010. Beginning February 1, 2010, OTP's transmission rider rate is reflected on Minnesota customer electric service statements at $0.00039 per kwh plus $0.035 per kW for large general service customers and $0.00007 per kwh for controlled service customers, $0.00025 per kwh for lighting customers, and $0.00057 per kwh for all other customers.

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

OTP and a coalition of six other electric providers filed an application for a CON for the Minnesota portion of the Big Stone II transmission line project on October 3, 2005 and filed an application for a Route Permit for the Minnesota portion of the Big Stone II transmission line project with the MPUC on December 9, 2005. On January 15, 2009, the MPUC approved, by a vote of 5-0, a motion to grant the CON and Route Permit for the Minnesota portion of the Big Stone II transmission line.

The MPUC granted the CON subject to a number of additional conditions, including but not limited to: (1) fulfilling various requirements relating to renewable energy goals, energy efficiency, community-based energy development projects and emissions reduction; (2) that the generation plant be built as a "carbon capture retrofit ready" facility; (3) that the applicants report to the MPUC on the feasibility of building the plant using ultra-supercritical technology; and (4) that the applicants achieve specific limits on construction costs at $3,000/kW and CO_2 costs at $26/ton.

The CON and Route Permit, required by state law, would have allowed the Big Stone II utilities to construct and upgrade 112 miles of electric transmission lines in western Minnesota for delivery of power from the Big Stone site and from numerous other planned generation projects, most of which are wind energy.

Following OTP's September 11, 2009 withdrawal from the Big Stone II project and the remaining Big Stone II participants' November 2, 2009 cancellation of the project, the suitability of the route permits and easements obtained by OTP as a MISO transmission owner for other interconnection customers backfilling through the MISO interconnection process into the Big Stone area continues to be evaluated.

On December 14, 2009 OTP filed a request with the MNPUC for deferred regulatory accounting treatment for the costs incurred related to the cancelled Big Stone II plant. If the MNPUC denies the request to use deferred accounting or eventually denies recovery of all or any portion of the deferred costs, the costs would be subject to expense in the period they are deemed to be inappropriate for deferral or unrecoverable.

The Minnesota legislature enacted the Minnesota Energy Security and Reliability Act in 2001. Its primary focus was to streamline the siting and routing processes for the construction of new electric generation and transmission projects. The bill also added to utility requirements for renewable energy and energy conservation. The legislation later transferred environmental review authority from the Environmental Quality Board to the MNDOC.

Planning studies have shown there will be significant electric load growth and more transmission will be necessary for renewable energy in the coming decade. The study resulted in a joint transmission planning initiative among eleven utilities that own transmission lines in Minnesota and the surrounding region, called CapX 2020 — capacity expansion by 2020. On August 16, 2007 the eleven CapX 2020 utilities asked the MPUC to determine the need for three 345-kV transmission lines. These lines would help ensure continued reliable electricity service in Minnesota and the surrounding region by upgrading and expanding the high-voltage transmission network and providing capacity for more wind energy resources to be developed in southern and western Minnesota, eastern North Dakota and South Dakota. The proposed lines would span more than 600 miles and represent one of the largest single transmission initiatives in the region in several years. Evidentiary hearings for the CON for the three CapX 2020 345-kV transmission line projects began in July 2008 and continued into August 2008. On April 16, 2009 the MPUC approved the CON for the three 345-kV Group 1 CapX 2020 line projects (Fargo-St. Cloud, Brookings-Southeast Twin Cities, and Twin Cities-LaCrosse). The MPUC then voted to impose conditions pertaining to reserving line capacity for renewable energy sources on the Brookings line project. The MPUC did take up reconsideration of the original order regarding the conditions and, on deliberation, the MPUC slightly modified the conditions on the Brookings line. As part of the CON approval, the MPUC accepted a CapX 2020 request to build the 345-kV lines for double-circuit capability to have two 345-kV transmission circuits on each structure. The current plan is to string only one circuit. The MPUC CON orders were appealed to the Minnesota Court of Appeals on October 9, 2009 and the appellate court's determination is expected to be made in the fall of 2010. Route permit applications were filed in Minnesota for the Brookings project in late December 2008. The route permit for the Monticello to St. Cloud portion of the Fargo project was filed in April 2009 and is anticipated to be received in mid-2010. The Minnesota route permit for the St. Cloud to Fargo portion of the Fargo Project was filed on October 1, 2009. Portions of the projects would also require approvals by federal officials and by regulators in North Dakota, South Dakota and Wisconsin. After regulatory need is established and routing decisions are completed, construction will begin. The lines would be expected to be completed over a period of two to four years. Great River Energy and Xcel Energy are leading these projects, and OTP and eight other utilities are involved in permitting, building and financing. OTP is directly involved in two of these three 345-kV projects.

OTP serves as the lead utility in a fourth CapX 2020 Group 1 project, the Bemidji-Grand Rapids 230-kV line, which has an expected in-service date of 2012-2013. OTP filed a CON for this fourth project on March 17, 2008. The MNOES staff completed briefing papers regarding the Bemidji-Grand Rapids route permit application. The MNOES staff recommended to the MPUC that: (1) the route permit application be found to be complete, (2) the need determination not be sent to a contested case but be handled informally by MPUC review, and (3) the CON and route permit proceedings be combined as requested. The MPUC met on June 26, 2008 to act on the MNOES staff recommendation. The MPUC agreed that the CON and route permit applications were complete. The MNOES subsequently recommended a determination that need for the line has been established. An environmental report for the CON was issued in April 2009. CON hearings were conducted on May 20 and May 21, 2009 and a summary of comments was issued on June 8, 2009. The CON was issued on July 9, 2009 and the written order received on July 14, 2009. The applicants continue to work with the MNOES to define the schedule for issuance of the draft environmental impact statement (EIS) and the route contested case hearing. The route hearing is expected to occur in early 2010. The MPUC is expected to determine the route for this line and, if appropriate, issue a route permit in fall 2010. A federal EIS also will be needed for this project.

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. OTP’s current capital structure petition is in effect until the MPUC issues a new capital structure order for 2010. The MPUC ordered OTP to file its 2010 capital structure petition by the end of March 2010.

North Dakota

OTP is subject to the jurisdiction of the NDPSC with respect to rates, services, certain issuances of securities 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 new electric power generating plants exceeding 60,000 kW and proposed new transmission lines with a design in excess of 115 kV. OTP is required to submit a ten-year plan to the NDPSC annually.

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 Securities and Exchange Commission is expressly exempted from review by the NDPSC under North Dakota state law.

On May 21, 2008 the NDPSC approved OTP’s request for a Renewable Resource Cost Recovery Rider to enable OTP to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. The North Dakota Renewable Resource Cost Recovery Rider Adjustment (NDRRA) of $0.00193 per kwh was included on North Dakota customers’ electric service statements beginning in June 2008, and reflects cost recovery for OTP’s twenty-seven 1.5 MW wind turbines and collector system at the Langdon Wind Energy Center, which became fully operational in January 2008. The rider also allows OTP to recover costs associated with other new renewable energy projects as they are completed. OTP included investment costs and expenses related to its 32 wind turbines at the Ashtabula Wind Energy Center that became commercially operational in November 2008 in its 2009 annual request to the NDPSC to increase the amount of the NDRRA. An NDRRA of $0.0051 per kwh was approved by the NDPSC on January 14, 2009 and went into effect beginning with billing statements sent on February 1, 2009.

On November 3, 2008 OTP filed a general rate case in North Dakota requesting an overall revenue increase of approximately $6.1 million, or 5.1%, and an interim rate increase of approximately 4.1%, or $4.8 million annualized, that went into effect on January 2, 2009. In an order issued by the NDPSC on November 25, 2009 OTP was granted an increase in North Dakota retail electric rates of $3.6 million, or approximately 3.0%, which went into effect in December 2009. The NDPSC order authorizing an interim rate increase required OTP to refund North Dakota customers the difference between final and interim rates, with interest. OTP established a refund reserve for revenues collected under interim rates that exceeded the final rate increase. The refund reserve balance was $0.9 million as of December 31, 2009, which was refunded to North Dakota customers in January 2010. OTP deferred recognition of $0.5 million in rate case-related filing and administrative costs that are subject to amortization and recovery over a three-year period beginning in January 2010.

In a proceeding that was combined with OTP’s general rate case, the NDPSC reviewed whether to move the costs of the projects currently being recovered through the NDRRA into base rate cost recovery and whether to make changes to the rider. A settlement of the general rate case and the NDRRA reduced the NDRRA to $0.00369 for the period from December 1, 2009, until the effective date for the next annual NDRRA filing, requested to be April 1, 2010. Because the 2008 annual

NDRRA filing was combined with the general rate case proceedings (concluded in November 2009), the 2009 annual filing to establish the 2010 NDRRA rate (which includes cost recovery for OTP's investment in its Luverne Wind Farm project) was delayed until December 31, 2009, with a requested effective date of April 1, 2010. Terms of the approved settlement provide for the recovery of accrued but unbilled NDRRA revenues over a period of 48 months beginning in January 2010.

North Dakota legislation also 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 requested recovery of such costs in its general rate case filed in November 2008, and was granted recovery of such costs by the NDPSC in its November 25, 2009 order.

In February 2005, OTP filed a petition with the NDPSC to seek recovery of certain MISO-related costs through the fuel clause adjustment (FCA) in North Dakota. The NDPSC granted interim recovery through the FCA in April 2005, but conditioned the relief as being subject to refund until the merits of the case are determined. In August 2007, the NDPSC approved a settlement agreement between OTP and an intervener representing several large industrial customers in North Dakota. Under the approved settlement agreement, OTP refunded $493,000 of MISO schedule 16 and 17 costs collected through the FCA from April 2005 through July 2007 to North Dakota customers beginning in October 2007 and ending in January 2008. OTP deferred recognition of these costs plus $330,000 in MISO schedule 16 and 17 costs incurred from August 2007 through December 2008 and requested recovery of these deferred costs in its general rate case filed in North Dakota in November 2008. OTP began amortizing its deferred MISO schedule 16 and 17 costs in North Dakota over a 36-month period beginning in December 2009 in conjunction with the implementation of rates approved by the NDPSC in its November 25, 2009 order. As of December 31, 2009 the balance of OTP's deferred MISO schedule 16 and 17 costs was $1,091,000. Base rate recovery for on-going MISO schedule 16 and 17 costs was also approved by the NDPSC in its November 25, 2009 order.

A filing in North Dakota for an advance determination of prudence of Big Stone II was made by OTP in November 2006. 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. The NDPSC decision was appealed to Burleigh County District Court by interveners in the matter, which affirmed the NDPCS's decision in August 2009. The interveners appealed to the North Dakota Supreme Court in November 2009. In its August 27, 2008 decision, the NDPSC also ordered OTP to file, for approval, proposals to implement demand-side management and conservation programs identified as more economic resources than Big Stone II. This filing was submitted in February 2009. 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. North Dakota's advance determination of prudence statute allows a utility to recover costs, and a reasonable return on the costs pending recovery, for a project previously deemed prudent and for which the NDPSC later makes a determination that continuing with the project was no longer prudent. The above-referenced intervener appeal of the NDPSC's initial advance determination of prudence for Big Stone II has been suspended pursuant to an agreement of the parties, pending the outcome of OTP's subsequent request for a determination that continuing with the project would not have been prudent.

On December 14, 2009 OTP filed a request with the NDPSC for deferred regulatory accounting treatment for the costs incurred related to cancelled Big Stone II plant. The NDPSC has appointed an administrative law judge. OTP expects a possible hearing on this request in May 2010. If the NDPSC denies the request to use deferred accounting or eventually denies recovery of all or any portion of the deferred costs, the costs would be subject to expense in the period they are deemed to be inappropriate for deferral or unrecoverable.

On October 5, 2009, OTP filed an application for an advance determination of prudence with the NDPSC for its proposed participation in three of the four Group 1 CapX 2020 transmission line projects (Fargo-St. Cloud, Brookings-Southeast Twin Cities, and Bemidji-Grand Rapids). An administrative law judge has been assigned to conduct a hearing that is currently scheduled for April 2010.

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, establishment of assigned service areas and other matters. OTP is not currently subject to the jurisdiction of the SDPUC with respect to the issuance of securities. 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.

On October 31, 2008 OTP filed a general rate case in South Dakota requesting an overall revenue increase of approximately $3.8 million, or 15.3%, which included, among other things, recovery of investments and expenses relating to renewable resources in base rates. OTP increased rates by approximately 11.7% on a temporary basis beginning with electricity consumed on and after May 1,2009, as allowed under South Dakota law. In an order issued by the SDPUC on June 30, 2009 OTP was granted an increase in South Dakota retail electric rates of $2.9 million, or approximately 11.7%. OTP implemented final, approved rates in July 2009.

On December 14, 2009 OTP filed a request with the SDPUC for deferred regulatory accounting treatment for the costs incurred related to cancelled Big Stone II plant. On February 9, 2010 the SDPUC approved the deferred accounting treatment for the South Dakota jurisdictional portion of the costs. OTP will request recovery of and a return on these costs during the filing of its next general rate case. If the SDPUC would deny recovery of all or any portion of the deferred costs, the costs would be subject to expense in the period they are deemed to be unrecoverable.

On January 4, 2007 the SDPUC encouraged all investor-owned utilities in South Dakota to be part of an Energy Efficiency Partnership to significantly reduce energy use. On July 28, 2008 the SDPUC approved OTP's energy efficiency plan for South Dakota customers. The plan is being implemented with program costs, carrying costs and a financial incentive being recovered through an approved rider.

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, which has 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.

On October 30, 2009, OTP filed a request with the FERC for approval of various transmission infrastructure investment incentives and proposed revisions to OTP's transmission formula rate under Attachment O of the MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff. OTP requested recovery of (1) 100% of prudently incurred Construction Work in Progress (CWIP) in rate base, and (2) 100% prudently incurred costs of transmission facilities that are cancelled or abandoned for reasons beyond OTP's control (Abandoned Plant Recovery). In addition, OTP proposed changes to its Attachment O — OTP to recover its revenue requirement under a forward-looking formula rate using projected test period cost inputs with an annual true-up, rather than a formula rate based on historic test period data. On December 30, 2009, the FERC issued an order approving OTP's request for 100% CWIP recovery and 100% Abandoned Plant Recovery for OTP's proposed investment in the CapX 2020 transmission projects (Fargo project, Bemidji project and Brookings project) to be effective January 1, 2010. In addition, the FERC conditionally approved OTP's request for using a forward looking Attachment O under the MISO Tariff to be effective January 1, 2010 pending the completion of a compliance filing.

Revenue Sufficiency Guarantee (RSG) Charges : Since 2006, OTP has been a party to litigation before the FERC regarding the application of RSG charges to market participants who withdraw energy from the market or engage in financial-only, virtual sales of energy into the market or both. These litigated proceedings occurred in several electric rate and complaint dockets before the FERC and several of the FERC's orders are on review before the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit).

On November 7, 2008 the FERC issued an order on rehearing and compliance in the RSG proceeding, reversing its determination in a prior order and stating that MISO should remove the volume of virtual supply offers of market participants—not physically withdrawing energy—from the denominator of the rate calculation from April 25, 2006 forward. MISO interpreted the order to mean that all virtual supply offers and deviations in the denominator of the rate calculation that do not ultimately pay the rate should be removed from April 1, 2005 (start of the Energy Market) forward. On November 10, 2008 the FERC issued an order finding the current RSG rate unjust and unreasonable and accepting an interim rate that applied RSG charges to all virtual sales until such time as MISO makes a subsequent filing of the new RSG rate.

On May 6, 2009 the FERC issued an order on rehearing of the November 10, 2008 order. The May order relieved MISO from having to resettle RSG payments resulting from the FERC's earlier decision to remove the words "actually withdraws energy" (AWE) from the RSG tariff provisions. Absent this relief (or waiver), the removal of the AWE language would have had two relevant impacts on the RSG charge: (1) it would tend to reduce the RSG rate because the rate denominator would include all virtual supply volumes and (2) it would impose RSG charges on all cleared virtual supply transactions. The waiver applies to the period August 10, 2007 through November 9, 2008. Beginning November 10, 2008, the MISO is obliged to resettle RSG charges by recalculating the RSG rate and impose RSG charges on all virtual supply transactions.

On June 12, 2009 the FERC issued an order on rehearing of the November 7, 2008 order. The June order, at a minimum, relieved MISO from having to resettle RSG payments resulting from any difference between the mwhs associated with virtual supply in the denominator of the RSG rate and the billing determinants associated with virtual supply transactions (VSO mismatch). This relief (or waiver) applies to the period April 25, 2006 through November 4, 2007. Since OTP would have had a payment obligation during this period associated with the virtual supply and other mismatches, the June order eliminates that payment obligation. However, the June order, like many of the other orders in this docket, is subject to appellate review and potential reversal. Beginning from November 5, 2007, MISO is obligated to resettle to correct the VSO mismatch. As of September 30, 2009, OTP had paid all its resettlement obligations determined and imposed by MISO. On August 7, 2009 the FERC issued an order requiring MISO's RSG Task Force to develop a recommendation on any transactions that should be exempted from paying RSG charges. The RSG Task Force has completed its review and provided recommendations to the FERC. The Company does not know when these litigation proceedings will conclude.

The Comprehensive Energy Policy Act of 2005 (the 2005 Energy Act), signed into law in August 2005, substantially affected the regulation of energy companies, including OTP. The 2005 Energy Act amended federal energy laws and provided the FERC with new oversight responsibilities. Among the important changes implemented as a result of this legislation were the following:

- The Public Utility Holding Company Act of 1935 (PUHCA) was repealed effective February 8, 2006. PUHCA significantly restricted mergers and acquisitions in the electric utility sector.
- FERC was authorized to create an Electric Reliability Organization (ERO) to establish and enforce mandatory reliability rules regarding the interstate electric transmission system. In July 2006, FERC approved the application of the North American Electric Reliability Corporation (NERC) to become the ERO for the United States. On January 1, 2007 the ERO began operating.
- The FERC established incentives for transmission companies, such as performance based rates, recovery of costs to comply with reliability rules and accelerated depreciation for investments in transmission infrastructure.
- Federal support was made available for certain clean coal power initiatives, nuclear power projects and renewable energy technologies.

MEMA

OTP is a member of the Mid-Continent Energy Marketers Association (MEMA) which is an independent, non-profit trade association representing entities involved in the marketing of energy or in providing services to the energy industry. MEMA operates in the MAPP, MISO, Southwest Power Pool, PJM Interconnection, LLC and Southeast regions and was formed in 2003 as a successor organization of the Power and Energy Market of MAPP. Power pool sales are conducted continuously through MEMA in accordance with schedules filed by MEMA with the FERC.

MRO

OTP is a member of the Midwest Reliability Organization (MRO). The MRO, a non-profit organization, is one of eight Regional Reliability Councils that comprise the NERC. The MRO operates to ensure the reliability of the bulk power system in the Midwest part of North America. The MRO, through its balanced stakeholder board with independent oversight, operates independently from any member, market participant or operator, so that the standards developed and enforced by the MRO are fair and administered without undue influence from market participants. The MRO is approximately 40% larger in terms of net end use load than MAPP. The MRO region includes more than 40 members supplying approximately 280 million mwhs to more than 20 million people. Its membership is comprised of municipal utilities, cooperatives, investor-owned utilities, a federal power marketing agency, Canadian Crown Corporations and independent power producers.

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 13 states and the Canadian province of Manitoba. The MISO began operational control of OTP's transmission facilities above 100 kV on February 1, 2002 but OTP continues to own and maintain its transmission assets.

The MISO Energy Markets commenced operation on April 1, 2005. Through its 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) commenced on January 6, 2009. The market 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.

In December 2008 pursuant to the provisions of the MISO Transmission Owners Agreement, OTP sent MISO a letter of intent to withdraw from MISO on or after December 31, 2009. This procedural step was taken to allow OTP the earliest available opportunity to withdraw from MISO if its concerns about the unintended consequences produced by the MISO Tariff, which imposed a disproportionate allocation of charges to its customers, attributable to the allocation of costs for transmission network upgrades, cannot be equitably resolved. Withdrawal from MISO would require OTP to either secure replacement of and/or self-provide the services currently provided by MISO. In December 2009, OTP provided MISO notice that it was reaffirming its notice of intent to withdraw given the on-going uncertainty around the potential for large negative impacts on OTP customers.

MAPP

OTP had been a participant in the MAPP generation reserve sharing pool, which operates in parts of eight states in the Upper Midwest and in three provinces in Canada. As a result of the start up of the ASM, OTP withdrew from the generation reserve sharing pool of MAPP as of March 1, 2009. The MAPP generation reserve sharing pool provided for, among other things, the contingency reserves necessary to meet certain major events such as the loss of a large generating unit or a transmission line.

Other

OTP is subject to various federal and state laws, including the Federal 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 2005 Energy Act described above.

The holding company reorganization was subject to, and received approvals from, the MPUC, NDPSC, SDPUC, and FERC.

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. OTP may also face competition as the restructuring of the electric industry evolves.

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 which would regulate holding companies doing business within the state that include in the ownership chain a public utility. Proposed legislation in 2009 would have foreclosed public utilities, or holding companies of which public utilities are members, from acquiring an interest in a company that is not a public utility or that does not receive 50 percent or more of its revenue from electric or gas utility-related business. This legislation, which failed, could have limited the Company’s ability to maintain and grow its nonelectric businesses.

OTP’s 49.5 MW portion of the Luverne Wind Farm, which achieved commercial operation in September 2009, benefited from the American Recovery and Reinvestment Act of 2009 (ARRA). OTP received $30.2 million under provisions authorized by the ARRA, and this sum was used to partially finance OTP’s investment in its portion of the Luverne Wind Farm.

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, 2009 OTP invested approximately $17.8 million in environmental control facilities. The 2010 construction budget includes approximately $0.5 million for environmental equipment for existing facilities.

Air Quality : Pursuant to the Federal Clean Air Act (the CAA), the Environmental Protection Agency (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 turbine generator, which is the smallest of the three coal-fired units at Hoot Lake Plant, was retired as of December 31, 2005. OTP has retained the unit 1 boiler for use as a source of emergency heat. A fabric filter collects particulates from stack gases on Hoot Lake Plant unit 1. As a result, OTP believes the units at the Hoot Lake Plant currently meet all presently applicable federal and state air quality and emission standards.

During the fall 2007 maintenance outage at the Big Stone Plant, the demonstration project Advanced Hybrid™ technology was replaced with a pulse jet baghouse. The South Dakota Department of Environment and Natural Resources issued a Title V Operating Permit to the Big Stone site on June 9, 2009 allowing for operation of both the existing Big Stone Plant and Big Stone II. On August 3, 2009 the Sierra Club and Clean Water Action petitioned the EPA to object to certain Title V permit provisions applicable to Big Stone II. The Big Stone Plant Title V permit provisions were unchallenged and Big Stone Plant continues to operate under those 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 SO_2 emission reduction goals are achieved through a market based system under which power plants are allocated "emissions allowances" that will 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.

The national NO_x emission reduction goals are achieved by imposing mandatory emissions standards on individual sources. In order to meet the national NO_x emission standards required at the Hoot Lake Plant unit 2 in 2008, OTP installed low NO_x burners and over-fire air in the first quarter of 2008, enabling the unit to meet the annual average emission rate. The remaining generating units meet EPA NO_x emission regulations. All of OTP's generating facilities met the NO_x standards during 2009.

The EPA Administrator signed the final Interstate Air Quality Rule, also known as 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 non-attainment.

Twenty-three states and the District of Columbia were found to contribute to ambient air quality PM2.5 non-attainment 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 for emissions caps. Twenty-five states were found to contribute to downwind 8-hour ozone non-attainment. None of the states in OTP's service territory were slated for NO_x reduction for ambient air quality 8-hour ozone non-attainment purposes. On July 11, 2007, 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 and remanded the case for the EPA to conduct further proceedings consistent with the court's prior opinion. The court did not impose a definitive deadline by which the EPA must correct CAIR, although the EPA informed the Court that development and finalization of the replacement CAIR rule could take place by mid-2011. 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 conducts 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. Given the uncertainty of whether Minnesota will be included in CAIR as a result of future EPA rulemaking, the impact on OTP facilities is uncertain at this time. Nonetheless, NO_x emissions control equipment has been installed on Hoot Lake Plant unit 2 as described above, and was installed on unit 3 in 2006 in anticipation of having to meet CAIR requirements.

The CAA calls for the EPA to study the effects of emissions of listed pollutants by electric steam generating plants. The EPA has completed the studies and submitted reports to Congress. The CAA required the EPA to make a finding as to whether regulation of emissions of hazardous air pollutants from fossil fuel-fired electric utility generating units is appropriate and necessary. On December 14, 2000 the EPA announced it affirmatively decided to regulate mercury emissions from electric generating units. The EPA published the proposed mercury rule on January 30, 2004. The proposal included two options for regulating mercury emissions from coal-fired electric generating units. One option would set technology-based maximum achievable control technology standards under paragraph 111(d) of the CAA. The other option embodied a market-based cap and trade approach to emissions reduction. The EPA published final rules in May 2005 based on the cap and trade approach. On October 28, 2005 the EPA announced a reconsideration of portions of the final rules. Final rules were published on June 9, 2006 that maintained the cap and trade approach. On February 8, 2008 the United States Court of Appeals for the D.C. Circuit granted petitions for review of the EPA rules and vacated the rules that would have allowed the EPA to regulate mercury emissions based on a cap and trade approach. On March 14, 2008 the U.S. Court of Appeals for the D.C. Circuit issued a mandate vacating the EPA final rule regulating utility mercury emissions. The EPA appealed the court's decision to the U.S. Supreme Court, but withdrew its appeal in early 2009. The Supreme Court denied the appeals of other parties to the litigation on February 23, 2009. The EPA rulemaking is slated to proceed under the maximum achievable control technologies (MACT) provision of the CAA section 112(d) for existing units and section 112(g) case-by-case MACT provisions for affected new units. EPA and petitioners have agreed to a schedule where EPA would adopt final MACT rules that regulate hazardous air pollutants, including mercury, by November 16, 2011. OTP anticipates that the MACT standard may require installation of control technology at its power plants, but it cannot determine what will ultimately be required to meet the EPA's final standard. Given the potential for legal challenges and regulatory uncertainties associated with EPA's revised rulemaking, it is not possible to assess to what extent the EPA rulemaking will impact OTP.

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 their 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. At this time, OTP cannot determine what, if any, actions will be taken by the EPA.

On November 20, 2006, the Sierra Club notified OTP and the two other Big Stone Plant co-owners of its intent to sue alleging violations of the Prevention of Significant Deterioration (PSD) requirements of the CAA at the Big Stone Plant with respect to three past plant activities. On June 10, 2008 the Sierra Club filed a complaint in the U.S. District Court for the District of South Dakota (Northern Division) against the Company and two other co-owners of the Big Stone Plant. The complaint alleges certain violations of the PSD and New Source Performance Standards (NSPS) provisions of the CAA and certain violations of the South Dakota State Implementation Plan (South Dakota SIP). The action further alleges the defendants modified and operated Big Stone without obtaining the appropriate permits, without meeting certain emissions limits and NSPS requirements and without installing appropriate emission control technology, all allegedly in violation of the CAA and the South Dakota SIP. The Sierra Club alleges the defendants' actions have contributed to air pollution and visibility impairment and have increased the risk of adverse health effects and environmental damage. The Sierra Club seeks both declaratory and injunctive relief to bring the defendants into compliance with the CAA and the South Dakota SIP and to require the defendants to remedy the alleged violations. The Sierra Club also seeks unspecified civil penalties, including a beneficial mitigation project. The Company believes these claims are without merit and that Big Stone has been and is being operated in compliance with the CAA and the South Dakota SIP. OTP and the co-owners filed a motion to dismiss the citizen's suit. On March 31, 2009, the District Court granted the Big Stone Plant co-owners' motion to dismiss the Sierra Club's citizen suit against the co-owners for alleged violations of the PSD provisions of the CAA, the South Dakota SIP, and the NSPS of the CAA. On April 17, 2009 Sierra Club filed a Motion for Reconsideration of the Amended Memorandum and Order dated April 6, 2009. The District Court denied the motion on July 22, 2009. On July 30, 2009, the Sierra Club appealed the District Court's decision to the U. S. Court of Appeals for the 8th Circuit. On October 13, 2009, the United States Department of Justice filed a motion seeking a 30-day extension of the time to file an amicus brief in support of the Sierra Club's position. The State of South Dakota Department of Environment and Natural Resources is also participating in the appeal as an amicus, and has filed a brief in support of the District Court's dismissal of a claim relating to one of the past plant activities. Briefing was completed on January 22, 2010 upon the filing of the Sierra Club reply brief. The ultimate outcome of these matters cannot be determined at this time.

On September 22, 2008, the Sierra Club notified OTP and the two other Big Stone Plant co-owners of its intent to sue alleging violations of the PSD and NSPS requirements of the CAA with respect to two past plant activities. The Sierra Club stated that unless the matter is otherwise fully resolved, it intended to file suit in the applicable district courts any time 60 days after the September 22, 2008 letter. As of the date of this report the Sierra Club has not filed suit in the applicable district courts as contemplated in the September 22, 2008 notification. OTP believes that the Big Stone Plant is in material compliance with all applicable requirements of the CAA.

On June 15, 2005 the EPA signed the Regional Haze Best Available Retrofit Technology (BART) rule. The rule requires emissions reductions from designated sources that are deemed to contribute to visibility impairment in Class I air quality areas. The Big Stone Plant is potentially subject to emission reduction requirements. At the request of the South Dakota Department of Environment and Natural Resources (DENR), OTP agreed to model Big Stone Plant emissions to evaluate the impact of plant emissions on Class I air quality areas. The modeling effort was completed and the final report submitted to the DENR on March 19, 2008. The report was not acceptable to all parties and DENR requested that OTP submit a BART modeling protocol that was acceptable to DENR, EPA, and other federal land management agencies. OTP submitted a modeling protocol in June 2009 and committed to making certain changes to the protocol in August 2009. On September 18, 2009 DENR approved the modeling protocol and on November 2, 2009 OTP submitted to DENR its analysis of what control technology should be considered BART for NO_X, SO_2, and particulate matter for the Big Stone Plant. In that filing, OTP estimated the cost of BART technologies to be approximately $146 million for the Big Stone Plant (OTP's share would be 53.9%).

On January 15, 2010, the DENR provided OTP with a copy of South Dakota's draft proposed Regional Haze State Implementation Plan (SIP). Comments are requested on or before March 16, 2010. South Dakota's draft proposed Regional Haze SIP recommends the sulfur dioxide and particulate matter emission control technology and emission rates that generally followed OTP's BART analysis. The DENR recommended a Selective Catalytic Reduction (SCR) technology for NOx emission reduction instead of the OTP-recommended separated over-fire air. OTP estimates the cost of the BART technologies based on the DENR proposal to be approximately $223 million for Big Stone Plant (OTP's share would be 53.9%). The DENR proposes to require that BART be installed and operating as expeditiously as practicable, but no later than five years from EPA's approval of the South Dakota Regional Haze SIP, which is expected no later than January 15, 2011.

The Coyote Station is subject to certain emission limitations under the PSD program of the CAA. The EPA and the North Dakota Department of Health reached an agreement to identify a process for resolving several issues relating to the modeling protocol for the state's PSD program. Modeling was completed and the results were submitted to the EPA for its review. On April 19, 2005 the North Dakota Department of Health held a Periodic Review Hearing relating to the PSD Air Quality Modeling Report that was submitted to the EPA. One of the Hearing Officer's Findings and Conclusion was that the air quality relating to impacts of SO_2 emissions is being adequately protected and that at 2002-2003 SO_2 emission levels the relevant Class I increments are not violated.

The issue of global climate change and the connection between global warming and increased levels of CO_2—a greenhouse gas (GHG)—in the atmosphere is receiving significant attention. Combustion of fossil fuels for the generation of electricity is a major 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 generating capability of 679 MW. In 2009, these plants emitted approximately 3.7 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. Debate continues in Congress on the direction and scope of U.S. policy on climate change and regulation of GHGs. Although several bills have been introduced in Congress that would compel reductions in CO_2 emissions (for example, the U.S. House of Representatives on June 26, 2009 passed the American Clean Energy and Security Act of 2009, also known as Waxman-Markey, and the Clean Energy Jobs and American Power Act, also known as Kerry-Boxer, was introduced in the U.S. Senate on September 30, 2009), there are presently no federal mandatory GHG reduction requirements. 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 sent the case back to 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. The first step in the EPA rulemaking process was the publication of an endangerment finding in the December 15, 2009 Federal Register where EPA found that CO_2 and five other GHGs — methane, NO_x, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride — threaten public health and the environment.

The EPA's final findings respond to the 2007 U.S. Supreme Court decision that GHGs fit within the CAA's definition of air pollutants. The findings do not in and of themselves impose any emission reduction requirements but rather allow the EPA to finalize the GHG standards proposed earlier this year for new light-duty vehicles as part of the joint rulemaking with the Department of Transportation. Once these standards are final, which is expected in early 2010, the EPA is also expected to finalize its New Source Review (NSR) Greenhouse Gas Tailoring Rule (proposed October 27, 2009). NSR requires owners and operators that construct new major sources to obtain permits and install air pollution control equipment at affected facilities. The EPA's proposal would add GHGs to the list of pollutants that must be considered in a Best Available Control Technology analysis. For new sources, the EPA proposed a threshold of 25,000 tons per year of GHGs (CO_2 equivalent), and is considering a range of 10,000 to 25,000 tons per year for modifications to existing sources. These requirements would apply to future projects by OTP if its potential GHG emissions exceed the EPA's thresholds. Unless the Congress enacts legislation directing otherwise, the EPA could begin to regulate GHG emissions under the CAA. Specific requirements of regulation under the CAA's various programs, and thus their impact on OTP, are uncertain at this time.

Although standards have not been developed at the national level, several states and regional organizations are 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 will require retail electricity providers to obtain 25% of the electricity sold to Minnesota customers from renewable sources by the year 2025. 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, has established an estimate of future CO_2 regulation cost at between $4/ton and $30/ton emitted in 2012 and after. Annual updates of the range are required. The MPUC has established the 2009 and 2010 estimates of the likely range of costs of future CO_2 regulation on electricity to be between $9/ton and $34/ton.

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.

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: Between 1990 and 2008, OTP decreased its CO_2 intensity (lbs. of CO_2/mwh generated) by nearly 16%.
- Conservation: Since 1992 OTP has helped its customers conserve more than 1.2 million mwh of electricity. That is roughly equivalent to the amount of electricity that 110,000 average homes would have used in a year. OTP continues to educate customers about energy efficiency and demand-side management and to work with regulators to develop new programs and measurements. OTP's integrated resource plan calls for an additional 100 MW of conservation impacts by 2020.
- Renewable energy: Since 2002, OTP's customers have been able to purchase 100% of their electricity from wind generation through OTP's TailWinds program. Also, 40.5 MW of purchased power agreement wind projects and 138 MW of owned wind resources were on line by December 2009 for serving OTP's customers.
- Other: OTP will continue to participate as a member of the EPA's SF6 (sulfur hexafluoride) Emission Reduction Partnership for Electric Power Systems program. The partnership 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. OTP is studying the potential for certain methane reduction projects. Methane has a global-warming potential 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 more than 80 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 the central interior of North America.

In late 2009, two federal circuit courts of appeal reversed dismissals of GHG nuisance suits and remanded them to district court for trial. OTP is 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, open 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.

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.

On February 16, 2004 the EPA Administrator signed the final Phase II rule implementing Section 316(b) of the Clean Water Act establishing standards for cooling water intake structures for certain existing facilities. Hoot Lake Plant is OTP's only facility that could be impacted by this rule. On January 25, 2007 the U.S. Court of Appeals for the Second Circuit remanded portions of the rule to the EPA. OTP has completed an information collection program for the Hoot Lake Plant cooling water intake structure, but given the Court decision OTP is uncertain of the impact on the facility at this time.

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 either been issued or are under renewal for the Coyote Station, the Big Stone Plant and the Hoot Lake Plant.

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 their Voluntary Investigation and Cleanup 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.

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 2009, approximately $146 million was invested for additions and replacements to its electric utility properties. During the five years ended December 31, 2009 gross electric property additions, including construction work in progress, were approximately $478 million and gross retirements were approximately $56 million. OTP estimates that during the five-year period 2010-2014 it will invest approximately $641 million for electric construction, which includes $245 million for additional generation and $110 million for CapX 2020 transmission projects. The remainder of the 2010-2014 anticipated capital expenditures is for asset replacements, additions and improvements across OTP's generation, transmission, distribution and general plant.

Franchises

At December 31, 2009 OTP had franchises to operate as an electric utility in all but two incorporated municipalities that 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, 2009 OTP had approximately 692 equivalent full-time employees. A total of 416 employees are represented by local unions of the International Brotherhood of Electrical Workers. One labor contract was renewed in January 2010 and has an expiration date in the fall of 2010. The other labor contract was renewed in the fall of 2008 and will expire in the fall of 2011. OTP has not experienced any strike, work stoppage or strike vote, and considers its present relations with employees to be good.

PLASTICS

General

Plastics consists of businesses producing PVC pipe in the Upper Midwest and Southwest regions of the United States. The Company derived 8%, 9% and 12% of its consolidated operating revenues from the Plastics segment for each of the three years ended December 31, 2009, 2008 and 2007, respectively. The Company derived 0%, 5% and 15% of its consolidated net income from the Plastics segment for each of the three years ended December 31, 2009, 2008 and 2007, 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 and Western regions of the United States as well as Central and Western Canada. Production facilities are located in Fargo, North Dakota and Hampton, Iowa.

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, Southwestern and South-central regions of the United States.

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

Customers

PVC pipe products are marketed through a combination of independent sales representatives, company salespersons and customer service representatives. Customers for the PVC pipe products consist primarily of wholesalers and distributors throughout the Upper Midwest, Southwest and Western United States.

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. Over the last several years, there has been consolidation in PVC resin producers. There are a limited number of third party vendors that supply the PVC resin used by Northern Pipe and Vinyltech. Two vendors provided approximately 96% and 94% of total resin purchases in 2009 and 2008, 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 2009, capital expenditures of approximately $4 million were made in the Plastics segment. Total capital expenditures for the five-year period 2010-2014 are estimated to be approximately $11 million. This investment is primarily to replace existing equipment.

Employees

At December 31, 2009 the Plastics segment had approximately 134 full-time employees.

MANUFACTURING

General

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

The Company derived 31%, 36% and 31% of its consolidated operating revenues from the Manufacturing segment for each of the three years ended December 31, 2009, 2008 and 2007, respectively. The Company has one customer within the Manufacturing segment that accounted for approximately 13.6% of the Company’s consolidated revenues in 2009. The Company derived (8)%, 15% and 29% of its consolidated net income from the Manufacturing segment for each of the three years ended December 31, 2009, 2008 and 2007, respectively. Following is a brief description of each of these businesses:

BTD Manufacturing, Inc. (BTD) , with headquarters located in Detroit Lakes, Minnesota, is a metal stamping and tool and die manufacturer that provides its services mainly to customers in the Midwest. BTD stamps, fabricates, welds and laser cuts metal components according to manufacturers’ specifications primarily for the recreational vehicle, gas fireplace, health and fitness and enclosure industries. BTD’s wholly owned subsidiary, Miller Welding and Iron Works, Inc., is located in Washington, Illinois and 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.

DMI Industries, Inc. (DMI) , with headquarters located in West Fargo, North Dakota, manufactures wind towers and other heavy metal fabricated products. DMI has manufacturing facilities in West Fargo, North Dakota; Tulsa, Oklahoma; and Ft. Erie, Ontario, Canada. DMI has a wholly owned subsidiary, DMI Canada, Inc. located in Ft. Erie, Ontario, Canada.

ShoreMaster, Inc. (ShoreMaster), with headquarters in Fergus Falls, Minnesota, produces and markets residential and commercial waterfront equipment, ranging from boatlifts and docks to full marina systems that are marketed throughout the United States. ShoreMaster has four wholly owned subsidiaries, Galva Foam Marine Industries, Inc., Shoreline Industries, Inc., Aviva Sports, Inc., and ShoreMaster Costa Rica Limitada. ShoreMaster has manufacturing facilities located in Fergus Falls, Minnesota; Camdenton and Montreal, Missouri; and St. Augustine, Florida.

T. O. Plastics, Inc. (T.O. Plastics) , located in Minneapolis 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 other industries.

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, ease of use, 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 technologies, cost-effective manufacturing techniques, close customer relations and support, and increasing product offerings.

Raw Materials Supply

The companies in the Manufacturing segment use a variety of raw materials in the products they manufacture, including steel, aluminum, lumber, resin and concrete. 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 the 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 2010 revenues of approximately $239 million compared with $241 million one year ago.

Legislation

The demand for wind towers manufactured by DMI depends in part on the existence of either renewable portfolio standards or a federal production tax credit for wind energy. Renewable portfolio standards or objectives exist in approximately one-half of the states. A federal production tax credit is in place through December 31, 2012.

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 2009, capital expenditures of approximately $19 million were made in the Manufacturing segment driven mainly by the completion of the DMI expansion projects in West Fargo, North Dakota and Tulsa, Oklahoma. Total capital expenditures for the Manufacturing segment during the five-year period 2010-2014 are estimated to be approximately $95 million. This investment is primarily to replace existing equipment at the manufacturing companies.

Employees

At December 31, 2009 the Manufacturing segment had approximately 1,378 full-time employees.

HEALTH SERVICES

General

Health Services consists of the DMS Health Group, which includes businesses involved in the sale of diagnostic medical equipment, patient monitoring equipment and related supplies and accessories. These businesses also provide equipment maintenance, diagnostic imaging services, and rental of diagnostic medical imaging equipment.

The Company derived 10%, 9% and 11% of its consolidated operating revenues from the Health Services segment for each of the three years ended December 31, 2009, 2008 and 2007, respectively. The Company derived (8)%, 1% and 3% of its consolidated net income from the Health Services segment for each of the three years ended December 31, 2009, 2008 and 2007, respectively. The companies comprising the DMS Health Group that deliver diagnostic imaging and healthcare solutions across the United States include:

DMS Health Technologies, Inc. (DMSHT) , located in Fargo, North Dakota, sells and services diagnostic medical imaging equipment, cardiac and other patient monitoring equipment, defibrillators, EKGs and related medical supplies and accessories and provides ongoing service maintenance. DMSHT sells radiology equipment primarily manufactured by Philips Medical Systems (Philips), a large multi-national company based in the Netherlands. Philips manufactures fluoroscopic, radiographic and vascular equipment, along with ultrasound, computerized tomography (CT), magnetic resonance imaging (MR), positron emission tomography (PET), PET/CT and cardiac catheterization labs. The business agreement with Philips expires on December 31, 2013. This agreement can be terminated on 180 days written notice by either party for any reason and can be terminated by Philips if certain compliance requirements are not met. DMSHT is also a supplier of medical film and related accessories. DMSHT markets mainly to hospitals, clinics and mobile imaging service companies.

DMS Imaging, Inc. (DMSI) , a subsidiary of DMSHT located in Fargo, North Dakota, operates diagnostic medical imaging equipment, including CT, MRI, PET and PET/CT and provides nuclear medicine and other similar radiology services to hospitals, clinics, long-term care facilities and other medical providers. Regional offices are located in Minneapolis, Minnesota; Los Angeles, California; and Sioux Falls, South Dakota. DMS Imaging, Inc. provides services through four different business units and one subsidiary:

- DMS Imaging — provides shared diagnostic medical imaging equipment and nonphysician personnel (primarily mobile) for MR, CT, nuclear medicine, PET, PET/CT, ultrasound, mammography and bone density analysis.
- DMS Interim Solutions — offers interim and rental options for diagnostic imaging equipment.
- DMS MedSource Partners — develops long-term relationships with healthcare providers to offer dedicated in-house diagnostic imaging equipment.
- DMS Portable X-Ray — delivers portable x-ray, ultrasound and electrocardiography services to nursing homes and other facilities.
- DMS Health Technologies — Canada, Inc., a subsidiary of DMSI is located in Fargo, North Dakota. It provides limited interim and rental options for diagnostic equipment to Canadian healthcare entities.

Combined, the DMS Health Group covers the three basics of the medical imaging industry: (1) ownership and operation of the imaging equipment for healthcare providers; (2) sale, lease and/or maintenance of medical imaging equipment and related supplies; and (3) scheduling, billing and administrative support of medical imaging services.

Regulation

The healthcare industry is subject to extensive federal and state regulations relating to licensure, conduct of operation, ownership of facilities, payment of services and expansion or addition of facilities and services.

The federal Anti-Kickback Statute prohibits persons from knowingly and willfully soliciting, receiving, offering or providing remuneration, directly or indirectly, to induce the referral of an individual or the furnishing or arranging for a good or service for which payment may be made under a federal healthcare program such as Medicare or Medicaid. Several states have similar statutes. The term “remuneration” has been broadly interpreted to include anything of value, including, for example, gifts, discounts, credit arrangements, payments of cash, waiver of payments and ownership interests. Penalties for violating the Anti-Kickback Statute can include both criminal and civil sanctions as well as possible exclusion from participating in federal healthcare programs.

The Ethics and Patient Referral Act of 1989 (Stark Law) prohibits a physician from making referrals for certain designated health services payable under Medicare, including services provided by the Health Services companies, to an entity with which the physician has a financial relationship, unless certain exceptions apply. The Stark Law also prohibits an entity from billing for designated health services pursuant to a prohibited referral. A person who engages in a scheme to violate the Stark Law or a person who presents a claim to Medicare in violation of the Stark Law may be subject to civil fines and possible exclusion from participation in federal healthcare programs. Several states have similar statutes, the violation of which can result in civil fines and possible exclusion from state healthcare programs. From time to time, the Center for Medicare and Medicaid Services (CMS) considers additional modifications to the Stark Law that may further limit the ability of physicians to provide certain imaging services. Changes to Stark Law effective October 1, 2009 expand Stark Law coverage to persons and entities that “perform” designated health services. CMS has not defined what it means to perform designated health services.

On May 20, 2009, President Obama signed the Fraud Enforcement and Recovery Act of 2009, which substantially amends the federal False Claims Act. These amendments significantly expand the scope of liability for individuals and entities that receive government funds, including health care providers and suppliers receiving federal funds through Medicare or Medicaid. As amended, the False Claims Act imposes liability on those who knowingly make false or fraudulent claims for federal funds or property, whether or not the claim is presented to a government official or employee. A suit under the False Claims Act can be brought directly by the United States Department of Justice, or can be brought by a “whistleblower.” A whistleblower brings suit on behalf of themselves and the United States, and the whistleblower is awarded a percentage of any recovery. Conduct that has given rise to False Claims Act liability includes but is not limited to current and past failures to comply with technical Medicare and Medicaid billing requirements, failure to comply with certain Medicare documentation requirements, and failure to comply with Medicare physician supervision requirements. Violations of the Stark Law and Anti-Kickback Statute have also served as the basis of False Claims Act liability. Many states have adopted or are seeking to adopt state false claims act laws modeled on the federal statute.

The Health Insurance Portability and Accountability Act of 1996 (HIPAA) created federal crimes related to healthcare fraud and to making false statements related to healthcare matters. HIPAA prohibits knowingly and willfully executing a scheme to defraud any healthcare benefit program including a program involving private payors. Further, HIPAA prohibits knowingly and willfully falsifying, concealing or covering up a material fact or making any materially false statement in connection with the delivery of or payment for healthcare benefits or services. HIPAA also provides rules to protect the privacy and security of certain patient information.

President Obama signed into law on February 17, 2009 the Health Information Technology for Economic and Clinical Health Act that among other things, amends and expands HIPAA privacy and security rules, and provides for enhanced enforcement of HIPAA privacy violations by covered entities and contractors. Entities that experience certain privacy or data breaches are subject to significant fines.

In some states a certificate of need or similar regulatory approval is required prior to the acquisition of high-cost capital items or services, including diagnostic imaging systems or the provision of diagnostic imaging services by companies or its customers. Certificate of need laws were enacted to contain rising healthcare costs by preventing unnecessary duplication of health resources.

DMSI maintains a limited number of Independent Diagnostic Testing Facilities (IDTFs) that enroll in the Medicare program as participating Medicare suppliers, so that they may receive reimbursement directly from the Medicare program for services provided to Medicare beneficiaries. Over the last two years CMS has issued rule changes increasing the oversight of IDTFs. These regulations delineate certain stringent performance standards for IDTFs including standards for physical facilities, patient privacy, technician qualifications, insurance, equipment inspections, reporting changes to CMS, physician supervision, and the manner in which IDTFs are defined and enrolled in Medicare. These standards also include a provision prohibiting certain staff or space sharing arrangements.

The final rules published as part of the 2008 Medicare Physician Fee Schedule also alter the scope of the federal anti-markup rule for diagnostic tests, a federal law which delineates instances when physicians and other suppliers are prohibited from marking-up to Medicare the price of diagnostic tests when the physician performing or supervising the test does not share a practice with the billing physician or other supplier.

CMS also finalized regulations that require mobile diagnostic entities under certain circumstances to enroll in the Medicare program for diagnostic tests that they perform and to bill Medicare directly these tests. Medicare has published guidance indicating that entities that lease or contract with a Medicare enrolled supplier or provider to provide equipment and/or nonphysician personnel need not enroll in Medicare and bill directly for tests performed. Both the changes to the Medicare anti-markup rule and the mobile diagnostic testing rules are subject to interpretation by Medicare and local Medicare carriers, and could require us to make operational changes. Furthermore, if we are found not to be in compliance with these rules, or if Medicare reimbursement available to certain customers is impaired by these rules, our business could be adversely affected.

Additional federal and state regulations that the Health Services companies are subject to include state laws that prohibit the practice of medicine by non-physicians and prohibit fee-splitting arrangements involving physicians; Federal Food and Drug Administration requirements; state licensing and certification requirements; and federal and state laws governing diagnostic imaging and therapeutic equipment. Courts and regulatory authorities have not fully interpreted a significant number of the current laws and regulations.

President Obama and members of Congress have proposed significant reforms to the U.S. healthcare system. It is not possible to predict at this time whether the proposed legislation will be enacted and, if so, in what form. Therefore, the Company cannot say with any certainty what effect U.S. healthcare reform will have on the Health Services companies.

The Health Services companies continue to monitor developments in healthcare law. The Health Services companies believe their operations comply with these laws and they are prepared to modify their operations from time to time as the legal and regulatory environment changes. However, there can be no assurances that the Health Services companies will always be able to modify their operations to address changes in the legal and regulatory environment without any adverse effect to their financial performance. The consequences of failing to comply with applicable laws can be severe, including criminal penalties. In many instances violations of applicable law can result in substantial fines and damages. Moreover, in some cases violations of applicable law can result in exclusion in participation in federal and state healthcare programs. If any of the Health Services companies were excluded from participation in federal or state healthcare programs, our customers who participate in those programs could not do business with us.

Reimbursement

The companies in the Health Services segment derive significant revenue for their diagnostic imaging services from direct billings to customers and third-party payors such as Medicare, Medicaid, managed care and private health insurance companies. Health Services customers are primarily healthcare providers who receive the majority of their payments from third-party payors. Payments by third-party payors to such healthcare providers depend, in part, upon their patients' health insurance benefits and policies.

New Medicare regulations reduced 2006 Medicare reimbursement for certain imaging services performed on contiguous body parts during the same day. In addition, the Deficit Reduction Act of 2005 (DRA) limited reimbursement for imaging services provided in physician offices and in free-standing imaging centers to the reimbursement amount for that same service when provided in a hospital outpatient department. This DRA provision impacted a small number of imaging services provided by the Health Services segment. Federal and state legislatures may seek additional cuts in Medicare and Medicaid programs that could impact the value of the services provided by the Health Services segment.

Competition

The market for selling, servicing and operating diagnostic imaging services, patient monitoring equipment and imaging systems is highly competitive. In addition to direct competition from other providers of items and services similar to those offered by the Health Services companies, the companies within Health Services compete with free-standing imaging centers and health care providers that have their own diagnostic imaging systems, as well as with equipment manufacturers that sell imaging equipment directly to healthcare providers for permanent installation. Some of the direct competitors, which provide contract MR and PET/CT services, have access to greater financial resources than the Health Services companies. In addition, some Health Services customers are capable of providing the same services to their patients directly, subject only to their decision to acquire a high-cost diagnostic imaging system, assume the financial and technology risk, and employ the necessary technologists, rather than obtain the services from the Health Services companies. The Health Services companies may also experience greater competition in states that currently have certificate of need laws if such laws were repealed, thereby reducing barriers to entry and competition in that state. The Health Services companies compete against other similar providers on the basis of quality of services, quality and magnetic field strength of imaging systems, relationships with health care providers, knowledge and service quality of technologists, price, availability and reliability.

Environmental, Health or Safety Laws

PET, PET/CT and nuclear medicine services require the use of radioactive material. While this material has a short life and quickly breaks down into inert, or non-radioactive substances, using such materials presents the risk of accidental environmental contamination and physical injury. Federal, state and local regulations govern the storage, use and disposal of radioactive material and waste products. The Company believes that its safety procedures for storing, handling and disposing of these hazardous materials comply with the standards prescribed by law and regulation; however the risk of accidental contamination or injury from those hazardous materials cannot be completely eliminated. The companies in the Health Services segment have not had any material expenses related to environmental, health or safety laws or regulations.

Capital Expenditures

Capital expenditures in this segment principally relate to the acquisition of diagnostic imaging equipment used in the imaging business. During 2009, capital expenditures of approximately $3 million were made in the Health Services segment. Total capital expenditures during the five-year period 2010-2014 are estimated to be approximately $28 million. Operating leases are also used to finance the acquisition of medical equipment used by Health Services companies. Current operating lease commitments during the five-year period 2010-2014 are estimated to be $43 million.

Employees

At December 31, 2009 the Health Services segment had approximately 319 full-time employees.

FOOD INGREDIENT PROCESSING

General

Food ingredient processing consists of Idaho Pacific Holdings, Inc. (IPH), headquartered in Ririe, Idaho, manufactures and supplies dehydrated potato products to food manufacturers in the snack food, bakery and foodservice industries. IPH has three processing facilities located in Ririe, Idaho; Center, Colorado; and Souris, Prince Edward Island, Canada. Together these three facilities have the capacity to process approximately 114 million pounds of dehydrated potato products annually.

The Company derived 8%, 5% and 6% of its consolidated operating revenues from the Food Ingredient Processing segment for each of the years ended December 31, 2009, 2008 and 2007, respectively. This segment's contribution to consolidated net income for each of three years ended December 31, 2009, 2008 and 2007 was 28%, 5% and 8%, respectively.

Customers

IPH sells to customers in the United States and internationally. Products are sold through company sales persons, agents and broker sales representatives. Customers include end users in the food manufacturing industry and distributors to the food manufacturing industry and foodservice industry, both domestically and internationally.

Competition

The market for processed, dehydrated potato flakes, flour and granules is highly competitive. The ability to compete depends on superior product quality, competitive product pricing and strong customer relationships. IPH competes with numerous manufacturers and dehydrators of varying sizes in the United States and overseas, including companies with greater financial resources.

Potato Supply

The principal raw material used by IPH is washed process-grade potatoes from fresh packing operations and growers. These potatoes are unsuitable for use in other markets due to imperfections. They do not meet United States Department of Agriculture's general requirements and expectations for size, shape or quality. While IPH has processing capabilities in three geographically distinct growing regions, there can be no assurance it will be able to obtain raw materials due to poor growing conditions, a loss of key growers and other factors. A loss of raw materials or the necessity of paying much higher prices for raw materials could adversely affect the financial performance of IPH.

Regulation

IPH is regulated by the United States Department of Agriculture and the Federal Food and Drug Administration and other federal, state, local and foreign governmental agencies relating to the quality of products, sanitation, food safety and environmental compliance. IPH adheres to strict manufacturing practices that dictate sanitary conditions conducive to a high quality food product. All facilities use wastewater systems that are regulated by government environmental agencies in their respective locations and are subject to permitting by these agencies. IPH believes that it complies with applicable laws and regulations in all material respects, and that continued compliance with such laws and regulations will not have a material effect on its capital expenditures, earnings or competitive position.

Capital Expenditures

Capital expenditures in the Food Ingredient Processing segment typically include additional investments in new dehydration equipment or expenditures to replace worn-out equipment and improve efficiency. Capital expenditures may also be made for the purchase of land and buildings for plant capacity expansion and for investments in management information systems. During 2009, capital expenditures of $1 million were made in the Food Ingredient Processing segment. Total capital expenditures for the Food Ingredient Processing segment to support growth and margin improvement during the five-year period 2010-2014 are estimated to be approximately $9 million.

Employees

At December 31, 2009 the Food Ingredient Processing segment had approximately 422 full-time employees.

OTHER BUSINESS OPERATIONS

General

Other Business Operations consists of businesses in residential, commercial and industrial electric contracting industries; fiber optic and electric distribution systems; water, wastewater and HVAC systems construction; transportation and energy services.

The Company derived 13%, 15% and 15% of its consolidated operating revenues from the Other Business Operations segment for each of the years ended December 31, 2009, 2008 and 2007, respectively. This segment's contribution to consolidated net income for each of the three years ended December 31, 2009, 2008 and 2007 was (7)%, 15% and 8%, respectively. Following is a brief description of the businesses included in this segment.

Foley Company , headquartered in Kansas City, Missouri, provides mechanical and prime contracting services for water and wastewater treatment plants, power generation plants, hospital and pharmaceutical facilities, and other industrial and manufacturing projects across a multi-state service area in the Central United States.

Aevenia, Inc. (Aevenia) , formerly Midwest Construction Services, Inc., located in Moorhead, Minnesota, is a holding company for subsidiaries that provide a full spectrum of electrical design and construction services for the industrial, commercial and municipal business markets, including government, institutional, utility communications, electric distribution and renewable energy generation.

Otter Tail Energy Services Company , headquartered in Fergus Falls, Minnesota, provides technical and engineering services and energy efficient lighting primarily in North Dakota and Minnesota.

E. W. Wylie Corporation (Wylie) , located in West Fargo, North Dakota, is a flatbed, heavy-haul and specialized contract and common carrier operating a fleet of tractors and trailers in 48 states and four Canadian provinces. Wylie has trucking terminals in West Fargo, North Dakota; Fort Worth, Texas; Denver, Colorado; and Albertville, Minnesota.

Competition

Each of the businesses in Other Business Operations is subject to competition, as well as the effects of general economic conditions in their respective industries. The construction companies in this segment must compete with other construction companies in the Upper Midwest and the Central regions of the United States, including companies with greater financial resources, when bidding on new projects. The Company believes the principal competitive factors in the construction segment are price, quality of work and customer service.

The trucking industry, in which Wylie participates, is highly competitive. Wylie competes primarily with other short- to medium-haul, flatbed truckload carriers, internal shipping conducted by existing and potential customers and, to a lesser extent, railroads. Wylie entered the transportation market in 2008 with specialized heavy-haul trucks and trailers capable of hauling wind towers. Competition for the freight transported by Wylie is based primarily on safety, service, efficiency and freight rates. There are other trucking companies that have greater financial resources, operate more equipment or carry a larger volume of freight than Wylie and these companies compete with Wylie for qualified drivers.

Backlog

The construction companies in the Other Business Operations segment have backlog in place of $84 million for 2010 compared with $71 million one year ago.

Capital Expenditures

Capital expenditures in this segment typically include investments in additional trucks, trailers and construction equipment. During 2009, capital expenditures of approximately $4 million were made in Other Business Operations. Capital expenditures during the five-year period 2010-2014 are estimated to be approximately $31 million for Other Business Operations. Operating leases are also used to finance the acquisition of trucks used by Wylie. Current operating lease commitments during the five-year period 2010-2014 are estimated to be $14 million.

Employees

At December 31, 2009 there were approximately 558 full-time employees in Other Business Operations. Moorhead Electric, Inc., a subsidiary of Aevenia, has 43 employees represented by local unions of the International Brotherhood of Electrical Workers and covered by a labor contract that expires on June 1, 2010. Foley Company has 142 employees represented by various unions, including Carpenters and Millwrights, Sheet Metal Workers, Laborers, Operators, Operating Engineers, Pipe Fitters, Steamfitters, Plumbers and Teamsters. Foley Company has several labor contracts with various expiration dates in 2010 through 2013. Moorhead Electric, Inc. and Foley Company have not experienced any strike, work stoppage or strike vote, and consider their present relations with employees to be good.

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.

The value of our defined benefit pension plan assets declined significantly in 2008 due to volatile equity markets. Asset values increased in 2009 and we made a $4 million discretionary contribution to the pension plan in 2009. If the market value of pension plan assets declines again as in 2008 or does not increase as projected, we could be required to contribute additional capital to the pension plan in future years. We have a substantial liability for postretirement health care benefit obligations including $3.7 million in expenses recorded in 2009. Legislative changes in health care could result in significant changes to our employee benefit programs.

Any significant impairment of our goodwill would cause a decrease in our assets and a reduction in our net operating performance.

We had approximately $106.8 million of goodwill recorded on our consolidated balance sheet as of December 31, 2009. We have recorded goodwill for businesses in each of our business segments, except for our electric utility. 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.

A sustained decline in our common stock price below book value may result in goodwill impairments that could adversely affect our results of operations and financial position.

The inability of our subsidiaries to provide sufficient earnings and cash flows to allow us to meet our financial obligations 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 $200 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. While this restriction is 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 dividends paid per common share exceeded our earnings per common share by 68% in 2009 and 9% in 2008.

Economic conditions could negatively impact our businesses.

Our businesses are affected by local, national and worldwide economic conditions. The current tightening of credit in financial markets could continue to 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 diversify through acquisitions may not be successful, which could result in poor financial performance.

As part of our business strategy, we intend to acquire new businesses. We may not be able to identify appropriate acquisition candidates or successfully negotiate, finance or integrate acquisitions. If we are unable to make acquisitions, we may be unable to realize the growth we anticipate. 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 of an acquisition, we could face reductions in net income in future periods.

Our plans to acquire, grow and operate our nonelectric businesses could be limited by state law.

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

The terms of some of our contracts could expose us to unforeseen costs and costs not within our control, which may not be recoverable and could adversely affect our results of operations and financial condition.

DMI and ShoreMaster, two businesses in our manufacturing segment, and our construction companies frequently provide products and services pursuant to fixed-price contracts. Revenues recognized on jobs in progress under fixed-price contracts were $460 million at December 31, 2009 and $425 million at December 31, 2008. Under those contracts, we agree to perform the contract for a fixed price and, as a result, can improve our expected profit by superior contract performance, productivity, worker safety and other factors resulting in cost savings. However, we could incur cost overruns above the approved contract price, which may not be recoverable.

Fixed-price contract prices are established based largely upon estimates and assumptions relating to project scope and specifications, personnel and material needs. These estimates and assumptions may prove inaccurate or conditions may change due to factors out of our control, resulting in cost overruns, which we may be required to absorb and that could have a material adverse effect on our business, financial condition and results of our operations. In addition, our profits from these contracts could decrease and we could experience losses if we incur difficulties in performing the contracts or are unable to secure fixed-pricing commitments from our manufacturers, suppliers and subcontractors at the time we enter into fixed-price contracts with our customers.

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.

Certain of our operating companies sell products to consumers that could be subject to recall.

Certain of our operating companies sell products to consumers that could be subject to recall due to product defect or other safety concerns. If such a recall were to occur, it could have a negative impact on our consolidated results of operations and financial position.

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.

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. Electric wholesale trading margins could also be adversely affected by losses due to trading activities. 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.

In September 2009, OTP announced its withdrawal as a participating utility and the lead developer for the planned construction of a second electric generating unit at OTP's Big Stone Plant site. As of December 31, 2009 OTP had incurred $13.0 million in costs related to the project. OTP has deferred recognition of these costs as operating expenses pending determination of recoverability by the state and federal regulatory commissions that approve its rates. If OTP is denied recovery of all or any portion of these deferred costs, such costs would be subject to expense in the period they are deemed to be unrecoverable. Additionally, if OTP is unable to find alternatives to the project to meet generation needs, it may be forced to purchase power in order to meet customer needs. There is no guarantee that in such a case OTP would be able to obtain sufficient supplies of power at reasonable costs. If OTP is forced to pay higher than normal prices for power, the increase in costs could reduce our earnings if OTP is not able to recover the increased costs from its electric customers through the fuel clause adjustment.

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.

OTP could be required to absorb a disproportionate share of costs for investments in transmission infrastructure required to provide independent power producers access to the transmission grid. These costs may not be recoverable through a transmission tariff and could result in reduced returns on invested capital and/or increased rates to OTP's retail electric customers.

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. 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 greenhouse gas 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. The U.S. House of Representatives has passed a comprehensive greenhouse gas reduction bill, and bills covering similar areas are under active consideration by committees in the U.S. Senate at this time. The EPA is also moving forward with proposed greenhouse gas regulations by recently completing its "endangerment" finding. The EPA is expected to adopt its first GHG emission control rules for motor vehicles and new source review of stationary sources of GHGs in early 2010.

Fluctuations in wholesale electric sales and prices could result in earnings volatility.

The levels of wholesale sales depend on the wholesale market price, transmission availability and the availability of generation for wholesale sales, among other factors. A substantial portion of wholesale sales are made in the spot market, and thus we have immediate exposure to wholesale price changes. Wholesale power prices can be volatile and generally increase in times of high regional demand and high natural gas prices. We will not recover any shortfall in non-firm wholesale electric sales margin, any amount above the level reflected in retail rates will be returned to retail customers in a future rate case. Declines in wholesale market price, availability of generation, transmission constraints in the wholesale markets, or low wholesale demand could reduce wholesale sales. These events could adversely affect our results of operations, financial position and cash flows.

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 96% of our total purchases of PVC resin in 2009 and approximately 94% of our total purchases of PVC resin in 2008. 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.

MANUFACTURING

Competition from foreign and domestic manufacturers, the price and availability of raw materials, fluctuations in foreign currency exchange rates 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, lumber, concrete, aluminum and resin. 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. Fluctuations in foreign currency exchange rates could have a negative impact on the net income and competitive position of our wind tower manufacturing operations in Ft. Erie, Ontario because the plant pays its operating expenses in Canadian dollars.

HEALTH SERVICES

Changes in the rates or methods of third-party reimbursements for our diagnostic imaging services could result in reduced demand for those services or create downward pricing pressure, which would decrease our revenues and earnings.

Our health services businesses derive significant revenue from direct billings to customers and third-party payors such as Medicare, Medicaid, managed care and private health insurance companies for our diagnostic imaging services. Moreover, customers who use our diagnostic imaging services generally rely on reimbursement from third-party payors. Adverse changes in the rates or methods of third-party reimbursements could reduce the number of procedures for which we or our customers can obtain reimbursement or the amounts reimbursed to us or our customers.

Our health services businesses may be unable to continue to maintain agreements with Philips from which we derive significant revenues from the sale and service of Philips diagnostic imaging equipment.

Our health services business agreement with Philips expires on December 31, 2013. This agreement can be terminated on 180 days written notice by either party for any reason. It also includes other compliance requirements. If this agreement is terminated under the existing termination provisions or we are not able to comply with the agreement, the financial results of our health services operations would be adversely affected.

Technological change in the diagnostic imaging industry could reduce the demand for diagnostic imaging services and require our health services operations to incur significant costs to upgrade its equipment.

Although we believe substantially all of our diagnostic imaging systems can be upgraded to maintain their state-of-the-art character, the development of new technologies or refinements of existing technologies might make our existing systems technologically or economically obsolete, or cause a reduction in the value of, or reduce the need for, our systems.

Actions by regulators of our health services operations could result in monetary penalties or restrictions in our health services operations.

Our health services operations are subject to federal and state regulations relating to licensure, conduct of operations, ownership of facilities, addition of facilities and services and payment of services. Our failure to comply with these regulations, including regulations released by the Centers for Medicare and Medicaid in 2008 that imposed additional restrictions on diagnostic imaging services, or our inability to obtain and maintain necessary regulatory approvals, may result in adverse actions by regulators with respect to our health services operations, which may include civil and criminal penalties, damages, fines, injunctions, operating restrictions or suspension of operations. Any such action could adversely affect our financial results. Courts and regulatory authorities have not fully interpreted a significant number of these laws and regulations, and this uncertainty in interpretation increases the risk that we may be found to be in violation. Any action brought against us for violation of these laws or regulations, even if successfully defended, may result in significant legal expenses and divert management’s attention from the operation of our businesses.

FOOD INGREDIENT PROCESSING

Our company that processes dehydrated potato flakes, flour and granules, IPH, competes in a highly competitive market and is dependent on adequate sources of potatoes for processing.

The market for processed, dehydrated potato flakes, flour and granules is highly competitive. The profitability and success of our potato processing company is dependent on superior product quality, competitive product pricing, strong customer relationships, raw material costs, fuel prices and availability and customer demand for finished goods. In most product categories, our company competes with numerous manufacturers of varying sizes in the United States.

The principal raw material used by IPH, our potato processing company, is washed process-grade potatoes from growers. These potatoes are unsuitable for use in other markets due to imperfections. They are not subject to the United States Department of Agriculture's general requirements and expectations for size, shape or color. While our food ingredient processing company has processing capabilities in three geographically distinct growing regions, there can be no assurance it will be able to obtain raw materials due to poor growing conditions, a loss of key growers, loss of potato production acres to other crops and other factors. A loss or shortage of raw materials or the necessity of paying much higher prices for raw materials or fuel could adversely affect the financial performance of this company. Fluctuations in foreign currency exchange rates could have a negative impact on our potato processing company's net income and competitive position because approximately 16% of IPH sales in 2009 and approximately 25% of IPH sales in 2008 were outside the United States and the Canadian plant pays its operating expenses in Canadian dollars.

OTHER BUSINESS OPERATIONS

Our construction companies may be unable to properly bid and perform on projects.

The profitability and success of our construction companies require us to identify, estimate and timely bid on profitable projects. The quantity and quality of projects up for bids at any time is uncertain. Additionally, once a project is awarded, we must be able to perform within cost estimates that were set when the bid was submitted and accepted. A significant failure or an inability to properly bid or perform on projects could lead to adverse financial results for our construction companies.

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 with a combined nameplate rating of 128,500 kW. 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 (66,000 kW nameplate rating) and modified in 1988 to provide cycling capability, allowing this unit to be more efficiently brought online from a standby mode.

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, 2009 OTP's transmission facilities, which are interconnected with lines of other public utilities, consisted of 48 miles of 345 kV lines; 417 miles of 230 kV lines; 862 miles of 115 kV lines; and 3,976 miles of lower voltage lines, principally 41.6 kV. OTP owns the uprated portion of the 48 miles of the 345 kV line, with Minnkota Power Cooperative retaining title to the original 230 kV construction.

In addition to the properties mentioned above, the Company owns and has investments in offices and service buildings. The Company's subsidiaries own: construction equipment and tools, medical imaging equipment, a fleet of flatbed trucks and trailers and facilities and equipment used to manufacture PVC pipe, wind towers and other heavy metal fabricated products, thermoformed products, and commercial and waterfront equipment; produce dehydrated potato products; and perform metal 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

Sierra Club Complaint

On June 10, 2008 the Sierra Club filed a complaint in the U.S. District Court for the District of South Dakota (Northern Division) against the Company and two other co-owners of Big Stone Generating Station (Big Stone). The complaint alleged certain violations of the PSD and NSPS provisions of the CAA and certain violations of the South Dakota SIP. The action further alleged the defendants modified and operated Big Stone without obtaining the appropriate permits, without meeting certain emissions limits and NSPS requirements and without installing appropriate emission control technology, all allegedly in violation of the CAA and the South Dakota SIP. The Sierra Club alleged the defendants' actions have contributed to air pollution and visibility impairment and have increased the risk of adverse health effects and environmental damage. The Sierra Club sought both declaratory and injunctive relief to bring the defendants into compliance with the CAA and the South Dakota SIP and to require the defendants to remedy the alleged violations. The Sierra Club also seeks unspecified civil penalties, including a beneficial mitigation project. The Company believes these claims are without merit and that Big Stone was and is being operated in compliance with the CAA and the South Dakota SIP.

The defendants filed a motion to dismiss the Sierra Club complaint on August 12, 2008. On March 31, 2009 and April 6, 2009, the District Court issued a Memorandum and Order and Amended Memorandum and Order, respectively, granting the defendants' motion to dismiss the Sierra Club complaint. On April 17, 2009 the Sierra Club filed a motion for reconsideration of the Amended Memorandum Opinion and Order. The Sierra Club motion was opposed by the defendants. The Sierra Club motion for reconsideration was denied on July 22, 2009. On July 30, 2009 the Sierra Club filed a notice of appeal to the 8th U.S. Circuit Court of Appeals. The briefing schedule called for the appellant to submit its brief by mid-October, for appellees to submit their brief by mid-November and for the appellant to submit its reply brief by the end of November. On October 13, 2009, the United States Department of Justice filed a motion seeking a 30-day extension of the time to file an amicus brief in support of the Sierra Club's position. The Court of Appeals granted this motion, as well as the appellees' subsequent joint motion with the Sierra Club, extending the time to file the appellees' brief and the Sierra Club's reply brief. Briefing was complete on January 22, 2010 on filing of the Sierra Club's reply brief. The ultimate outcome of this matter cannot be determined at this time.

Federal Power Act Complaint

On August 29, 2008 Renewable Energy System Americas, Inc. (RES), a developer of wind generation, and PEAK Wind Development, LLC (PEAK Wind), a group of landowners in Barnes County, North Dakota, filed a complaint with the FERC alleging that OTP and Minnkota Power Cooperative, Inc. (Minnkota) had acted together in violation of the Federal Power Act (FPA) to deny RES and PEAK Wind access to the Pillsbury Line, an interconnection facility which Minnkota owns to interconnect generation projects being developed by OTP and NextEra Energy Resources, Inc. (fka FPL Energy, Inc.) (NextEra). RES and PEAK Wind asked that (1) the FERC order Minnkota to interconnect its Glacier Ridge project to the Pillsbury Line, or in the alternative, (2) the FERC direct MISO to interconnect the Glacier Ridge project to the Pillsbury Line. RES and Peak Wind also requested that OTP, Minnkota and NextEra pay any costs associated with interconnecting the Glacier Ridge Project to the MISO transmission system which would result from the interconnection of the Pillsbury Line to the Minnkota transmission system, and that the FERC assess civil penalties against OTP. OTP answered the complaint on September 29, 2008, denying the allegations of RES and PEAK Wind and requesting that the FERC dismiss the complaint. On October 14, 2008, RES and PEAK Wind filed an answer to OTP's answer and, restated the allegations included in the initial complaint. RES and PEAK Wind also added a request that the FERC rescind both OTP's waiver from the FERC Standards of Conduct and its market-based rate authority. On October 28, 2008, OTP filed a reply, denying the allegations made by RES and PEAK Wind in its answer. By order issued on December 19, 2008, the FERC set the complaint for hearing and established settlement procedures. A formal settlement agreement was filed with the FERC requesting approval of the settlement and withdrawal of the complaint. We expect the FERC will issue an order approving the settlement and terminating the proceeding. The settlement is not expected to have a material impact on OTP's financial position or results of operations.

Other

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 FEBRUARY 26, 2010)

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 Securities and Exchange Commission. Each of the executive officers has been employed by the Company for more than five years in an executive or management position either with the Company or its wholly owned subsidiary, Otter Tail Power Company.

NAME AND AGE	DATES ELECTED TO OFFICE	PRESENT POSITION AND BUSINESS EXPERIENCE	
John D. Erickson (51)	4/8/02	Present:	President and Chief Executive Officer
George A. Koeck (57)	4/10/00	Present:	Corporate Secretary and General Counsel
Lauris N. Molbert (52)	6/10/02	Present:	Executive Vice President and Chief Operating Officer
Kevin G. Moug (50)	4/9/01	Present:	Chief Financial Officer
Charles S. MacFarlane (45)	5/1/03	Present:	President, Otter Tail Power Company

With the exception of Charles S. MacFarlane, 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. Mr. MacFarlane is not appointed by the Board of Directors. Mr. MacFarlane is a son of John MacFarlane, who is the Chairman of the Board of Directors. There are no other family relationships between any of the executive officers or directors.

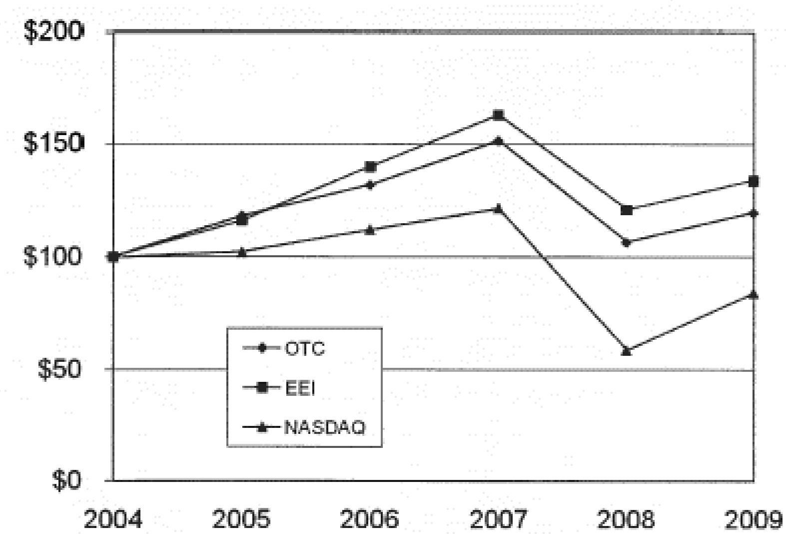
PART II

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 39 of this Annual Report on Form 10-K under the heading "Selected Financial Data," on Page 99 under the heading "Retained Earnings Restriction" and on Page 116 under the heading "Quarterly Information." The Company did not repurchase any equity securities during the three months ended December 31, 2009.

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, 2004, and reinvestment of all dividends).



	2004	2005	2006	2007	2008	2009
OTC	**$100.00**	**$118.10**	**$132.05**	**$151.81**	**$106.38**	**$119.57**
EEI	**$100.00**	**$116.05**	**$140.14**	**$163.34**	**$121.03**	**$133.99**
NASDAQ	**$100.00**	**$102.13**	**$112.19**	**$121.68**	**$ 58.64**	**$ 84.28**

Item 6. SELECTED FINANCIAL DATA

(thousands, except number of shareholders and per-share data)	**2009**	2008	2007	2006	2005
Revenues					
Electric	**$ 314,625**	$ 340,020	$ 323,478	$ 306,014	$ 312,985
Plastics	**80,208**	116,452	149,012	163,135	158,548
Manufacturing	**323,895**	470,462	381,599	311,811	244,311
Health Services	**110,006**	122,520	130,670	135,051	123,991
Food Ingredient Processing	**79,098**	65,367	70,440	45,084	38,501
Other Business Operations *(1)*	**136,088**	199,511	185,730	145,603	105,821
Corporate Revenues and Intersegment Eliminations *(1)*	**(4,408)**	(3,135)	(2,042)	(1,744)	(2,288)
Total Operating Revenues	**$1,039,512**	$1,311,197	$1,238,887	$1,104,954	$ 981,869
Net Income from Continuing Operations	**$ 26,031**	$ 35,125	$ 53,961	$ 50,750	$ 53,902
Net Income from Discontinued Operations	**—**	—	—	362	8,649
Net Income	**$ 26,031**	$ 35,125	$ 53,961	$ 51,112	$ 62,551
Operating Cash Flow from Continuing Operations	**$ 162,750**	$ 111,321	$ 84,812	$ 79,207	$ 90,348
Operating Cash Flow — Continuing and Discontinued Operations	**162,750**	111,321	84,812	80,246	95,800
Capital Expenditures — Continuing Operations	**177,125**	265,888	161,985	69,448	59,969
Total Assets	**1,745,678**	1,692,587	1,454,754	1,258,650	1,181,496
Long-Term Debt	**436,170**	339,726	342,694	255,436	258,260
Basic Earnings Per Share — Continuing Operations *(2)*	**0.71**	1.09	1.79	1.70	1.82
Basic Earnings Per Share — Total *(2)*	**0.71**	1.09	1.79	1.71	2.12
Diluted Earnings Per Share — Continuing Operations *(2)*	**0.71**	1.09	1.78	1.69	1.81
Diluted Earnings Per Share — Total *(2)*	**0.71**	1.09	1.78	1.70	2.11
Return on Average Common Equity	**3.8%**	6.0%	10.5%	10.6%	13.9%
Dividends Per Common Share	**1.19**	1.19	1.17	1.15	1.12
Dividend Payout Ratio	**168%**	109%	66%	68%	53%
Common Shares Outstanding — Year End	**35,812**	35,385	29,850	29,522	29,401
Number of Common Shareholders *(3)*	**14,923**	14,627	14,509	14,692	14,801

(1) *Beginning in 2007 corporate revenues and expenses are no longer reported as components of Other Business Operations. Prior years have been restated accordingly.*

(2) *Based on average number of shares outstanding.*

(3) *Holders of record at year end.*

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

On July 1, 2009, Otter Tail Corporation completed a holding company reorganization whereby Otter Tail Power Company (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 (formerly known as Otter Tail Holding Company). The new parent holding company (now known as Otter Tail Corporation) was incorporated in June 2009 under the laws of the State of Minnesota in connection with the holding company reorganization. References in this report to Otter Tail Corporation and the Company refer, for periods prior to July 1, 2009, to the corporation that was the registrant prior to the reorganization, and, for periods after the reorganization, to the new parent holding company, in each case including its consolidated subsidiaries, unless otherwise indicated or the context otherwise requires.

Otter Tail Corporation and its subsidiaries form a diverse group of businesses with operations classified into six segments: Electric, Plastics, Manufacturing, Health Services, Food Ingredient Processing and Other Business Operations. 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 solid 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 develop a core regulated electric utility combined with a diversified multi-industry platform. Reliable utility performance combined with growth opportunities at all our businesses provides long-term value. Growing our core electric utility business provides a strong base of revenues, earnings and cash flows. We look to our nonelectric operating 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 the next few years will come from utilizing expanded plant capacity from capital investments made in 2007 and 2008. We may also grow through acquisitions. We adhere to strict guidelines when reviewing acquisition candidates. Our aim is to add companies that will produce an immediate positive impact on earnings and provide long-term growth potential. We believe that owning well-run, profitable companies across different industries will bring more growth opportunities and more balance to our results. In doing this, we also avoid concentrating business risk within a single industry. All of our operating companies operate under a decentralized business model with disciplined corporate oversight.

We assess the performance of our operating companies over time, using the following criteria:

- ability to provide returns on invested capital that exceed our weighted average cost of capital over the long term; and
- assessment of an operating company's business and potential for future earnings growth.

We are a committed long-term owner and therefore we do not acquire companies in pursuit of short-term gains. However, we may divest operating companies that no longer fit into our strategy over the long term.

Following, are highlights of our 2009 operations:

- We achieved record annual net cash from operations of $162.7 million.
- Our food ingredient processing segment reported record net income of $7.4 million.
- Net income from our electric segment increased 2.5% to $34.1 million.
- OTP invested $100.6 million in its third rate-base wind farm. This is a 49.5 MW project which is a portion of the Luverne Wind Farm in Steele County, North Dakota.
- OTP received grant proceeds of $30.2 million under the American Recovery and Reinvestment Act of 2009 related to its $100.6 million investment in 33 wind turbines at the Luverne Wind Farm.
- OTP announced its withdrawal from participation in the planned construction of a 500- to 600-megawatt generating unit at its Big Stone Plant site.
- OTP was granted general rate increases of 11.7% in South Dakota and 3.0% in North Dakota.

Major growth strategies and initiatives in our company's future include:

- Planned capital budget expenditures of up to $817 million for the years 2010 through 2014 of which $641 million is for capital projects at OTP, including $245 million for additional generation and $110 million for anticipated expansion of transmission capacity in Minnesota (CapX 2020). See "Capital Requirements" section for further discussion.
- Utilization of expanded plant capacity from capital investments made in our nonelectric businesses in 2007 and 2008.
- The continued investigation and evaluation of organic growth and strategic acquisition opportunities.

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

(in thousands)	2009	2008
Operating Revenues:		
Electric	$ 314,424	$ 339,726
Nonelectric	725,088	971,471
Total Operating Revenues	$1,039,512	$1,311,197
Net Income (Loss):		
Electric	$ 34,079	$ 33,234
Nonelectric	1,336	14,194
Corporate	(9,384)	(12,303)
Total Net Income	$ 26,031	$ 35,125

The 20.7% decrease in consolidated revenues in 2009 compared with 2008 reflects significant revenue reductions from our manufacturing, other business operations and plastics segments as a result of the 2009 economic recession. Revenues decreased $146.6 million in our manufacturing segment mainly due to decreased production and sales of wind towers and other fabricated steel products. Our construction companies' revenues were down $53.2 million as the recession resulted in a reduction in volume of jobs in progress. Revenues at our transportation company decreased $10.2 million as a result of a reduction in miles driven by company-owned trucks combined with a reduction in fuel surcharge revenues related to significantly lower fuel costs in 2009. Revenues decreased by $36.2 million in our plastics segment as a result of lower pipe prices combined with lower sales volumes due to a decrease in construction activity related to the recent economic downturn. Electric segment revenues decreased by $25.3 million as a result of an $11.1 million decrease in wholesale revenues from sales off of company-owned generation, an $8.4 million decrease in revenues from contracted electrical construction work performed for other entities and a $5.5 million decrease in retail revenues related to the recovery of lower fuel and purchased power costs. The decrease in wholesale revenues mainly related to lower wholesale prices and a 14.8% decrease in wholesale kilowatt-hour (kwh) sales. Revenues from our health services segment decreased $12.5 million, mainly due to a reduction in imaging services revenue. Food ingredient processing revenues increased $13.7 million as a result of a 6.6% increase in pounds of products sold combined with a 13.5% increase in revenue per pound of product sold.

Following is a more detailed analysis of our operating results by business segment for the three years ended December 31, 2009, 2008 and 2007, followed by a discussion of our financial position at the end of 2009 and our outlook for 2010.

RESULTS OF OPERATIONS

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

Amounts presented in the following segment tables for 2009, 2008 and 2007 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)*	2009	2008	2007
Operating Revenues:			
Electric	$ 201	$ 294	$ 320
Nonelectric	4,207	2,841	1,722
Cost of Goods Sold	3,948	2,703	1,553
Other Nonelectric Expenses	460	432	489

ELECTRIC

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

(in thousands)	2009	% change	2008	% change	2007
Retail Sales Revenues	$282,116	(2)	$287,631	4	$276,894
Wholesale Revenues	13,578	(46)	25,122	13	22,306
Net Marked-to-Market Gains	2,184	3	2,114	(37)	3,334
Other Revenues	16,747	(33)	25,153	20	20,944
Total Operating Revenues	$314,625	(7)	$340,020	5	$323,478
Production Fuel	59,387	(17)	71,930	19	60,482
Purchased Power — System Use	52,942	(6)	56,329	(25)	74,690
Other Operation and Maintenance Expenses	105,867	(8)	115,300	8	107,041
Depreciation and Amortization	36,946	16	31,755	22	26,097
Property Taxes	8,853	(1)	8,949	(5)	9,413
Operating Income	$ 50,630	(9)	$ 55,757	22	$ 45,755

Electric kwh Sales *(in thousands)*	2009	% change	2008	% change	2007
Retail kwh Sales	4,244,377	—	4,241,907	3	4,123,831
Wholesale kwh Sales — Company Generation	402,498	(15)	472,441	28	368,061
Wholesale kwh Sales — Purchased Power Resold	1,004,916	(55)	2,210,188	73	1,280,780

2009 compared with 2008

The main reasons for the $5.5 million decline in retail sales revenue was a $15.5 million decrease in revenues related to a reduction in costs of fuel and purchased power to serve retail customers, a $1.5 million increase in 2008 revenue related to the cost of replacement power purchased in November and December of 2007 when Big Stone Plant was down for maintenance, and a $0.5 million increase in the first quarter of 2009 in a Minnesota interim rate refund. These revenue decreases were partially offset by revenue increases of: (1) $6.6 million in Minnesota and North Dakota renewable resource recovery rider revenues, (2) $3.8 million from a 3.0% general rate increase in North Dakota, approved in November 2009 but effective with interim rates beginning in January 2009, and (3) $1.5 million from an 11.7% general rate increase in South Dakota effective in May 2009 and approved in June 2009. Retail kwh sales grew by only 0.1% between the years.

Wholesale electric revenues from sales from company-owned generation were $12.6 million in 2009 compared with $23.7 million in 2008 as a result of a 37.7% decrease in the average price per kwh sold, combined with a 14.8% decrease in wholesale kwh sales. Fuel costs related to wholesale sales decreased $3.7 million between the years as a result of the decrease in wholesale kwh sales combined with reductions in fuel costs and generation at OTP’s combustion turbine peaking plants. Reductions in industrial consumption of electricity, declining natural gas prices, increased efficiency in wholesale electric markets and increased generation from renewable wind and hydroelectric resources have driven down prices for electricity in the wholesale market. Net gains from energy trading activities, including net mark-to-market gains on forward energy contracts, were $3.2 million in 2009 compared with $3.5 million in 2008 as a result of a reduction in margins on energy trades between the years. Other electric operating revenues decreased as a result of an $8.0 million reduction in revenues from construction and permitting work completed for other entities on regional energy projects and a $0.4 million decrease in revenues from transmission and dispatch related services.

The $12.5 million decrease in fuel costs reflects a 16.4% decrease in kwhs generated from OTP’s fossil fuel-fired plants. Another major factor contributing to the decrease in fuel costs was a 32.6% decrease in kwhs generated from OTP’s fuel-oil and natural gas-fired combustion turbines, in combination with lower fuel and natural gas prices. Fuel costs were also reduced as a result of wind turbines owned by OTP providing 10.6% of total kwh generation in 2009 compared with 4.0% in 2008. Generation for retail sales decreased 9.4% while generation used for wholesale electric sales decreased 14.8% between the years.

The $3.4 million decrease in purchased power — system use is due to a 30.8% reduction in the cost per kwh purchased offset by a 35.8% increase in kwhs purchased. The increase in kwh purchases for system use is related to a reduction in the availability of company-owned generation resulting from maintenance outages at Big Stone and Hoot Lake Plants, a six-week scheduled maintenance shutdown of Coyote Station in the second quarter of 2009 and an unplanned outage for generator repairs at Coyote Station in the third quarter of 2009. The decrease in the cost per kwh of purchased power reflects a significant decrease in fuel and purchased power costs across the Mid-Continent Area Power Pool region as a result of reductions in industrial consumption of electricity related to the recent economic recession, lower natural gas prices and the availability of increased generation from renewable wind and hydroelectric sources.

The $9.4 million decrease in other electric operating and maintenance expenses includes: (1) a $7.5 million decrease in costs associated with construction work completed for other entities on regional energy projects, commensurate with an $8.0 million decrease in related revenue, (2) a $1.1 million reduction in external services expenses, for tree trimming and power-plant maintenance, and (3) a $0.9 million reduction in vehicle and travel expenses related to a 37.3% reduction in fuel prices and an increase in vehicle costs capitalized for transportation and equipment used on construction projects in 2009.

The $5.2 million increase in depreciation expense mainly is due to the additions of 32 wind turbines at the Ashtabula Wind Energy Center placed in service at the end of 2008 and 33 wind turbines at the Luverne Wind Farm placed in service in September 2009.

2008 compared with 2007

The $10.7 million increase in retail electric sales revenues in 2008 compared with 2007 reflects $8.0 million in 2008 Minnesota and North Dakota renewable resource cost recovery rider revenue and an approved increase in Minnesota retail electric rates of approximately 2.9% that resulted in a $3.6 million increase in retail revenues in 2008. These revenue increases were augmented by an additional $5.8 million in revenue mainly related to a 2.9% increase in retail kwh sales resulting from load growth and a 7.8% increase in heating degree days between the years. These increases in retail sales revenues were offset by a $6.7 million reduction in FCA revenues related to a reduction in kwhs purchased for system use in 2008.

Wholesale electric revenues from company-owned generation increased to $23.7 million in 2008 compared with $20.3 million in 2007 as a result of a 28.4% increase in wholesale kwh sales, partially offset by a 9.2% decrease in the price per kwh sold. Greater plant availability in 2008 provided OTP with more opportunities to respond to wholesale market demands. Net gains from energy trading activities, including net mark-to-market gains and losses on forward energy contracts, were $3.5 million in 2008 compared with $5.3 million in 2007 as a result of a decrease in volume of forward energy purchase and sales contracts entered into by OTP in 2008.

The $4.2 million increase in other electric revenues includes a $3.6 million increase in revenues from contracted construction work completed for other entities on regional wind power projects and a $0.8 million increase in revenues from steam sales to an ethanol plant near the Big Stone Plant site, offset by a $0.2 million reduction in revenues from shared use of transmission facilities.

Fuel and purchased-power costs to serve retail and wholesale electric customers decreased $6.9 million between the years. Fuel costs for generation for retail customers increased $8.3 million as a result of a 12.1% increase in generation for system use combined with a 3.4% increase in fuel costs per kwh generated for system use. Purchased power costs to serve retail customers decreased $18.4 million as a result of a 23.8% decrease in kwhs purchased combined with a 1.0% decrease in the cost per kwh purchased for system use. Fuel costs for wholesale sales increased $3.2 million due to a 28.4% increase in wholesale kwh sales combined with a 7.1% increase in the cost of fuel per kwh generated for wholesale sales. Overall fuel-fired kwh generation increased 9.3% as a result of greater plant availability in 2008. Fuel costs per kwh generated increased 8.8%, but kwhs generated from zero-fuel-cost wind turbines mitigated the increase in fuel costs per kwh from generation used to serve retail customers.

The $8.3 million increase in electric operating and maintenance expenses includes: (1) $3.1 million in increased material costs not subject to recovery through retail rates, related to contracted construction work completed for other entities on regional wind power projects, (2) $1.7 million in turbine repair costs at Hoot Lake Plant in 2008, (3) $0.9 million in higher wage and benefit expenses related to a general wage increase, (4) $0.6 million in wind turbine related expenses, and (5) a net increase of $2.0 million in other operating expenses. The $5.7 million increase in depreciation and amortization expense is due to recent capital additions, including 27 wind turbines at the Langdon Wind Energy Center that were built in 2007. Property tax expense decreased $0.5 million as a result of decreases in utility property assessed values in Minnesota and South Dakota and changes in assessment methodology in South Dakota.

PLASTICS

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

(in thousands)	2009	% change	2008	% change	2007
Operating Revenues	$80,208	(31)	$116,452	(22)	$149,012
Cost of Goods Sold	71,872	(31)	104,186	(16)	124,344
Operating Expenses	4,764	(4)	4,956	(31)	7,223
Depreciation and Amortization	2,945	(3)	3,050	(1)	3,083
Operating Income	$ 627	(85)	$ 4,260	(70)	$ 14,362

2009 compared with 2008

The $36.2 million decrease in plastics operating revenues in 2009 compared with 2008 was due to a 9.5% decrease in pounds of pipe sold combined with a 24.0% decrease in the price per pound of pipe sold. The $32.3 million decrease in costs of goods sold was due to the decrease in pounds of pipe sold and a 23.8% decrease in the cost per pound of pipe sold. Beginning in 2008, significant reductions in new home construction in markets served by the plastic pipe companies have resulted in reduced demand and lower prices for polyvinyl chloride (PVC) pipe products.

2008 compared with 2007

The $32.6 million decrease in plastics operating revenues in 2008 compared with 2007 reflects a 26.2% decrease in pounds of pipe sold, partially offset by a 5.9% increase in the price per pound of pipe sold. The decrease in pounds of pipe sold is due to sluggish housing and construction markets in 2008. The $2.3 million decrease in plastics segment operating expenses is mostly due to decreases in employee incentives and sales commissions directly related to the decreases in pipe sales and operating margins between the years, but also reflects reductions in bad debt and property tax expenses.

MANUFACTURING

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

(in thousands)	2009	% change	2008	% change	2007
Operating Revenues	$323,895	(31)	$470,462	23	$381,599
Cost of Goods Sold	260,815	(33)	389,060	30	300,146
Operating Expenses	37,625	(15)	44,093	25	35,278
Product Recall and Testing Costs	1,625	—	—	—	—
Plant Closure Costs	—	—	2,295	—	—
Depreciation and Amortization	22,530	17	19,260	47	13,124
Operating Income	$ 1,300	(92)	$ 15,754	(52)	$ 33,051

2009 compared with 2008

The decrease in revenues in our manufacturing segment in 2009 compared with 2008 relates to the following:

- Revenues at DMI Industries, Inc., (DMI), our manufacturer of wind towers, decreased $88.3 million (35.5%) as a result of a lower volume of wind towers being sold in 2009.
- Revenues at BTD Manufacturing, Inc. (BTD), our metal parts stamping and fabrication company, decreased $30.4 million (26.7%) as a result of decreases of $18.8 million from reduced sales volume, $9.0 million from lower prices and $2.7 million in scrap sales revenue related to lower steel prices and less scrap available for sale.
- Revenues at ShoreMaster, Inc. (ShoreMaster), our waterfront equipment manufacturer, decreased $20.8 million (31.7%). The decrease in revenues mainly reflects a lower volume of commercial construction projects in 2009 and lower sales of residential products between the years related to the economic recession and credit restraints affecting consumers.
- Revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products, decreased $7.0 million (16.8%) due to a decrease in volume of products sold, mainly as a result of delays in, or suspension of, orders related to the economic recession. Revenues in 2008 included $1.7 million from a small facility in South Carolina that was sold in 2008.

The decrease in cost of goods sold in our manufacturing segment in 2009 compared with 2008 relates to the following:

- Cost of goods sold at DMI decreased $87.3 million as a result of the reductions in production and sales of wind towers. Also, cost of goods sold in 2008 included $4.3 million in costs associated with start-up inefficiencies at DMI's Oklahoma plant, $3.5 million in additional labor and material costs on a production contract in Ft. Erie and higher costs due to steel surcharges.
- Cost of goods sold at BTD decreased $17.3 million. A decrease of $13.7 million in cost of goods sold related to a decrease in sales volume and $7.0 million in lower prices for raw materials was partially offset by $3.3 million in unabsorbed overhead costs due to the lower volume of products produced and sold.
- Cost of goods sold at ShoreMaster decreased $17.5 million mainly due to the completion of a large commercial construction project in 2008 and reduced sales of residential products between the years.
- Cost of goods sold at T.O. Plastics decreased $6.1 million mainly as a result of a decrease in volume of products sold.

The decrease in operating expenses in our manufacturing segment in 2009 compared with 2008 relates to the following:

- Operating expenses at DMI decreased $2.5 million, reflecting decreases in labor, selling and promotional expenses.
- Operating expenses at BTD decreased $1.6 million mainly due to a reduction in incentive compensation directly related to decreased profitability between the years.
- Operating expenses at ShoreMaster decreased $3.0 million, which reflects a reduction of $2.3 million mainly in payroll costs and selling expenses and $2.3 million in plant closure costs incurred in 2008, offset by $1.6 million of product recall and testing costs incurred in 2009. The $2.3 million in plant closure costs in 2008 includes employee-related termination obligations, asset impairment costs and other losses and expenses incurred related to the shutdown and sale of a production facility in California following the completion of a major marina project in the state. The $1.6 million in product recall and testing costs in 2009 includes the recognition of $1.1 million in costs related to the recall of certain trampoline products and $0.5 million in costs to test imported products for lead and phthalate content.
- Operating expenses at T.O. Plastics were flat between the years.

Depreciation expense increased as a result of capital additions at DMI in 2008 and the acquisition of Miller Welding & Iron Works, Inc. (Miller Welding), in May 2008.

2008 compared with 2007

The increase in revenues in our manufacturing segment in 2008 compared with 2007 relates to the following:

- Revenues at DMI increased $64.6 million (35.0%) as a result of increases in production and sales activity, including first-year production from its new plant in Oklahoma.
- Revenues at BTD increased $32.0 million (39.0%) between the years, including $17.5 million in 2008 revenues from Miller Welding, acquired in May 2008, $7.6 million from higher prices driven by higher material costs and $6.9 million from increased sales to existing customers.
- Revenues at T.O. Plastics increased $2.5 million (6.5%) between the years as a result of increased sales of horticultural products.
- Revenues at ShoreMaster decreased $10.3 million (13.5%) between the years as a result of lower residential and commercial sales.

The increase in cost of goods sold in our manufacturing segment in 2008 compared with 2007 relates to the following:

- Cost of goods sold at DMI increased $63.7 million between the years as a result of increases in production and sales activity, including initial operations at its new plant in Oklahoma. DMI experienced only a $0.9 million increase in gross profit margins between the years mainly due to the start-up of its Oklahoma plant, where the levels of labor and overhead spending was higher than expected and production had not reached levels necessary to cover these costs. Included in cost of goods sold for 2008 are costs of $4.3 million associated with start-up of the Oklahoma plant, $3.5 million in additional labor and material costs on a production contract at the Ft. Erie plant and higher costs due to steel surcharges.
- Cost of goods sold at BTD increased $23.4 million between the years, mainly in the categories of materials, labor and shop supply costs, as a result of increased sales volumes to existing customers and higher material prices. Miller Welding accounted for $13.2 million of the increase in cost of goods sold. BTD’s gross margin was also reduced by $1.0 million in 2008 as a result of the sale of Miller Welding’s inventory that was adjusted to fair value on acquisition, as required under business combination accounting rules.
- Cost of goods sold at T.O. Plastics increased $2.2 million, mainly in material costs related to increased sales of horticultural products.
- Cost of goods sold at ShoreMaster decreased by $0.3 million despite a $10.3 million decrease in revenues between the years. Reduced sales combined with dealer discounts and tighter profit margins, as well as losses incurred on a commercial construction project, contributed to the $10.0 million decline in gross profits at ShoreMaster.

The increase in operating expenses in our manufacturing segment in 2008 compared with 2007 relates to the following:

- Operating expenses at DMI increased $5.3 million, including expenses related to the operation of its new plant in Oklahoma, which began construction in the third quarter of 2007 and went into operation in January 2008. The increase also includes approximately $1.0 million in increased severance and retention costs in 2008 related to personnel changes and delayed orders for towers that resulted in workforce reductions at the end of 2008.
- Operating expenses at BTD increased $3.6 million between the years, mainly as a result of increases in labor, benefit and contracted service expenses and the May 2008 acquisition of Miller Welding.
- Operating expenses at T.O. Plastics decreased by $0.1 million, but T.O. Plastics operating income was flat between the years as its depreciation expenses increased by $0.4 million related to $7.0 million in capital expenditures in 2007 and 2008.
- Operating expenses at ShoreMaster increased $2.3 million as a result of the shutdown and sale of ShoreMaster’s production facility in California following the completion of a major marina project in the state. Plant closure costs include employee-related termination obligations, asset impairment costs plus other related losses and expenses.

Depreciation and amortization expense increased mainly as a result of capital additions at DMI and T.O. Plastics and the May 2008 acquisition of Miller Welding.

Segment operating income decreased by $17.3 million primarily due to a $12.3 million decline in operating income at ShoreMaster.

HEALTH SERVICES

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

(in thousands)	2009	% change	2008	% change	2007
Operating Revenues	$110,006	(10)	$122,520	(6)	$130,670
Cost of Goods Sold	89,315	(7)	96,349	(3)	99,612
Operating Expenses	19,844	(6)	21,030	(11)	23,691
Depreciation and Amortization	3,907	(5)	4,133	5	3,937
Operating (Loss) Income	$ (3,060)	(404)	$ 1,008	(71)	$ 3,430

2009 compared with 2008

The $12.5 million decrease in health services operating revenues reflects a $9.5 million decrease in revenues from scanning and other related services due to a 33.1% decrease in scans and a $3.7 million decrease in rental revenue. Revenues from equipment sales and servicing decreased $3.0 million mainly due to a continued reduction in dealership distribution of products and declining film sales. The $7.0 million decrease in cost of goods sold was directly related to the decreases in sales revenue, but was negatively impacted by higher-than-expected service and maintenance costs in the third quarter of 2009. The $1.2 million decrease in operating expenses is the result of measures taken to control and reduce operating expenses. Also, operating expenses in 2008 are net of a $1.1 million pre-tax gain on the sale of fixed assets. The imaging side of the business continues to be affected by less-than-optimal utilization of certain imaging assets.

2008 compared with 2007

The $8.2 million decrease in health services operating revenues reflects a $4.6 million decrease in revenues from scanning and other related services as a result of a decrease in revenues from rental and interim installations. Revenues from equipment sales and servicing decreased $3.6 million and cost of goods sold decreased $3.3 million between the years as a decrease in traditional dealership distribution of products was mostly offset by increases in manufacturer representative commissions on more manufacturer-direct sales. The $2.7 million decrease in operating expenses includes a $0.9 million increase in gains on sales of imaging company assets, reductions in sales, marketing and advertising expenses totaling $1.2 million and a $0.4 million decrease in labor costs. The increase in depreciation and amortization expense is due to capital additions in 2007 and 2008. The imaging side of the business was affected by less-than-optimal utilization of certain imaging assets.

FOOD INGREDIENT PROCESSING

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

(in thousands)	2009	% change	2008	% change	2007
Operating Revenues	$79,098	21	$65,367	(7)	$70,440
Cost of Goods Sold	58,718	6	55,415	(2)	56,591
Operating Expenses	3,796	27	2,998	(4)	3,135
Depreciation and Amortization	4,333	6	4,094	4	3,952
Operating Income	$12,251	328	$ 2,860	(58)	$ 6,762

2009 compared with 2008

The $13.7 million increase in food ingredient processing revenues is due to a 6.6% increase in pounds of product sold, combined with a 13.5% increase in the price per pound of product sold. A $3.3 million increase in cost of goods sold was due to increased product sales, slightly mitigated by a 0.6% decrease in the cost per pound of product sold as a result of decreases in raw potato costs and natural gas prices. Also, increased production and sales have resulted in a decrease in overhead absorption costs per pound of product produced and sold. The $0.8 million increase in operating expenses is mostly due to an increase in incentive pay directly related to increased sales and improved operating results in 2009.

2008 compared with 2007

The $5.1 million decrease in food ingredient processing revenues is due to a 13.2% decrease in pounds of product sold, partially offset by a 7.0% increase in the price per pound of product sold. The decrease in product sales was due to a reduction in sales to European customers and major snack customers and to lower production caused by potato supply shortages. European sales were higher than normal in 2007 due to reduced crop yields in Europe in 2006. Supply constraints combined with energy costs rising at rates faster than could be passed through to customers increased costs and lowered profits on products sold in 2008.

OTHER BUSINESS OPERATIONS

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

(in thousands)	2009	% change	2008	% change	2007
Operating Revenues	$136,088	(32)	$199,511	7	$185,730
Cost of Goods Sold	88,427	(34)	132,985	—	133,407
Operating Expenses	47,826	(12)	54,538	28	42,448
Depreciation and Amortization	2,550	14	2,230	8	2,058
Operating (Loss) Income	$ (2,715)	(128)	$ 9,758	25	$ 7,817

2009 compared with 2008

The decrease in operating revenues in 2009 compared with 2008 in our other business operations is due to the following:

- Revenues at Foley Company (Foley), a mechanical and prime contractor on industrial projects, decreased $34.4 million (35.0%) due to a decrease in volume of jobs in progress related to the recent economic recession and increased competition for available work.
- Revenues at Aevenia, Inc. (Aevenia), our electrical design and construction services company, formerly Midwest Construction Services Inc., decreased $18.8 million (32.1%) as a result of a decrease in jobs in progress, especially wind-energy projects, related to the recent economic recession and increased competition for available work.
- Revenues at E.W. Wylie Corporation (Wylie), our flatbed trucking company, decreased $10.2 million (24.0%) as a result of a 13.8% reduction in miles driven by company-owned trucks directly related to the recent economic recession combined with the effect of lower diesel fuel prices being passed through to customers. Also, increased competition for fewer loads has driven down shipping rates.

The decrease in cost of goods sold in 2009 compared with 2008 is due to the following:

- Foley’s cost of goods sold decreased $31.9 million as a result of decreases in construction activity and jobs in progress.
- Cost of goods sold at Aevenia decreased $12.7 million as a result of a reduction of jobs in progress.

The decrease in operating expenses in 2009 compared with 2008 is due to the following:

- Wylie’s operating expenses decreased $5.3 million between the years. Fuel costs decreased $7.2 million as a result of a 37.6% decrease in fuel costs per gallon combined with the 13.8% decrease in miles driven by company-owned trucks. Payments to owner-operators decreased $1.2 million as a result of lower fuel prices. The decreases in fuel costs were partially offset by an increase in repair and maintenance expenses of $1.7 million, an increase in rent expenses of $1.0 million, mainly related to additional equipment leases, and an increase in labor costs of $0.5 million.
- Aevenia’s operating expenses decreased $0.9 million between the years as a result of reductions in employee incentive bonuses and benefits from reduced profitability between the years and reductions in other contracted services related to less work volume.
- Foley’s operating expenses decreased $0.3 million between the periods due to reductions in incentive bonuses because of lower profitability in 2009.

2008 compared with 2007

The increase in operating revenues in 2008 compared with 2007 in our other business operations is due to the following:

- Revenues at Foley increased $16.6 million (20.3%) between the years due to an increase in volume of jobs performed.

- Revenues at Aevenia decreased $10.3 million (15.0%) between the years as a result of a reduction in the number of jobs in progress in 2008 compared to 2007 in the area of electrical infrastructure for delivery of wind generated electricity and Aevenia supplied materials for more jobs in 2007 resulting in a reduction in material pass through costs and revenues in 2008.
- Revenues at Wylie increased $7.5 million (21.5%) mainly as a result of the impact of increased fuel costs on shipping rates. Miles driven by company-owned trucks increased 15.7% as a result of the addition of heavy haul and wind tower transport services. Miles driven by owner-operated trucks decreased 32.6%. Combined miles driven by company-owned and owner-operated trucks decreased 1.1% between the years, reflecting a reduction in transport activity related to the economic downturn that started in 2008.

The slight decrease in cost of goods sold in 2008 compared with 2007 is due to the following:

- Foley's cost of goods sold increased $14.2 million, including increases of $6.2 million in direct labor and benefit costs, $5.1 million in subcontractor costs and $2.7 million in material costs as a result of increased construction activity and jobs in progress.
- Cost of goods sold at Aevenia decreased $14.7 million due to decreases in material and subcontractor costs directly related to Aevenia having fewer jobs in progress and supplying materials on fewer jobs in 2008. However, Aevenia's gross margins increased by $4.4 million mainly as a result of higher productivity and increased margins on wind turbine and electric transmission line projects in 2008.

The increase in operating expenses in 2008 compared with 2007 is due to the following:

- Wylie's operating expenses increased $8.8 million between the years. Fuel costs increased $6.9 million as a result of higher diesel fuel prices and a 15.7% increase in miles driven by company-owned trucks. Labor and benefit costs increased by $1.3 million and equipment rental costs increased by $0.6 million due to the addition of heavy-haul services in the fourth quarter of 2007.
- Aevenia's operating expenses increased $2.0 million between the years due to increases in salary, benefit and professional services expenses.
- Foley's operating expenses increased $0.9 million between the years due to increases in labor, professional services and insurance costs.
- Operating expenses at Otter Tail Energy Services Company, our energy services subsidiary, increased $0.4 million between the years related to the investigation of renewable energy wind-generation projects.

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)	2009	% change	2008	% change	2007
Operating Expenses	$13,246	(17)	$15,867	62	$9,824
Depreciation and Amortization	397	(26)	538	(7)	579

2009 compared with 2008

Corporate operating expenses decreased $2.6 million as a result of reductions for salaries and benefits, including health care expenses and insurance costs.

2008 compared with 2007

Corporate operating expenses increased $6.0 million as a result of a combination of increases in self insured health insurance plan costs, insurance expenses and claims experience in the captive insurance company, stock-based compensation and benefit expenses and outside professional service costs related to the formation of a holding company. These increases were partially offset by a decrease in incentive compensation expense.

CONSOLIDATED OTHER INCOME

Other income increased by $0.4 million in 2009 compared with 2008 as a result of an increase in Allowance for Funds used During Construction (AFUDC) at OTP in 2009.

Other income increased by $2.1 million in 2008 compared with 2007 mainly as a result of an increase in AFUDC at OTP in 2008. No equity AFUDC was recorded in 2007 because our 2007 average short-term debt balance was in excess of the average balance of Construction Work in Progress (CWIP) at OTP in 2007. Average CWIP exceeded average short-term debt in 2008. As a result, 63% of AFUDC in 2008 was equity funded.

CONSOLIDATED INTEREST CHARGES

Interest charges increased $1.6 million in 2009 compared with 2008 as a result of the following: (1) the issuance of $75 million in debt in May 2009 to finance construction of OTP's 33 wind turbines at the Luverne Wind Farm, (2) an increase in the interest rate on our $50 million senior unsecured note due November 30, 2017, from 5.778% to 8.89%, in connection with our change to a holding company structure effective July 1, 2009, (3) the issuance of $100 million in debt in December 2009 to pay down line of credit borrowings that were used to finance plant expansions and acquisitions at our nonelectric subsidiaries, (4) increases in the amortization of debt issuance costs related to 2009 debt issuances, and (5) a $0.9 million reduction in capitalized interest charges related to a reduction in the average balance of construction work in progress and short-term debt between the years. These increases in interest charges were partially offset by reductions in interest paid on short-term borrowings as the average daily balance of short-term debt outstanding decreased by $24.4 million and the weighted-average rate of interest on short-term borrowings decreased by 1.7 percentage points between the years.

Interest charges increased $6.1 million in 2008 compared with 2007 primarily as a result of a net increase of $87 million in long-term debt in August and October of 2007. Short-term debt interest charges increased by $1.8 million in 2008 as a result of a $76.3 million increase in the average daily balance of short-term debt outstanding in 2008, mitigated by a 1.9 percentage point decrease in the weighted average interest rate paid on short-term debt between the years. Interest charges also increased in 2008 as a result of a $0.5 million reduction in capitalized interest in 2008 compared with 2007.

CONSOLIDATED INCOME TAXES

The $19.6 million (130.6%) decrease in income taxes in 2009 compared with 2008 is mainly due to three items: (1) a $28.7 million decrease in income before income taxes in 2009 compared with 2008, (2) a permanent difference in the depreciable tax value of OTP's Luverne Wind Farm assets of $15 million, which resulted in a $3.1 million reduction in our consolidated income taxes in 2009, and (3) the benefits of federal production tax credits and North Dakota wind energy credits related to OTP's wind projects of approximately $7.4 million in 2009 compared with $3.6 million in 2008. Federal production tax credits are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. 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. Income tax reductions from federal production tax credits and North Dakota wind energy credits are passed back to OTP's retail electric customers through reductions to renewable resource recovery riders or renewable energy costs recovered in general rates.

The $12.9 million (46.2%) reduction in income tax expense in 2008 compared with 2007 is mostly due to a 38.8% decrease in income before income taxes. The decrease also is due to federal production tax credits earned on electricity generated from renewable resources in 2008. These items caused our effective tax rate on income from continuing operations to be 30.0% in 2008 compared with 34.1% in 2007.

IMPACT OF INFLATION

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

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

LIQUIDITY

The following table presents the status of our lines of credit as of December 31, 2009 and December 31, 2008:

(in thousands)	Line Limit	In Use on December 31, 2009	Restricted due to Outstanding Letters of Credit	Available on December 31, 2009	Available on December 31, 2008
Otter Tail Corporation Credit Agreement	$200,000	$6,000	$14,245	$179,755	$ 77,706
OTP Credit Agreement [1]	170,000	1,585	680	167,735	142,935
Total	$370,000	$7,585	$14,925	$347,490	$220,641

[1] On January 4, 2010, OTP paid off the remaining $58.0 million balance outstanding on its two-year, $75.0 million term loan that was originally due on May 20, 2011, using lower costs funds available under the OTP Credit Agreement. OTP did not incur any penalties for the early repayment and retirement of this debt.

We believe we have the necessary liquidity to effectively conduct business operations for an extended period if current market conditions continue. Despite the recent economic recession, our balance sheet is strong and we are in compliance with our debt covenants.

We believe our financial condition is strong and that our cash, other liquid assets, operating cash flows, existing lines of credit, access to capital markets and borrowing ability because of solid credit ratings, when taken together, provide adequate resources to fund ongoing operating requirements and future capital expenditures related to expansion of existing businesses and development of new projects. On May 11, 2009 we filed a shelf registration statement with the Securities and Exchange Commission under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement. Equity or debt financing will be required in the period 2010 through 2014 given the expansion plans related to our electric segment to fund construction of new rate base investments, in the event we decide to reduce borrowings under our lines of credit, to refund or retire early any of our presently outstanding debt or cumulative preferred shares, to complete acquisitions or for other corporate purposes. Also, our operating cash flow and access to capital markets can be impacted by macroeconomic factors outside our control. In addition, our borrowing costs can be impacted by changing interest rates on short-term and long-term debt and ratings assigned to us by independent rating agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios.

Our dividend payout ratio for the year ended December 31, 2009 was 168% compared to 109% and 66% for the years ended December 31, 2008 and 2007, respectively. The determination of the amount of future cash dividends to be declared and paid will depend on, among other things, our financial condition, cash flows from operations, the level of our capital expenditures, restrictions under our credit facilities and our future business prospects.

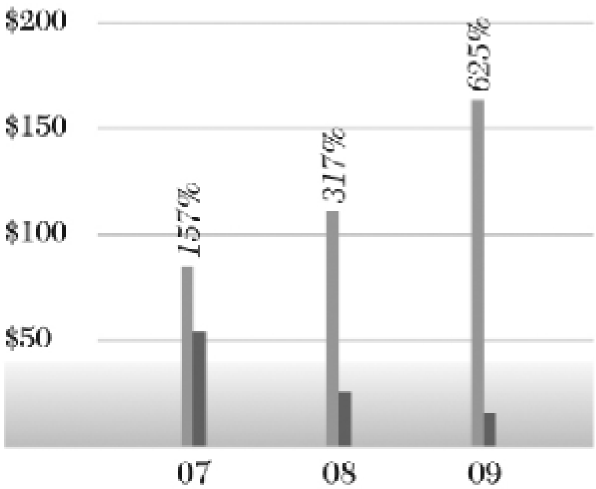
DMI has a $40 million receivable purchase agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation on a revolving basis. The agreement expires in March 2011. Accounts receivable totaling $133.9 million were sold in 2009. Discounts, fees and commissions of $0.4 million for the year ended December 31, 2009 were charged to operating expenses in the consolidated statements of income. The balance of receivables sold that was outstanding to the buyer as of December 31, 2009 was $15.0 million. The sales of these accounts receivable are reflected as a reduction of accounts receivable in our consolidated balance sheets and the proceeds are included in the cash flows from operating activities in our consolidated statement of cash flows.

Cash provided by operating activities was $162.7 million in 2009 compared with $111.3 million in 2008. The $51.4 million increase in cash from operating activities reflects a $45.2 million increase in cash from working capital items between the years. Major sources of funds from working capital items in 2009 were a decrease in receivables of $43.8 million, a decrease in inventories of $16.3 million and a decrease in other current assets of $13.1 million, offset by a decrease in payables and other current liabilities of $34.5 million and an increase in income taxes receivable of $21.3 million. We received net tax refunds of $27.4 million in cash in 2009 and recorded additional income taxes receivable in 2009 of $48.7 million, most of which we expect to receive in the second quarter of 2010.

The $43.8 million decrease in accounts receivable reflects decreases in trade receivables of $25.0 million at DMI, $6.4 million at BTD and $6.8 million at Foley due to declines in manufacturing and construction activity related to the recent economic recession. The $16.3 million decrease in inventories includes reductions of $7.7 million at the plastic pipe companies and $7.1 million at BTD due to reductions in production and sales, and decreases in PVC resin and steel prices. The $13.1 million decrease in other current assets includes an $8.2 million decrease in accrued utility revenues due to decreases in accrued fuel clause adjustment revenues related to declining prices for purchased power and a $4.3 million decrease in costs in excess of billings at DMI as a result of a decrease in production and sales activity between the years.

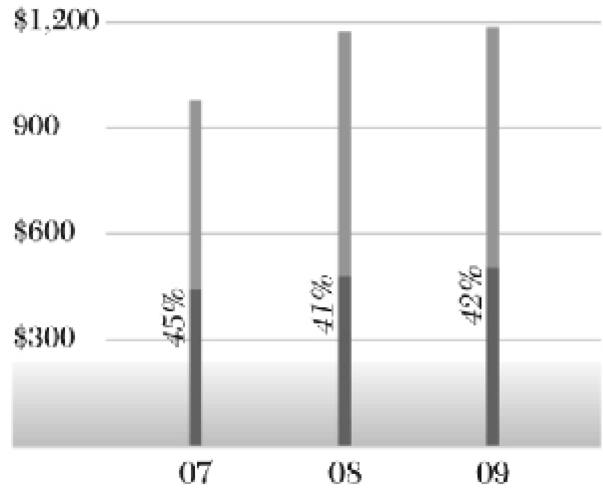
The $34.5 million decrease in payables and other current liabilities includes decreases of: (1) $12.9 million at DMI related to a decrease in production activity, (2) $9.7 million at OTP related to reductions in construction activity, energy purchases and purchased power costs, (3) $8.6 million related to the payment of accrued wages and benefits in 2009, and (4) $5.4 million at Foley related to a reduction in construction activity in 2009. The $21.3 million increase in income taxes receivable is due to recording a tax refund receivable mainly related to bonus tax depreciation and renewable production and energy tax credits earned in 2009 along with the ability to apply those credits and losses against taxes paid in previous years.

CASH REALIZATION RATIOS (millions)



The cash realization ratio represents cash flows from operations expressed as a percent of net income.

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



Otter Tail has maintained a 40-45% interest-bearing debt to total capital ratio for the past three years.

Net cash used in investing activities was $147.7 million in 2009 compared with $299.4 million in 2008. Cash used for capital expenditures decreased by $88.8 million between the years mainly due to reductions in capital expenditures at OTP. Cash used for capital expenditures of $177.1 million in 2009 includes $145.8 million at OTP, of which $100.6 million related to the construction of 33 wind turbines and a collector system at the Luverne Wind Farm. OTP received grant proceeds of $30.2 million under the American Recovery and Reinvestment Act of 2009 related to this investment in renewable energy, which reduced the capitalized cost of these generation assets. DMI had capital expenditures of $10.8 million in 2009, mainly for equipment. We paid $41.7 million in cash to acquire Miller Welding in May 2008.

Net cash used in financing activities was $17.1 million in 2009 compared with net cash provided by financing activities of $154.6 million in 2008. Reductions in short-term borrowings were $127.3 million in 2009 compared to proceeds from short-term borrowings of $39.9 million in 2008. We borrowed $75.0 million in May 2009 under a two-year term loan agreement. The proceeds were used to support OTP's construction of 49.5 MW of renewable wind-generation assets at the Luverne Wind Farm. In December 2009 we issued $100 million of our 9.000% notes due 2016. Proceeds from the issuance were used to repay our revolving credit facility, which had an outstanding balance due of $107.0 million on November 30, 2009 at an interest rate of approximately 2.6%. We used approximately $44.5 million of the borrowings under our revolving credit facility to fund costs incurred for the expansion of our subsidiary companies' manufacturing facilities in 2008 and 2009. We used approximately $23.0 million to fund the acquisition of Miller Welding in 2008 and approximately $28.5 million in connection with the capitalization of our holding company reorganization in 2009.

We paid $5.5 million in short-term and long-term debt issuance expenses in 2009. We made payments of $23.4 million for the retirement of long-term debt in 2009 compared with $3.6 million in 2008. The $23.4 million in long-term debt payments in 2009 includes $17.0 million used to retire early a portion of the $75.0 million borrowed in May 2009 under a two-year term loan agreement and a $3.5 million payment for the early retirement of our Lombard US Equipment Finance Note in June 2009. We paid no penalties on either of these early retirements. We paid $43.0 million in dividends on common and preferred shares in 2009 compared with $38.1 million in 2008. The increase in dividend payments is due to an increase in common shares outstanding between the periods mainly related to our September 2008 common stock offering. We received proceeds of $7.4 million from the issuance of common stock in 2009, mainly to meet the requirements of our dividend reinvestment and share purchase plans.

CAPITAL REQUIREMENTS

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

Cash used for consolidated capital expenditures was $177 million in 2009, $266 million in 2008 and $162 million in 2007. As a result of the recent economic recession and difficult credit market conditions we have reduced capital expenditures across all of our operating companies. Estimated capital expenditures for 2010 are $80 million. Total capital expenditures for the five-year period 2010 through 2014 are estimated to be approximately $817 million, which includes $245 million for additional generation and $110 million for CapX 2020 transmission projects at OTP.

The breakdown of 2007, 2008 and 2009 actual and 2010 through 2014 estimated capital expenditures by segment is as follows:

(in millions)	2007	2008	2009	2010	2010-2014
Electric	$ 104	$ 199	$ 146	$ 50	$ 641
Plastics	3	9	4	2	11
Manufacturing	43	48	19	12	95
Health Services	5	4	3	11	28
Food Ingredient Processing	—	2	1	1	9
Other Business Operations	6	4	4	3	31
Corporate	1	—	—	1	2
Total	$ 162	$ 266	$ 177	$ 80	$ 817

The following table summarizes our contractual obligations at December 31, 2009 and the effect these obligations are expected to have on our liquidity and cash flow in future periods.

(in millions)	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-Term Debt Obligations	$ 495	$ 59	$ 101	$ 1	$ 334
Interest on Long-Term Debt Obligations	309	31	61	50	167
Capacity and Energy Requirements	155	19	35	16	85
Coal Contracts (required minimums)	111	52	27	19	13
Operating Lease Obligations	106	38	37	13	18
Postretirement Benefit Obligations	66	3	8	8	47
Other Purchase Obligations	21	21	—	—	—
Total Contractual Cash Obligations	$ 1,263	$ 223	$ 269	$ 107	$ 664

Interest on $10.4 million of variable-rate debt outstanding on December 31, 2009 was projected based on the interest rates applicable to that debt instrument on December 31, 2009. Postretirement Benefit Obligations include estimated cash expenditures for the payment of retiree medical and life insurance benefits and supplemental pension benefits under our unfunded Executive Survivor and Supplemental Retirement Plan, but do not include amounts to fund our noncontributory funded pension plan as we are not currently required to make a contribution to that plan.

CAPITAL RESOURCES

The following table presents the status of our lines of credit as of December 31, 2009 and December 31, 2008:

(in thousands)	Line Limit	In Use on December 31, 2009	Restricted due to Outstanding Letters of Credit	Available on December 31, 2009	Available on December 31, 2008
Otter Tail Corporation Credit Agreement	$200,000	$ 6,000	$ 14,245	$ 179,755	$ 77,706
OTP Credit Agreement [1]	170,000	1,585	680	167,735	142,935
Total	$370,000	$ 7,585	$ 14,925	$ 347,490	$ 220,641

1 On January 4, 2010, OTP paid off the remaining $58.0 million balance outstanding on its two-year, $75.0 million term loan that was originally due on May 20, 2011, using lower costs funds available under the OTP Credit Agreement. OTP did not incur any penalties for the early repayment and retirement of this debt.

Financial flexibility is provided by operating cash flows, unused lines of credit, strong financial coverages, solid credit ratings, and alternative financing arrangements such as leasing. Equity or debt financing will be required in the period 2010 through 2014 given the expansion plans related to our electric segment to fund construction of new rate base investments, in the event we decide to reduce borrowings under our lines of credit, to refund or retire early any of our presently outstanding debt or cumulative preferred shares, to complete acquisitions or for other corporate purposes. There can be no assurance that any additional required financing will be available through bank borrowings, debt or equity financing or otherwise, or that if such financing is available, it will be available on terms acceptable to us. If adequate funds are not available on acceptable terms, our businesses, results of operations and financial condition could be adversely affected.

Prior to our holding company reorganization on July 1, 2009, our wholly owned subsidiary, Varistar Corporation (Varistar), was the borrower under the $200 million credit agreement referred to in the table above (the Credit Agreement) with the following banks: U.S. Bank National Association, as agent for the Banks and as Lead Arranger, Bank of America, N.A., Keybank National Association, and Wells Fargo Bank, National Association, as Co-Documentation Agents, and JPMorgan Chase Bank, N.A., Bank of the West and Union Bank of California, N.A. Effective July 1, 2009 all of Varistar's rights and obligations under the Credit Agreement were assigned to and assumed by Otter Tail Corporation. Beginning July 1, 2009 borrowings bear interest at LIBOR plus 2.375%, subject to adjustment based on the senior unsecured credit ratings of the Company. The Credit Agreement expires October 2, 2010 and is an unsecured revolving credit facility. The Credit Agreement contains a number of restrictions on us and the businesses of Varistar and its material subsidiaries, including restrictions on their ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of certain other parties and engage in transactions with related parties. The Credit Agreement also contains affirmative covenants and events of default. The Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the borrower's credit ratings. Our obligations under the Credit Agreement are guaranteed by Varistar and its material subsidiaries. Outstanding letters of credit issued by the borrower under the Credit Agreement can reduce the amount available for borrowing under the line by up to $30 million. The Credit Agreement has an accordion feature whereby the line can be increased to $300 million as described in the Credit Agreement. We are in the process of negotiating a renewal of the Credit Agreement to be effective at the expiration of current term of the Credit Agreement.

Prior to our holding company reorganization on July 1, 2009, Otter Tail Corporation, dba Otter Tail Power Company (now OTP) was the borrower under the $170 million credit agreement referred to in the table above (the OTP Credit Agreement) with an accordion feature whereby the line can be increased to $250 million as described in the OTP Credit Agreement. The credit agreement was entered into between Otter Tail Corporation, dba Otter Tail Power Company (now OTP) and JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association and Merrill Lynch Bank USA, as Banks, U.S. Bank National Association, as a Bank and as agent for the Banks, and Bank of America, N.A., as a Bank and as Syndication Agent. The OTP Credit Agreement is an unsecured revolving credit facility that OTP can draw on to support the working capital needs and other capital requirements of its operations. Borrowings under this line of credit bear interest at LIBOR plus 0.5%, subject to adjustment based on the ratings of the borrower's senior unsecured debt. The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Credit Agreement also contains affirmative covenants and events of default. The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the borrower's credit ratings. The OTP Credit Agreement is subject to renewal on July 30, 2011. The OTP Credit Agreement is an obligation of OTP.

In November 2009, OTP paid down $17 million of its two-year, $75 million term loan, originally due May 11, 2011. OTP paid off the remaining $58 million balance in January 2010, using lower cost funds available under the OTP Credit Agreement. OTP did not incur any penalties for the early repayments and retirement of this debt.

The note purchase agreement relating to the $90 million 6.63% senior notes due December 1, 2011 entered into in December 2001 by Otter Tail Corporation (now known as OTP), as amended (the 2001 Note Purchase Agreement), the note purchase agreement relating to the $50 million 5.778% senior note due November 30, 2017 entered into in February 2007 by Otter Tail Corporation (now known as OTP) and assigned to the Company (formerly known as Otter Tail Holding Company), as amended (the Cascade Note Purchase Agreement), and the note purchase agreement relating to our $155 million senior unsecured notes issued in four series consisting of $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017; $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022; $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027; and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037, entered into in August 2007 by Otter Tail Corporation (now known as OTP), as amended (the 2007 Note Purchase Agreement) each states that the applicable obligor may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. Each of the Cascade Note Purchase Agreement and the 2001 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require the applicable obligor to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the respective note purchase agreements. The 2007 Note Purchase Agreement states the applicable obligor must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of such obligor. The 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and the Cascade Note Purchase Agreement each contain a number of restrictions on the applicable obligor and its subsidiaries. These include restrictions on the obligor's ability and the ability of the obligor's subsidiaries to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. Prior to the effectiveness of the holding company reorganization, our obligations under the 2001 Note Purchase Agreement and the Cascade Note Purchase Agreement were guaranteed by Varistar and certain of its material subsidiaries. Following the effectiveness of the holding company reorganization, only our obligations under the Cascade Note Purchase Agreement remain guaranteed by Varistar and certain of its material subsidiaries (and not by OTP).

On December 4, 2009 we issued $100 million of our 9.000% notes due 2016 under the indenture (for unsecured debt securities) dated as of November 1, 1997, as amended by the First Supplemental Indenture dated as of July 1, 2009, between us and U.S. Bank National Association (formerly First Trust National Association), as trustee. The notes are senior unsecured indebtedness and bear interest at 9.000% per year, payable semi-annually in arrears on June 15 and December 15 of each year, beginning June 15, 2010. The entire principal amount of the notes, unless previously redeemed or otherwise repaid, will mature and become due and payable on December 15, 2016. The net proceeds from the issuance of approximately $98.3 million, after deducting the underwriting discount and offering expenses, were used to repay our revolving credit facility, which had an outstanding balance due of $107.0 million on November 30, 2009 at an interest rate of approximately 2.6%.

Financial Covenants

As of December 31, 2009 the Company was in compliance with the financial statement covenants that existed in its debt agreements.

None of the Credit and Note Purchase Agreements contains any provisions that would trigger an acceleration of the related debt as a result of changes in the credit rating levels assigned to the related obligor by rating agencies.

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

- Under the Credit Agreement, we may not permit the ratio of our Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit our Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), as provided in the Credit Agreement.
- Under the Cascade Note Purchase Agreement, we may not permit our ratio of Consolidated Debt to Consolidated Total Capitalization to be greater than 0.60 to 1.00 or our Interest Charges Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), permit the ratio of OTP's Debt to OTP's Total Capitalization to be greater than 0.60 to 1.00, or permit Priority Debt to exceed 20% of Varistar Consolidated Total Capitalization, as provided in the Cascade Note Purchase Agreement.
- Under the OTP Credit Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, as provided in the Loan Agreement.

[Table of Contents](#)

- Under the 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and the financial guaranty insurance policy with Ambac Assurance Corporation relating to certain pollution control refunding bonds, OTP may not permit the ratio of its Consolidated Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio (or, in the case of the 2001 Note Purchase Agreement, its Interest Charges Coverage Ratio) to be less than 1.50 to 1.00, in each case as provided in the related borrowing or insurance agreement. In addition, under the 2001 Note Purchase Agreement and the 2007 Note Purchase Agreement, OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement.

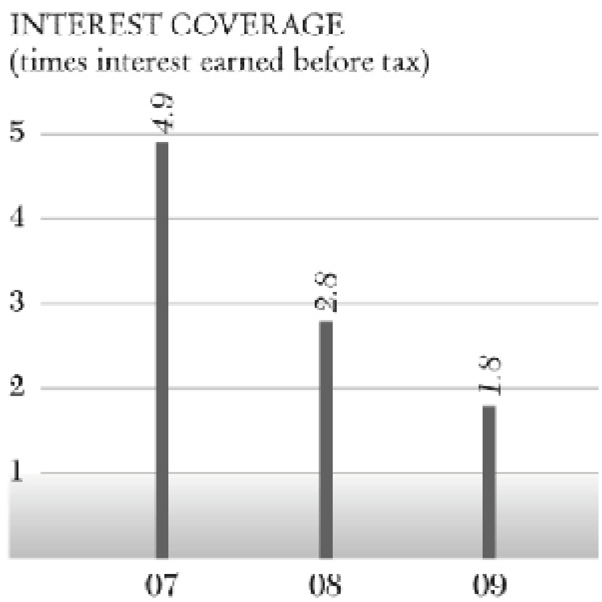
Our ratings at December 31, 2009 were:

Otter Tail Corporation	Moody's Investors Service	Fitch Ratings	Standard & Poor's
Corporate Credit/Long-Term Issuer Default Rating	Baa3	BBB-	BBB-
Senior Unsecured Debt	Baa3	BBB-	BB+
9.000% Notes Due 2016	Ba1	BBB-	BB+
Outlook	Stable	Stable	Stable

Otter Tail Power Company	Moody's Investors Service	Fitch Ratings	Standard & Poor's
Corporate Credit/Long-Term Issuer Default Rating	A3	BBB	BBB-
Senior Unsecured Debt	A3	BBB+	BBB-
Outlook	Stable	Stable	Stable

Our disclosure of these securities ratings is not a recommendation to buy, sell or hold our securities. Downgrades in these securities ratings could adversely affect our company. Further, downgrades could increase our borrowing costs resulting in possible reductions to net income in future periods and increase the risk of default on our debt obligations.

Our ratio of earnings to fixed charges from continuing operations, which includes imputed finance costs on operating leases, was 1.6x for 2009 compared to 2.4x for 2008, and our debt interest coverage ratio before taxes was 1.8x for 2009 compared to 2.8x for 2008. During 2010, we expect these coverage ratios to increase, assuming 2010 net income meets our expectations.



Otter Tail has maintained coverage ratios in excess of its debt covenant requirements.

OFF-BALANCE-SHEET ARRANGEMENTS

We and our subsidiary companies have outstanding letters of credit totaling $23.5 million. We do not have any other off-balance-sheet arrangements or any relationships with unconsolidated entities or financial partnerships. These entities are often referred to as structured finance special purpose entities or variable interest entities, which are established for the purpose of facilitating off-balance-sheet arrangements or for other contractually narrow or limited purposes. We are not exposed to any financing, liquidity, market or credit risk that could arise if we had such relationships.

2010 BUSINESS OUTLOOK

We anticipate 2010 diluted earnings per share to be in the range of $1.00 to $1.40. This guidance considers the cyclical nature of some of our businesses and reflects challenges presented by current economic conditions and our plans and strategies for improving operating results as the economy recovers. Our current consolidated capital expenditures expectation for 2010 is in the range of $75-85 million. This compares with $177 million of capital expenditures in 2009. We continue to explore investments in generation and transmission projects for the electric segment that could have positive impacts on our earnings and returns on capital.

Contributing to our earnings guidance for 2010 are the following items:

- We expect lower levels of net income from our electric segment in 2010. This decrease is due to continued soft wholesale power markets, lower AFUDC earnings as there are no large construction projects expected in 2010, and increased operating and maintenance expense in 2010 due primarily to increased employee benefit costs. Expectations in 2010 also reflect an interim rate increase of approximately $1.5 million in the Minnesota jurisdiction.
- We expect our plastics segment's 2010 performance to improve and be more in line with 2008 results.
- We expect earnings from our manufacturing segment to improve in 2010 as a result of the following:
  - Improved earnings are expected at BTD in 2010 due to productivity improvements and cost reductions made in 2009.
  - Results at ShoreMaster are expected to be near breakeven in 2010 given the restructuring of costs that occurred in 2009. ShoreMaster continues to be affected by current depressed economic conditions and does not expect any improvement to overall business conditions until the economy starts to recover.
  - Improved earnings are expected at DMI in 2010 due to a better backlog of business going into 2010 and continued improvements in productivity from cost controls implemented in 2009.
  - Slightly better earnings are expected at T. O. Plastics in 2010 compared with 2009.
  - Backlog in place in the manufacturing segment to support 2010 revenues is approximately $239 million compared with $241 million one year ago.
- We expect increased net income from our health services segment in 2010. In an effort to right-size its fleet of imaging assets, health services will not renew leases on a large number of imaging assets that come off lease in 2010. This will result in a lower level of rental costs in 2010.
- We expect a similar level of net income from our food ingredient processing business in 2010 compared with 2009.
- We expect our other business operations segment to have improved earnings in 2010 compared with 2009. Backlog in place for the construction businesses is $84 million for 2010 compared with $71 million one year ago.
- We expect corporate general and administrative costs to return to more normal levels in 2010.

Our outlook for 2010 is dependent on a variety of factors and is subject to the risks and uncertainties discussed in Item 1A. Risk Factors, and elsewhere in this Annual Report on Form 10-K.

CRITICAL ACCOUNTING POLICIES INVOLVING SIGNIFICANT ESTIMATES

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

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

PENSION AND OTHER POSTRETIREMENT BENEFITS OBLIGATIONS AND COSTS

Pension and postretirement benefit liabilities and expenses for our electric utility and corporate employees are determined by actuaries using assumptions about the discount rate, expected return on plan assets, rate of compensation increase and healthcare cost-trend rates. Further discussion of our pension and postretirement benefit plans and related assumptions is included in note 12 to consolidated financial statements.

These benefits, for any individual employee, can be earned and related expenses can be recognized and a liability accrued over periods of up to 40 or more years. These benefits can be paid out for up to 40 or more years after an employee retires. Estimates of liabilities and expenses related to these benefits are among our most critical accounting estimates. Although deferral and amortization of fluctuations in actuarially determined benefit obligations and expenses are provided for when actual results on a year-to-year basis deviate from long-range assumptions, compensation increases and healthcare cost increases or a reduction in the discount rate applied from one year to the next can significantly increase our benefit expenses in the year of the change. Also, a reduction in the expected rate of return on pension plan assets in our funded pension plan or realized rates of return on plan assets that are well below assumed rates of return could result in significant increases in recognized pension benefit expenses in the year of the change or for many years thereafter because actuarial losses can be amortized over the average remaining service lives of active employees.

The pension benefit cost for 2010 for our noncontributory funded pension plan is expected to be $6.3 million compared to $3.1 million in 2009. The estimated discount rate used to determine annual benefit cost accruals will be 6.00% in 2010 compared with 6.70% used in 2009. In selecting the discount rate, we consider the yields of fixed income debt securities, which have ratings of “Aa” published by recognized rating agencies, along with bond matching models specific to our plans as a basis to determine the rate.

Subsequent increases or decreases in actual rates of return on plan assets over assumed rates or increases or decreases in the discount rate or rate of increase in future compensation levels could significantly change projected costs. For 2009, all other factors being held constant: a 0.25 increase in the discount rate would have decreased our 2009 pension benefit cost by $160,000; a 0.25 decrease in the discount rate would have increased our 2009 pension benefit cost by $480,000; a 0.25 increase in the assumed rate of increase in future compensation levels would have increased our 2009 pension benefit cost by $460,000; a 0.25 decrease in the assumed rate of increase in future compensation levels would have decreased our 2009 pension benefit cost by $350,000; a 0.25 increase (or decrease) in the expected long-term rate of return on plan assets would have decreased (or increased) our 2009 pension benefit cost by $410,000.

Increases or decreases in the discount rate or in retiree healthcare cost inflation rates could significantly change our projected postretirement healthcare benefit costs. A 0.25 increase (or decrease) in the discount rate would have decreased (or increased) our 2009 postretirement medical benefit costs by $70,000. See note 12 to consolidated financial statements for the cost impact of a change in medical cost inflation rates.

We believe the estimates made for our pension and other postretirement benefits are reasonable based on the information that is known at the point in time the estimates are made. These estimates and assumptions are subject to a number of variables and are subject to change.

REVENUE RECOGNITION

Our construction companies and two of our manufacturing companies record operating revenues on a percentage-of-completion basis for fixed-price construction contracts. The method used to determine the progress of completion is based on the ratio of labor costs incurred to total estimated labor costs at our wind tower manufacturer, square footage completed to total bid square footage for certain floating dock projects and costs incurred to total estimated costs on all other construction projects. The duration of the majority of these contracts is less than a year. Revenues recognized on jobs in progress as of December 31, 2009 were $460 million. Any expected losses on jobs in progress at year-end 2009 have been recognized. We believe the accounting estimate related to the percentage-of-completion accounting on uncompleted contracts is critical to the extent that any underestimate of total expected costs on fixed-price construction contracts could result in reduced profit margins being recognized on these contracts at the time of completion.

FORWARD ENERGY CONTRACTS CLASSIFIED AS DERIVATIVES

OTP’s forward contracts for the purchase and sale of electricity are derivatives subject to mark-to-market accounting under generally accepted accounting principles. The market prices used to value OTP’s forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP’s power services’ personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models and, as such, are estimates. The forward energy sales contracts that are marked to market as of December 31, 2009, are 100% offset by forward energy purchase contracts in terms of volumes, delivery periods and delivery points. OTP’s recognized but unrealized net gains on the forward energy purchases and sales marked to market on December 31, 2009 are expected to be realized on settlement as scheduled over the following years in the amounts listed:

(in thousands)	2010	2011	2012	Total
Net Gain	$389	$320	$321	$1,030

ALLOWANCE FOR DOUBTFUL ACCOUNTS

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

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

During 2009, $3.0 million of bad debt expense (0.3% of total 2009 revenue of $1.0 billion) was recorded and the allowance for doubtful accounts was $4.4 million (4.4% of trade accounts receivable) as of December 31, 2009. General economic conditions and specific geographic concerns are major factors that may affect the adequacy of the allowance and may result in a change in the annual bad debt expense. An increase or decrease in our consolidated allowance for doubtful accounts based on one percentage point of outstanding trade receivables at December 31, 2009 would result in a $1.0 million increase or decrease in bad debt expense.

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

DEPRECIATION EXPENSE AND DEPRECIABLE LIVES

The provisions for depreciation of electric utility property for financial reporting purposes are made on the straight-line method based on the estimated service lives (5 to 65 years) of the properties. Such provisions as a percent of the average balance of depreciable electric utility property were 2.90% in 2009, 2.81% in 2008 and 2.78% in 2007. Depreciation rates on electric utility property are subject to annual regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. Although the useful lives of electric utility properties are estimated, the recovery of their cost is dependent on the ratemaking process. Deregulation of the electric industry could result in changes to the estimated useful lives of electric utility property that could impact depreciation expense.

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

TAXATION

We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income, real estate and use taxes. These judgments could result in the recognition of a liability for potential adverse outcomes regarding uncertain tax positions that we have taken. While we believe our liability for uncertain tax positions as of December 31, 2009 reflects the most likely probable expected outcome of these tax matters in accordance with the requirements of ASC 740, *Income Taxes* , the ultimate outcome of such matters could result in additional adjustments to our consolidated financial statements. However, we do not believe such adjustments would be material.

Deferred income taxes are provided for revenue and expenses which are recognized in different periods for income tax and financial reporting purposes. We assess our deferred tax assets for recoverability based on both historical and anticipated earnings levels. We have not recorded a valuation allowance related to the probability of recovery of our deferred tax assets as we believe reductions in tax payments related to these assets will be fully realized in the future.

ASSET IMPAIRMENT

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

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

As of December 31, 2009 an assessment of the carrying amounts of our long-lived assets and other intangibles indicated these assets were not impaired.

GOODWILL IMPAIRMENT

Goodwill is required to be evaluated annually for impairment, according to ASC 350-20-35, *Goodwill - Subsequent Measurement* . The standard requires a two-step process be performed to analyze whether or not goodwill has been impaired. Step one is to test for potential impairment and requires that the fair value of the reporting unit be compared to its book value including goodwill. If the fair value is higher than the book value, no impairment is recognized. If the fair value is lower than the book value, a second step must be performed. The second step is to measure the amount of impairment loss, if any, and requires that a hypothetical purchase price allocation be done to determine the implied fair value of goodwill. This fair value is then compared to the carrying amount of goodwill. If the implied fair value is lower than the carrying amount, an impairment adjustment must be recorded.

We believe accounting estimates related to goodwill impairment are critical because the underlying assumptions used for the discounted cash flow can change from period to period and could potentially cause a material impact to the income statement. Management's assumptions about inflation rates and other internal and external economic conditions, such as earnings growth rate, require significant judgment based on fluctuating rates and expected revenues. Additionally, ASC 350-20-35 requires goodwill be analyzed for impairment on an annual basis using the assumptions that apply at the time the analysis is updated.

As of December 31, 2009 we have $12.2 million of goodwill and $4.9 million in nonamortizable trade names recorded on our balance sheet related to the acquisition of ShoreMaster and its subsidiary companies. ShoreMaster produces and markets residential and commercial waterfront equipment, ranging from boatlifts and docks for lakefront property to full commercial marina projects. The business has experienced reduced demand for its products due to the recent economic recession and has incurred net losses. We considered these adverse developments in the business to be an indicator of potential impairment of ShoreMaster's goodwill and other intangible assets.

Based on the current goodwill review, we concluded that no impairment charge was necessary. However, if current economic conditions continue to impact the amount of sales of waterfront products and ShoreMaster is not successful with reorganizing and streamlining its business to improve operating margins according to our projections, the reductions in anticipated cash flows from this business may indicate, in a future period, that its fair value is less than its carrying amount resulting in an impairment of some or all of the goodwill and nonamortizable intangible assets associated with ShoreMaster along with a corresponding charge against earnings.

ShoreMaster's current operating plan calls for modest revenue growth in 2010 in line with growth in gross domestic product. With the cost reduction efforts that have occurred over the past year, we expect ShoreMaster's earnings to be near breakeven in 2010. Given the nature of ShoreMaster's products and the markets it serves, our operating plans assume revenue and earnings growth will begin to occur in 2011. These revenue growth assumptions are consistent with ShoreMaster's historical growth rates before the recent economic downturn. Inherent in these assumptions is that ShoreMaster's manufacturing capacity utilization will increase from current utilization of 40% to approximately 70% of capacity for the year ending 2014. ShoreMaster is expecting its dealer base to grow during this period of time which is reasonable given its historic ability to grow its dealer base. ShoreMaster has not experienced any deterioration in its dealer base during the economic downturn.

The weighted average cost of capital used for this analysis was 13.3% which is reflective of the risks inherent in ShoreMaster's industry. This compares with the previous weighted average cost of capital of 12% which was used in the previous year annual goodwill review for ShoreMaster. We used a terminal value growth rate of 3% in this discounted cash flow analysis.

The current operating plan with its assumptions shows the following:

(in thousands)	
Enterprise Value	$ 48,600
Interest Bearing Debt	36,500
Market Value of Common Equity	12,100
Book Value of Common Equity	12,000
Excess of Market Value over Book Value	$ 100

The following changes in our assumptions would have the following impact on these estimated values:

Assumption	Change	Impact on Fair Value *(in thousands)*
Annual Revenue Growth Rate	Plus 1%	$ 3,700
Annual Revenue Growth Rate	Minus 1%	(3,600)
Annual Gross Margin	Plus 1%	3,800
Annual Gross Margin	Minus 1%	(3,800)
Discount Rate	Plus .5%	(2,200)
Discount Rate	Minus .5%	2,400

Should the assumptions used in these current operating plans not materialize and the market value of ShoreMaster's common equity be significantly below its book value, an impairment charge of up to $17.1 million could be recorded.

We currently have $12.0 million of goodwill and $0.7 million in nonamortizable trade names recorded on our balance sheet related to the acquisition of BTD and its subsidiary companies. BTD provides stamped metal parts and fabricated metal products to a number of equipment and product manufacturers and assemblers throughout the United States. We expect BTD to return to 2008 revenue and earnings levels by 2012. If current economic conditions continue to impact sales of manufactured metal products and BTD is not able to achieve sales and earnings consistent with 2008 levels as projected, the reductions in anticipated cash flows from this business may indicate, in a future period, that its fair value is less than its carrying value resulting in an impairment of some or all of the goodwill and nonamortizable intangible assets associated with BTD along with a corresponding charge against earnings.

An impairment charge consisting of the goodwill and nonamortizable intangible assets of both ShoreMaster and BTD combined would not have a significant impact on our financial position and would not put us in violation of our debt covenants.

We evaluate goodwill for impairment on an annual basis and as conditions warrant. As of December 31, 2009 an assessment of the carrying amounts of our goodwill indicated no impairment and the fair values of our remaining reporting units are substantially in excess of their respective book values.

ACQUISITION METHOD OF ACCOUNTING

Through December 31, 2008, under Statement of Financial Accounting Standards (SFAS) No.141, *Business Combinations* , we have accounted for our acquisitions under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed are recorded at their respective fair values. The excess of purchase price over the fair value of the assets acquired and liabilities assumed is recorded as goodwill. The recorded values of assets and liabilities are based on third party estimates and valuations when available. The remaining values are based on management's judgments and estimates, and, accordingly, our consolidated financial position or results of operations may be affected by changes in estimates and judgments.

We account for acquisitions under the requirements of ASC 805, *Business Combinations* . Under ASC 805 the term "purchase method of accounting" is replaced with "acquisition method of accounting" and requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions. This guidance replaces SFAS No. 141's cost-allocation process, which required the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values.

Acquired assets and liabilities assumed that are subject to critical estimates include property, plant and equipment and intangible assets.

The fair value of property, plant and equipment is based on valuations performed by qualified internal personnel and/or outside appraisers. Fair values assigned to plant and equipment are based on several factors including the age and condition of the equipment, maintenance records of the equipment and auction values for equipment with similar characteristics at the time of purchase.

Intangible assets are identified and valued using the guidelines of ASC 805. The fair value of intangible assets is based on estimates including royalty rates, customer attrition rates and estimated cash flows.

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

KEY ACCOUNTING PRONOUNCEMENTS

Business Combinations— In December 2007, the FASB issued new guidance on business combinations that applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. The new guidance, under ASC 805, *Business Combinations*, applies to all transactions or other events in which an entity (the acquirer) obtains control of one or more businesses (the acquiree). In addition to replacing the term "purchase method of accounting" with "acquisition method of accounting," ASC 805 requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions. This guidance replaces previous guidance on the cost-allocation process, which required the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. The new guidance results in not recognizing some assets and liabilities at the acquisition date, and it also results in measuring some assets and liabilities at amounts other than their fair values at the acquisition date. For example, prior guidance required the acquirer to include the costs incurred to effect an acquisition (acquisition-related costs) in the cost of the acquisition that is allocated to the assets acquired and the liabilities assumed. The new guidance requires those costs to be expensed as incurred. In addition, under previous guidance, restructuring costs that the acquirer expected but was not obligated to incur were recognized as if they were a liability assumed at the acquisition date. The new guidance requires the acquirer to recognize those costs separately from the business combination. We adopted the new guidance on business combinations on January 1, 2009. The adoption did not have a material impact on our consolidated financial statements.

Disclosures about Derivative Instruments and Hedging Activities— In March 2008, the FASB issued new guidance on disclosures about derivative instruments and hedging activities. The new guidance under ASC 815, *Derivatives and Hedging,* requires enhanced disclosures about an entity's derivative and hedging activities to improve the transparency of financial reporting and is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted the new guidance on January 1, 2009. Adoption of the new guidance resulted in additional footnote disclosures related to our use of derivative instruments, the location and fair value of derivatives reported on our consolidated balance sheets, the location and amounts of derivative instrument gains and losses reported on our consolidated statements of income and information on credit risk exposure related to derivative instruments.

Employers' Disclosures about Postretirement Benefit Plan Assets— In December 2008, the FASB issued new guidance on Employers' Disclosures about Pensions and Other Postretirement Benefits. The new guidance under ASC 715-20 *Defined Benefit Plans—General,* expands an employer's required disclosures about plan assets of a defined benefit pension or other postretirement plan to include investment policies and strategies, major categories of plan assets, information regarding fair value measurements, and significant concentrations of credit risk. The new guidance is effective for fiscal years ending after December 15, 2009. We do not expect the adoption of the new guidance to have a material impact on our consolidated financial statements.

Interim Disclosures about Fair Value of Financial Instruments— In April 2009, the FASB issued new guidance on disclosures about fair value of financial instruments to require disclosures regarding the fair value of financial instruments in interim financial statements. The new disclosure requirements under ASC 825, *Financial Instruments,* are effective for interim periods ending after June 15, 2009. We implemented the new guidance on April 1, 2009. The implementation did not have a material impact on our consolidated financial statements. ASC 825 required disclosures have been included in our notes to consolidated financial statements, where applicable.

Subsequent Events— In May 2009, the FASB issued new guidance regarding subsequent events. The new guidance under ASC 855, *Subsequent Events*, establishes general standards of accounting and disclosure for events that occur after the balance sheet date but before financial statements are issued. The new accounting guidance is consistent with the auditing literature widely used for accounting and disclosure of subsequent events, however, the new guidance requires an entity to disclose the date through which subsequent events have been evaluated. The new guidance is effective for interim and annual periods ending after June 15, 2009. We implemented the new guidance on April 1, 2009. The implementation did not have a material impact on our consolidated financial statements.

SFAS No. 167, Amendments to FASB Interpretation No. 46(R), was issued by the FASB in June 2009. SFAS No. 167 amends the consolidation guidance applicable to variable interest entities. The amendments will significantly affect various elements of consolidation guidance under FASB Interpretation No. 46(R), including guidance for determining whether an entity is a variable interest entity and whether an enterprise is the primary beneficiary of a variable interest entity. SFAS No. 167 is effective for fiscal years beginning after November 15, 2009. We do not expect the implementation of SFAS No. 167 to have a significant impact on our consolidated financial statements. SFAS No. 167 will remain authoritative until it is integrated into the ASC.

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

This Annual Report on Form 10-K contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 (the Act). When used in this Form 10-K and in future filings by the Company with the Securities and Exchange Commission (SEC), in the Company's press releases and in oral statements, words such as "may," "will," "expect," "anticipate," "continue," "estimate," "project," "believes" or similar expressions are intended to identify forward-looking statements within the meaning of the Act. Such statements are based on current expectations and assumptions, and entail various risks and uncertainties that could cause actual results to differ materially from those expressed in such forward-looking statements. Such risks and uncertainties include the various factors set forth in Item 1A. Risk Factors of this Annual Report on Form 10-K and in our other SEC filings.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

At December 31, 2009 we had exposure to market risk associated with interest rates because we had $6.0 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 2.375% under the credit agreement relating to our $200 million revolving credit facility and $1.6 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 0.5% under the credit agreement relating to OTP’s $170 million revolving credit facility. At December 31, 2009 we had exposure to changes in foreign currency exchange rates. DMI has market risk related to changes in foreign currency exchange rates at its plant in Ft. Erie, Ontario because the plant pays its operating expenses in Canadian dollars. Outstanding trade accounts receivable of the Canadian operations of IPH are not at risk of valuation change due to changes in foreign currency exchange rates because the Canadian company transacts all sales in U.S. dollars. However, IPH does have market risk related to changes in foreign currency exchange rates because approximately 16.5% of IPH sales in 2009 were outside the United States and the Canadian operation of IPH pays its operating expenses in Canadian dollars.

The majority of our consolidated long-term debt has fixed interest rates. The interest rate on variable rate long-term debt is reset on a periodic basis reflecting current market conditions. We manage our interest rate risk through the issuance of fixed-rate debt with varying maturities, through economic refunding of debt through optional refundings, limiting the amount of variable interest rate debt, and the utilization of short-term borrowings to allow flexibility in the timing and placement of long-term debt. As of December 31, 2009 we had $68.4 million of long-term debt subject to variable interest rates. However, $58.0 million of this debt was OTP’s variable rate term loan due May 20, 2011 that was early retired on January 4, 2010, without penalty. Assuming no change in our financial structure, if variable interest rates were to average one percentage point higher or lower than the average variable rate on December 31, 2009, annualized interest expense and pre-tax earnings would change by approximately $104,000.

We have not used interest rate swaps to manage net exposure to interest rate changes related to our portfolio of borrowings. We maintain a ratio of fixed-rate debt to total debt within a certain range. It is our policy to enter into interest rate transactions and other financial instruments only to the extent considered necessary to meet our stated objectives. We do not enter into interest rate transactions for speculative or trading purposes.

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

The companies in our manufacturing segment are exposed to market risk related to changes in commodity prices for steel, lumber, aluminum, cement and resin. The price and availability of these raw materials could affect the revenues and earnings of our manufacturing segment.

OTP has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of December 31, 2009 OTP had recognized, on a pretax basis, $1,030,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity and electricity generating capacity. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can cause transmission constraints that result in unanticipated gains or losses in the process of settling transactions.

The market prices used to value OTP’s forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP’s power services’ personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The forward energy sales contracts that are marked to market as of December 31, 2009, are 100% offset by forward energy purchase contracts in terms of volumes, delivery periods and delivery points.

We have in place an energy risk management policy with a goal to manage, through the use of defined risk management practices, price risk and credit risk associated with wholesale power purchases and sales. With the advent of the MISO Day 2 market in April 2005, we made several changes to our energy risk management policy to recognize new trading opportunities created by this new market. Most of the changes were in new volumetric limits and loss limits to adequately manage the risks associated with these new opportunities. In addition, we implemented a Value at Risk (VaR) limit to further manage market price risk. There was no market exposure risk as of December 31, 2009 due to all forward positions being closed.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity and electricity generating capacity on our consolidated balance sheet as of December 31, 2009 and the change in our consolidated balance sheet position from December 31, 2008 to December 31, 2009:

(in thousands)	December 31, 2009
Current Asset – Marked-to-Market Gain	$ 8,321
Regulatory Asset – Deferred Marked-to-Market Loss	7,614
Total Assets	15,935
Current Liability – Marked-to-Market Loss	(14,681)
Regulatory Liability – Deferred Marked-to-Market Gain	(224)
Total Liabilities	(14,905)
Net Fair Value of Marked-to-Market Energy Contracts	$ 1,030

(in thousands)	Year ended December 31, 2009
Fair Value at Beginning of Year	$ (123)
Amount Realized on Contracts Entered into in 2008 and Settled in 2009	123
Changes in Fair Value of Contracts Entered into in 2008	—
Net Fair Value of Contracts Entered into in 2009 at Year End 2009	—
Changes in Fair Value of Contracts Entered into in 2009	1,030
Net Fair Value at End of Year	$ 1,030

The $1,030,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on December 31, 2009 is expected to be realized on settlement as scheduled over the following years in the amounts listed:

(in thousands)	2010	2011	2012	Total
Net Gain	$389	$320	$321	$1,030

OTP has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy and capacity purchases and sales agreements. We have established guidelines and limits to manage credit risk associated with wholesale power and capacity purchases and sales. Specific limits are determined by a counterparty's financial strength. OTP's credit risk with its largest counterparty on delivered and marked-to-market forward contracts as of December 31, 2009 was $222,000. As of December 31, 2009 OTP had a net credit risk exposure of $387,000 from four counterparties with investment grade credit ratings. OTP had no exposure at December 31, 2009 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch).

The $387,000 credit risk exposure includes net amounts due to OTP on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery after December 31, 2009. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

IPH has market risk associated with the price of fuel oil and natural gas used in its potato dehydration process as IPH may not be able to increase prices for its finished products to recover increases in fuel costs.

The Canadian operations of IPH records its sales and carries its receivables in U.S. dollars but pays its expenses for goods and services consumed in Canada in Canadian dollars. The payment of its bills in Canada requires the periodic exchange of U.S. currency for Canadian currency. In order to lock in acceptable exchange rates and hedge its exposure to future fluctuations in foreign currency exchange rates between the U.S. dollar and the Canadian dollar, IPH's Canadian subsidiary entered into forward contracts for the exchange of U.S. dollars into Canadian dollars in 2008 for the months of January through October 2009. Each monthly contract was for the exchange of $400,000 U.S. dollars for the amount of Canadian dollars stated in each contract. IPH's Canadian subsidiary entered into forward contracts for the exchange of U.S. dollars into Canadian dollars in July 2009 for the months of August through December 2009. Each monthly contract was for the exchange of $200,000 U.S. dollars for the amount of Canadian dollars stated in each contract.

The following table shows the change in the Company's consolidated balance sheet position from December 31, 2008 to December 31, 2009:

(in thousands)	Year-to-Date December 31, 2009
Fair Value at Beginning of Year	$ (289)
Changes in Fair Value of Contracts Entered into in 2008	232
Less: Amount Realized on Contracts Entered into in 2008 and Settled in 2009	57
Net Fair Value of Contracts Entered into in 2008 at the End of the Year	—
Changes in Fair Value of Contracts Entered into in 2009	88
Less: Amount Realized on Contracts Entered into in 2009 and Settled in 2009	(88)
Net Fair Value End of the Year	$ —

These contracts were derivatives subject to mark-to-market accounting. IPH did not enter into these contracts for speculative purposes or with the intent of early settlement, but for the purpose of locking in acceptable exchange rates and hedging its exposure to future fluctuations in exchange rates. IPH settled these contracts during their stated settlement periods and used the proceeds to pay its Canadian liabilities when they came due. These contracts did not qualify for hedge accounting treatment because the timing of their settlements did not coincide with the payment of specific bills or contractual obligations. There were no forward foreign currency exchange contracts outstanding as of December 31, 2009.

In order to limit its exposure to fluctuations in future prices of natural gas and fuel oil, IPH entered into contracts with its fuel suppliers in August 2008, January 2009 and December 2009 for firm purchases of natural gas and fuel oil to cover portions of its anticipated natural gas needs in Ririe, Idaho and Center, Colorado from September 2008 through August 2009, its fuel oil needs in Souris, Prince Edward Island, Canada from January 2009 through August 2009 and its natural gas needs in Ririe, Idaho from January 2010 through August 2010 at fixed prices. These contracts qualified for the normal purchase exception to mark-to-market accounting under ASC 815-10-15, *Derivatives and Hedging* .

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE SHAREHOLDERS OF OTTER TAIL CORPORATION

We have audited the accompanying consolidated balance sheets and statements of capitalization of Otter Tail Corporation and its subsidiaries (the "Company") as of December 31, 2009 and 2008, and the related consolidated statements of income, common shareholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2009. We also have audited the Company's internal control over financial reporting as of December 31, 2009 based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report Regarding Internal Control Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 26, 2010

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

(in thousands, except per-share amounts)	**2009**	2008	2007
Operating Revenues			
Electric	**$ 314,424**	$ 339,726	$ 323,158
Nonelectric	**725,088**	971,471	915,729
Total Operating Revenues	**1,039,512**	1,311,197	1,238,887
Operating Expenses			
Production Fuel — Electric	**59,387**	71,930	60,482
Purchased Power — Electric System Use	**52,942**	56,329	74,690
Electric Operation and Maintenance Expenses	**105,867**	115,300	107,041
Cost of Goods Sold — Nonelectric (excludes depreciation; included below)	**565,199**	775,292	712,547
Other Nonelectric Expenses	**126,641**	143,050	121,110
Product Recall and Testing Costs	**1,625**	—	—
Plant Closure Costs	**—**	2,295	—
Depreciation and Amortization	**73,608**	65,060	52,830
Property Taxes — Electric	**8,853**	8,949	9,413
Total Operating Expenses	**994,122**	1,238,205	1,138,113
Operating Income	**45,390**	72,992	100,774
Other Income	**4,550**	4,128	2,012
Interest Charges	**28,514**	26,958	20,857
Income Before Income Taxes	**21,426**	50,162	81,929
Income Tax (Benefit) Expense	**(4,605)**	15,037	27,968
Net Income	**26,031**	35,125	53,961
Preferred Dividend Requirements	**736**	736	736
Earnings Available for Common Shares	**$ 25,295**	$ 34,389	$ 53,225
Average Number of Common Shares Outstanding—Basic	**35,463**	31,409	29,681
Average Number of Common Shares Outstanding—Diluted	**35,717**	31,673	29,970
Earnings Per Common Share:			
Basic	**$ 0.71**	$ 1.09	$ 1.79
Diluted	**$ 0.71**	$ 1.09	$ 1.78
Dividends Per Common Share	**$ 1.19**	$ 1.19	$ 1.17

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION
Consolidated Balance Sheets, December 31

(in thousands)	**2009**	2008
ASSETS		
Current Assets		
Cash and Cash Equivalents	**$ 4,432**	$ 7,565
Accounts Receivable:		
Trade (less allowance for doubtful accounts of $4,391 for 2009 and $2,744 for 2008)	**95,747**	136,609
Other	**10,883**	13,587
Inventories	**86,515**	101,955
Deferred Income Taxes	**11,457**	8,386
Accrued Utility and Cost-of-Energy Revenues	**15,840**	24,030
Costs and Estimated Earnings in Excess of Billings	**61,835**	65,606
Income Taxes Receivable	**48,049**	26,754
Other	**15,265**	8,519
Total Current Assets	**350,023**	393,011
Investments	**9,889**	7,542
Other Assets	**26,098**	22,615
Goodwill	**106,778**	106,778
Other Intangibles—Net	**33,887**	35,441
Deferred Debits		
Unamortized Debt Expense and Reacquisition Premiums	**10,676**	7,247
Regulatory Assets and Other Deferred Debits	**118,700**	82,384
Total Deferred Debits	**129,376**	89,631
Plant		
Electric Plant in Service	**1,313,015**	1,205,647
Nonelectric Operations	**362,088**	321,032
Total	**1,675,103**	1,526,679
Less Accumulated Depreciation and Amortization	**599,839**	548,070
Plant—Net of Accumulated Depreciation and Amortization	**1,075,264**	978,609
Construction Work in Progress	**23,363**	58,960
Net Plant	**1,098,627**	1,037,569
Total	**$1,754,678**	$1,692,587

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION
Consolidated Balance Sheets, December 31

(in thousands, except share data)	**2009**	2008
LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	**$ 7,585**	$ 134,914
Current Maturities of Long-Term Debt	**59,053**	3,747
Accounts Payable	**83,724**	113,422
Accrued Salaries and Wages	**21,057**	29,688
Accrued Taxes	**11,304**	10,939
Other Accrued Liabilities	**24,319**	12,034
Total Current Liabilities	**207,042**	304,744
Pensions Benefit Liability	**95,039**	80,912
Other Postretirement Benefits Liability	**37,712**	32,621
Other Noncurrent Liabilities	**22,697**	19,391
Commitments (note 9)		
Deferred Credits		
Deferred Income Taxes	**155,306**	123,086
Deferred Tax Credits	**47,660**	34,288
Regulatory Liabilities	**64,274**	64,684
Other	**562**	397
Total Deferred Credits	**267,802**	222,455
Capitalization (page 73)		
Long-Term Debt, Net of Current Maturities	**436,170**	339,726
Class B Stock Options of Subsidiary	**1,220**	1,220
Cumulative Preferred Shares	**15,500**	15,500
Common Shares, Par Value $5 Per Share—Authorized, 50,000,000 Shares; Outstanding, 2009—35,812,280 Shares; 2008—35,384,620 Shares	**179,061**	176,923
Premium on Common Shares	**250,398**	241,731
Retained Earnings	**243,352**	260,364
Accumulated Other Comprehensive Loss	**(1,315)**	(3,000)
Total Common Equity	**671,496**	676,018
Total Capitalization	**1,124,386**	1,032,464
Total	**$1,754,678**	$1,692,587

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION
Consolidated Statements of Common Shareholders' Equity and Comprehensive Income

(in thousands, except common shares outstanding)	Common Shares Outstanding	Par Value, Common Share	Premium on Common Shares	Retained Earnings	Accumulated Other Comprehensive (Loss)/Income	Total Common Equity
Balance, December 31, 2006	**29,521,770**	**$147,609**	**$ 99,223**	**$245,005**	**$ (1,067)(a)**	**$490,770**
Common Stock Issuances, Net of Expenses	336,508	1,683	6,018			7,701
Common Stock Retirements	(8,489)	(43)	(252)			(295)
Comprehensive Income:						
Net Income				53,961		53,961
Unrealized Gain on Marketable Equity Securities (net-of-tax)					4	4
Foreign Currency Exchange Translation (net-of-tax)					2,019	2,019
SFAS No. 158 Items (net-of-tax):						
Amortization of Unrecognized Postretirement Benefit Costs					165	165
Actuarial Gains and Regulatory Allocations Adjustments					60	60
Total Comprehensive Income						56,209
Tax Benefit for Exercise of Stock Options			1,092			1,092
Stock Incentive Plan Performance Award Accrual			2,213			2,213
Vesting of Restricted Stock Granted to Employees			860			860
Premium on Purchase of Stock for Employee Purchase Plan			(269)			(269)
Cumulative Effect of Adoption of FIN No. 48				(118)		(118)
Cumulative Preferred Dividends				(736)		(736)
Common Dividends				(34,780)		(34,780)
Balance, December 31, 2007	**29,849,789**	**$149,249**	**$108,885**	**$263,332**	**$ 1,181(a)**	**$522,647**
Common Stock Issuances, Net of Expenses	5,557,531	27,788	128,818			156,606
Common Stock Retirements	(22,700)	(114)	(642)			(756)
Comprehensive Income:						
Net Income				35,125		35,125
Unrealized Loss on Marketable Equity Securities (net-of-tax)					(40)	(40)
Foreign Currency Exchange Translation (net-of-tax)					(2,784)	(2,784)
SFAS No. 158 Items (net-of-tax):						
Amortization of Unrecognized Postretirement Benefit Costs					153	153
Actuarial Gains and Regulatory Allocations Adjustments					(1,510)	(1,510)
Total Comprehensive Income						30,944
Tax Benefit for Exercise of Stock Options			1,777			1,777
Stock Incentive Plan Performance Award Accrual			3,093			3,093
Vesting of Restricted Stock Granted to Employees			165			165
Premium on Purchase of Stock for Employee Purchase Plan			(365)			(365)
Cumulative Preferred Dividends				(736)		(736)
Common Dividends				(37,357)		(37,357)
Balance, December 31, 2008	**35,384,620**	**$176,923**	**$241,731**	**$260,364**	**$ (3,000)(a)**	**$676,018**
Common Stock Issuances, Net of Expenses	437,843	2,189	6,243			8,432
Common Stock Retirements	(10,183)	(51)	(178)			(229)

Comprehensive Income:						
Net Income				26,031		26,031
Unrealized Gain on Marketable Equity Securities (net-of-tax)					74	74
Foreign Currency Exchange Translation (net-of-tax)					1,965	1,965
SFAS No. 158 Items (net-of-tax):						
Amortization of Unrecognized Postretirement Benefit Costs					357	357
Actuarial Gains and Regulatory Allocations Adjustments					(711)	(711)
Total Comprehensive Income						27,716
Tax Benefit for Exercise of Stock Options			(23)			(23)
Stock Incentive Plan Performance Award Accrual			2,592			2,592
Vesting of Restricted Stock Granted to Employees			52			52
Premium on Purchase of Stock for Employee Purchase Plan			(19)			(19)
Cumulative Preferred Dividends				(736)		(736)
Common Dividends				(42,307)		(42,307)
Balance, December 31, 2009	**35,812,280**	**$179,061**	**$250,398**	**$243,352**	**$ (1,315)(a)**	**$671,496**

(a) Accumulated Other Comprehensive Income (Loss) on December 31 is comprised of the following *(in thousands)*

		Before Tax	Tax Effect	Net-of-Tax
2007	Unamortized Actuarial Losses and Transition Obligation Related to Pension and Postretirement Benefits	$ (3,863)	$ 1,545	$ (2,318)
	Foreign Currency Exchange Translation	5,795	(2,318)	3,477
	Unrealized Gain on Marketable Equity Securities	36	(14)	22
	Net Accumulated Other Comprehensive Income	$ 1,968	$ (787)	$ 1,181
2008	Unamortized Actuarial Losses and Transition Obligation Related to Pension and Postretirement Benefits	$ (6,125)	$ 2,450	$ (3,675)
	Foreign Currency Exchange Translation	1,155	(462)	693
	Unrealized Loss on Marketable Equity Securities	(30)	12	(18)
	Net Accumulated Other Comprehensive Loss	$ (5,000)	$ 2,000	$ (3,000)
2009	Unamortized Actuarial Losses and Transition Obligation Related to Pension and Postretirement Benefits	$ (6,715)	$ 2,686	$ (4,029)
	Foreign Currency Exchange Translation	4,430	(1,772)	2,658
	Unrealized Gain on Marketable Equity Securities	94	(38)	56
	Net Accumulated Other Comprehensive Loss	$ (2,191)	$ 876	$ (1,315)

See accompanying notes to consolidated financial statements.

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

(in thousands)	**2009**	2008	2007
Cash Flows from Operating Activities			
Net Income	**$ 26,031**	$ 35,125	$ 53,961
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Depreciation and Amortization	**73,608**	65,060	52,830
Deferred Tax Credits	**(2,331)**	(1,692)	(1,169)
Deferred Income Taxes	**44,792**	40,665	4,366
Change in Deferred Debits and Other Assets	**(18,527)**	(41,851)	6,505
Discretionary Contribution to Pension Plan	**(4,000)**	(2,000)	(4,000)
Change in Noncurrent Liabilities and Deferred Credits	**24,895**	40,918	481
Allowance for Equity (Other) Funds Used During Construction	**(3,180)**	(2,786)	—
Change in Derivatives Net of Regulatory Deferral	**(1,442)**	1,044	(800)
Stock Compensation Expense — Equity Awards	**3,563**	3,850	2,986
Other—Net	**1,489**	298	(1,837)
Cash Provided by (Used for) Current Assets and Current Liabilities:			
Change in Receivables	**43,822**	19,522	(18,903)
Change in Inventories	**16,344**	(743)	8,407
Change in Other Current Assets	**13,146**	(12,362)	(14,333)
Change in Payables and Other Current Liabilities	**(34,490)**	(8,572)	(2,556)
Change in Interest Payable and Income Taxes Receivable/Payable	**(20,970)**	(25,155)	(1,126)
Net Cash Provided by Operating Activities	**162,750**	111,321	84,812
Cash Flows from Investing Activities			
Capital Expenditures	**(177,125)**	(265,888)	(161,985)
2009 American Recovery and Reinvestment Act Grant — Luverne Wind Farm	**30,182**	—	—
Proceeds from Disposal of Noncurrent Assets	**4,909**	8,174	12,486
Acquisitions—Net of Cash Acquired	**—**	(41,674)	(6,750)
Net (Increase) Decrease in Other Investments	**(5,706)**	4	(7,745)
Net Cash Used in Investing Activities	**(147,740)**	(299,384)	(163,994)
Cash Flows from Financing Activities			
Net Short-Term (Repayments) Borrowings	**(127,329)**	39,914	56,100
Proceeds from Issuance of Common Stock	**7,420**	162,978	7,733
Common Stock Issuance Expenses	**(23)**	(6,418)	—
Payments for Retirement of Common Stock and Class B Stock of Subsidiary	**(229)**	(91)	(305)
Proceeds from Issuance of Long-Term Debt	**175,000**	1,240	205,129
Short-Term and Long-Term Debt Issuance Expenses	**(5,526)**	(1,252)	(1,762)
Payments for Retirement of Long-Term Debt	**(23,356)**	(3,639)	(118,171)
Dividends Paid	**(43,043)**	(38,093)	(35,516)
Net Cash (Used in) Provided by Financing Activities	**(17,086)**	154,639	113,208
Effect of Foreign Exchange Rate Fluctuations on Cash	**(1,057)**	1,165	(993)
Net Change in Cash and Cash Equivalents	**(3,133)**	(32,259)	33,033
Cash and Cash Equivalents at Beginning of Year	**7,565**	39,824	6,791
Cash and Cash Equivalents at End of Year	**$ 4,432**	$ 7,565	$ 39,824

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION
Consolidated Statements of Capitalization, December 31

(in thousands, except share data)		**2009**	2008
Long-Term Debt			
Lombard US Equipment Finance Note 6.76%, early retired in June 2009		**$ —**	$ 4,657
Term Loan, Variable 3.73% at December 31, 2009, due May 20, 2011 (early retired on January 4, 2010)		**58,000**	—
Senior Unsecured Notes 6.63%, due December 1, 2011		**90,000**	90,000
Pollution Control Refunding Revenue Bonds, Variable, 3.00% at December 31, 2009, due December 1, 2012		**10,400**	10,400
9.000% Notes, due December 15, 2016		**100,000**	—
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017		**33,000**	33,000
Grant County, South Dakota Pollution Control Refunding Revenue Bonds 4.65%, due September 1, 2017		**5,125**	5,165
Senior Unsecured Note 8.89%, due November 30, 2017		**50,000**	50,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022		**30,000**	30,000
Mercer County, North Dakota Pollution Control Refunding Revenue Bonds 4.85%, due September 1, 2022		**20,400**	20,625
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027		**42,000**	42,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037		**50,000**	50,000
Obligations of Varistar Corporation — Various up to 13.31% at December 31, 2009		**6,684**	7,982
Total		**495,609**	343,829
Less:			
Current Maturities		**59,053**	3,747
Unamortized Debt Discount		**386**	356
Total Long-Term Debt		**436,170**	339,726
Class B Stock Options of Subsidiary		**1,220**	1,220
Cumulative Preferred Shares —Without Par Value (Stated and Liquidating Value $100 a Share)— Authorized 1,500,000 Shares; nonvoting and redeemable at the option of the Company:			
Series Outstanding:	Call Price December 31, 2009		
$3.60, 60,000 Shares	$102.25	**6,000**	6,000
$4.40, 25,000 Shares	$102.00	**2,500**	2,500
$4.65, 30,000 Shares	$101.50	**3,000**	3,000
$6.75, 40,000 Shares	$101.35	**4,000**	4,000
Total Preferred		**15,500**	15,500
Cumulative Preference Shares —Without Par Value, Authorized 1,000,000 Shares; Outstanding: None			
Total Common Shareholders' Equity		**671,496**	676,018
Total Capitalization		**$1,124,386**	$1,032,464

See accompanying notes to consolidated financial statements.

Otter Tail Corporation
Notes to Consolidated Financial Statements
For the years ended December 31, 2009, 2008 and 2007

1. Summary of Significant Accounting Policies

Principles of Consolidation

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

Regulation and ASC 980

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

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

Plant, Retirements and Depreciation

Utility plant is stated at original cost. The cost of additions includes contracted work, direct labor and materials, allocable overheads and allowance for funds used during construction. The amount of interest capitalized on electric utility plant was $1,036,000 in 2009, $1,692,000 in 2008 and $2,276,000 in 2007. The cost of depreciable units of property retired less salvage is charged to accumulated depreciation. Removal costs, when incurred, are charged against the accumulated reserve for estimated removal costs, a regulatory liability. Maintenance, repairs and replacement of minor items of property are charged to operating expenses. The provisions for utility depreciation for financial reporting purposes are made on the straight-line method based on the estimated service lives of the properties. Such provisions as a percent of the average balance of depreciable electric utility property were 2.90% in 2009, 2.81% in 2008 and 2.78% in 2007. Gains or losses on group asset dispositions are taken to the accumulated provision for depreciation reserve and impact current and future depreciation rates.

Property and equipment of nonelectric operations are carried at historical cost or at the then-current replacement cost if acquired in a business combination accounted for under the purchase method of accounting, and are depreciated on a straight-line basis over the assets' estimated useful lives (3 to 40 years). The cost of additions includes contracted work, direct labor and materials, allocable overheads and capitalized interest. The amount of interest capitalized on nonelectric plant was $200,000 in 2009, $465,000 in 2008 and $390,000 in 2007. Maintenance and repairs are expensed as incurred. Gains or losses on asset dispositions are included in the determination of operating income.

Jointly Owned Plants

The consolidated balance sheets include OTP's ownership interests in the assets and liabilities of Big Stone Plant (53.9%) and Coyote Station (35.0%). The following amounts are included in the December 31, 2009 and 2008 consolidated balance sheets:

(in thousands)	2009	2008
Big Stone Plant:		
Electric Plant in Service	$135,500	$135,623
Accumulated Depreciation	(78,306)	(74,416)
Net Plant	$ 57,194	$ 61,207
Coyote Station:		
Electric Plant in Service	$155,417	$148,109
Accumulated Depreciation	(87,269)	(86,911)
Net Plant	$ 68,148	$ 61,198

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

Recoverability of Long-Lived Assets

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

Income Taxes

Comprehensive interperiod income tax allocation is used for substantially all book and tax temporary differences. Deferred income taxes arise for all temporary differences between the book and tax basis of assets and liabilities. Deferred taxes are recorded using the tax rates scheduled by tax law to be in effect in the periods when the temporary differences reverse. The Company amortizes investment tax credits over the estimated lives of related property. The Company records income taxes in accordance with ASC 740, *Income Taxes,* and has recognized in its consolidated financial statements the tax effects of all tax positions that are "more-likely-than-not" to be sustained on audit based solely on the technical merits of those positions as of the balance sheet date. The term "more-likely-than-not" means a likelihood of more than 50%. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes. See note 15 to the consolidated financial statements regarding the Company's accounting for uncertain tax positions.

Revenue Recognition

Due to the diverse business operations of the Company, revenue recognition depends on the product produced and sold or service performed. The Company recognizes revenue when the earnings process is complete, evidenced by an agreement with the customer, there has been delivery and acceptance, and the price is fixed or determinable. In cases where significant obligations remain after delivery, revenue recognition is deferred until such obligations are fulfilled. Provisions for sales returns and warranty costs are recorded at the time of the sale based on historical information and current trends. In the case of derivative instruments, such as OTP's forward energy contracts, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with ASC 815-10-45-9. Gains and losses on forward energy contracts subject to regulatory treatment, if any, are deferred and recognized on a net basis in revenue in the period realized.

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

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

Revenues on wholesale electricity sales from Company-owned generating units are recognized when energy is delivered.

The Company's unrealized gains and losses on forward energy contracts that do not meet the definition of capacity contracts are marked to market and reflected on a net basis in electric revenue on the Company's consolidated statement of income. Under ASC 815, *Derivatives and Hedging* , the Company's forward energy contracts that do not meet the definition of a capacity contract and are subject to unplanned netting do not qualify for the normal purchase and sales exception from mark-to-market accounting. The Company is required to mark to market these forward energy contracts and recognize changes in the fair value of these contracts as components of income over the life of the contracts. See note 5 for further discussion.

Plastics operating revenues are recorded when the product is shipped.

Manufacturing operating revenues are recorded when products are shipped and on a percentage-of-completion basis for construction type contracts.

Health Services operating revenues on major equipment and installation contracts are recorded when the equipment is delivered or when installation is completed and accepted. Amounts received in advance under customer service contracts are deferred and recognized on a straight-line basis over the contract period. Revenues generated in the imaging operations are recorded on a fee-per-scan basis when the scan is performed.

Food Ingredient Processing revenues are recorded when the product is shipped.

Other Business Operations operating revenues are recorded when services are rendered or products are shipped. In the case of construction contracts, the percentage-of-completion method is used.

Some of the operating businesses enter into fixed-price construction contracts. Revenues under these contracts are recognized on a percentage-of-completion basis. The Company's consolidated revenues recorded under the percentage-of-completion method were 27.6% in 2009, 33.5% in 2008 and 30.1% in 2007. The method used to determine the progress of completion is based on the ratio of labor costs incurred to total estimated labor costs at the Company's wind tower manufacturer, square footage completed to total bid square footage for certain floating dock projects and costs incurred to total estimated costs on all other construction projects. If a loss is indicated at a point in time during a contract, a projected loss for the entire contract is estimated and recognized. The following table summarizes costs incurred and billings and estimated earnings recognized on uncompleted contracts:

(in thousands)	December 31, 2009	December 31, 2008
Costs Incurred on Uncompleted Contracts	$ 400,577	$ 377,237
Less Billings to Date	(400,711)	(366,931)
Plus Estimated Earnings Recognized	59,202	47,355
	$ 59,068	$ 57,661

The following costs and estimated earnings in excess of billings are included in the Company's consolidated balance sheet. Billings in excess of costs and estimated earnings on uncompleted contracts are included in Accounts Payable.

(in thousands)	December 31, 2009	December 31, 2008
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$ 61,835	$ 65,606
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(2,767)	(7,945)
	$ 59,068	$ 57,661

Costs and Estimated Earnings in Excess of Billings at DMI Industries, Inc. (DMI), the Company's wind tower manufacturer, were $54,977,000 as of December 31, 2009 and $59,300,000 as of December 31, 2008. This amount is related to costs incurred on wind towers in the process of completion on major contracts under which the customer is not billed until towers are completed and ready for shipment.

Retainage

Accounts Receivable include amounts billed by the Company's subsidiaries under long-term contracts that have been retained by customers pending project completion of $9,215,000 on December 31, 2009 and $10,311,000 on December 31, 2008.

Sales of Receivables

DMI has a three-year, $40 million receivables purchase agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation on a revolving basis. The agreement expires in March 2011. Accounts receivable sold totaled $133,900,000 in 2009 and $132,911,000 in 2008. Discounts and commissions and fees charged to operating expenses in the consolidated statements of income were $430,000 in 2009 and $722,000 in 2008. In compliance with guidance under ASC 860-20, *Sales of Financial Assets* , sales of accounts receivable are reflected as a reduction of accounts receivable in the consolidated balance sheets and the proceeds are included in the cash flows from operating activities in the consolidated statements of cash flows.

Marketing and Sales Incentive Costs

ShoreMaster, Inc. (ShoreMaster), the Company's waterfront equipment manufacturer, provides dealer floor plan financing assistance for certain dealer purchases of ShoreMaster products for certain set time periods based on the timing and size of a dealer's order. ShoreMaster recognizes the estimated cost of projected interest payments related to each financed sale as a liability and a reduction of revenue at the time of sale, based on historical experience of the average length of time floor plan debt is outstanding, in accordance with guidance under ASC 605-50, *Customer Payments and Incentives* . The liability is reduced when interest is paid. To the extent current experience differs from previous estimates the accrued liability for financing assistance costs is adjusted accordingly. Financing assistance costs charged to revenue were $131,000 in 2009 and $500,000 in 2008.

Foreign Currency Translation

The functional currency for the operations of the Canadian subsidiary of Idaho Pacific Holdings, Inc. (IPH) is the Canadian dollar (CAD). This subsidiary realizes foreign currency transaction gains or losses on settlement of receivables related to its sales, which are mostly in U.S. dollars (USD), and on exchanging U.S. currency for Canadian currency for its Canadian operations. This subsidiary recorded foreign currency transaction losses of $337,000 USD in 2009 as a result of a decrease in the value of the Canadian dollar relative to the U.S. dollar in 2009, foreign currency transaction losses of $60,000 USD in 2008 as a result of a decrease in the value of the Canadian dollar relative to the U.S. dollar in 2008 and foreign currency transaction losses of $656,000 USD in 2007 as a result of an increase in the value of the Canadian dollar relative to the U.S. dollar in 2007. The translation of CAD to USD is performed for balance sheet accounts using exchange rates in effect at the balance sheet dates—except for the common equity accounts which are at historical rates—and for revenue and expense accounts using a weighted average exchange during the year. Gains or losses resulting from the translation are included in Accumulated Other Comprehensive Loss in the equity section of the Company’s consolidated balance sheet.

The functional currency for the Canadian subsidiary of DMI is the U.S. dollar. There are no foreign currency translation gains or losses related to this entity. However, this subsidiary may realize foreign currency transaction gains or losses on settlement of liabilities related to goods or services purchased in CAD. Foreign currency transaction gains related to balance sheet adjustments of CAD liabilities to USD equivalents and realized gains on settlement of those liabilities were $77,000 USD in 2009 and $399,000 USD in 2008 as a result of decreases in the value of the Canadian dollar relative to the U.S. dollar in 2009 and 2008. Foreign currency transaction losses related to balance sheet adjustments of CAD liabilities to USD equivalents and realized losses on settlement of those liabilities were $102,000 USD in 2007 as a result of an increase in the value of the Canadian dollar relative to the U.S. dollar in 2007.

Shipping and Handling Costs

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

Use of Estimates

The Company uses estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, unbilled electric revenues, accrued renewable resource and transmission rider revenues, valuations of forward energy contracts, service contract maintenance costs, percentage-of-completion and actuarially determined benefits costs and liabilities. As better information becomes available (or actual amounts are known), the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash Equivalents

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

Supplemental Disclosures of Cash Flow Information

(in thousands)	2009	2008	2007
(Decreases) Increases in Accounts Payable and Other Liabilities Related to Capital Expenditures	$ (3,832)	$(22,729)	$23,514
Noncash Investing and Financing Transactions:			
Capital Leases	—	$ 2,084	—
Cash Paid During the Year for:			
Interest (net of amount capitalized)	$ 23,563	$ 25,032	$18,155
Income Tax (Refunds) Payments	$(27,412)	$ 1,356	$25,906

Investments

The following table provides a breakdown of the Company’s investments at December 31, 2009 and 2008:

(in thousands)	December 31, 2009	December 31, 2008
Cost Method:		
Economic Development Loan Pools	$ 482	$ 528
Other	334	1,057
Equity Method:		
Affordable Housing and Other Partnerships	1,025	1,441
Marketable Securities Classified as Available-for-Sale	8,048	4,516
Total Investments	$ 9,889	$ 7,542

The Company has investments in eleven limited partnerships that invest in tax-credit-qualifying affordable-housing projects that provided tax credits of $25,000 in 2009, $55,000 in 2008 and $285,000 in 2007. The Company owns a majority interest in eight of the eleven limited partnerships with a total investment of $1,009,000. ASC 810, *Consolidation,* requires full consolidation of the majority-owned partnerships. However, the Company includes these entities on its consolidated financial statements on a declining balance basis due to immateriality and uncertainty regarding residual values. Consolidating these entities would have represented 0.4% of total assets, 0.1% of total revenues and (0.9%) of operating income for the Company as of, and for the year ended, December 31, 2009 and would have an insignificant impact on the Company's 2009 consolidated net income.

The Company's marketable securities classified as available-for-sale are held for insurance purposes and are reflected at their market values on December 31, 2009. See further discussion below and under note 13.

Fair Value Measurements

Effective January 1, 2008, the Company adopted ASC 820, *Fair Value Measurements and Disclosures* , for recurring fair value measurements. ASC 820 provides a single definition of fair value and requires enhanced disclosures about assets and liabilities measured at fair value. ASC 820-10-35 establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. The three levels defined by the hierarchy and examples of each level are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reported date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed by the New York Stock Exchange and commodity derivative contracts listed on the New York Mercantile Exchange.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation and may include complex and subjective models and forecasts.

The following table presents, for each of these hierarchy levels, the Company's assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2009 and 2008:

2009 *(in thousands)*	Level 1	Level 2	Level 3
Assets:			
Investments for Nonqualified Retirement Savings Retirement Plan:			
Money Market and Mutual Funds and Cash	$ 731	$ —	
Forward Energy Contracts		8,321	
Investments of Captive Insurance Company:			
Corporate Debt Securities	7,795		
U.S. Government Debt Securities	253		
Total Assets	$ 8,779	$ 8,321	
Liabilities:			
Forward Energy Contracts	$ —	$ 14,681	
Total Liabilities	$ —	$ 14,681	
Net Assets (Liabilities)	$ 8,779	$ (6,360)	

2008 *(in thousands)*	Level 1	Level 2	Level 3
Assets:			
Investments for Nonqualified Retirement Savings Retirement Plan:			
Money Market and Mutual Funds and Cash	$ 890	$ —	
Forward Energy Contracts		405	
Investments of Captive Insurance Company:			
Corporate Debt Securities	3,569		
U.S. Government Debt Securities	947		
Total Assets	$ 5,406	$ 405	
Liabilities:			
Forward Energy Contracts	$ —	$ 1,690	
Forward Foreign Currency Exchange Contracts	289		
Total Liabilities	$ 289	$ 1,690	
Net Assets (Liabilities)	$ 5,117	$ (1,285)	

Inventories

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

(in thousands)	December 31, 2009	December 31, 2008
Finished Goods	$ 42,784	$ 38,943
Work in Process	3,824	10,205
Raw Material, Fuel and Supplies	39,907	52,807
Total Inventories	$ 86,515	$ 101,955

Goodwill and Intangible Assets

The Company accounts for goodwill and other intangible assets in accordance with the requirements of ASC 350, *Intangibles—Goodwill and Other*, requiring goodwill and indefinite-lived intangible assets to be measured for impairment at least annually and more often when events indicate the assets may be impaired. Intangible assets with finite lives are amortized over their estimated useful lives and reviewed for impairment in accordance with requirements under ASC 360-10-35, *Property, Plant, and Equipment—Overall—Subsequent Measurement* .

The Company recorded no changes in the carrying amount of Goodwill in 2009:

(in thousands)	Balance December 31, 2008	Adjustment to Goodwill in 2009	Goodwill Acquired in 2009	Balance December 31, 2009
Plastics	$ 19,302	$ —	$ —	$ 19,302
Manufacturing	24,732	—	—	24,732
Health Services	23,878	—	—	23,878
Food Ingredient Processing	24,324	—	—	24,324
Other Business Operations	14,542	—	—	14,542
Total	$ 106,778	$ —	$ —	$ 106,778

The following table summarizes components of the Company's intangible assets as of December 31:

(in thousands)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Periods
2009				
Amortized Intangible Assets:				
Covenants Not to Compete	$ 2,190	$ 2,047	$ 143	3 — 5 years
Customer Relationships	26,956	3,696	23,260	15 — 25 years
Other Intangible Assets Including Contracts	2,358	1,757	601	5 — 30 years
Total	$ 31,504	$ 7,500	$ 24,004	
Nonamortized Intangible Assets:				
Brand/Trade Name	$ 9,883	$ —	$ 9,883	
2008				
Amortized Intangible Assets:				
Covenants Not to Compete	$ 2,250	$ 1,889	$ 361	3 — 5 years
Customer Relationships	26,854	2,429	24,425	15 — 25 years
Other Intangible Assets Including Contracts	2,710	1,921	789	5 — 30 years
Total	$ 31,814	$ 6,239	$ 25,575	
Nonamortized Intangible Assets:				
Brand/Trade Name	$ 9,866	$ —	$ 9,866	

The amortization expense for these intangible assets was $1,656,000 for 2009, $1,464,000 for 2008 and $1,227,000 for 2007. The estimated annual amortization expense for these intangible assets for the next five years is $1,461,000 for 2010, $1,332,000 for 2011, $1,312,000 for 2012, $1,308,000 for 2013 and $1,308,000 for 2014.

New Accounting Standards

Business Combinations— In December 2007, the FASB issued new guidance on business combinations that applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. The new guidance, under ASC 805, *Business Combinations,* applies to all transactions or other events in which an entity (the acquirer) obtains control of one or more businesses (the acquiree). In addition to replacing the term "purchase method of accounting" with "acquisition method of accounting," ASC 805 requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions. This guidance replaces previous guidance on the cost-allocation process, which required the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. The new guidance results in not recognizing some assets and liabilities at the acquisition date, and it also results in measuring some assets and liabilities at amounts other than their fair values at the acquisition date. For example, prior guidance required the acquirer to include the costs incurred to effect an acquisition (acquisition-related costs) in the cost of the acquisition that is allocated to the assets acquired and the liabilities assumed. The new guidance requires those costs to be expensed as incurred. In addition, under previous guidance, restructuring costs that the acquirer expected but was not obligated to incur were recognized as if they were a liability assumed at the acquisition date. The new guidance requires the acquirer to recognize those costs separately from the business combination. The Company adopted the new guidance on business combinations on January 1, 2009. The adoption did not have a material impact on its consolidated financial statements.

Disclosures about Derivative Instruments and Hedging Activities— In March 2008, the FASB issued new guidance on disclosures about derivative instruments and hedging activities. The new guidance under ASC 815, *Derivatives and Hedging,* requires enhanced disclosures about an entity's derivative and hedging activities to improve the transparency of financial reporting and is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The Company adopted the new guidance on January 1, 2009. Adoption of the new guidance resulted in additional footnote disclosures related to the Company's use of derivative instruments, the location and fair value of derivatives reported on the Company's consolidated balance sheets, the location and amounts of derivative instrument gains and losses reported on the Company's consolidated statements of income and information on credit risk exposure related to derivative instruments.

Employers' Disclosures about Postretirement Benefit Plan Assets— In December 2008, the FASB issued new guidance on Employers' Disclosures about Pensions and Other Postretirement Benefits. The new guidance under ASC 715-20 *Defined Benefit Plans—General,* expands an employer's required disclosures about plan assets of a defined benefit pension or other postretirement plan to include investment policies and strategies, major categories of plan assets, information regarding fair value measurements, and significant concentrations of credit risk. The new guidance is effective for fiscal years ending after December 15, 2009. (See note 12 to consolidated financial statements.)

Interim Disclosures about Fair Value of Financial Instruments— In April 2009, the FASB issued new guidance on disclosures about fair value of financial instruments to require disclosures regarding the fair value of financial instruments in interim financial statements. The new disclosure requirements under ASC 825, *Financial Instruments,* are effective for interim periods ending after June 15, 2009. The Company implemented the new guidance on April 1, 2009. The implementation did not have a material impact on the Company's consolidated financial statements. ASC 825 required disclosures have been included in the Company's notes to consolidated financial statements, where applicable.

Subsequent Events— In May 2009, the FASB issued new guidance regarding subsequent events. The new guidance under ASC 855, *Subsequent Events*, establishes general standards of accounting and disclosure for events that occur after the balance sheet date but before financial statements are issued. The new accounting guidance is consistent with the auditing literature widely used for accounting and disclosure of subsequent events, however, the new guidance requires an entity to disclose the date through which subsequent events have been evaluated. The new guidance is effective for interim and annual periods ending after June 15, 2009. The Company implemented the new guidance on April 1, 2009. The implementation did not have a material impact on the Company's consolidated financial statements. The Company has evaluated events occurring through February 26, 2010 and determined there are no events that have occurred subsequent to December 31, 2009 that would affect the Company's consolidated financial statements as of, and for the periods ending December 31, 2009, or that require additional disclosure in this Annual Report on Form 10-K.

SFAS No. 167, Amendments to FASB Interpretation No. 46(R), was issued by the FASB in June 2009. SFAS No. 167 amends the consolidation guidance applicable to variable interest entities. The amendments will significantly affect various elements of consolidation guidance under FASB Interpretation No. 46(R), including guidance for determining whether an entity is a variable interest entity and whether an enterprise is the primary beneficiary of a variable interest entity. SFAS No. 167 is effective for fiscal years beginning after November 15, 2009. The Company does not expect the implementation of SFAS No. 167 to have a significant impact on its consolidated financial statements. SFAS No. 167 will remain authoritative until it is integrated into the ASC.

2. Business Combinations, Dispositions and Segment Information

There were no acquisitions or dispositions of businesses in 2009.

On May 1, 2008 BTD Manufacturing, Inc. (BTD), acquired the assets of Miller Welding & Ironworks, Inc. (Miller Welding) of Washington, Illinois for $41.7 million in cash. Miller Welding, a custom job shop fabricator and finisher, recorded $26 million in revenue in 2007. Miller Welding 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. This acquisition will provide opportunities for growth in new and existing markets for both BTD and Miller Welding, and complementing production capabilities will expand the scope and capacity of services offered by both companies.

Below is condensed balance sheet information, at the date of the business combination, disclosing the allocation of the purchase price assigned to each major asset and liability category of Miller Welding:

(in thousands)	
Assets	
Current Assets	$ 8,855
Goodwill	7,986
Other Intangible Assets	16,600
Fixed Assets	8,994
Total Assets	$ 42,435
Liabilities	
Current Liabilities	$ 761
Noncurrent Liabilities	—
Total Liabilities	$ 761
Cash Paid	$ 41,674

Other Intangible Assets related to the Miller Welding acquisition include $16,100,000 for Customer Relationships being amortized over 20 years, $400,000 for a Nonamortizable Trade Name and a $100,000 Covenant Not to Compete being amortized over three years.

On February 19, 2007 ShoreMaster acquired the assets of the Aviva Sports product line for $2.0 million in cash. The Aviva Sports product line operates under Aviva Sports, Inc. (Aviva), a newly formed, wholly owned subsidiary of ShoreMaster. The Aviva Sports product line is sold internationally and consists of products for consumer use in the pool, lake and yard, as well as commercial use at summer camps, resorts and large public swimming pools. The acquisition of the Aviva Sports product line fits well with the other product lines of ShoreMaster, a leading manufacturer and supplier of waterfront equipment.

On May 15, 2007 BTD acquired the assets of Pro Engineering, LLC (Pro Engineering) for $4.8 million in cash. Pro Engineering specializes in providing metal parts stampings to customers in the Midwest. The acquisition of Pro Engineering by BTD provides expanded growth opportunities for both companies.

Below, are condensed balance sheets, at the dates of the respective business combinations, disclosing the allocation of the purchase price assigned to each major asset and liability category of Aviva and Pro Engineering:

(in thousands)	Aviva	Pro Engineering
Assets		
Current Assets	$ 2,083	$ 1,956
Goodwill	—	1,048
Other Intangible Assets	870	396
Plant	—	1,600
Total Assets	$ 2,953	$ 5,000
Liabilities		
Current Liabilities	$ 988	$ 215
Noncurrent Liabilities	—	—
Total Liabilities	$ 988	$ 215
Cash Paid	$ 1,965	$ 4,785

Other Intangible Assets related to the Aviva acquisition include $83,000 for a nonamortizable brand name and $787,000 in intangible assets being amortized over various periods up to 15 years. Other Intangible Assets related to the Pro Engineering acquisition include $51,000 for a nonamortizable brand name and $345,000 in intangible assets being amortized over various periods up to 20 years.

All of the acquisitions described above were accounted for using the purchase method of accounting. Disclosure of pro forma information related to the results of operations of the entities acquired in 2008 and 2007 for the periods presented in this report is not required due to immateriality.

Segment Information

The accounting policies of the segments are described under note 1 — Summary of Significant Accounting Policies. The Company's businesses have been classified into six segments based on products and services and reach customers in all 50 states and international markets. The six segments are: Electric, Plastics, Manufacturing, Health Services, Food Ingredient Processing and Other Business Operations.

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

Plastics consists of businesses producing polyvinyl chloride (PVC) pipe in the Upper Midwest and Southwest regions of the United States.

Manufacturing consists of businesses in the following manufacturing activities: production of wind towers, contract machining, metal parts stamping and fabrication, and production of waterfront equipment, material and handling trays and horticultural containers. These businesses have manufacturing facilities in Florida, Illinois, Minnesota, Missouri, North Dakota, Oklahoma and Ontario, Canada and sell products primarily in the United States.

Health Services consists of businesses involved in the sale of diagnostic medical equipment, patient monitoring equipment and related supplies and accessories. These businesses also provide equipment maintenance, diagnostic imaging services and rental of diagnostic medical imaging equipment to various medical institutions located throughout the United States.

Food Ingredient Processing consists of IPH, which owns and operates potato dehydration plants in Ririe, Idaho; Center, Colorado; and Souris, Prince Edward Island, Canada. IPH produces dehydrated potato products that are sold in the United States, Canada and other countries.

Other Business Operations consists of businesses in residential, commercial and industrial electric contracting industries, fiber optic and electric distribution systems, water, wastewater and HVAC systems construction, transportation and energy services. These businesses operate primarily in the Central United States, except for the transportation company which operates in 48 states and four Canadian provinces.

The Company's electric operations, including wholesale power sales, are operated by its wholly owned subsidiary, OTP, and its energy services operation is operated by a separate wholly owned subsidiary of the Company. All of the Company's other businesses are owned by its wholly owned subsidiary, Varistar Corporation (Varistar).

Corporate includes items such as corporate staff and overhead costs, the results of the Company's captive insurance company and other items excluded from the measurement of operating segment performance. Corporate assets consist primarily of cash, prepaid expenses, investments and fixed assets. Corporate is not an operating segment. Rather, it is added to operating segment totals to reconcile to totals on the Company's consolidated financial statements.

The Company has one customer within the manufacturing segment that accounted for 13.6% of the Company's consolidated revenues in 2009. No other single external customer accounts for 10% or more of the Company's consolidated revenues. Substantially all of the Company's long-lived assets are within the United States except for a food ingredient processing dehydration plant in Souris, Prince Edward Island, Canada and a wind tower manufacturing plant in Fort Erie, Ontario, Canada.

Percent of Sales Revenue by Country for the Year Ended December 31:	2009	2008	2007
United States of America	97.8%	97.3%	96.9%
Canada	0.8%	1.1%	1.3%
All Other Countries	1.4%	1.6%	1.8%

Table of Contents

The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information on continuing operations for the business segments for 2009, 2008 and 2007 is presented in the following table.

(in thousands)	2009	2008	2007
Operating Revenue			
Electric	$ 314,625	$ 340,020	$ 323,478
Plastics	80,208	116,452	149,012
Manufacturing	323,895	470,462	381,599
Health Services	110,006	122,520	130,670
Food Ingredient Processing	79,098	65,367	70,440
Other Business Operations	136,088	199,511	185,730
Corporate and Intersegment Eliminations	(4,408)	(3,135)	(2,042)
Total	$1,039,512	$1,311,197	$1,238,887
Depreciation and Amortization			
Electric	$ 36,946	$ 31,755	$ 26,097
Plastics	2,945	3,050	3,083
Manufacturing	22,530	19,260	13,124
Health Services	3,907	4,133	3,937
Food Ingredient Processing	4,333	4,094	3,952
Other Business Operations	2,550	2,230	2,058
Corporate	397	538	579
Total	$ 73,608	$ 65,060	$ 52,830
Interest Charges			
Electric	$ 19,414	$ 12,895	$ 9,405
Plastics	811	1,156	970
Manufacturing	5,724	8,666	8,546
Health Services	448	714	883
Food Ingredient Processing	36	109	177
Other Business Operations	509	1,171	1,234
Corporate and Intersegment Eliminations	1,572	2,247	(358)
Total	$ 28,514	$ 26,958	$ 20,857
Income Before Income Taxes			
Electric	$ 34,725	$ 46,160	$ 37,422
Plastics	(126)	3,114	13,452
Manufacturing	(4,331)	7,650	24,503
Health Services	(3,210)	342	2,626
Food Ingredient Processing	11,817	2,655	5,912
Other Business Operations	(3,194)	8,736	6,762
Corporate	(14,255)	(18,495)	(8,748)
Total	$ 21,426	$ 50,162	$ 81,929
Earnings Available for Common Shares			
Electric	$ 33,711	$ 32,498	$ 23,762
Plastics	(59)	1,880	8,314
Manufacturing	(2,025)	5,269	15,632
Health Services	(2,096)	85	1,427
Food Ingredient Processing	7,407	1,681	4,386
Other Business Operations	(1,891)	5,279	4,049
Corporate	(9,752)	(12,303)	(4,345)
Total	$ 25,295	$ 34,389	$ 53,225
Capital Expenditures			
Electric	$ 145,787	$ 198,798	$ 104,288
Plastics	4,269	8,883	3,305
Manufacturing	18,702	47,606	42,786
Health Services	3,439	4,039	5,276
Food Ingredient Processing	686	2,402	47
Other Business Operations	3,678	3,919	5,589
Corporate	564	241	694
Total	$ 177,125	$ 265,888	$ 161,985
Identifiable Assets			
Electric	$1,119,822	$ 992,159	$ 813,565
Plastics	70,380	78,054	77,971
Manufacturing	306,011	356,697	274,780

Health Services	58,164	61,086	64,824
Food Ingredient Processing	88,478	88,813	91,966
Other Business Operations	59,915	71,359	72,258
Corporate	51,908	44,419	59,390
Total	$1,754,678	$1,692,587	$1,454,754

3. Rate and Regulatory Matters

Minnesota

General Rate Case —In an order issued by the Minnesota Public Utilities Commission (MPUC) on August 1, 2008 OTP was granted an increase in Minnesota retail electric rates of $3.8 million, or approximately 2.9%, which went into effect in February 2009. The MPUC approved a rate of return on equity of 10.43% on a capital structure with 50.0% equity. An interim rate increase of 5.4% was in effect from November 30, 2007 through January 31, 2009. Amounts refundable totaling $3.9 million had been recorded as a liability on the Company's consolidated balance sheet as of December 31, 2008. An additional $0.5 million refund liability was accrued in January 2009. OTP refunded Minnesota customers the difference between interim and final rates, with interest, in March 2009. In June 2008, OTP deferred recognition of $1.5 million in rate case-related regulatory assessments and fees of outside experts and attorneys that are subject to amortization and recovery over a three-year period beginning in February 2009.

Capacity Expansion 2020 (CapX 2020) Mega Certificate of Need (CON) —On August 16, 2007 the eleven CapX 2020 utilities asked the MPUC to determine the need for three 345-kilovolt (kV) transmission lines. Evidentiary hearings for the CON for the three CapX 2020 345-kV transmission line projects began in July 2008 and continued into August 2008. On April 16, 2009 the MPUC approved the CON for the three 345-kV Group 1 CapX 2020 line projects (Fargo-St. Cloud, Brookings-Southeast Twin Cities, and Twin Cities-LaCrosse). The MPUC then voted to impose conditions pertaining to reserving line capacity for renewable energy sources on the Brookings line project. The MPUC did take up reconsideration of the original order regarding the conditions. The MPUC slightly modified the conditions on the Brookings line. As part of the CON approval, the MPUC accepted a CapX 2020 request to build the 345-kV lines for double-circuit capability to have two 345-kV transmission circuits on each structure. The current plan is to string only one circuit. The MPUC CON orders were appealed to the Minnesota Court of Appeals on October 9, 2009 and the appellate court's determination is expected to be made in the fall of 2010. Route permit applications were filed in Minnesota for the Brookings project in late December 2008. The route permit for the Monticello to St. Cloud portion of the Fargo project was filed in April 2009 and is anticipated to be received in mid-2010. The Minnesota route permit for the St. Cloud to Fargo portion of the Fargo Project was filed on October 1, 2009. Portions of the projects would also require approvals by federal officials and by regulators in North Dakota, South Dakota and Wisconsin. After regulatory need is established and routing decisions are completed, construction will begin. The lines would be expected to be completed over a period of two to four years. Great River Energy and Xcel Energy are leading these projects, and OTP and eight other utilities are involved in permitting, building and financing. OTP is directly involved in two of these three 345-kV projects.

OTP serves as the lead utility in a fourth CapX 2020 Group 1 project, the Bemidji-Grand Rapids 230-kV line, which has an expected in-service date of 2012-2013. OTP filed an application for a CON for this fourth project on March 17, 2008. The Department of Commerce Office of Energy Security (MNOES) staff completed briefing papers regarding the Bemidji-Grand Rapids route permit application. The MNOES staff recommended to the MPUC that: (1) the route permit application be found to be complete, (2) the need determination not be sent to a contested case but be handled informally by MPUC review, and (3) the CON and route permit proceedings be combined as requested. The MPUC met on June 26, 2008 to act on the MNOES staff recommendation. The MPUC agreed that the CON and route permit applications were complete. The MNOES subsequently recommended a determination that need for the line has been established. An environmental report for the CON was issued in April 2009. CON hearings were conducted on May 20 and May 21, 2009 and a summary of comments was issued on June 8, 2009. The CON was issued on July 9, 2009 and the written order received on July 14, 2009. The applicants continue to work with the MNOES to define the schedule for issuance of the draft environmental impact statement (EIS) and the route contested case hearing. The route hearing is expected to occur in early 2010. The MPUC is expected to determine the route for this line and, if appropriate, issue a route permit in fall 2010. A federal EIS also will be needed for this project.

Renewable Energy Standards, Conservation and Renewable Resource Riders —In February 2007, the Minnesota legislature passed a renewable energy standard requiring 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: 12% by 2012; 17% by 2016; 20% by 2020 and 25% by 2025. Additionally, Minnesota law requires utilities to make a good faith effort to generate or procure sufficient renewable generation such that 7% of total retail electric sales to retail customers in Minnesota come from qualifying renewable sources by 2010. Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards. OTP has acquired renewable resources and expects to acquire additional renewable resources in order to maintain compliance with the Minnesota renewable energy standard. OTP has sufficient renewable energy resources available and in service to comply with the required 2016 level of the Minnesota renewable energy standard. 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 standards. 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 now 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.

In an order issued on August 15, 2008, the MPUC approved OTP's proposal to implement a Renewable Resource Cost Recovery Rider for its Minnesota jurisdictional portion of investment in qualifying renewable energy facilities. The rider enables OTP to recover from its Minnesota retail customers its investments in owned renewable energy facilities and provides for a return on those investments. The Minnesota Renewable Resource Adjustment (MNRRA) of $0.0019 per kilowatt-hour (kwh) was included on Minnesota customers' electric service statements beginning in September 2008, reflecting cost recovery for OTP's twenty-seven 1.5 megawatt (MW) wind turbines and collector system at the Langdon Wind Energy Center, which became fully operational in January 2008.

The MPUC approved OTP's petition for a 2009 MNRRA in July 2009, which increased the MNRRA rate to provide cost recovery for its 32 wind turbines at the Ashtabula Wind Energy Center that became commercially operational in November 2008. This approval increased the 2009 MNRRA to $0.00415 per kwh for the recovery of $6.6 million through March 31, 2010—$4.0 million from August through December 2009 and $2.6 million from January through March 2010 The approval also granted OTP authority to recover over a 48-month period beginning in April 2010 accrued renewable resource recovery revenues that had not previously been recovered. OTP has recognized a regulatory asset of $5.3 million for revenues that are eligible for recovery through the rider but have not been billed to Minnesota customers as of December 31, 2009. On January 12, 2010, the MPUC issued an order finding OTP's Luverne Wind Farm project eligible for cost recovery through the MNRRA. The 2010 annual MNRRA cost recovery filing was made on December 31, 2009 with a requested effective date of April 1, 2010.

In addition to the Renewable Resource Cost Recovery Rider, the Minnesota Public Utilities 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 otherwise deemed eligible by the MPUC. Such transmission cost recovery riders allow a return on investments 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 request for approval of a transmission cost recovery rider was granted by the MPUC on January 7, 2010, and became effective February 1, 2010. Beginning February 1, 2010, OTP's transmission rider rate is reflected on Minnesota customer electric service statements at $0.00039 per kwh plus $0.035 per kW for large general service customers and $0.00007 per kwh for controlled service customers, $0.00025 per kwh for lighting customers, and $0.00057 per kwh for all other customers. As of December 31, 2009 OTP had accrued $0.4 million in revenues that are eligible for recovery through the rider but have not been billed.

Recovery of MISO Costs —In an order issued on December 20, 2006 the MPUC stated that except for schedule 16 and 17 administrative costs, discussed below, each petitioning utility may recover the charges imposed by the MISO for MISO Day 2 operations (offset by revenues from Day 2 operations via net accounting) through the calculation of the utility's FCA from the period April 1, 2005 through a period of at least three years after the date of the order. The MPUC also ordered the utilities to refund schedule 16 and 17 costs collected through the FCA since the inception of MISO Day 2 Markets in April 2005 and stated that each petitioning utility may use deferred accounting for MISO schedule 16 and 17 costs incurred since April 1, 2005. This deferred accounting may continue for ongoing schedule 16 and 17 costs, without the accumulation of interest, until the earlier of March 1, 2009 or the utility's next electric rate case. Pursuant to this December 20, 2006 order, OTP was ordered to refund $446,000 in MISO schedule 16 and 17 costs to Minnesota retail customers through the FCA over a twelve-month period beginning in January 2007. OTP requested recovery of the deferred costs and recovery of the ongoing costs in its general rate case filed in October 2007 and began amortizing its deferred MISO schedule 16 and 17 costs over a 35-month period in January 2008. The remaining unamortized balance was $252,000 as of December 31, 2009. The August 1, 2008 MPUC Order in the general rate case allowed future recovery of MISO schedule 16 and 17 costs and recovery of the deferred Schedule 16 and 17 costs.

Minnesota Annual Automatic Adjustment Report on Energy Costs (AAA Report) —The MNDOC and OTP identified two operational situations which are not covered in the approved method for allocating MISO costs contained in the final December 20, 2006 MPUC order discussed above. One relates to plants not expected to be available for retail but that produce energy in certain hours, resulting in wholesale sales. The other situation is related to Financial Transmission Rights (FTRs) not needed for retail load. For the period July 1, 2005 through June 30, 2007 OTP determined its Minnesota customers' portion of costs associated with these situations to be $765,000. The data was provided to the MNDOC during the course of the MNDOC's review of the AAA Report. OTP offered to refund $765,000 to its Minnesota customers to settle this and other issues raised by the MNDOC in the AAA Report docket before the MPUC and the MNDOC accepted the offer in October 2007 and recommended that the MPUC include the refund in its final order. OTP also agreed to modifications to the MISO Day 2 cost allocations that were resolved in the MPUC's December 20, 2006 order. OTP agreed to make some of those modifications retroactive back to January 1, 2007. The MPUC accepted OTP's refund offer and modifications and closed this docket on February 6, 2008. In December 2007, OTP recorded a liability and a reduction to revenue of $805,000 for the amount of the refund offer and similar revenues collected subsequent to June 30, 2007. Refunds to Minnesota customers were completed during 2008.

North Dakota

General Rate Case —On November 3, 2008 OTP filed a general rate case in North Dakota requesting an overall revenue increase of approximately $6.1 million, or 5.1%, and an interim rate increase of approximately 4.1%, or $4.8 million annualized, that went into effect on January 2, 2009. In an order issued by the North Dakota Public Service Commission (NDPSC) on November 25, 2009 OTP was granted an increase in North Dakota retail electric rates of $3.6 million or approximately 3.0%, which went into effect in December 2009. The NDPSC order authorizing an interim rate increase requires OTP to refund North Dakota customers the difference between final and interim rates, with interest. OTP established a refund reserve for revenues collected under interim rates that exceeded the final rate increase. The refund reserve balance was $0.9 million as of December 31, 2009, which will be refunded to North Dakota customers in January 2010. OTP deferred recognition of $0.5 million in rate case-related filing and administrative costs that are subject to amortization and recovery over a three year period beginning in January 2010.

Renewable Resource Cost Recovery Rider —On May 21, 2008 the NDPSC approved OTP's request for a Renewable Resource Cost Recovery Rider to enable OTP to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. The North Dakota Renewable Resource Cost Recovery Rider Adjustment (NDRRA) of $0.00193 per kwh was included on North Dakota customers' electric service statements beginning in June 2008, and reflects cost recovery for OTP's twenty-seven 1.5 MW wind turbines and collector system at the Langdon Wind Energy Center, which became fully operational in January 2008. The rider also allows OTP to recover costs associated with other new renewable energy projects as they are completed. OTP included investment costs and expenses related to its 32 wind turbines at the Ashtabula Wind Energy Center that became commercially operational in November 2008 in its 2009 annual request to the NDPSC to increase the amount of the NDRRA. An NDRRA of $0.0051 per kwh was approved by the NDPSC on January 14, 2009 and went into effect beginning with billing statements sent on February 1, 2009.

In a proceeding that was combined with OTP's general rate case, the NDPSC reviewed whether to move the costs of the projects currently being recovered through the NDRRA into base rate cost recovery and whether to make changes to the rider. A settlement of the general rate case and the NDRRA reduced the NDRRA to $0.00369 for the period from December 1, 2009 until the effective date for the next annual NDRRA filing, requested to be April 1, 2010. Because the 2008 annual NDRRA filing was combined with the general rate case proceedings (concluded in November 2009), the 2009 annual filing to establish the 2010 NDRRA rate (which includes cost recovery for OTP's investment in its Luverne Wind Farm project) was delayed until December 31, 2009, with a requested effective date of April 1, 2010.

OTP had not been deferring recognition of its renewable resource costs eligible for recovery under the NDRRA but had been charging those costs to operating expense since January 2008. After approval of the rider in May 2008, OTP accrued revenues related to its investment in renewable energy and for renewable energy costs incurred since January 2008 that are eligible for recovery through the NDRRA. Terms of the approved settlement provide for the recovery of accrued but unbilled NDRRA revenues over a period of 48 months beginning in January 2010. The Company's December 31, 2009 consolidated balance sheet includes a regulatory asset of $0.6 million for revenues that are eligible for recovery through the NDRRA but have not been billed to North Dakota customers.

North Dakota legislation also 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 requested recovery of such costs in its general rate case filed in November 2008, and was granted recovery of such costs by the NDPSC in its November 25, 2009 order.

CapX 2020 Request for Advance Determination of Prudence —On October 5, 2009 OTP filed an application for an advance determination of prudence with the NDPSC for its proposed participation in three of the four Group 1 projects (Fargo-St. Cloud, Brookings-Southeast Twin Cities, and Bemidji-Grand Rapids). An administrative law judge has been assigned to conduct a hearing that is currently scheduled for April 2010.

Recovery of MISO Costs —In February 2005, OTP filed a petition with the NDPSC to seek recovery of certain MISO-related costs through the FCA. The NDPSC granted interim recovery through the FCA in April 2005, but similar to the decision of the MPUC, conditioned the relief as being subject to refund until the merits of the case are determined. In August 2007, the NDPSC approved a settlement agreement between OTP and an intervener representing several large industrial customers in North Dakota. Under the approved settlement agreement, OTP refunded $493,000 of MISO schedule 16 and 17 costs collected through the FCA from April 2005 through July 2007 to North Dakota customers beginning in October 2007 and ending in January 2008. OTP deferred recognition of these costs plus $330,000 in MISO schedule 16 and 17 costs incurred from August 2007 through December 2008 and requested recovery of these deferred costs in its general rate case filed in North Dakota in November 2008. OTP began amortizing its deferred MISO schedule 16 and 17 costs in North Dakota over a 36-month period beginning in December 2009 in conjunction with the implementation of rates approved by the NDPSC in its November 25, 2009 order. As of December 31, 2009 the balance of OTP's deferred MISO schedule 16 and 17 costs was $1,091,000. Base rate recovery for on-going MISO schedule 16 and 17 costs was also approved by the NDPSC in its November 25, 2009 order.

South Dakota

General Rate Case —On October 31, 2008 OTP filed a general rate case in South Dakota requesting an overall revenue increase of approximately $3.8 million, or 15.3%, which included, among other things, recovery of investments and expenses related to renewable resources in base rates. OTP increased rates by approximately 11.7% on a temporary basis beginning with electricity consumed on and after May 1, 2009, as allowed under South Dakota law. In an order issued by the South Dakota Public Utilities Commission (SDPUC) on June 30, 2009, OTP was granted an increase in South Dakota retail electric rates of $2.9 million or approximately 11.7%. OTP implemented final, approved rates in July 2009.

Federal

Revenue Sufficiency Guarantee (RSG) Charges —Since 2006, OTP has been a party to litigation before the FERC regarding the application of RSG charges to market participants who withdraw energy from the market or engage in financial-only, virtual sales of energy into the market or both. These litigated proceedings occurred in several electric rate and complaint dockets before the FERC and several of the FERC's orders are on review before the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit).

On November 7, 2008 the FERC issued an order on rehearing and compliance in the RSG proceeding, reversing its determination in a prior order and stating that MISO should remove the volume of virtual supply offers of market participants — not physically withdrawing energy — from the denominator of the rate calculation from April 25, 2006 forward. MISO interpreted the order to mean that all virtual supply offers and deviations in the denominator of the rate calculation that do not ultimately pay the rate should be removed from April 1, 2005 (start of the Energy Market) forward. On November 10, 2008 the FERC issued an order finding the current RSG rate unjust and unreasonable and accepting an interim rate that applied RSG charges to all virtual sales until such time as MISO makes a subsequent filing of the new RSG rate.

On May 6, 2009 the FERC issued an order on rehearing of the November 10, 2008 order. The May order relieved MISO from having to resettle RSG payments resulting from the FERC's earlier decision to remove the words "actually withdraws energy" (AWE) from the RSG tariff provisions. Absent this relief (or waiver), the removal of the AWE language would have had two relevant impacts on the RSG charge: (1) it would tend to reduce the RSG rate because the rate denominator would include all virtual supply volumes and (2) it would impose RSG charges on all cleared virtual supply transactions. The waiver applies to the period August 10, 2007 through November 9, 2008. Beginning November 10, 2008, the MISO is obliged to resettle RSG charges by recalculating the RSG rate and impose RSG charges on all virtual supply transactions.

On June 12, 2009 the FERC issued an order on rehearing of the November 7, 2008 order. The June order, at a minimum, relieved MISO from having to resettle RSG payments resulting from any difference between the megawatt hours associated with virtual supply in the denominator of the RSG rate and the billing determinants associated with virtual supply transactions (VSO mismatch). This relief (or waiver) applies to the period April 25, 2006 through November 4, 2007. Since OTP would have had a payment obligation during this period associated with the virtual supply and other mismatches, the June order eliminates that payment obligation. However, the June order, like many of the other orders in this docket, is subject to appellate review and potential reversal. Beginning from November 5, 2007, MISO is obligated to resettle to correct the VSO mismatch. As of September 30, 2009, OTP had paid all its resettlement obligations determined and imposed by MISO. On August 7, 2009 the FERC issued an order requiring MISO's RSG Task Force to develop a recommendation on any transactions that should be exempted from paying RSG charges. The RSG Task Force has completed its review and provided recommendations to the FERC. The Company does not know when these litigation proceedings will conclude.

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, due to a number of factors. The broad economic downturn, a high level of uncertainty associated with proposed federal climate legislation and existing federal environmental regulations and challenging credit and equity markets made proceeding with Big Stone II and committing to approximately $400 million in capital expenditures untenable for OTP's customers and the Company's shareholders. On November 2, 2009, the remaining Big Stone II participants announced the cancellation of the Big Stone II project.

As of December 31, 2009, OTP had incurred $13.0 million in costs related to this project that it believes are probable of recovery in future rates and has deferred recognition of these costs as operating expenses pending determination of recoverability by the state and federal regulatory commissions that approve OTP's rates. In filings made on December 14, 2009, OTP requested from its three state commissions authority to reflect these costs on its books as a regulatory asset through the use of deferred accounting, pending a determination on the recoverability of the costs. The SDPUC approved OTP's request for deferred accounting treatment on February 9, 2010. If Minnesota or North Dakota denies the requests to use deferred accounting or if any of the three jurisdictions eventually denies recovery of all or any portion of these deferred costs, such costs would be subject to expense in the period they are deemed to be inappropriate for deferral or unrecoverable.

4. Regulatory Assets and Liabilities

As a regulated entity OTP accounts for the financial effects of regulation in accordance with ASC 980, *Regulated Operations* . This accounting standard allows for the recording of a regulatory asset or liability for costs that will be collected or refunded in the future as required under regulation.

The following table indicates the amount of regulatory assets and liabilities recorded on the Company's consolidated balance sheet:

(in thousands)	December 31, 2009	December 31, 2008
Regulatory Assets:		
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits	$ 78,871	$ 64,490
Unrecovered Project Costs – Big Stone II	12,982	—
Deferred Marked-to-Market Losses	7,614	1,162
Deferred Income Taxes	5,441	7,094
Minnesota Renewable Resource Rider Accrued Revenues	5,324	3,045
Debt Reacquisition Premiums	3,051	3,357
Deferred Conservation Improvement Program Costs	1,908	280
Accumulated ARO Accretion/Depreciation Adjustment	1,808	1,437
Minnesota General Rate Case Recoverable Expenses	1,693	1,457
Accrued Cost-of-Energy Revenue	1,175	8,982
MISO Schedule 16 and 17 Deferred Administrative Costs — ND	1,091	823
North Dakota Renewable Resource Rider Accrued Revenues	566	2,009
Minnesota Transmission Rider Accrued Revenues	420	—
South Dakota – Asset-Based Margin Sharing Shortfall	330	—
MISO Schedule 16 and 17 Deferred Administrative Costs — MN	252	526
Deferred Holding Company Formation Costs	248	—
Plant Acquisition Costs	18	63
Total Regulatory Assets	$ 122,792	$ 94,725
Regulatory Liabilities:		
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$ 58,937	$ 58,768
Deferred Income Taxes	4,965	4,943
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Gains on Other Postretirement Benefits	—	834
Deferred Marked-to-Market Gains	224	—
Other Regulatory Liabilities	148	139
Total Regulatory Liabilities	$ 64,274	$ 64,684
Net Regulatory Asset Position	$ 58,518	$ 30,041

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

Unrecovered Project Costs – Big Stone II are costs incurred by OTP since 2005 related to its participation in the planned construction of a 500- to 600-megawatt generating unit at its Big Stone Plant site. On September 11, 2009 OTP announced its withdrawal from participation in the Big Stone II project due to a number of factors. The broad economic downturn, a high level of uncertainty associated with proposed federal climate legislation and existing federal environmental regulations and challenging credit and equity markets made proceeding with Big Stone II and committing to approximately $400 million in capital expenditures untenable for OTP's customers and the Company's shareholders. OTP believes the costs it incurred during its participation in the project are probable of recovery in future rates and has deferred recognition of these costs as operating expenses pending determination of recoverability by the state and federal regulatory commissions that approve OTP's rates. No recovery period has been established for these deferred costs as OTP is in the initial phase of seeking recovery of these costs through the regulatory process. If OTP is denied recovery of all or any portion of these deferred costs, such costs would be subject to expense in the period they are deemed to be unrecoverable.

All Deferred Marked-to-Market Gains and Losses recorded as of December 31, 2009 are related to forward purchases of energy scheduled for delivery through December 2013.

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

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 and 2009 renewable resource costs incurred to serve Minnesota customers that have not been billed to Minnesota customers as of December 31, 2009. Minnesota Renewable Resource Rider Accrued Revenues are expected to be recovered over 51 months, from January 2010 through March 2014.

Debt Reacquisition Premiums included in Unamortized Debt Expense are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is 23 years.

Deferred Conservation Program Costs represent mandated conservation expenditures and incentives recoverable through retail electric rates over the next 18 months.

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

Minnesota General Rate Case Recoverable Expenses will be recovered over the next 25 months.

Accrued Cost-of-Energy Revenue included in Accrued Utility and Cost-of-Energy Revenues will be recovered over the next 20 months.

MISO Schedule 16 and 17 Deferred Administrative Costs – ND will be recovered over the next 35 months.

North Dakota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 and 2009 renewable resource costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of December 31, 2009. North Dakota Renewable Resource Rider Accrued Revenues are expected to be recovered over 48 months, from January 2010 through December 2013.

Minnesota Transmission Rider Accrued Revenues are expected to be recovered over the next 12 months.

South Dakota – Asset-Based Margin Sharing Shortfall represents a difference in OTP’s South Dakota share of actual profit margins on wholesale sales of electricity from company-owned generating units and estimated profit margins from those sales that were used in determining current South Dakota retail electric rates. Net shortfalls or excess margins accumulated over 14 months will be subject to recovery or refund through future retail rate adjustments in South Dakota.

MISO Schedule 16 and 17 Deferred Administrative Costs – MN will be recovered over the next 11 months.

Deferred Holding Company Formation Costs will be amortized over the next 54 months.

Plant Acquisition Costs will be amortized over the next 5 months.

The Accumulated Reserve for Estimated Removal Costs – Net of Salvage is reduced as actual removal costs are incurred.

Other Regulatory Liabilities includes: 1) a portion of profit margins on wholesales sales of purchased power subject to refund to South Dakota customers through future retail rate adjustments and 2) a deferred gain on the sale of utility property that will be paid to Minnesota retail electric customers over the next 24 years.

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

5. Forward Contracts Classified as Derivatives

Electricity Contracts

All of OTP's wholesale purchases and sales of energy under forward contracts that do not meet the definition of capacity contracts are considered derivatives subject to mark-to-market accounting. OTP's objective in entering into forward contracts for the purchase and sale of energy is to optimize the use of its generating and transmission facilities and leverage its knowledge of wholesale energy markets in the region to maximize financial returns for the benefit of both its customers and shareholders. OTP's intent in entering into certain of these contracts is to settle them through the physical delivery of energy when physically possible and economically feasible. OTP also enters into certain contracts for trading purposes with the intent to profit from fluctuations in market prices through the timing of purchases and sales.

As of December 31, 2009 OTP had recognized, on a pretax basis, $1,030,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity. The market prices used to value OTP's forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The fair value measurements of these forward energy contracts fall into level 2 of the fair value hierarchy set forth in ASC 820-10-35.

Electric revenues include $15,762,000 in 2009, $27,236,000 in 2008 and $25,640,000 in 2007 related to wholesale electric sales and net unrealized derivative gains on forward energy contracts and sales of financial transmission rights and daily settlements of virtual transactions in the MISO market, broken down as follows for the years ended December 31:

(in thousands)	2009	2008	2007
Wholesale Sales — Company-Owned Generation	$ 12,579	$ 23,708	$ 20,345
Revenue from Settled Contracts at Market Prices	110,124	520,280	389,643
Market Cost of Settled Contracts	(109,125)	(518,866)	(387,682)
Net Margins on Settled Contracts at Market	999	1,414	1,961
Marked-to-Market Gains on Settled Contracts	14,585	39,375	31,243
Marked-to-Market Losses on Settled Contracts	(13,431)	(37,138)	(28,541)
Net Marked-to-Market Gain on Settled Contracts	1,154	2,237	2,702
Unrealized Marked-to-Market Gains on Open Contracts	8,097	405	5,117
Unrealized Marked-to-Market Losses on Open Contracts	(7,067)	(528)	(4,485)
Net Unrealized Marked-to-Market Gain (Loss) on Open Contracts	1,030	(123)	632
Wholesale Electric Revenue	$ 15,762	$ 27,236	$ 25,640

The following tables show the effect of marking to market forward contracts for the purchase and sale of energy on the Company's consolidated balance sheets:

(in thousands)	December 31, 2009	December 31, 2008
Current Asset – Marked-to-Market Gain	$ 8,321	$ 405
Regulatory Asset – Deferred Marked-to-Market Loss	7,614	1,162
Total Assets	15,935	1,567
Current Liability – Marked-to-Market Loss	(14,681)	(1,690)
Regulatory Liability – Deferred Marked-to-Market Gain	(224)	—
Total Liabilities	(14,905)	(1,690)
Net Fair Value of Marked-to-Market Energy Contracts	$ 1,030	$ (123)

(in thousands)		Year ended December 31, 2009		Year ended December 31, 2008
Fair Value at Beginning of Year	$	(123)	$	632
Amount Realized on Contracts Entered into in Prior Year		123		(1,169)
Changes in Fair Value of Contracts Entered into in Prior Year		—		537
Net Fair Value of Contracts Entered into in Prior Year at Year End		—		—
Changes in Fair Value of Contracts Entered into in Current Year		1,030		(123)
Net Fair Value at End of Year	$	1,030	$	(123)

The $1,030,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on December 31, 2009 is expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	2010	2011	2012	Total
Net Gain	$ 389	$ 320	$ 321	$ 1,030

OTP has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy and capacity purchases and sales agreements. We have established guidelines and limits to manage credit risk associated with wholesale power and capacity purchases and sales. Specific limits are determined by a counterparty's financial strength. OTP's credit risk with its largest counterparty on delivered and marked-to-market forward contracts as of December 31, 2009 was $222,000. As of December 31, 2009 OTP had a net credit risk exposure of $387,000 from four counterparties with investment grade credit ratings. OTP had no exposure at December 31, 2009 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch).

The $387,000 credit risk exposure includes net amounts due to OTP on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery after December 31, 2009. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

Mark-to-market losses of $72,000 on certain of OTP's derivative energy contracts included in the $14,681,000 derivative liability on December 31, 2009 are covered by deposited funds. Certain other of OTP's derivative energy contracts contain provisions that require an investment grade credit rating from each of the major credit rating agencies on OTP's debt. If OTP's debt ratings were to fall below investment grade, the counterparties to these forward energy contracts could request immediate and ongoing full overnight collateralization on contracts in net liability positions. The aggregate fair value of all forward energy derivative contracts with credit-risk-related contingent features that are in a liability position on December 31, 2009 is $7,958,000, for which OTP has posted $7,760,000 as collateral in the form of offsetting gain positions on other contracts with one of its counterparties under a master netting agreement. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2009, OTP would have been required to post $198,000 in additional collateral to its counterparties. The remaining derivative liability balance of $6,651,000 relates to mark-to-market losses on contracts that have no ratings triggers or deposit requirements.

Fuel Contracts

In order to limit its exposure to fluctuations in future prices of natural gas and fuel oil, IPH entered into contracts with its fuel suppliers in August 2008, January 2009 and December 2009 for firm purchases of natural gas and fuel oil to cover portions of its anticipated natural gas needs in Ririe, Idaho and Center, Colorado from September 2008 through August 2009, its fuel oil needs in Souris, Prince Edward Island, Canada from January 2009 through August 2009 and its natural gas needs in Ririe, Idaho from January 2010 through August 2010 at fixed prices. These contracts qualified for the normal purchase exception to mark-to-market accounting under ASC 815-10-15.

Foreign Currency Exchange Forward Windows

The Canadian operations of IPH records its sales and carries its receivables in U.S. dollars but pays its expenses for goods and services consumed in Canada in Canadian dollars. The payment of its bills in Canada requires the periodic exchange of U.S. currency for Canadian currency. In order to lock in acceptable exchange rates and hedge its exposure to future fluctuations in foreign currency exchange rates between the U.S. dollar and the Canadian dollar, IPH's Canadian subsidiary entered into forward contracts for the exchange of U.S. dollars into Canadian dollars in 2008. Each monthly contract was for the exchange of $400,000 U.S. dollars for the amount of Canadian dollars stated in each contract. IPH's Canadian subsidiary also entered into forward contracts for the exchange of U.S. dollars into Canadian dollars in July 2009. Each monthly contract was for the exchange of $200,000 U.S. dollars for the amount of Canadian dollars stated in each contract. All contracts were settled as of December 31, 2009.

The following table lists the contracts entered into in 2008 and 2009 that were settled in 2009.

(in thousands)	Settlement Periods	USD	CAD
Contracts Entered into in July 2008	January 2009 - July 2009	$2,800	$2,918
Mark-to-Market Losses on Open Contracts at Year End 2008	January 2009 - July 2009	(401)	
Contracts Entered into in October 2008	January 2009 - October 2009	$4,000	$5,001
Mark-to-Market Gains on Open Contracts at Year End 2008	January 2009 - October 2009	112	
Net Mark-to-Market Losses Recognized on Open Contracts at Year End 2008		$ (289)	
Net Mark-to-Market Gains in 2009 on Open Contracts at Year End 2008		232	
Net Losses Realized on Settlement of 2008 contacts in 2009		$ (57)	
Contracts Entered Into in July 2009	August 2009 - December 2009	$1,000	$1,163
Net Mark-to-Market Gains Recognized and Realized on contracts entered into in 2009		$ 88	
Net Mark-to-Market Gains Recognized in 2009		$ 320	
Net Mark-to-Market Gains Realized in 2009		$ 31	

These contracts were derivatives subject to mark-to-market accounting. IPH did not enter into these contracts for speculative purposes or with the intent of early settlement, but for the purpose of locking in acceptable exchange rates and hedging its exposure to future fluctuations in exchange rates. IPH settled these contracts during their stated settlement periods and used the proceeds to pay its Canadian liabilities when they came due. These contracts did not qualify for hedge accounting treatment because the timing of their settlements did not coincide with the payment of specific bills or contractual obligations.

The fair value measurements of the above foreign currency exchange forward windows fall into level 1 of the fair value hierarchy set forth in ASC 820-10-35.

6. Common Shares and Earnings Per Share

On May 11, 2009 the Company filed a shelf registration statement with the U.S. Securities and Exchange Commission (SEC) under which it may offer for sale, from time to time, either separately or together in any combination, equity and/or debt securities described in the shelf registration statement, including common shares of the Company.

On July 1, 2009 Otter Tail Corporation completed a holding company reorganization in accordance with Section 302A.626 of the Minnesota Business Corporation Act (the MBCA) whereby OTP (also referred to as Old Otter Tail), 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 (formerly known as Otter Tail Holding Company).

The new holding company structure was effected as of July 1, 2009 pursuant to a Plan of Merger dated as of June 30, 2009 (the Plan of Merger), by and among Old Otter Tail, Otter Tail Holding Company (now known as Otter Tail Corporation), a Minnesota corporation and, prior to the reorganization, a direct subsidiary of Old Otter Tail, and Otter Tail Merger Sub Inc., a Minnesota corporation and indirect subsidiary of Old Otter Tail and direct subsidiary of Otter Tail Holding Company (Merger Sub). The Plan of Merger provided for the merger (the Merger) of Old Otter Tail with Merger Sub, with Old Otter Tail as the surviving corporation. Pursuant to Section 302A.626 (subd. 2) of the MBCA shareholder approval was not required for the Merger. As a result of the Merger, Old Otter Tail is now a wholly owned subsidiary of the Company with the name Otter Tail Power Company. Immediately following the completion of the Merger, the Company changed its name from Otter Tail Holding Company to Otter Tail Corporation.

In the Merger, each issued and outstanding common share of Old Otter Tail was converted into one common share of the Company, par value $5 per share, and each issued and outstanding cumulative preferred share of Old Otter Tail was converted into one cumulative preferred share of the Company having the same designations, rights, powers and preferences. In connection with the Merger, each person that held rights to purchase, or other rights to or interests in, common shares of Old Otter Tail under any stock option, stock purchase or compensation plan or arrangement of Old Otter Tail immediately prior to the Merger holds a corresponding number of rights to purchase, and other rights to or interests in, common shares of the Company, par value $5 per share, immediately following the Merger.

The conversion of the common shares in the Merger occurred without an exchange of certificates. Accordingly, certificates formerly representing outstanding common shares of Old Otter Tail are deemed to represent the same number of common shares of the Company.

Pursuant to Section 302A.626 (subd. 7) of the MBCA, the provisions of the Restated Articles of Incorporation and Restated Bylaws of the Company are consistent with those of Old Otter Tail prior to the Merger. The authorized common shares and cumulative preferred shares of the Company, the designations, rights, powers and preferences of such shares and the qualifications, limitations and restrictions thereof are also consistent with those of Old Otter Tail's common shares and cumulative preferred shares immediately prior to the Merger. The directors and executive officers of the Company are the same individuals who were directors and executive officers, respectively, of Old Otter Tail immediately prior to the Merger.

Immediately prior to the Merger, Old Otter Tail transferred to the Company by means of assignment the capital stock of its direct subsidiaries and all of its other assets not specific to the operation of the OTP. As a result, the Company is a holding company with two primary subsidiaries, OTP (the electric utility) and Varistar (a holding company for the Company's nonelectric businesses).

Following is a reconciliation of the Company's common shares outstanding from December 31, 2008 through December 31, 2009:

Common Shares Outstanding, December 31, 2008	35,384,620
Issuances:	
Dividend Reinvestment Plan – Dividend Purchases	163,224
Dividend Reinvestment Plan — Direct Purchases	70,719
Stock Options Exercised	50,350
Employee Stock Purchase Plan – Direct Purchase	45,413
Executive Officer Stock Performance Awards	29,350
Restricted Stock Issued to Nonemployee Directors	28,800
Restricted Stock Issued to Employees	27,600
Employee Stock Purchase Plan – Dividend Reinvestment	17,037
Vesting of Restricted Stock Units	5,350
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(10,183)
Common Shares Outstanding, December 31, 2009	35,812,280

Stock Incentive Plan

The 1999 Stock Incentive Plan, as amended (Incentive Plan), provides for the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, performance awards, and other stock and stock-based awards. A total of 3,600,000 common shares are authorized for granting stock awards, of which 822,317 were still available as of December 31, 2009 under the Incentive Plan, which terminates on December 13, 2013.

Employee Stock Purchase Plan

The 1999 Employee Stock Purchase Plan (Purchase Plan) allows eligible employees to purchase the Company's common shares at 85% of the market price at the end of each six-month purchase period. The number of common shares authorized to be issued under the Purchase Plan is 900,000, of which 230,482 were still available for purchase as of December 31, 2009. At the discretion of the Company, shares purchased under the Purchase Plan can be either new issue shares or shares purchased in the open market. To provide shares for the Purchase Plan, the Company issued 62,450 common shares and purchased 42,611 common shares in the open market in 2009, 49,684 common shares were purchased in the open market in 2008 and 52,558 common shares were purchased in the open market in 2007. The shares to be purchased by employees participating in the Purchase Plan are not considered dilutive during the investment period for the purpose of calculating diluted earnings per share.

Dividend Reinvestment and Share Purchase Plan

On August 30, 1996 the Company filed a shelf registration statement with the SEC for the issuance of up to 2,000,000 common shares pursuant to the Company's Automatic Dividend Reinvestment and Share Purchase Plan (the Plan), which permits shares purchased by shareholders or customers who participate in the Plan to be either new issue common shares or common shares purchased in the open market. The Company's shelf registration statement expired on December 1, 2008 and was replaced by an automatically effective shelf registration statement filed by the Company on November 26, 2008 for the issuance of up to 1,000,000 common shares pursuant to the Plan. From November 2004 through April 2009 the Company had purchased common shares in the open market to provide shares for the Plan. From May 2009 through December 2009 the Company issued 233,943 common shares to provide shares for the Plan.

Earnings Per Share

Basic earnings per common share are calculated by dividing earnings available for common shares by the weighted average number of common shares outstanding during the period. Diluted earnings per common share are calculated by adjusting outstanding shares, assuming conversion of all potentially dilutive stock options. Stock options with exercise prices greater than the market price are excluded from the calculation of diluted earnings per common share. Nonvested restricted shares granted to the Company's directors and employees are considered dilutive for the purpose of calculating diluted earnings per share but are considered contingently returnable and not outstanding for the purpose of calculating basic earnings per share. Underlying shares related to nonvested restricted stock units granted to employees are considered dilutive for the purpose of calculating diluted earnings per share. Shares expected to be awarded for stock performance awards granted to executive officers are considered dilutive for the purpose of calculating diluted earnings per share.

Excluded from the calculation of diluted earnings per share are the following outstanding stock options which had exercise prices greater than the average market price for the years ended December 31, 2009, 2008 and 2007:

Year	Options Outstanding	Range of Exercise Prices
2009	415,710	$ 24.93 — $31.34
2008	—	NA
2007	—	NA

7. Share-Based Payments

Purchase Plan

The Purchase Plan allows employees through payroll withholding to purchase shares of the Company's common stock at a 15% discount from the average market price on the last day of a six month investment period. Under ASC 718, *Compensation—Stock Compensation*, the Company is required to record compensation expense related to the 15% discount. The 15% discount resulted in compensation expense of $310,000 in 2009, $275,000 in 2008 and $257,000 in 2007. The 15% discount is not taxable to the employee and is not a deductible expense for tax purposes for the Company.

Stock Options Granted Under the Incentive Plan

Since the inception of the Incentive Plan in 1999, the Company has granted 2,041,500 options for the purchase of the Company's common stock. All of the options granted had vested or were forfeited as of December 31, 2007. The exercise price of the options granted was the average market price of the Company's common stock on the grant date. Under ASC 718 accounting requirements, compensation expense is recorded based on the estimated fair value of the options on their grant date using a fair-value option pricing model. Under ASC 718 accounting, the fair value of the options granted has been recorded as compensation expense over the requisite service period (the vesting period of the options). The estimated fair value of all options granted under the Incentive Plan was based on the Black-Scholes option pricing model.

Under the modified prospective application of share-based payment accounting requirements, the difference between the intrinsic value of nonvested options and the fair value of those options of $362,000 on January 1, 2006 was recognized on a straight-line basis as compensation expense over the remaining 16 months of the options vesting period. Accordingly, the Company recorded compensation expense of $91,000 in 2007 related to options that were not vested as of January 1, 2006.

Presented below is a summary of the stock options activity:

Stock Option Activity	2009		2008		2007	
	Options	Average Exercise Price	Options	Average Exercise Price	Options	Average Exercise Price
Outstanding, Beginning of Year	507,702	$ 26.00	787,137	$ 25.73	1,091,238	$ 25.74
Granted	—	—	—	—	—	—
Exercised	50,350	19.73	276,685	25.23	298,601	25.73
Forfeited	12,542	21.87	2,750	27.11	5,500	28.85
Outstanding, End of Year	444,810	26.82	507,702	26.00	787,137	25.73
Exercisable, End of Year	444,810	26.82	507,702	26.00	787,137	25.73
Cash Received for Options Exercised		$ 994,000		$ 6,981,000		$ 7,682,000
Fair Value of Options Granted During Year		none granted		none granted		none granted

The following table summarizes information about options outstanding as of December 31, 2009:

Options Outstanding and Exercisable			
Range of Exercise Prices	Outstanding and Exercisable as of 12/31/09	Weighted-Average Remaining Contractual Life (yrs)	Weighted-Average Exercise price
$18.80-$21.94	29,100	0.3	$19.75
$21.95-$25.07	26,550	5.3	24.93
$25.08-$28.21	304,010	1.9	26.48
$28.22-$31.34	85,150	2.2	31.06

Restricted Stock Granted to Directors

Under the Incentive Plan, restricted shares of the Company's common stock have been granted to members of the Company's Board of Directors as a form of compensation. Under ASC 718 accounting requirements, compensation expense related to restricted shares is based on the fair value of the restricted shares on their grant dates. On April 20, 2009 the Company's Board of Directors granted 28,800 shares of restricted stock to the Company's nonemployee directors. The restricted shares vest 25% per year on April 8 of each year in the period 2010 through 2013 and are eligible for full dividend and voting rights. The grant date fair value of each share of restricted stock was $22.15 per share, the average market price on the date of grant.

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

Directors' Restricted Stock Awards	2009		2008		2007	
	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	39,300	$ 33.45	34,100	$ 30.80	32,775	$ 27.27
Granted	28,800	22.15	20,000	35.345	15,200	35.04
Vested	13,800	32.06	14,800	29.92	13,875	27.10
Forfeited	—		—		—	
Nonvested, End of Year	54,300	27.81	39,300	33.45	34,100	30.80
Compensation Expense Recognized		$ 535,000		$ 461,000		$ 454,000
Fair Value of Shares Vested in Year		442,000		443,000		376,000

Restricted Stock Granted to Employees

Under the Incentive Plan, restricted shares of the Company's common stock have been granted to employees as a form of compensation. Under ASC 718 accounting requirements, compensation expense related to restricted shares is based on the fair value of the restricted shares on their grant dates. On April 20, 2009 the Company's Board of Directors granted 27,600 shares of restricted stock to the Company's executive officers under the Incentive Plan. The restricted shares vest 25% per year on April 8 of each year in the period 2010 through 2013 and are eligible for full dividend and voting rights. The grant date fair value of each share of restricted stock was $22.15 per share, the average market price on the date of grant.

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

Employees' Restricted Stock Awards	2009		2008		2007	
	Shares	Weighted Average Fair Value	Shares	Weighted Average Fair Value	Shares	Weighted Average Fair Value
Nonvested, Beginning of Year	34,146	$ 34.72	24,058	$ 35.46	31,666	$ 31.47
Granted	27,600	22.15	19,371	35.345	17,300	35.82
Variable/Liability Awards Vested	2,250	22.91	4,808	34.85	24,608	35.09
Nonvariable Awards Vested	9,018	35.84	4,475	35.80	300	35.30
Forfeited	—		—		—	
Nonvested, End of Year	50,478	28.31	34,146	34.72	24,058	35.46
Compensation Expense Recognized		$ 439,000		$ 434,000		$ 549,000
Fair Value of Variable Awards Vested/Liability Paid		52,000		168,000		863,000
Fair Value of Nonvariable Awards Vested		323,000		160,000		11,000

Table of Contents

Restricted Stock Units Granted to Employees

On April 20, 2009 the Company's Board of Directors granted 29,515 restricted stock units to key employees under the Incentive Plan payable in common shares on April 8, 2013, the date the units vest. The grant date fair value of each restricted stock unit was $18.86 per share. The weighted average contractual term of stock units outstanding as of December 31, 2009 is 2.4 years.

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

Employees' Restricted Stock Unit Awards	2009		2008		2007	
	Restricted Stock Units	Weighted Average Grant-Date Fair Value	Restricted Stock Units	Weighted Average Grant-Date Fair Value	Restricted Stock Units	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	73,585	$ 28.13	55,480	$ 26.66	38,615	$ 24.65
Granted	29,515	18.86	26,650	30.92	23,450	30.07
Converted	5,350	24.94	3,850	25.93	4,850	26.95
Forfeited	5,080	27.33	4,695	28.07	1,735	27.03
Nonvested, End of Year	92,670	25.42	73,585	28.13	55,480	26.66
Compensation Expense Recognized		$ 543,000		$ 535,000		$ 383,000
Fair Value of Units Converted in Year		133,000		100,000		131,000

Stock Performance Awards granted to Executive Officers

The Compensation Committee of the Company's Board of Directors has approved stock performance award agreements under the Incentive Plan for the Company's executive officers. Under these agreements, the officers could be awarded shares of the Company's common stock based on the Company's total shareholder return relative to that of its peer group of companies in the Edison Electric Institute (EEI) Index over a three-year period beginning on January 1 of the year the awards are granted. The number of shares earned, if any, will be awarded and issued at the end of each three-year performance measurement period. The participants have no voting or dividend rights under these award agreements until the shares are issued at the end of the performance measurement period. Under ASC 718 accounting requirements, the amount of compensation expense recorded related to awards granted is based on the estimated grant-date fair value of the awards as determined under a Monte Carlo valuation method for awards granted prior to 2009. The offsetting credit to amounts expensed related to the stock performance awards granted prior to 2009 is included in common shareholders' equity.

On April 20, 2009 the Company's Board of Directors granted performance share awards to the Company's executive officers under the Incentive Plan for the 2009-2011 performance measurement period. The terms of these awards are such that the entire award will be classified and accounted for as a liability, as required under ASC 718-10-25-18, and will be measured over the performance period based on the fair value of the award at the end of each reporting period subsequent to the grant date.

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

Performance Period	Maximum Shares Subject to Award	Shares Used to Estimate Expense	Fair Value	Expense Recognized in the Year Ended December 31, 2009	2008	2007	Shares Awarded
2009-2011	181,200	90,600	$ 27.98	$ 845,000	$ —	$ —	
2008-2010	114,800	70,843	$ 37.59	888,000	888,000	—	
2007-2009	109,000	67,263	$ 38.01	852,000	852,000	852,000	34,768
2006-2008	88,050	58,700	$ 25.95	—	508,000	508,000	29,350
2005-2007	75,150	50,872	$ 22.10	—	—	375,000	62,625
Total				$2,585,000	$2,248,000	$1,735,000	126,743

As of December 31, 2009 the total remaining unrecognized amount of compensation expense related to stock-based compensation for all of the Company's stock-based payment programs was approximately $5.8 million (before income taxes), which will be amortized over a weighted-average period of 2.1 years.

8. Retained Earnings Restriction

The Company's Restated Articles of Incorporation, as amended, contain provisions that limit the amount of dividends that may be paid to common shareholders by the amount of any declared but unpaid dividends to holders of the Company's cumulative preferred shares. Under these provisions none of the Company's retained earnings were restricted at December 31, 2009.

9. Commitments and Contingencies

Electric Utility Construction Contracts, Capacity and Energy Requirements and Coal and Delivery Contracts

At December 31, 2009 OTP had commitments under contracts in connection with construction programs aggregating approximately $8,944,000. For capacity and energy requirements, OTP has agreements extending through 2034 at annual costs of approximately $19,374,000 in 2010, $16,599,000 in 2011, $17,844,000 in 2012 and $10,726,000 in 2013, $5,696,000 in 2014, and $84,579,000 for the years beyond 2014.

OTP has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. These contracts expire in 2010, 2011 and 2016. In total, OTP is committed to the minimum purchase of approximately $111,039,000 or to make payments in lieu thereof, under these contracts. The FCA mechanism lessens the risk of loss from market price changes because it provides for recovery of most fuel costs.

IPH Potato Supply and Fuel Purchase Commitments

IPH has commitments of approximately $10,000,000 for the purchase of a portion of its 2010 raw potato supply requirements and $1,600,000 for the firm purchase of natural gas to cover a portion of its anticipated fuel needs in Ririe, Idaho through August 2010.

Operating Lease Commitments

The amounts of future operating lease payments are as follows:

(in thousands)	Electric	Nonelectric	Total
2010	$ 2,491	$ 35,821	$ 38,312
2011	1,411	22,097	23,508
2012	924	12,590	13,514
2013	933	6,921	7,854
2014	944	4,317	5,261
Later years	15,642	1,698	17,340
Total	$22,345	$ 83,444	$105,789

The electric future operating lease payments are primarily related to coal rail-car leases. The nonelectric future operating lease payments are primarily related to medical imaging equipment. Rent expense from continuing operations was $50,293,000, $50,761,000 and $47,904,000 for 2009, 2008 and 2007, respectively.

Sierra Club Complaint

On June 10, 2008 the Sierra Club filed a complaint in the U.S. District Court for the District of South Dakota (Northern Division) against the Company and two other co-owners of Big Stone Generating Station (Big Stone). The complaint alleged certain violations of the Prevention of Significant Deterioration and New Source Performance Standards (NSPS) provisions of the Clean Air Act (CAA) and certain violations of the South Dakota State Implementation Plan (South Dakota SIP). The action further alleged the defendants modified and operated Big Stone without obtaining the appropriate permits, without meeting certain emissions limits and NSPS requirements and without installing appropriate emission control technology, all allegedly in violation of the CAA and the South Dakota SIP. The Sierra Club alleged the defendants' actions have contributed to air pollution and visibility impairment and have increased the risk of adverse health effects and environmental damage. The Sierra Club sought both declaratory and injunctive relief to bring the defendants into compliance with the CAA and the South Dakota SIP and to require the defendants to remedy the alleged violations. The Sierra Club also seeks unspecified civil penalties, including a beneficial mitigation project. The Company believes these claims are without merit and that Big Stone was and is being operated in compliance with the CAA and the South Dakota SIP.

The defendants filed a motion to dismiss the Sierra Club complaint on August 12, 2008. On March 31, 2009 and April 6, 2009, the District Court issued a Memorandum and Order and Amended Memorandum and Order, respectively, granting the defendants' motion to dismiss the Sierra Club complaint. On April 17, 2009 the Sierra Club filed a motion for reconsideration of the Amended Memorandum Opinion and Order. The Sierra Club motion was opposed by the defendants. The Sierra Club motion for reconsideration was denied on July 22, 2009. On July 30, 2009 the Sierra Club filed a notice of appeal to the 8th U.S. Circuit Court of Appeals. The briefing schedule calls for the appellant to submit its brief by mid-October, for appellees to submit their brief by mid-November and for the appellant to submit its reply brief by the end of November. On October 13, 2009, the United States Department of Justice filed a motion seeking a 30-day extension of the time to file an amicus brief in support of the Sierra Club's position. The Court of Appeals granted this motion, as well as the appellees' subsequent joint motion with the Sierra Club, extending the time to file the appellees' brief and the Sierra Club's reply brief. Briefing was complete on January 22, 2010 on filing of the Sierra Club's reply brief. The ultimate outcome of this matter cannot be determined at this time.

Federal Power Act Complaint

On August 29, 2008 Renewable Energy System Americas, Inc. (RES), a developer of wind generation, and PEAK Wind Development, LLC (PEAK Wind), a group of landowners in Barnes County, North Dakota, filed a complaint with the FERC alleging that OTP and Minnkota Power Cooperative, Inc. (Minnkota) had acted together in violation of the Federal Power Act (FPA) to deny RES and PEAK Wind access to the Pillsbury Line, an interconnection facility which Minnkota owns to interconnect generation projects being developed by OTP and NextEra Energy Resources, Inc. (fka FPL Energy, Inc.) (NextEra). RES and PEAK Wind asked that (1) the FERC order Minnkota to interconnect its Glacier Ridge project to the Pillsbury Line, or in the alternative, (2) the FERC direct MISO to interconnect the Glacier Ridge project to the Pillsbury Line. RES and Peak Wind also requested that OTP, Minnkota and NextEra pay any costs associated with interconnecting the Glacier Ridge Project to the MISO transmission system which would result from the interconnection of the Pillsbury Line to the Minnkota transmission system, and that the FERC assess civil penalties against OTP. OTP answered the complaint on September 29, 2008, denying the allegations of RES and PEAK Wind and requesting that the FERC dismiss the complaint. On October 14, 2008, RES and PEAK Wind filed an answer to OTP's answer and, restated the allegations included in the initial complaint. RES and PEAK Wind also added a request that the FERC rescind both OTP's waiver from the FERC Standards of Conduct and its market-based rate authority. On October 28, 2008, OTP filed a reply, denying the allegations made by RES and PEAK Wind in its answer. By order issued on December 19, 2008, the FERC set the complaint for hearing and established settlement procedures. A formal settlement agreement was filed with the FERC requesting approval of the settlement and withdrawal of the complaint. The Company expects the FERC will issue an order approving the settlement and terminating the proceeding. The settlement is not expected to have a material impact on OTP's financial position or results of operations.

Product Recall

Aviva Sports, Inc. (Aviva), a subsidiary of ShoreMaster, markets a variety of consumer products to catalog companies and internet based retailers. Some of these products are regulated by the U.S. Consumer Product Safety Commission (CPSC). On February 3, 2009 Aviva received a report of consumer contacts from a catalog customer related to one of Aviva's trampoline products. Aviva has not received any personal injury claims or lawsuits related to this product. Aviva submitted notification of the complaints to the CPSC and voluntarily agreed to undertake a recall of approximately 13,200 of the trampoline products sold to consumers. ShoreMaster recorded a liability and operating expense of $1.4 million related to the recall in the first quarter of 2009. The expense included a projected 50% response rate on the recall request, fees to the third party recall administrator, costs to destroy inventory and all legal and administration fees. Due to dwindling customer response, ShoreMaster concluded its recall effort in February, 2010. The number of products returned or otherwise captured by the recall is consistent with the anticipated rate of 50%. ShoreMaster anticipates the final cost of the recall to be $1.2 million.

Other

The Company is a party to litigation arising in the normal course of business. The Company regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. The Company believes the effect on its consolidated results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of December 31, 2009 will not be material.

10. Short-Term and Long-Term Borrowings

Short-Term Debt

The following table presents the status of our lines of credit as of December 31, 2009 and December 31, 2008:

(in thousands)	Line Limit	In Use on December 31, 2009	Restricted due to Outstanding Letters of Credit	Available on December 31, 2009	Available on December 31, 2008
Otter Tail Corporation Credit Agreement	$200,000	$ 6,000	$ 14,245	$ 179,755	$ 77,706
OTP Credit Agreement [1]	170,000	1,585	680	167,735	142,935
Total	$370,000	$ 7,585	$ 14,925	$ 347,490	$ 220,641

1 On January 4, 2010, OTP paid off the remaining $58.0 million balance outstanding on its two-year, $75.0 million term loan that was originally due on May 20, 2011, using lower costs funds available under the OTP Credit Agreement. OTP did not incur any penalties for the early repayment and retirement of this debt.

The weighted average interest rates on consolidated short-term debt outstanding on December 31, 2009 and 2008 were 2.2% and 2.8%, respectively. The weighted average interest rate paid on consolidated short-term debt was 2.4% in 2009 and 4.1% in 2008.

Prior to the Company's holding company reorganization on July 1, 2009, Varistar, the Company's wholly owned subsidiary, was the borrower under a $200 million credit agreement (the Credit Agreement) with the following banks: U.S. Bank National Association, as agent for the Banks and as Lead Arranger, Bank of America, N.A., Keybank National Association, and Wells Fargo Bank, National Association, as Co-Documentation Agents, and JPMorgan Chase Bank, N.A., Bank of the West and Union Bank of California, N.A. Effective July 1, 2009 all of Varistar's rights and obligations under the Credit Agreement were assigned to and assumed by the Company. Beginning July 1, 2009 borrowings bear interest at LIBOR plus 2.375%, subject to adjustment based on the senior unsecured credit ratings of the Company. The Credit Agreement expires October 2, 2010 and is an unsecured revolving credit facility. The Credit Agreement contains a number of restrictions on the Company and the businesses of Varistar and its material subsidiaries, including restrictions on their ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of certain other parties and engage in transactions with related parties. The Credit Agreement also contains affirmative covenants and events of default. The Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the borrower's credit ratings. The Company's obligations under the Credit Agreement are guaranteed by Varistar and its material subsidiaries. Outstanding letters of credit issued by the borrower under the Credit Agreement can reduce the amount available for borrowing under the line by up to $30 million. The Credit Agreement has an accordion feature whereby the line can be increased to $300 million as described in the Credit Agreement. The Company is in the process of negotiating a renewal of the Credit Agreement to be effective at the expiration of current term of the Credit Agreement.

Prior to the Company's holding company reorganization on July 1, 2009, Otter Tail Corporation, dba Otter Tail Power Company (now OTP) was the borrower under a $170 million credit agreement (the OTP Credit Agreement) with an accordion feature whereby the line can be increased to $250 million as described in the OTP Credit Agreement. The credit agreement was entered into between Otter Tail Corporation, dba Otter Tail Power Company (now OTP) and JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association and Merrill Lynch Bank USA, as Banks, U.S. Bank National Association, as a Bank and as agent for the Banks, and Bank of America, N.A., as a Bank and as Syndication Agent. The OTP Credit Agreement is an unsecured revolving credit facility that OTP can draw on to support the working capital needs and other capital requirements of its operations. Borrowings under this line of credit bear interest at LIBOR plus 0.5%, subject to adjustment based on the ratings of the borrower's senior unsecured debt. The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Credit Agreement also contains affirmative covenants and events of default. The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the borrower's credit ratings. The OTP Credit Agreement is subject to renewal on July 30, 2011. Following the Company's holding company reorganization, the OTP Credit Agreement is an obligation of OTP.

Long-Term Debt

On May 11, 2009 the Company filed a shelf registration statement with the SEC under which it may offer for sale, from time to time, either separately or together in any combination, equity and/or debt securities described in the shelf registration statement.

9.000% Notes due 2016

On December 4, 2009 the Company issued $100 million of its 9.000% notes due 2016 under the indenture (for unsecured debt securities) dated as of November 1, 1997, as amended by the First Supplemental Indenture dated as of July 1, 2009, between the Company and U.S. Bank National Association (formerly First Trust National Association), as trustee. The notes are unsecured indebtedness and bear interest at 9.000% per year, payable semi-annually in arrears on June 15 and December 15 of each year, beginning June 15, 2010. The entire principal amount of the notes, unless previously redeemed or otherwise repaid, will mature and become due and payable on December 15, 2016. The net proceeds from the issuance of approximately $98.3 million, after deducting the underwriting discount and offering expenses, were used to repay our revolving credit facility, which had an outstanding balance due of $107.0 million on November 30, 2009 at an interest rate of approximately 2.6%. The Company used approximately $44.5 million of the borrowings under its revolving credit facility to fund costs incurred for the expansion of its subsidiary companies' manufacturing facilities in 2008 and 2009. The Company used approximately $23.0 million to fund the acquisition of Miller Welding in 2008 and approximately $28.5 million in connection with the capitalization of its holding company reorganization in 2009.

Term Loan Agreement and Retirement

Prior to the Company's holding company reorganization on July 1, 2009, Otter Tail Corporation, dba Otter Tail Power Company (now OTP) was the borrower under a $75 million term loan agreement (the OTP Loan Agreement). The OTP Loan Agreement was entered into between Otter Tail Corporation, dba Otter Tail Power Company (now OTP) and JPMorgan Chase Bank, N.A., as Administrative Agent, KeyBank National Association, as Syndication Agent, Union Bank, N.A., as Documentation Agent, and the Banks named therein. On completion of the Company's holding company formation on July 1, 2009, the OTP Loan Agreement became an obligation of OTP. The OTP Loan Agreement provided for a $75 million term loan due May 20, 2011. The proceeds were used to support OTP's construction of 49.5 MW of renewable wind-generation assets at the Luverne Wind Farm. In November 2009, OTP paid down $17 million of the $75 million term loan. OTP paid off the remaining $58 million balance in January 2010, using lower cost funds available under the OTP Credit Agreement. OTP did not incur any penalties for the early repayments and retirement of its debt under the Loan Agreement.

Borrowings under the OTP Loan Agreement bore interest at a rate equal to the base rate in effect from time to time. The base rate was a fluctuating rate per annum equal to (i) the highest of (A) JPMorgan Chase Bank, N.A.'s prime rate, (B) the Federal funds effective rate plus 0.5% per annum, and (C) a daily LIBOR rate plus 1.0% per annum, plus (ii) a margin of 1.5% to 3.0% determined on the basis of OTP's senior unsecured credit ratings, as provided in the Loan Agreement. The interest rate on borrowings under the OTP Loan Agreement was 3.73% at December 31, 2009.

The OTP Loan Agreement contained a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets , make certain investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Loan Agreement also contained certain financial covenants. Specifically, OTP could not permit the ratio of its "Interest-bearing Debt" to "Total Capitalization" (each as defined in the OTP Loan Agreement) to be greater than 0.60 to 1.00, or permit its "Interest and Dividend Coverage Ratio" (as defined in the OTP Loan Agreement) for any period of four consecutive fiscal quarters to be less than 1.50 to 1.00. The OTP Loan Agreement also contained affirmative covenants and events of default. The OTP Loan Agreement did not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. The obligations of OTP under the OTP Loan Agreement were unsecured.

Other Debt Retirement

In June 2009, the Company paid $3,493,000 to retire early its Lombard US Equipment Finance note due October 2, 2010. No penalty was paid for early retirement of the note.

Amendments to Note Purchase Agreements

In connection with Otter Tail Corporation's holding company reorganization on July 1, 2009, amendments to the following note purchase agreements were entered into in order to obtain the consent of the related noteholders to the reorganization.

Fourth Amendment to 2001 Note Purchase Agreement

On June 30, 2009 Otter Tail Corporation (now known as OTP) (Old Otter Tail) entered into a Fourth Amendment dated as of June 30, 2009 to Note Purchase Agreement dated as of December 1, 2001 (the Fourth Amendment) with the holders of the 2001 Notes referred to below, amending the Note Purchase Agreement dated as of December 1, 2001 among Old Otter Tail and each of the purchasers named on Schedule A attached thereto, as amended (the 2001 Note Purchase Agreement). The 2001 Note Purchase Agreement relates to the issuance and sale by Old Otter Tail, in a private placement transaction, of its $90,000,000 6.63% Senior Notes due December 1, 2011 (the 2001 Notes). The Fourth Amendment sets forth the terms and conditions of the 2001 Noteholders' consent to the holding company reorganization and amends certain provisions of the 2001 Note Purchase Agreement, both in connection with the holding company reorganization and for the purpose of achieving greater consistency among Old Otter Tail's note purchase agreements. These amendments include changes to negative covenants in the 2001 Note Purchase Agreement regarding limitations on liens and contingent liabilities, and to events of default. As provided in the Fourth Amendment, the 2001 Note Purchase Agreement and the 2001 Notes remained obligations of Old Otter Tail, under the name Otter Tail Power Company, following the effectiveness of the holding company reorganization. In addition, the guaranties issued by certain subsidiaries of Old Otter Tail under the 2001 Note Purchase Agreement and the 2001 Notes were released on the effectiveness of the holding company reorganization.

The 2001 Note Purchase Agreement, as amended, states OTP may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. The 2001 Note Purchase Agreement, as amended, states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require OTP to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the agreement. The 2001 Note Purchase Agreement, as amended, contains a number of restrictions on the business of OTP. These include restrictions on the ability of OTP to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties.

Third Amendment to 2007 Note Purchase Agreement

On June 26, 2009 Old Otter Tail entered into a Third Amendment dated as of June 26, 2009 to Note Purchase Agreement dated as of August 20, 2007 (the Third Amendment) with the holders of the 2007 Notes referred to below, amending the Note Purchase Agreement dated as of August 20, 2007 among Old Otter Tail and each of the purchasers party thereto, as amended (the 2007 Note Purchase Agreement). The 2007 Note Purchase Agreement relates to the issuance and sale by Old Otter Tail of $155 million aggregate principal amount of Old Otter Tail's Senior Unsecured Notes in four series, in the designations and aggregate principal amounts set forth in the 2007 Note Purchase Agreement (the 2007 Notes). The Third Amendment sets forth the terms and conditions of the 2007 Noteholders' consent to the holding company reorganization and also amends certain provisions of the 2007 Note Purchase Agreement, both in connection with the holding company reorganization and for the purpose of achieving greater consistency among Old Otter Tail's note purchase agreements. These amendments include changes to negative covenants in the 2007 Note Purchase Agreement regarding limitations on liens and subsidiary guarantees. As provided in the Third Amendment, the 2007 Note Purchase Agreement and the 2007 Notes remained obligations of Old Otter Tail, under the name Otter Tail Power Company, following the effectiveness of the holding company reorganization.

The 2007 Note Purchase Agreement, as amended, states OTP may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. The 2007 Note Purchase Agreement, as amended, states OTP must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of OTP. The 2007 Note Purchase Agreement, as amended, contains a number of restrictions on the business of OTP. These include restrictions on the ability of OTP to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties.

Amendment No. 2 to Cascade Note Purchase Agreement

On June 30, 2009 Old Otter Tail entered into an Amendment No. 2 dated as of June 30, 2009 to Note Purchase Agreement dated as of February 23, 2007 (Amendment No. 2) with Cascade Investment, L.L.C. (Cascade), amending the Note Purchase Agreement dated as of February 23, 2007 between Old Otter Tail and Cascade, as amended (the Cascade Note Purchase Agreement). The Cascade Note Purchase Agreement relates to the issuance and sale by Old Otter Tail to Cascade, in a private placement transaction, of Old Otter Tail's $50,000,000 5.778% Senior Note due November 30, 2017 (the Cascade Note). Amendment No. 2 sets forth the terms and conditions of Cascade's consent to the assignment by Old Otter Tail of its rights and obligations in, to and under the Cascade Note Purchase Agreement and the Cascade Note to Otter Tail Holding Company, the new parent holding company of Old Otter Tail that is now known as Otter Tail Corporation (the Company), effective immediately prior to the effectiveness of the holding company reorganization. Amendment No. 2 also provides for Cascade's consent to the holding company reorganization, and amends certain provisions of the Cascade Note Purchase Agreement, both in connection with the holding company reorganization and for the purpose of achieving greater consistency among the Company's note purchase agreements. These amendments include changes to negative covenants in the Cascade Note Purchase Agreement regarding limitations on liens, contingent liabilities and to events of default. In addition, Amendment No. 2 provides for an additional financial covenant applicable to the Company as of the effectiveness of the holding company reorganization. Specifically, the Company may not permit the aggregate principal amount of all debt of OTP and its subsidiaries to exceed 60% of Otter Tail Consolidated Total Capitalization (as defined in the Cascade Note Purchase Agreement, as amended by Amendment No. 2), determined as of the end of each fiscal quarter of the Company. In addition, the interest rate applicable to the Cascade Note was increased to 8.89% per annum which is reflective of the Company's new senior unsecured debt ratings. The obligations of the Company under the Cascade Note Purchase Agreement and the Cascade Note continue to be guaranteed by Varistar Corporation and certain of its subsidiaries. As provided in Amendment No. 2, the Cascade Note Purchase Agreement and the Cascade Note became obligations of the Company immediately prior to the effectiveness of the holding company reorganization.

The Cascade Note Purchase Agreement, as amended, states the Company may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. The Cascade Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require the Company to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the Cascade Note Purchase Agreement. The Cascade Note Purchase Agreement contains a number of restrictions on the businesses of the Company and its subsidiaries. These include restrictions on the ability of the Company and certain of its subsidiaries to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. Following the effectiveness of the holding company reorganization, the obligations of the Company under the Cascade Note Purchase Agreement remain guaranteed by Varistar and certain of its material subsidiaries (and not by OTP). Cascade owned approximately 9.6% of the Company's outstanding common stock as of December 31, 2009.

The following table provides a breakdown of the assignment of the Company's consolidated short-term and long-term debt outstanding as of December 31, 2009:

(in thousands)	OTP	Varistar	Otter Tail Corporation	Otter Tail Corporation Consolidated
Lines of Credit	$ 1,585		$ 6,000	$ 7,585
Term Loan, Variable 3.73% at December 31, 2009, due May 20, 2011 (early retired on January 4, 2010)	$ 58,000			$ 58,000
Senior Unsecured Notes 6.63%, due December 1, 2011	90,000			90,000
Pollution Control Refunding Revenue Bonds, Variable, 3.00% at December 31, 2009, due December 1, 2012	10,400			10,400
9.000% Notes, due December 15, 2016			$ 100,000	100,000
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017	33,000			33,000
Grant County, South Dakota Pollution Control Refunding Revenue Bonds 4.65%, due September 1, 2017	5,125			5,125
Senior Unsecured Note 8.89%, due November 30, 2017			50,000	50,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	30,000			30,000
Mercer County, North Dakota Pollution Control Refunding Revenue Bonds 4.85%, due September 1, 2022	20,400			20,400
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	42,000			42,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000			50,000
Obligations of Varistar Corporation — Various up to 13.31% at December 31, 2009		$ 6,684		6,684
Total	$338,925	$ 6,684	$ 150,000	$ 495,609
Less:				
Current Maturities	58,000	1,053	—	59,053
Unamortized Debt Discount	—	380	6	386
Total Long-Term Debt	$280,925	$ 5,251	$ 149,994	$ 436,170
Total Short-Term and Long-Term Debt (with current maturities)	$340,510	$ 6,304	$ 155,994	$ 502,808

The aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2009 for each of the next five years are $59,077,000 for 2010, $90,585,000 for 2011, $10,817,000 for 2012, $786,000 for 2013 and $1,000 for 2014.

Financial Covenants

As of December 31, 2009 the Company was in compliance with the financial statement covenants that existed in its debt agreements.

None of the Credit and Note Purchase Agreements contains any provisions that would trigger an acceleration of the related debt as a result of changes in the credit rating levels assigned to the related obligor by rating agencies.

Following the Company's holding company reorganization on July 1, 2009: (1) the credit agreement relating to the $200 million revolving credit facility originally entered into by Varistar is an obligation of the Company, as assignee of Varistar, and is guaranteed by Varistar and its material subsidiaries, (2) the Cascade Note Purchase Agreement is an obligation of the Company, as assignee of Otter Tail Corporation (now OTP) prior to the reorganization, and is guaranteed by Varistar and its material subsidiaries, and (3) the credit agreement relating to the $170 million revolving credit facility originally entered into by Otter Tail Corporation dba Otter Tail Power Company (now OTP), the 2001 Note Purchase Agreement and the 2007 Note Purchase Agreement are obligations of OTP.

Following the Company's holding company reorganization on July 1, 2009 the Company's borrowing agreements are subject to certain financial covenants. Specifically:

- Under the credit agreement relating to the $200 million credit facility of the Company (as assignee of Varistar), the Company may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), as provided in the credit agreement.
- Under the Cascade Note Purchase Agreement, the Company may not permit its ratio of Consolidated Debt to Consolidated Total Capitalization to be greater than 0.60 to 1.00 or its Interest Charges Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), permit the ratio of OTP's Debt to OTP's Total Capitalization to be greater than 0.60 to 1.00, or permit Priority Debt to exceed 20% of Varistar Consolidated Total Capitalization, as provided in the Cascade Note Purchase Agreement.
- Under the OTP Credit Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, as provided in the Loan Agreement.
- Under the 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and the financial guaranty insurance policy with Ambac Assurance Corporation relating to certain pollution control refunding bonds, OTP may not permit the ratio of its Consolidated Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio (or, in the case of the 2001 Note Purchase Agreement, its Interest Charges Coverage Ratio) to be less than 1.50 to 1.00, in each case as provided in the related borrowing or insurance agreement. In addition, under the 2001 Note Purchase Agreement and the 2007 Note Purchase Agreement, OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement.

11. Class B Stock Options of Subsidiary

In connection with the acquisition of IPH in August 2004, IPH management and certain other employees elected to retain stock options for the purchase of IPH Class B common shares valued at $1.8 million. The options are exercisable at any time and the option holder must deliver cash to exercise the option. Once the options are exercised for Class B shares, the Class B shareholder cannot put the shares back to the Company for 181 days. At that time, the Class B common shares are redeemable at any time during the employment of the individual holder, subject to certain limits on the total number of Class B common shares redeemable on an annual basis. The Class B common shares are nonvoting, except in the event of a merger, and do not participate in dividends but have liquidation rights at par with the Class A common shares owned by the Company. The value of the Class B common shares issued on exercise of the options represents an interest in IPH that changes as defined in the agreement. In 2009, 140 options were forfeited as a result of a voluntary termination. As of December 31, 2009 there were 772 options outstanding with a combined exercise price of $391,000, of which 732 options were "in-the-money" with a combined exercise price of $307,000.

12. Pension Plan and Other Postretirement Benefits

Pension Plan

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

The pension plan has a trustee who is responsible for pension payments to retirees. Six investment managers are responsible for managing the plan's assets. An independent actuary assists the Company in performing the necessary actuarial valuations for the plan.

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

Components of net periodic pension benefit cost:

(in thousands)	2009	2008	2007
Service Cost—Benefit Earned During the Period	$ 4,180	$ 4,630	$ 4,837
Interest Cost on Projected Benefit Obligation	11,943	11,325	10,790
Expected Return on Assets	(13,779)	(13,968)	(12,948)
Amortization of Prior-Service Cost	724	742	742
Amortization of Net Actuarial Loss	77	169	1,091
Net Periodic Pension Cost	$ 3,145	$ 2,898	$ 4,512

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

	2009	2008	2007
Discount Rate	6.70%	6.25%	6.00%
Long-Term Rate of Return on Plan Assets	8.50%	8.50%	8.50%
Rate of Increase in Future Compensation Level	3.75%	3.75%	3.75%

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

(in thousands)	2009	2008
Regulatory Assets:		
Unrecognized Prior Service Cost	$ 2,597	$ 3,303
Unrecognized Actuarial Loss	69,378	56,652
Total Regulatory Assets	71,975	59,955
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	45	55
Unrecognized Actuarial Loss	1,199	943
Total Accumulated Other Comprehensive Loss	1,244	998
Deferred Income Taxes	829	666
Noncurrent Liability	$ 66,598	$ 55,024

Funded status as of December 31:

(in thousands)	2009	2008
Accumulated Benefit Obligation	$(167,195)	$(153,676)
Projected Benefit Obligation	$(207,145)	$(182,559)
Fair Value of Plan Assets	140,547	127,535
Funded Status	$ (66,598)	$ (55,024)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's benefit obligations over the two-year period ended December 31, 2009:

(in thousands)	2009	2008
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$127,535	$170,935
Actual Return on Plan Assets	17,886	(36,523)
Discretionary Company Contributions	4,000	2,000
Benefit Payments	(8,874)	(8,877)
Fair Value of Plan Assets at December 31	$140,547	$127,535
Estimated Asset Return	14.30%	(21.94)%
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$182,559	$185,206
Service Cost	4,180	4,630
Interest Cost	11,943	11,325
Benefit Payments	(8,874)	(8,877)
Actuarial Loss (Gain)	17,337	(9,725)
Projected Benefit Obligation at December 31	$207,145	$182,559

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

	2009	2008
Discount Rate	6.00%	6.70%
Rate of Increase in Future Compensation Level	3.75%	3.75%

To develop the expected long-term rate of return on assets assumption, the Company considered the historical returns and the future expectations for returns for each asset class, as well as the target asset allocation of the pension portfolio.

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

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

The assumed rate of return on pension fund assets for the determination of 2010 net periodic pension cost is 8.50%.

Measurement Dates:	2009	2008
Net Periodic Pension Cost	January 1, 2009	January 1, 2008
End of Year Benefit Obligations	January 1, 2009 projected to December 31, 2009	January 1, 2008 projected to December 31, 2008
Market Value of Assets	December 31, 2009	December 31, 2008

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost in 2010 are:

(in thousands)	2010
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 664
Amortization of Unrecognized Actuarial Loss	1,963
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	19
Amortization of Unrecognized Actuarial Loss	57
Total Estimated Amortization	$ 2,703

Cash flows— The Company is not required to make a contribution to the pension plan in 2010.

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

(in thousands)	2010	2011	2012	2013	2014	Years 2015-2019
	$ 9,414	$ 9,772	$ 10,147	$ 10,590	$ 11,027	$ 67,340

The Company's pension plan asset allocations at December 31, 2009 and 2008, by asset category are as follows:

Asset Allocation	2009	2008
Large Capitalization Equity Securities	32.0%	39.6%
Small/Mid Capitalization Equity Securities	13.5%	9.2%
International Equity Securities	20.2%	8.3%
Total Equity Securities	65.7%	57.1%
Cash and Fixed-Income Securities	34.3%	42.9%
	100.0%	100.0%

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

- The Plan is managed to operate in perpetuity.
- The Plan will meet the pension benefit obligation payments of the Company.
- The Plan's assets should be invested with the objective of meeting current and future payment requirements while minimizing annual contributions and their volatility.
- The asset strategy reflects the desire to meet current and future benefit payments while considering a prudent level of risk and diversification.

The asset allocation strategy developed by the Company's Retirement Plans Administrative Committee is based on the current needs of the Plan, the investment objectives listed above, the investment preferences and risk tolerance of the committee and a desired degree of diversification.

The asset allocation strategy contains guideline percentages, at market value, of the total Plan invested in various asset classes. The strategic target allocation and the tactical range shown in the table that follows is a guide that will at times not be reflected in actual asset allocations that may be dictated by prevailing market conditions, independent actions of the Retirement Plans Administrative Committee (RPAC) and/or investment managers, and required cash flows to and from the Plan. The tactical range provides flexibility for the investment managers' portfolios to vary around the target allocation without the need for immediate rebalancing.

Allocation targets and tactical ranges shown below reflect the revised Investment Policy Statement recently approved by the RPAC. Each of the asset categories is within its respective tactical range. The RPAC monitors actual asset allocations and directs contributions and withdrawals toward maintaining the current targeted allocation percentages listed below.

Asset Allocation	Strategic Target	Tactical Range
Large Capitalization Equity Securities	30%	20%-40%
Small/Mid Capitalization Equity Securities	12%	6%-22%
International Equity Securities	18%	10%-30%
Total Equity Securities	60%	45%-75%
Cash and Fixed-Income Securities	40%	20%-50%

Executive Survivor and Supplemental Retirement Plan (ESSRP)

The ESSRP is an unfunded, nonqualified benefit plan for executive officers and certain key management employees. The ESSRP provides defined benefit payments to these employees on their retirements for life or to their beneficiaries on their deaths for a 15-year postretirement period. Life insurance carried on certain plan participants is payable to the Company on the employee's death. There are no plan assets in this nonqualified benefit plan due to the nature of the plan.

Components of net periodic pension benefit cost:

(in thousands)	2009	2008	2007
Service Cost—Benefit Earned During the Period	$ 752	$ 691	$ 626
Interest Cost on Projected Benefit Obligation	1,694	1,535	1,451
Amortization of Prior-Service Cost	71	66	67
Amortization of Net Actuarial Loss	385	480	540
Net Periodic Pension Cost	$ 2,902	$ 2,772	$ 2,684

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

	2009	2008	2007
Discount Rate	6.70%	6.25%	6.00%
Rate of Increase in Future Compensation Level	4.70%	4.70%	4.71%

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

(in thousands)	2009	2008
Regulatory Assets:		
Unrecognized Prior Service Cost	$ 389	$ 421
Unrecognized Actuarial Loss	4,433	4,114
Total Regulatory Assets	4,822	4,535
Projected Benefit Obligation Liability — Net Amount Recognized	(28,441)	(25,888)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	167	166
Unrecognized Actuarial Loss	1,910	1,626
Total Accumulated Other Comprehensive Loss	2,077	1,792
Deferred Income Taxes	1,385	1,194
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$(20,157)	$(18,367)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations over the two-year period ended December 31, 2009 and a statement of the funded status as of December 31 of both years:

(in thousands)	2009	2008
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ —	$ —
Actual Return on Plan Assets	—	—
Employer Contributions	1,112	1,067
Benefit Payments	(1,112)	(1,067)
Fair Value of Plan Assets at December 31	$ —	$ —
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 25,888	$ 25,158
Service Cost	752	691
Interest Cost	1,694	1,535
Benefit Payments	(1,112)	(1,067)
Plan Amendments	41	63
Actuarial Loss (Gain)	1,178	(492)
Projected Benefit Obligation at December 31	$ 28,441	$ 25,888
Reconciliation of Funded Status:		
Funded Status at December 31	$(28,441)	$(25,888)
Unrecognized Net Actuarial Loss	7,616	6,823
Unrecognized Prior Service Cost	668	698
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$(20,157)	$(18,367)

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

	2009	2008
Discount Rate	6.00%	6.70%
Rate of Increase in Future Compensation Level	4.71%	4.70%

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost for the ESSRP in 2010 are:

(in thousands)	2010
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 43
Amortization of Unrecognized Actuarial Loss	278
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	31
Amortization of Unrecognized Actuarial Loss	199
Total Estimated Amortization	$ 551

Cash flows— The ESSRP is unfunded and has no assets; contributions are equal to the benefits paid to plan participants. The following benefit payments, which reflect future service, as appropriate, are expected to be paid:

(in thousands)	2010	2011	2012	2013	2014	Years 2015-2019
	$ 1,114	$ 1,224	$ 1,279	$ 1,268	$ 1,274	$ 7,729

Other Postretirement Benefits

The Company provides a portion of health insurance and life insurance benefits for retired OTP and corporate employees. Substantially all of the Company’s electric utility and corporate employees may become eligible for health insurance benefits if they reach age 55 and have 10 years of service. On adoption of SFAS No. 106, *Employers’ Accounting for Postretirement Benefits Other Than Pensions* , in January 1993, the Company elected to recognize its transition obligation related to postretirement benefits earned of approximately $14,964,000 over a period of 20 years. There are no plan assets.

Components of net periodic postretirement benefit cost:

(in thousands)	2009	2008	2007
Service Cost—Benefit Earned During the Period	$ 1,172	$ 1,103	$ 1,098
Interest Cost on Projected Benefit Obligation	2,935	2,689	2,565
Amortization of Transition Obligation	748	748	748
Amortization of Prior-Service Cost	211	211	(206)
Amortization of Net Actuarial Loss	—	26	177
Expense Decrease Due to Medicare Part D Subsidy	(1,335)	(1,172)	(1,233)
Net Periodic Postretirement Benefit Cost	$ 3,731	$ 3,605	$ 3,149

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

	2009	2008	2007
Discount Rate	6.70%	6.25%	6.00%

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

(in thousands)	2009	2008
Regulatory Asset:		
Unrecognized Transition Obligation	$ 1,093	$ 1,454
Unrecognized Prior Service Cost	1,361	1,567
Unrecognized Net Actuarial Gain	(379)	(3,855)
Net Regulatory Asset (Liability)	2,075	(834)
Projected Benefit Obligation Liability — Net Amount Recognized	(37,712)	(32,621)
Accumulated Other Comprehensive Loss:		
Unrecognized Transition Obligation	691	923
Unrecognized Prior Service Cost	24	26
Unrecognized Net Actuarial Gain	(7)	(64)
Accumulated Other Comprehensive Loss	708	885
Deferred Income Taxes	472	590
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$(34,457)	$(31,980)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations and accrued postretirement benefit cost over the two-year period ended December 31, 2009:

(in thousands)	2009	2008
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ —	$ —
Actual Return on Plan Assets	—	—
Company Contributions	1,254	1,577
Benefit Payments (Net of Medicare Part D Subsidy)	(3,113)	(3,392)
Participant Premium Payments	1,859	1,815
Fair Value of Plan Assets at December 31	$ —	$ —
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 32,621	$ 30,488
Service Cost (Net of Medicare Part D Subsidy)	960	902
Interest Cost (Net of Medicare Part D Subsidy)	2,027	1,874
Benefit Payments (Net of Medicare Part D Subsidy)	(3,113)	(3,392)
Participant Premium Payments	1,859	1,815
Actuarial Loss	3,358	934
Projected Benefit Obligation at December 31	$ 37,712	$ 32,621
Reconciliation of Accrued Postretirement Cost:		
Accrued Postretirement Cost at January 1	$(31,980)	$(29,952)
Expense	(3,731)	(3,605)
Net Company Contribution	1,254	1,577
Accrued Postretirement Cost at December 31	$(34,457)	$(31,980)

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

	2009	2008
Discount Rate	5.75%	6.70%

Assumed healthcare cost-trend rates as of December 31:

	2009	2008
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	7.10%	7.40%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	7.63%	8.00%
Rate at Which the Cost-Trend Rate is Assumed to Decline	5.00%	5.00%
Year the Rate Reaches the Ultimate Trend Rate	2025	2017

Assumed healthcare cost-trend rates have a significant effect on the amounts reported for healthcare plans. A one-percentage-point change in assumed healthcare cost-trend rates for 2009 would have the following effects:

(in thousands)	1 point increase	1 point decrease
Effect on the Postretirement Benefit Obligation	$ 3,727	$ (3,188)
Effect on Total of Service and Interest Cost	$ 365	$ (302)
Effect on Expense	$ 579	$ (556)

Measurement dates:	2009	2008
Net Periodic Postretirement Benefit Cost	January 1, 2009	January 1, 2008
End of Year Benefit Obligations	January 1, 2009 projected to December 31, 2009	January 1, 2008 projected to December 31, 2008

The estimated net amounts of unrecognized transition obligation and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic postretirement benefit cost in 2010 are:

(in thousands)	2010
Decrease in Regulatory Assets:	
Amortization of Transition Obligation	$ 364
Amortization of Unrecognized Prior Service Cost	204
Amortization of Unrecognized Actuarial Gain	—
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Transition Obligation	384
Amortization of Unrecognized Prior Service Cost	6
Amortization of Unrecognized Actuarial Gain	—
Total Estimated Amortization	$ 958

Cash flows— The Company expects to contribute $2.3 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2010. The Company expects to receive a Medicare Part D subsidy from the Federal government of approximately $504,000 in 2010. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

(in thousands)	2010	2011	2012	2013	2014	Years 2015-2019
	$ 2,321	$ 2,456	$ 2,554	$ 2,671	$ 2,856	$ 16,127

Leveraged Employee Stock Ownership Plan

The Company has a leveraged employee stock ownership plan for the benefit of all its electric utility employees. Contributions made by the Company were $761,000 for 2009, $738,000 for 2008 and $733,000 for 2007.

13. Fair Value of Financial Instruments

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

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

Long-Term Debt —The fair value of the Company's long-term debt is estimated based on the current rates available to the Company for the issuance of debt. About $68.4 million of the Company's long-term debt, which is subject to variable interest rates, approximates fair value.

	December 31, 2009		December 31, 2008	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Short-Term Investments	$ 4,432	$ 4,432	$ 7,565	$ 7,565
Long-Term Debt	(436,170)	(457,907)	(339,726)	(308,283)

14. Property, Plant and Equipment

(in thousands)	December 31, 2009	December 31, 2008
Electric Plant		
Production	$ 660,654	$ 590,252
Transmission	216,508	201,456
Distribution	357,623	337,296
General	78,230	76,643
Electric Plant	1,313,015	1,205,647
Less Accumulated Depreciation and Amortization	446,008	421,177
Electric Plant Net of Accumulated Depreciation	867,007	784,470
Construction Work in Progress	11,104	25,547
Net Electric Plant	$ 878,111	$ 810,017
Nonelectric Operations Plant		
Equipment	$ 244,419	$ 220,985
Buildings and Leasehold Improvements	96,899	80,281
Land	20,770	19,766
Nonelectric Operations Plant	362,088	321,032
Less Accumulated Depreciation and Amortization	153,831	126,893
Nonelectric Plant Net of Accumulated Depreciation	208,257	194,139
Construction Work in Progress	12,259	33,413
Net Nonelectric Operations Plant	$ 220,516	$ 227,552
Net Plant	$1,098,627	$1,037,569

The estimated service lives for rate-regulated properties is 5 to 65 years. For nonelectric property the estimated useful lives are from 3 to 40 years.

	Service Life Range	
(years)	Low	High
Electric Fixed Assets:		
Production Plant	34	62
Transmission Plant	40	55
Distribution Plant	15	55
General Plant	5	65
Nonelectric Fixed Assets:		
Equipment	3	12
Buildings and Leasehold Improvements	7	40

15. Income Taxes

The total income tax expense differs from the amount computed by applying the federal income tax rate (35% in 2009, 2008 and 2007) to net income before total income tax expense for the following reasons:

(in thousands)	2009	2008	2007
Tax Computed at Federal Statutory Rate	$ 7,499	$ 17,556	$28,675
Increases (Decreases) in Tax from:			
State Income Taxes Net of Federal Income Tax Benefit	1,871	2,608	2,934
Differences Reversing in Excess of Federal Rates	893	1,089	929
Federal Production Tax Credit	(6,533)	(3,234)	(3)
Tax Depreciation — Treasury Grant for Wind Farms	(3,169)	—	—
Allowance for Funds Used During Construction — Equity	(1,113)	(975)	7
Investment Tax Credit Amortization	(992)	(1,125)	(1,137)
Corporate Owned Life Insurance	(973)	814	(507)
North Dakota Wind Tax Credit Amortization — Net of Federal Taxes	(870)	(369)	(21)
Dividend Received/Paid Deduction	(683)	(718)	(714)
Affordable Housing Tax Credits	(25)	(55)	(285)
Section 199 Domestic Production Activities Deduction	—	—	(1,159)
Permanent and Other Differences	(510)	(554)	(751)
Total Income Tax Expense	$ (4,605)	$ 15,037	$27,968
Overall Effective Federal and State Income Tax Rate	(21.5)%	30.0%	34.1%
Income Tax Expense Includes the Following:			
Current Federal Income Taxes	$(41,328)	$(20,011)	$23,199
Current State Income Taxes	3,492	(1,115)	2,371
Deferred Federal Income Taxes	42,470	39,051	2,832
Deferred State Income Taxes	(571)	5,280	2,116
Federal Production Tax Credit	(6,533)	(3,234)	(3)
Investment Tax Credit Amortization	(992)	(1,125)	(1,137)
North Dakota Wind Tax Credit Amortization — Net of Federal Taxes	(870)	(369)	(21)
Foreign Income Taxes	(248)	(3,385)	(1,104)
Affordable Housing Tax Credits	(25)	(55)	(285)
Total	$ (4,605)	$ 15,037	$27,968

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

(in thousands)	2009	2008
Deferred Tax Assets		
Related to North Dakota Wind Tax Credits	$ 58,191	$ 35,902
Benefit Liabilities	36,329	32,932
ASC 715 Liabilities	24,946	9,650
Cost of Removal	23,253	22,920
Net Operating Loss Carryforward	12,757	6,379
Differences Related to Property	11,445	10,300
Federal Production Tax Credits	6,533	—
Amortization of Tax Credits	4,966	4,946
Vacation Accrual	2,872	3,003
Other	5,940	5,619
Total Deferred Tax Assets	$ 187,232	$ 131,651
Deferred Tax Liabilities		
Differences Related to Property	$(269,718)	$(212,419)
ASC 715 Regulatory Asset	(24,946)	(9,650)
Related to North Dakota Wind Tax Credits	(16,116)	(10,074)
Transfer to Regulatory Asset	(5,808)	(7,093)
Excess Tax over Book Pension	(2,969)	(2,599)
Renewable Resource Rider Accrued Revenue	(2,300)	—
Impact of State Net Operating Losses on Federal Taxes	(2,060)	—
Other	(7,164)	(4,516)
Total Deferred Tax Liabilities	$(331,081)	$(246,351)
Deferred Income Taxes	$(143,849)	$(114,700)

The amounts of unused North Dakota wind energy tax credits being carried forward for North Dakota tax purposes as of December 31, 2009 are: $10.2 million which will fully expire in 2017, $17.7 million which will fully expire in 2032, and $15.4 million which will fully expire in 2033. The tax effect of net operating losses being carried forward for North Dakota tax purposes as of December 31, 2009 was $4.0 million, of which $1.4 million expire in 2029 and $2.6 million expire in 2030. The tax effect of net operating losses being carried forward for Minnesota tax purposes as of December 31, 2009 was $2.1 million which expire in 2024.

The following table summarizes the activity related to our unrecognized tax benefits:

(in thousands)	Total
Balance at January 1, 2009	$ 284
Increases Related to Tax Positions	900
Uncertain Positions Resolved in 2009	(284)
Balance at December 31, 2009	$ 900

The balance of unrecognized tax benefits as of December 31, 2009 would reduce our effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2009 is not expected to change significantly within the next 12 months. The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state and foreign income tax returns. As of December 31, 2009 the Company is no longer subject to U.S. federal income tax examinations by tax authorities for years before 2006. As of December 31, 2009 the Company’s earliest open tax year in which an audit can be initiated by state taxing authorities in the Company’s major operating jurisdictions is 2005 for Minnesota and 2006 for North Dakota. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes. Amounts accrued for interest and penalties on tax uncertainties as of December 31, 2009 were not material.

16. Asset Retirement Obligations (AROs)

The Company’s AROs are related to OTP’s coal-fired generation plants and its 92 wind turbines located in North Dakota. The AROs include site restoration, closure of ash pits, and removal of storage tanks, structures, generators and asbestos. The Company has legal obligations associated with the retirement of a variety of other long-lived tangible assets used in electric operations where the estimated settlement costs are individually and collectively immaterial. The Company has no assets legally restricted for the settlement of any of its AROs.

During 2009, OTP recorded new obligations related to the removal of 33 wind turbines and restoration of its tower sites located at the Luverne Wind Farm in Steele County, North Dakota, and for future renovations of areas currently occupied by various water treatment sludge ponds at the Big Stone Plant site. OTP determined the fair value of its future obligations related to the removal of its 33 wind turbines located at the Luverne Wind Farm by engaging an outside engineering firm with expertise in demolition and removal to provide an estimate of the current costs to remove these assets, then projected the costs forward to 2034 using an inflation rate of 2.9% per year and discounted this amount back to its present value using a credit adjusted risk free rate of 8.3%. OTP determined the fair value of its future obligations for future renovations of areas currently occupied by various water treatment sludge ponds by conducting an internal assessment incorporating the services of a local contractor to estimate the current cost to renovate these areas. OTP then projected the costs forward to 2024 using an inflation rate of 2.7% per year and discounted this amount back to its present value using a credit adjusted risk free rate of 8.75%.

During 2008, OTP recorded new obligations related to the removal of 32 wind turbines and restoration of its tower sites located at the Ashtabula Wind Energy Center in Barnes County, North Dakota and made revisions to previously recorded obligations related to site restoration, closure of ash pits, and removal of storage tanks, structures, generators and asbestos at its coal-fired generation plants. OTP determined the fair value of its future obligations related to the removal of 32 wind turbines located at the Ashtabula Wind Energy Center by engaging an outside engineering firm with expertise in demolition and removal to provide an estimate of the current costs to remove these assets, then projected the costs forward to 2033 using an inflation rate of 3.1% per year and discounted this amount back to its present value using a credit adjusted risk free rate of 9.0%.

Reconciliations of carrying amounts of the present value of the Company's legal AROs, capitalized asset retirement costs and related accumulated depreciation and a summary of settlement activity for the years ended December 31, 2009 and 2008 are presented in the following table:

(in thousands)	2009	2008
Asset Retirement Obligations		
Beginning Balance	$3,298	$2,447
New Obligations Recognized	436	317
Adjustments Due to Revisions in Cash Flow Estimates	—	407
Accrued Accretion	316	127
Settlements	—	—
Ending Balance	$4,050	$3,298
Asset Retirement Costs Capitalized		
Beginning Balance	$1,061	$1,309
New Obligations Recognized	436	317
Adjustments Due to Revisions in Cash Flow Estimates	—	(565)
Settlements	—	—
Ending Balance	$1,497	$1,061
Accumulated Depreciation — Asset Retirement Costs Capitalized		
Beginning Balance	$ 179	$ 185
New Obligations Recognized	—	—
Adjustments Due to Revisions in Cash Flow Estimates	—	(34)
Accrued Depreciation	54	28
Settlements	—	—
Ending Balance	$ 233	$ 179
Settlements		
Original Capitalized Asset Retirement Cost — Retired	$ —	$ —
Accumulated Depreciation	—	—
Asset Retirement Obligation	$ —	$ —
Settlement Cost	—	—
Gain on Settlement — Deferred Under Regulatory Accounting	$ —	$ —

Quarterly Information (not audited)

Because of changes in the number of common shares outstanding and the impact of diluted shares, the sum of the quarterly earnings per common share may not equal total earnings per common share.

Three Months Ended	March 31		June 30		September 30		December 31	
(in thousands, except per share data)	2009	2008	2009	2008	2009	2008	2009	2008
Operating Revenues	$277,239	$300,237	$246,857	$323,600	$257,440	$352,919	$257,976	$334,441
Operating Income	8,609	17,097	6,180	10,303	17,496	19,746	13,105	25,846
Net Income	4,388	8,230	2,731	3,517	10,592	9,631	8,320	13,747
Earnings Available for Common Shares	4,204	8,046	2,547	3,333	10,408	9,447	8,136	13,563
Basic Earnings Per Share	$ .12	$ .27	$ .07	$ .11	$ .29	$ .31	$ .23	$ .38
Diluted Earnings Per Share	$ .12	$ .27	$ .07	$ .11	$ .29	$ .31	$ .23	$ .38
Dividends Paid Per Common Share	$ .2975	$ .2975	$ .2975	$ .2975	$ .2975	$ .2975	$ .2975	$ .2975
Price Range:								
High	24.50	35.68	24.05	40.98	25.40	46.15	25.34	30.84
Low	15.47	31.28	18.63	34.93	20.73	29.71	22.37	14.99
Average Number of Common Shares Outstanding—Basic	35,325	29,818	35,389	29,993	35,528	30,514	35,611	35,311
Average Number of Common Shares Outstanding—Diluted	35,489	30,062	35,644	30,300	35,788	30,817	35,866	35,516

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosures Controls and Procedures . Under the supervision and with the participation of the Company's management, including the Chief Executive Officer and the Chief Financial Officer, the Company evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)) as of December 31, 2009, the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2009.

Changes in Internal Control over Financial Reporting . There were no changes in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) under the Exchange Act) during the fourth quarter ended December 31, 2009 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report Regarding Internal Control Over Financial Reporting. Management is responsible for the preparation and integrity of the consolidated financial statements and representations in this Annual Report on Form 10-K. The consolidated financial statements of the Company have been prepared in conformity with generally accepted accounting principles applied on a consistent basis and include some amounts that are based on informed judgments and best estimates and assumptions of management.

In order to assure the consolidated financial statements are prepared in conformance with generally accepted accounting principles, management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). These internal controls are designed only to provide reasonable assurance, on a cost-effective basis, that transactions are carried out in accordance with management's authorizations and assets are safeguarded against loss from unauthorized use or disposition.

Management has completed its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2009. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control — Integrated Framework* to conduct the required assessment of the effectiveness of the Company's internal control over financial reporting. Based on this assessment, management concluded that, as of December 31, 2009, the Company's internal control over financial reporting was effective based on those criteria. The Company's independent registered public accounting firm, Deloitte & Touche LLP, has audited the Company's consolidated financial statements included in this Annual Report on Form 10-K and issued an attestation report on the Company's internal control over financial reporting.

Attestation Report of Independent Registered Public Accounting Firm . The attestation report of Deloitte & Touche LLP, the Company's independent registered public accounting firm, regarding the Company's internal control over financial reporting is provided on Page 67.

Item 9B. OTHER INFORMATION

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item regarding Directors is incorporated by reference to the information under "Election of Directors" in the Company's definitive Proxy Statement for the 2010 Annual Meeting. The information regarding executive officers and family relationships is set forth in Item 3A hereto. The information regarding Section 16 reporting is incorporated by reference to the information under "Security Ownership of Directors and Officers — Section 16(a) Beneficial Ownership Reporting Compliance" in the Company's definitive Proxy Statement for the 2010 Annual Meeting. The information required by this Item regarding the Company's procedures for recommending nominees to the Board of Directors is incorporated by reference to the information under "Meetings and Committees of the Board of Directors — Corporate Governance Committee" in the Company's definitive Proxy Statement for the 2010 Annual Meeting. The information required by this Item in regards to the Audit Committee is incorporated by reference to the information under "Meetings and Committees of the Board of Directors — Audit Committee" in the Company's definitive Proxy Statement for the 2010 Annual Meeting. The information regarding the Company's Audit Committee financial experts is incorporated by reference to the information under "Meetings and Committees of the Board — Audit Committee" in the Company's definitive Proxy Statement for the 2010 Annual Meeting.

The Company has adopted a code of conduct that applies to all of its directors, officers (including its principal executive officer, principal financial officer, and its principal accounting officer or controller or person performing similar functions) and employees. The Company's code of conduct is available on its website at www.ottertail.com. The Company intends to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of its code of conduct by posting such information on its website at the address specified above. Information on the Company's website is not deemed to be incorporated by reference into this Annual Report on Form 10-K.

Item 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information under "Compensation Discussion and Analysis," "Report of Compensation Committee," "Executive Compensation" and "Director Compensation" in the Company's definitive Proxy Statement for the 2010 Annual Meeting.

Item 12. <u>SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS</u>

The information required by this Item regarding security ownership is incorporated by reference to the information under "Outstanding Voting Shares" and "Security Ownership of Directors and Officers" in the Company's definitive Proxy Statement for the 2010 Annual Meeting.

EQUITY COMPENSATION PLAN INFORMATION

The following table sets forth information as of December 31, 2009 about the Company's common stock that may be issued under all of its equity compensation plans:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column a)) (c)
Equity compensation plans approved by security holders:			
1999 Stock Incentive Plan	962,452(1)	$ 12.40	822,317(2)
1999 Employee Stock Purchase Plan	—	N/A	230,482(3)
Equity compensation plans not approved by security holders	—	—	—
Total	962,452	$ 12.40	1,052,799

(1) Includes 181,200, 114,800, and 109,000 performance based share awards made in 2009, 2008 and 2007, respectively, 92,670 restricted stock units outstanding as of December 31, 2009, and 19,972 phantom shares as part of the deferred director compensation program and excludes 104,778 shares of restricted stock issued under the 1999 Stock Incentive Plan.

(2) The 1999 Stock Incentive Plan provides for the issuance of any shares available under the plan in the form of restricted stock, performance awards and other types of stock-based awards, in addition to the granting of options, warrants or stock appreciation rights.

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

Item 13. <u>CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE</u>

The information required by this Item is incorporated by reference to the information under "Policy and Procedures Regarding Transactions with Related Persons" and "Election of Directors" in the Company's definitive Proxy Statement for the 2010 Annual Meeting.

Item 14. <u>PRINCIPAL ACCOUNTANT FEES AND SERVICES</u>

The information required by this Item is incorporated by reference to the information under "Ratification of Independent Registered Public Accounting Firm — Fees" and "Ratification of Independent Registered Public Accounting Firm — Pre-Approval of Audit/Non-Audit Services Policy" in the Company's definitive Proxy Statement for the 2010 Annual Meeting.

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

1. *Financial Statements*

2. *Financial Statement Schedules*

Schedules are omitted because of the absence of the conditions under which they are required, because the amounts are insignificant or because the information required is included in the financial statements or the notes thereto.

3. *Exhibits*

The following Exhibits are filed as part of, or incorporated by reference into, this report.

	Previously Filed		
	File No.	**As Exhibit No .**	
2-A	8-K filed 7/1/09	2.1	—Plan of Merger, dated as of June 30, 2009, by and among Otter Tail Corporation (now known as Otter Tail Power Company), Otter Tail Holding Company (now known as Otter Tail Corporation) and Otter Tail Merger Sub Inc.
3-A	8-K filed 7/1/09	3.1	—Restated Articles of Incorporation.
3-B	8-K filed 7/1/09	3.2	—Restated Bylaws.
4-A-1	10-K for year ended 12/31/01	4-D-7	—Note Purchase Agreement, dated as of December 1, 2001.
4-A-2	10-K for year ended 12/31/02	4-D-4	—First Amendment, dated as of December 1, 2002, to Note Purchase Agreement, dated as of December 1, 2001.
4-A-3	10-Q for quarter ended 9/30/04	4.2	—Second Amendment, dated as of October 1, 2004, to Note Purchase Agreement, dated as of December 1, 2001.
4-A-4	8-K filed 12/20/07	4.2	—Third Amendment, dated as of December 1, 2007, to Note Purchase Agreement, dated as of December 1, 2001.
4-A-5	8-K filed 7/01/09	4.1	—Fourth Amendment, dated as of June 30, 2009, to Note Purchase Agreement dated as of December 1, 2001.
4-B	8-K filed 8/01/08	4.1	—Credit Agreement, dated as of July 30, 2008, among Otter Tail Corporation, dba Otter Tail Power Company (now known as Otter Tail Power Company), the Banks named therein, Bank of America, N.A., as Syndication Agent, and U.S. Bank National Association, as agent for the Banks.

	Previously Filed		
	File No.	As Exhibit No .	
4-B-1	8-K filed 4/24/09	4.2	—First Amendment, dated as of April 21, 2009, to Credit Agreement, dated as of July 30, 2008.
4-C	8-K filed 2/28/07	4.1	—Note Purchase Agreement, dated as of February 23, 2007, between the Company and Cascade Investment L.L.C.
4-C-1	8-K filed 7/01/09	4.3	—Amendment No. 2, dated as of June 30, 2009, to Note Purchase Agreement, dated as of February 23, 2007.
4-D	8-K filed 8/23/07	4.1	—Note Purchase Agreement, dated as of August 20, 2007.
4-D-1	8-K filed 12/20/07	4.3	—First Amendment, dated as of December 14, 2007, to Note Purchase Agreement, dated as of August 20, 2007.
4-D-2	8-K filed 9/15/08	4.1	—Second Amendment, dated as of September 11, 2008, to Note Purchase Agreement, dated as of August 20, 2007
4-D-3	8-K filed 7/01/09	4.2	—Third Amendment, dated as of June 26, 2009, to Note Purchase Agreement dated as of August 20, 2007.
4-E	8-K filed 12/30/08	4.1	—Amended and Restated Credit Agreement, dated as of December 23, 2008 among the Company (as assignee of Varistar Corporation), the Banks named therein, U.S. Bank National Association, as agent for the Banks and as Lead Arranger, and Bank of America, N.A., Keybank National Association, and Wells Fargo Bank, National Association, as Co-Documentation Agents.
4-E-1	8-K filed 4/24/09	4.1	—First Amendment, dated as of April 21, 2009, to Credit Agreement, dated as of December 23, 2008.
4-F	8-K filed 5/29/09	4.1	—Term Loan Agreement, dated as of May 22, 2009, among Otter Tail Corporation, d/b/a Otter Tail Power Company (now known as Otter Tail Power Company), JPMorgan Chase Bank, N.A., as Administrative Agent, Keybank National Association, as Syndication Agent, Union Bank, N.A., as Documentation Agent, and the Banks named therein.
4-G	8-K filed 11/18/97	4-D-11	—Indenture (For Unsecured Debt Securities) dated as of November 1, 1997 between the registrant and U.S. Bank National Association (formerly First Trust National Association), as Trustee.
4-G-1	8-K filed 7/1/09	4.1	—First Supplemental Indenture, dated as of July 1, 2009, to the Indenture (For Unsecured Debt Securities) dated as of November 1, 1997.
4-G-2	8-K filed 12/4/09	4.1	—Officer's Certificate and Authentication Order, dated December 4, 2009, for the 9.000% Notes due 2016 (which includes the form of Note) issued pursuant to the Indenture (For Unsecured Debt Securities) dated as of November 1, 1997 and the First Supplemental Indenture thereto, dated as of July 1, 2009.
10-A	2-39794	4-C	—Integrated Transmission Agreement, dated August 25, 1967, between Cooperative Power Association and the Company.
10-A-1	10-K for year ended 12/31/92	10-A-1	—Amendment No. 1, dated as of September 6, 1979, to Integrated Transmission Agreement, dated as of August 25, 1967, between Cooperative Power Association and the Company.

	Previously Filed		
	File No.	As Exhibit No .	
10-A-2	10-K for year ended 12/31/92	10-A-2	—Amendment No. 2, dated as of November 19, 1986, to Integrated Transmission Agreement between Cooperative Power Association and the Company.
10-C-1	2-55813	5-E	—Contract dated July 1, 1958, between Central Power Electric Corporation, Inc., and the Company.
10-C-2	2-55813	5-E-1	—Supplement Seven dated November 21, 1973. (Supplements Nos. One through Six have been superseded and are no longer in effect.)
10-C-3	2-55813	5-E-2	—Amendment No. 1 dated December 19, 1973, to Supplement Seven.
10-C-4	10-K for year ended 12/31/91	10-C-4	—Amendment No. 2 dated June 17, 1986, to Supplement Seven.
10-C-5	10-K for year ended 12/31/92	10-C-5	—Amendment No. 3 dated June 18, 1992, to Supplement Seven.
10-C-6	10-K for year ended 12/31/93	10-C-6	—Amendment No. 4 dated January 18, 1994 to Supplement Seven.
10-D	2-55813	5-F	—Contract dated April 12, 1973, between the Bureau of Reclamation and the Company.
10-E-1	2-55813	5-G	—Contract dated January 8, 1973, between East River Electric Power Cooperative and the Company.
10-E-2	2-62815	5-E-1	—Supplement One dated February 20, 1978.
10-E-3	10-K for year ended 12/31/89	10-E-3	—Supplement Two dated June 10, 1983.
10-E-4	10-K for year ended 12/31/90	10-E-4	—Supplement Three dated June 6, 1985.
10-E-5	10-K for year ended 12/31/92	10-E-5	—Supplement No. Four, dated as of September 10, 1986.
10-E-6	10-K for year ended 12/31/92	10-E-6	—Supplement No. Five, dated as of January 7, 1993.
10-E-7	10-K for year ended 12/31/93	10-E-7	—Supplement No. Six, dated as of December 2, 1993
10-F	10-K for year ended 12/31/89	10-F	—Agreement for Sharing Ownership of Generating Plant by and between the Company, Montana-Dakota Utilities Co., and Northwestern Public Service Company (dated as of January 7, 1970).
10-F-1	10-K for year ended 12/31/89	10-F-1	—Letter of Intent for purchase of share of Big Stone Plant from Northwestern Public Service Company (dated as of May 8, 1984).
10-F-2	10-K for year ended 12/31/91	10-F-2	—Supplemental Agreement No. 1 to Agreement for Sharing Ownership of Big Stone Plant (dated as of July 1, 1983).
10-F-3	10-K for year ended 12/31/91	10-F-3	—Supplemental Agreement No. 2 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 1, 1985).

	Previously Filed		
	File No.	As Exhibit No .	
10-F-4	10-K for year ended 12/31/91	10-F-4	—Supplemental Agreement No. 3 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 31, 1986).
10-F-5	10-Q for quarter ended 9/30/03	10.1	—Supplemental Agreement No. 4 to Agreement for Sharing Ownership of Big Stone Plant (dated as of April 24, 2003).
10-F-6	10-K for year ended 12/31/92	10-F-5	—Amendment I to Letter of Intent dated May 8, 1984, for purchase of share of Big Stone Plant.
10-G	10-Q for quarter ended 06/30/04	10.3	—Master Coal Purchase and Sale Agreement by and between the Company, Montana-Dakota Utilities Co., Northwestern Corporation and Kennecott Coal Sales Company-Big Stone Plant (dated as of June 1, 2004).
10-H	2-61043	5-H	—Agreement for Sharing Ownership of Coyote Station Generating Unit No. 1 by and between the Company, Minnkota Power Cooperative, Inc., Montana-Dakota Utilities Co., Northwestern Public Service Company and Minnesota Power & Light Company (dated as of July 1, 1977).
10-H-1	10-K for year ended 12/31/89	10-H-1	—Supplemental Agreement No. One, dated as of November 30, 1978, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-H-2	10-K for year ended 12/31/89	10-H-2	—Supplemental Agreement No. Two, dated as of March 1, 1981, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1 and Amendment No. 2 dated March 1, 1981, to Coyote Plant Coal Agreement.
10-H-3	10-K for year ended 12/31/89	10-H-3	—Amendment, dated as of July 29, 1983, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-H-4	10-K for year ended 12/31/92	10-H-4	—Agreement, dated as of September 5, 1985, containing Amendment No. 3 to Agreement for Sharing Ownership of Coyote Generating Unit No.1, dated as of July 1, 1977, and Amendment No. 5 to Coyote Plant Coal Agreement, dated as of January 1, 1978.
10-H-5	10-Q for quarter ended 9/30/01	10-A	—Amendment, dated as of June 14, 2001, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-H-6	10-Q for quarter ended 9/30/03	10.2	—Amendment, dated as of April 24, 2003, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-I	2-63744	5-I	—Coyote Plant Coal Agreement by and between the Company, Minnkota Power Cooperative, Inc., Montana-Dakota Utilities Co., Northwestern Public Service Company, Minnesota Power & Light Company, and Knife River Coal Mining Company (dated as of January 1, 1978).
10-I-1	10-K for year ended 12/31/92	10-I-1	—Addendum, dated as of March 10, 1980, to Coyote Plant Coal Agreement.
10-I-2	10-K for year ended 12/31/92	10-I-2	—Amendment (No. 3), dated as of May 28, 1980, to Coyote Plant Coal Agreement.
10-I-3	10-K for year ended 12/31/92	10-I-3	—Fourth Amendment, dated as of August 19, 1985, to Coyote Plant Coal Agreement.

Table of Contents

	Previously Filed		
	File No.	As Exhibit No .	
10-I-4	10-Q for quarter ended 6/30/93	19-A	—Sixth Amendment, dated as of February 17, 1993, to Coyote Plant Coal Agreement.
10-I-5	10-K for year ended 12/31/01	10-I-5	—Agreement and Consent to Assignment of the Coyote Plant Coal Agreement.
10-J-1	10-Q for quarter ended 9/30/99	10	—Power Sales Agreement between the Company and Manitoba Hydro Electric Board (dated as of July 1, 1999).
10-K	10-K for year ended 12/31/91	10-L	—Integrated Transmission Agreement by and between the Company, Missouri Basin Municipal Power Agency and Western Minnesota Municipal Power Agency (dated as of March 31, 1986).
10-K-1	10-K for year ended 12/31/88	10-L-1	—Amendment No. 1, dated as of December 28, 1988, to Integrated Transmission Agreement (dated as of March 31, 1986).
10-L	10-Q for quarter ended 06/30/04	10.1	—Master Coal Purchase Agreement by and between the Company and Kennecott Coal Sales Company — Hoot Lake Plant (dated as of December 31, 2001).
10-M	8-K filed 7/01/09	10.1	—Standstill Agreement, dated July 1, 2009, by and between the Registrant and Cascade Investment, L.L.C.
10-N-1	10-K for year ended 12/31/02	10-N-1	—Deferred Compensation Plan for Directors, as amended*
10-N-2	8-K filed 02/04/05	10.1	—Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-N-2a	10-K for year ended 12/31/06	10-N-2a	—First Amendment of Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-N-3	10-K for year ended 12/31/93	10-N-5	—Nonqualified Profit Sharing Plan.*
10-N-4	10-Q for quarter ended 3/31/02	10-B	—Nonqualified Retirement Savings Plan, as amended.*
10-N-5	8-K filed 4/13/06	10.3	—1999 Employee Stock Purchase Plan, As Amended (2006).
10-N-6	8-K filed 4/13/06	10.4	—1999 Stock Incentive Plan, As Amended (2006).
10-N-7	10-K for year ended 12/31/05	10-N-7	—Form of Stock Option Agreement*
10-N-8	10-K for year ended 12/31/05	10-N-8	—Form of Restricted Stock Agreement*
10-N-9	8-K filed 4/13/06	10.2	—Form of 2006 Performance Award Agreement.*
10-N-10	8-K filed 04/15/05	10.2	—Executive Annual Incentive Plan (Effective April 1, 2005).*
10-N-11	10-Q for quarter ended 6/30/06	10.5	—Form of 2006 Restricted Stock Unit Award Agreement.*
10-N-12	8-K filed 4/13/06	10.1	—Form of Restricted Stock Award Agreement for Directors.

	Previously Filed		
	File No.	As Exhibit No .	
10-O-1	10-Q for quarter ended 6/30/02	10-A	—Executive Employment Agreement, John Erickson.*
10-O-2	10-Q for quarter ended 6/30/02	10-B	—Executive Employment Agreement and amendment no. 1, Lauris Molbert.*
10-O-3	10-Q for quarter ended 6/30/02	10-C	—Executive Employment Agreement, Kevin Moug.*
10-O-4	10-Q for quarter ended 6/30/02	10-D	—Executive Employment Agreement, George Koeck.*
10-P-1	8-K filed 11/2/07	10.1	—Change in Control Severance Agreement, John Erickson.*
10-P-2	8-K filed 11/2/07	10.2	—Change in Control Severance Agreement, Lauris Molbert.*
10-P-3	8-K filed 11/2/07	10.3	—Change in Control Severance Agreement, Kevin Moug.*
10-P-4	8-K filed 11/2/07	10.4	—Change in Control Severance Agreement, George Koeck.*
12.1			—Calculation of Ratios of Earnings to Fixed Charges and Preferred Dividends.
21-A			—Subsidiaries of Registrant.
23-A			—Consent of Deloitte & Touche LLP.
24-A			—Powers of Attorney.
31.1			—Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2			—Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1			—Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2			—Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Management contract of compensatory plan or arrangement required to be filed pursuant to Item 601(b)(10)(iii)(A) of Regulation S-K.

Pursuant to Item 601(b)(4)(iii) of Regulation S-K, copies of certain instruments defining the rights of holders of certain long-term debt of the Company are not filed, and in lieu thereof, the Company agrees to furnish copies thereof to the Securities and Exchange Commission upon request.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

OTTER TAIL CORPORATION

By /s/ Kevin G. Moug
Kevin G. Moug
Chief Financial Officer
Dated: February 26, 2010

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

Signature and Title

John D. Erickson President and Chief Executive Officer (principal executive officer) and Director	)	
Kevin G. Moug Chief Financial Officer (principal financial and accounting officer)	)	By /s/ John D. Erickson John D. Erickson Pro Se and Attorney-in-Fact Dated February 26, 2010
John C. MacFarlane Chairman of the Board and Director	)	
Karen M. Bohn, Director	)	
Arvid R. Liebe, Director	)	
Edward J. McIntyre, Director	)	
Joyce Nelson Schuette, Director	)	
Nathan I. Partain, Director	)	
Gary J. Spies, Director	)	
James B. Stake, Director	)	

EXHIBIT INDEX

Exhibit Number	Description
12.1	Calculation of Ratios of Earnings to Fixed Charges and Preferred Dividends
21-A	Subsidiaries of the Registrant
23-A	Consent of Independent Registered Public Accounting Firm
24-A	Power of Attorney
31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit 12.1

OTTER TAIL CORPORATION
CALCULATION OF RATIOS OF EARNINGS TO FIXED CHARGES AND PREFERRED DIVIDENDS

	Year Ended December 31,				
	2005	2006	2007	2008	2009
Earnings					
Pretax income from continuing operations	$ 81,912,596	$ 77,855,302	$ 81,928,914	$50,161,916	$21,425,878
Plus fixed charges (see below)	24,615,267	26,458,342	32,389,334	36,082,847	36,304,519
Total earnings (1)	$106,527,863	$104,313,644	$114,318,248	$86,244,763	$57,730,397
Fixed Charges					
Interest charges	$ 17,637,279	$ 18,789,945	$ 22,384,136	$28,094,844	$27,622,443
Amortization of debt expense, premium and discount	1,010,988	945,397	1,138,198	1,020,003	2,127,076
Estimated interest component of operating leases	5,967,000	6,723,000	8,867,000	6,968,000	6,555,000
Total fixed charges (2)	$ 24,615,267	$ 26,458,342	$ 32,389,334	$36,082,847	$36,304,519
Preferred Dividend Requirement	$ 1,044,009	$ 1,043,125	$ 1,033,385	$ 981,547	$ 633,832
Total Fixed Charges and Preferred Dividend Requirement (3)	$ 25,659,276	$ 27,501,467	$ 33,422,719	$37,064,394	$36,938,351
Ratio of Earnings to Fixed Charges (1) Divided by (2)	4.33	3.94	3.53	2.39	1.59
Ratio of Earnings to Fixed Charges and Preferred Dividends (1) Divided by (3)	4.15	3.79	3.42	2.33	1.56

OTTER TAIL CORPORATION

Subsidiaries of the Registrant
February 26, 2010

Company	State of Organization
Otter Tail Power Company	Minnesota
Otter Tail Energy Services Company, Inc.	Minnesota
Overland Mechanical Services, Inc.	Minnesota
Green Hills Energy, LLC	Minnesota
Sheridan Ridge I, LLC	Minnesota
Sheridan Ridge II, LLC	Minnesota
Otter Tail Assurance Limited	Cayman Islands
Varistar Corporation	Minnesota
Northern Pipe Products, Inc.	North Dakota
Vinyltech Corporation	Arizona
T.O. Plastics, Inc.	Minnesota
DMI Industries, Inc.	North Dakota
DMI Canada, Inc.	Ontario, Canada
DMI Equipment, LLC	Delaware
BTD Manufacturing, Inc.	Minnesota
Miller Welding & Iron Works, Inc.	Minnesota
ShoreMaster, Inc.	Minnesota
Galva Foam Marine Industries, Inc.	Missouri
Shoreline Industries, Inc.	Minnesota
Aviva Sports, Inc.	Minnesota
ShoreMaster Costa Rica, Limitada	Costa Rica
DMS Health Technologies, Inc.	North Dakota
DMS Imaging, Inc.	North Dakota
DMS Health Technologies – Canada, Inc.	North Dakota
DMS Leasing Corporation*	North Dakota
Aevenia, Inc.	Minnesota
Moorhead Electric, Inc.	Minnesota
Foley Company	Missouri
E. W. Wylie Corporation	North Dakota
Idaho Pacific Holdings, Inc.	Delaware
Idaho-Pacific Corporation	Idaho
Idaho-Pacific Colorado Corporation	Delaware
AWI Acquisition Company Limited	Prince Edward Island, Canada
AgraWest Investments Limited	Prince Edward Island, Canada

---

* Inactive

Exhibit 23-A

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in Registration Statement Nos. 333-155747-99 and 333-159137-99 on Form S-3 and 333-25261-99, 333-73041-99, 333-73075-99 and 333-136841-99 on Form S-8 of our report dated February 26, 2010 relating to the consolidated financial statements of Otter Tail Corporation and its subsidiaries (the “Company”) and the effectiveness of the Company’s internal control over financial reporting, which appears in this Annual Report on Form 10-K of the Company for the year ended December 31, 2009.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 26, 2010

Exhibit 24-A

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below hereby constitutes and appoints JOHN D. ERICKSON, LAURIS N. MOLBERT, KEVIN G. MOUG and GEORGE A. KOECK, and each of them, his or her true and lawful attorneys-in-fact and agents, each acting alone, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign the Annual Report on Form 10-K of Otter Tail Corporation for its fiscal year ended December 31, 2009, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite or necessary to be done in and about the premises, as fully as to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them, or their or his substitutes, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, this Power of Attorney has been signed on the 9 th day of February, 2010 by the following persons:

/s/ Karen M. Bohn
Karen M. Bohn

/s/ John D. Erickson
John D. Erickson

/s/ Arvid R. Liebe
Arvid R. Liebe

/s/ John C. MacFarlane
John C. MacFarlane

/s/ Edward J. McIntyre
Edward J. McIntyre

/s/ Kevin G. Moug
Kevin G. Moug

/s/ Nathan I. Partain
Nathan I. Partain

/s/ Joyce Nelson Schuette
Joyce Nelson Schuette

/s/ Gary J. Spies
Gary J. Spies

/s/ James B. Stake
James B. Stake

Exhibit 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John D. Erickson, certify that:

1. I have reviewed this Annual Report on Form 10-K of Otter Tail Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2010

/s/ John D. Erickson
John D. Erickson
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Kevin G. Moug, certify that:

1. I have reviewed this Annual Report on Form 10-K of Otter Tail Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2010

/s/ Kevin G. Moug
Kevin G. Moug
Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Otter Tail Corporation (the "Company") on Form 10-K for the period ended December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John D. Erickson, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ John D. Erickson
John D. Erickson
President and Chief Executive Officer
February 26, 2010

Exhibit 32.2

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Otter Tail Corporation (the "Company") on Form 10-K for the period ended December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Kevin G. Moug, Chief Financial Officer and Treasurer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Kevin G. Moug
Kevin G. Moug
Chief Financial Officer
February 26, 2010