Reconciliation of Cash and Cash Equivalents (Lines 88 and 90 on Page 121)
With Balance Sheet Accounts (Page 110):
Account 136 – Temporary Cash Investment (Line 38, Page 110), contains amounts which are considered cash equivalents.

	2009	2008
Cash Equivalents	$ 0	$ 0

Reconciliation	2009	2008
Cash – Account 131 (Line 35, Page 110)	$ 9,403	$ 7,902
Working Fund – Account 135 (Line 37, Page 110)	20,605	22,530
Cash Equivalent – Account 136 (Above)	0	0
	$ 30,008	$ 30,432

Otter Tail Power Company
Notes to Financial Statements
For the years ended December 31, 2009 and 2008

1. Summary of Significant Accounting Policies

Organization and Operations
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 (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.

OTP includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota In addition, OTP is an active wholesale participant in the Midwest Independent Transmission System Operator (MISO) markets.

OTP provides electricity to more than 129,000 customers in a 50,000 square mile area of Minnesota, North Dakota and South Dakota. 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.

Related Party
Included in the amounts presented in the balance sheet and income statement are the following related party balances:

(in thousands)	2009	2008
Accounts Receivable	$91	$209
Accounts Payable	1,055	1,078
Long-Term Debt	15,500	256,790
Operating Revenues	201	294
Other Operation and Maintenance Expenses	8,124	7,631

The related party transactions predominately relate to electric sales to operating subsidiaries of Otter Tail Corporation and to the allocation of corporate overhead expenses, insurance premiums and corporate aircraft usage to OTP. The corporate overhead expenses include such items as labor, professional services, office rent, subscriptions, information technology and general office expenses incurred by Otter Tail Corporation. These expenses are allocated to OTP based on the type of expenditure using an allocation methodology as defined in Otter Tail Corporation's Corporate Cost Allocation Manual.

Regulation and ASC 980

OTP, a regulated electric utility company, accounts for the financial effects of regulation in accordance with the requirements of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 980, *Regulated Operations,* (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 3 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).

Financial Statement Presentation and Basis of Accounting

The financial statements are presented on the basis of the accounting requirements of FERC as set forth in its applicable Uniform System of Accounts and this report differs from GAAP. The significant differences consist of the following:

- Comparative statements of net income per share are not presented.
- The accumulated reserve for depreciation for estimated removal costs is included in the accumulated provision for depreciation for FERC reporting. For GAAP reporting it is reported as a regulatory liability.
- Current and long-term debt is classified in the balance sheet as all long-term debt in accordance with regulatory treatment, while GAAP presentation reflects current and long-term debt separately.
- Accumulated deferred tax assets and liabilities are classified in the balance sheet as gross deferred debits and credits, respectively, while GAAP presentation reflects either a net deferred asset or liability.

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 (AFUDC). The amount of AFUDC on electric utility plant was $4,216,000 in 2009 and $4,478,000 in 2008. 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 and 2.81% in 2008. Gains or losses on group asset dispositions are taken to the accumulated provision for depreciation reserve and impact current and future depreciation rates.

Jointly Owned Plants

The 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 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

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

Recoverability of Long-Lived Assets

OTP reviews its long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. OTP 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, OTP 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. OTP amortizes investment tax credits over the estimated lives of related property. OTP records income taxes in accordance with ASC 740, *Income Taxes,* and has recognized in its 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%. OTP classifies interest and penalties on tax uncertainties as components of the provision for income taxes. See note 11 to the financial statements regarding OTP's accounting for uncertain tax positions.

Revenue Recognition

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.

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. OTP's unrealized gains and losses on forward energy contracts that do not meet the definition of capacity contracts are marked to market and reflected on a net basis in electric revenue on OTP's statement of income. Under ASC 815, *Derivatives and Hedging*, OTP's forward energy contracts that do not meet the definition of a capacity contract and are subject to unplanned netting do not qualify for the normal purchase and sales exception from mark-to-market accounting. OTP 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 4 for further discussion.

Use of Estimates

OTP 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, tax provisions, collectability of trade accounts receivable, self-insurance programs, unbilled revenues, accrued renewable resource and transmission rider revenues, valuations of forward energy contracts 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

OTP 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
Decreases in Accounts Payable and Other Liabilities Related to Capital Expenditures	$ (1,130)	$(21,067)
Noncash Financing Transaction:		
Preferred Stock Exchanged for Notes Payable to Parent – July 1, 2009	$ 15,500	$ --
Cash Paid During the Year for:		
Interest (net of amount capitalized)	$ 17,971	$ 13,943
Income Tax (Refunds)	$(20,527)	$ (808)

Investments
The following table provides a breakdown of OTP'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	16	514
Equity Method:		
Partnerships	17	17
Total Investments	$ 515	$ 1,059

Fair Value Measurements
Effective January 1, 2008, OTP 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 tables present, for each of these hierarchy levels, OTP'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:			
Forward Energy Contracts	$ --	$ 8,321	$ --
Liabilities:			
Forward Energy Contracts	--	$ 14,681	--
Net Assets (Liabilities)	$ --	$ (6,360)	$ --

2008 *(in thousands)*	Level 1	Level 2	Level 3
Assets:			
Forward Energy Contracts	$ --	$ 405	$ --
Liabilities:			
Forward Energy Contracts	--	$ 1,690	--
Net Assets (Liabilities)	$ --	$ (1,285)	$ --

Inventories

OTP inventories consisting of fuel, materials and supplies are reported at average cost.

New Accounting Standards

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. OTP adopted the new guidance on January 1, 2009. Adoption of the new guidance resulted in additional footnote disclosures related to OTP's use of derivative instruments, the location and fair value of derivatives reported on OTP's balance sheets, the location and amounts of derivative instrument gains and losses reported on OTP's 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 8 to 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. OTP implemented the new guidance on April 1, 2009. The implementation did not have a material impact on OTP's financial statements. ASC 825 required disclosures have been included in OTP's notes to 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. OTP implemented the new guidance on April 1, 2009. The implementation did not have a material impact on OTP's financial statements. OTP has evaluated events occurring through March 19, 2010 and determined there are no events that would have occurred subsequent to December 31, 2009 that would affect OTP's financial statements as of, and for the periods ending December 31 2009 or that require disclosure in this report.

2. 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 OTP's 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.

<u>Recovery of MISO Costs</u>--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. OTP's December 31, 2009 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.

<u>CapX 2020 Request for Advance Determination of Prudence</u>--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.

<u>Recovery of MISO Costs</u>--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.

<u>South Dakota</u>

<u>General Rate Case</u>--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.

<u>Federal</u>

<u>Revenue Sufficiency Guarantee (RSG) Charges</u>--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. OTP 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 OTP'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.

3. 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 OTP's 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
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
Accumulated ARO Accretion/Depreciation Adjustment	1,808	1,437
Minnesota General Rate Case Recoverable Expenses	1,693	1,457
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	--
Total Regulatory Assets	$ 103,658	$ 82,043
Regulatory Liabilities:		
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$ 12,043	$ 12,091
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	$ 17,380	$ 18,007
Net Regulatory Asset Position	$ 86,278	$ 64,036

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.

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.

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.

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.

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 balance sheet and included in the statement of income as an extraordinary expense or income item in the period in which the application of guidance under ASC 980 ceases.

4. 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 and $27,236,000 in 2008 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
Wholesale Sales - Company-Owned Generation	$ 12,579	$ 23,708
Revenue from Settled Contracts at Market Prices	110,124	520,280
Market Cost of Settled Contracts	(109,125)	(518,866)
Net Margins on Settled Contracts at Market	999	1,414
Marked-to-Market Gains on Settled Contracts	14,585	39,375
Marked-to-Market Losses on Settled Contracts	(13,431)	(37,138)
Net Marked-to-Market Gain on Settled Contracts	1,154	2,237
Unrealized Marked-to-Market Gains on Open Contracts	8,097	405
Unrealized Marked-to-Market Losses on Open Contracts	(7,067)	(528)
Net Unrealized Marked-to-Market Gain (Loss) on Open Contracts	1,030	(123)
Wholesale Electric Revenue	$ 15,762	$ 27,236

The following tables show the effect of marking to market forward contracts for the purchase and sale of energy on OTP's 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.

5. Common Shareholders' Equity and Cumulative Preferred Shares

At December 31, 2008 the Company had paid in capital of approximately $195,192,000, consisting entirely of equity infusions from Otter Tail Corporation, the parent company of OTP. As discussed in note 1, Otter Tail Corporation completed the holding company reorganization in July 2009. In conjunction with the reorganization, OTP issued 100 shares of common stock with a par value of $5, with the sole holder of those shares being Otter Tail Corporation. In addition to the issuance of the 100 shares of common stock, Otter Tail Corporation provided OTP with a capital infusion of approximately $9,668,000 of which $5,468,000 was for the transfer of the employee benefit liabilities and related tax benefits for the pension plan, executive survivor and supplemental retirement plan and other postretirement benefits from OTP to Otter Tail Corporation and $4,200,000 in additional equity in order align the debt to equity components for OTP.

At December 31, 2008, the Company had 1,500,000 shares of cumulative preferred shares authorized with no par value and 155,000 shares outstanding. The holder of the cumulative preferred shares was Otter Tail Corporation. As part of the holding company reorganization discussed in note 1, these shares were converted to term debt payable to Otter Tail Corporation.

6. Commitments and Contingencies

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.

Operating Lease Commitments

The amounts of future operating lease payments are as follows:

(in thousands)	
2010	$ 2,491
2011	1,411
2012	924
2013	933
2014	944
Later years	15,642
Total	$ 22,345

Future operating lease payments are primarily related to coal rail-car leases. Rent expense was $2,893,000 in 2009 and $2,634,000 in 2008.

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 OTP 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. OTP 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. OTP 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.

Other

OTP is a party to litigation arising in the normal course of business. OTP regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. OTP believes the effect on its 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.

7. Short-Term and Long-Term Borrowings

Short-Term Debt

The following table presents the status of OTP's 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
OTP Credit Agreement[1]	$ 170,000	$ 1,585	$ 680	$ 167,735	$ 142,935

[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 short-term debt outstanding on December 31, 2009 and 2008 were 0.73% and 0.97%, respectively. The weighted average interest rate paid on short-term debt was 0.92% in 2009 and 3.09% in 2008.

Prior to Otter Tail Corporation'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 Otter Tail Corporation's holding company reorganization, the OTP Credit Agreement is an obligation of OTP.

Long-Term Debt

On May 11, 2009 Otter Tail Corporation 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. Proceeds from any equity issuances or borrowings by Otter Tail Corporation under the shelf registration could be used to fund OTP's capital additions or construction expenditures, retire OTP's debt or for other OTP capital requirements.

All long-term debt outstanding and listed on the Statements of Capitalization as of December 31, 2008 was owed by OTP to Otter Tail Corporation. As part of the holding company reorganization discussed in note 1, Otter Tail Power Company became the obligor of these debt series to the external debt holders.

Term Loan Agreement and Retirement

Prior to Otter Tail Corporation'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 OTP'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.

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.

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 $58,000,000 for 2010, $90,000,000 for 2011, $10,400,000 for 2012 and no outstanding debt is scheduled to mature in 2013 and 2014.

Financial Covenants

As of December 31, 2009 OTP 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 Otter Tail Corporation's holding company reorganization on July 1, 2009: (1) the Cascade Note Purchase Agreement is an obligation of Otter Tail Corporation, as assignee of Otter Tail Corporation (now OTP) prior to the reorganization, and is guaranteed by Varistar and its material subsidiaries, and (2) 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 Otter Tail Corporation's holding company reorganization on July 1, 2009 OTP's borrowing agreements are subject to certain financial covenants. Specifically:

- 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.

- In addition, under the Otter Tail Corporation 8.89% Senior Note, Otter Tail Corporation may not permit the ratio of OTP's Debt to OTP's total Capitalization to be greater than 0.60 to 1.00. The 8.89% Senior Note is not an obligation of OTP.

8. Pension Plan and Other Postretirement Benefits

Pension Plan
Otter Tail Corporation's noncontributory funded pension plan covers substantially all OTP 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. Otter Tail Corporation reserves the right to discontinue the plan but no change or discontinuance may affect the pensions theretofore vested. OTP's portion of this plan makes up substantially all of the rights and obligations of the plan. The amounts presented herein are based upon the separate actuarial analysis of OTP and Otter Tail Corporation and its respective employees.

As of and for the twelve months ended December 31, 2008, OTP recorded the liabilities of the pension plan and is reflected in the amounts below. As part of the holding company restructuring completed in July 2009 discussed in note 1, the liabilities of the plan along with related tax benefits that related to Otter Tail Corporation were transferred to Otter Tail Corporation, resulting in a decrease of $3 million to OTP's equity.

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 Otter Tail Corporation 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 OTP or Otter Tail Corporation.

Components of net periodic pension benefit cost:

(in thousands)	2009	2008
Service Cost--Benefit Earned During the Period	$ 3,859	$ 4,505
Interest Cost on Projected Benefit Obligation	11,028	11,019
Expected Return on Assets	(12,723)	(13,591)
Amortization of Prior-Service Cost	703	722
Amortization of Net Actuarial Loss	75	165
Net Periodic Pension Cost	$ 2,942	$ 2,820

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

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

The following table presents amounts recognized in the 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
Noncurrent Liability:		
Otter Tail Power Company Portion	$ 64,733	$ 53,592
Corporate Portion Prior to Holding Company Formation	--	1,432
Total Noncurrent Liability	$ 64,733	$ 55,024
Deferred Income Taxes	--	$ 666
Accumulated Other Comprehensive Loss	--	$ 998

Funded status as of December 31:

(in thousands)	2009	2008
Accumulated Benefit Obligation:		
Otter Tail Power Company Portion	$(162,514)	$(149,896)
Corporate Portion Prior to Holding Company Formation	--	(3,780)
Total Accumulated Benefit Obligation	$(162,514)	$(153,676)
Projected Benefit Obligation:		
Otter Tail Power Company Portion	$(201,345)	$(177,556)
Corporate Portion Prior to Holding Company Formation	--	(5,003)
Fair Value of Plan Assets:	--	
Otter Tail Power Company Portion	136,612	123,964
Corporate Portion Prior to Holding Company Formation	--	3,571
Funded Status	$ (64,733)	$ (55,024)

The following tables provide a reconciliation of the changes in the OTP portion of 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 Otter Tail Power Company Portion of Plan Assets:		
Fair Value of Plan Assets at January 1	$ 123,964	$ 165,982
Actual Return on Plan Assets	17,546	(35,229)
Discretionary Company Contributions	3,888	2,000
Benefit Payments	(8,786)	(8,789)
Fair Value of Plan Assets at December 31	$ 136,612	$ 123,964
Estimated Asset Return	14.30%	(21.94)%
Reconciliation of Otter Tail Power Company Portion of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 177,556	$ 179,840
Service Cost	3,859	4,505
Interest Cost	11,028	11,109
Benefit Payments	(8,786)	(8,789)
Actuarial Loss (Gain)	17,688	(9,109)
Projected Benefit Obligation at December 31	$ 201,345	$ 177,556

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, OTP 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--OTP'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.

OTP 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
Total Estimated Amortization	$ 2,627

Cash flows—OTP 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 to retired OTP employees:

(in thousands)	2010	2011	2012	2013	2014	Years 2015-2019
	$9,321	$9,675	$10,047	$10,485	$10,918	$66,673

OTP'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 OTP's pension plan (the Plan):

- The Plan is managed to operate in perpetuity.
- The Plan will meet the pension benefit obligation payments of OTP.
- 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 OTP'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 Otter Tail Corporation and OTP 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. There are no plan assets in this nonqualified benefit plan due to the nature of the plan.

As of and for the twelve months ended December 31, 2008, OTP recorded the liabilities of this plan and is reflected in the amounts below. As part of the holding company restructuring completed in July 2009 discussed in note 1, the liabilities of the plan along with related tax benefits that related to Otter Tail Corporation were transferred to Otter Tail Corporation, resulting in an increase of $7.6 million to OTP's equity.

Components of net periodic pension benefit cost:

(in thousands)	2009	2008
Service Cost--Benefit Earned During the Period	$ 438	$ 417
Interest Cost on Projected Benefit Obligation	986	926
Amortization of Prior-Service Cost	41	40
Amortization of Net Actuarial Loss	224	289
Net Periodic Pension Cost	$ 1,689	$ 1,672

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

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

The following table presents amounts recognized in the 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:		
Otter Tail Power Company Portion	$ (16,541)	$ (15,612)
Corporate Portion Prior to Holding Company Formation	--	(10,276)
Total Projected Benefit Obligation Liability – Net Amount Recognized	$ (16,541)	$ (25,888)
Deferred Income Taxes		$ 1,194
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	--	$ 166
Unrecognized Actuarial Loss	--	1,626
Total Accumulated Other Comprehensive Loss	--	$ 1,792

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 Otter Tail Power Company Portion 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 Otter Tail Power Company Portion of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 15,612	$ 15,611
Service Cost	438	417
Interest Cost	986	926
Benefit Payments	(1,112)	(1,067)
Plan Amendments	24	38
Actuarial Loss (Gain)	593	(313)
Projected Benefit Obligation at December 31	$ 16,541	$ 15,612

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
Total Estimated Amortization	$ 321

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

OTP provides a portion of health insurance and life insurance benefits for retired OTP employees. Substantially all of OTP's electric utility 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, OTP elected to recognize its transition obligation related to postretirement benefits earned of approximately $14,548,000 over a period of 20 years. There are no plan assets.

As of and for the twelve months ended December 31, 2008, OTP recorded the liabilities of this plan and is reflected in the amounts below. As part of the holding company restructuring completed in July 2009 discussed in note 1, the liabilities of the plan along with related tax benefits that related to Otter Tail Corporation were transferred to Otter Tail Corporation, resulting in an increase of $1.0 million to OTP's equity.

Components of net periodic postretirement benefit cost:

(in thousands)	2009	2008
Service Cost--Benefit Earned During the Period	$ 1,111	$ 1,073
Interest Cost on Projected Benefit Obligation	2,782	2,616
Amortization of Transition Obligation	727	727
Amortization of Prior-Service Cost	205	205
Amortization of Net Actuarial Loss	--	(35)
Expense Decrease Due to Medicare Part D Subsidy	(1,335)	(1,172)
Net Periodic Postretirement Benefit Cost	$ 3,490	$ 3,414

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

	2009	2008
Discount Rate	6.70%	6.25%

The following table presents amounts recognized in the 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:		
Otter Tail Power Company Portion	$(36,656)	$(31,749)
Corporate Portion Prior to Holding Company Formation	--	(872)
Total Projected Benefit Obligation Liability – Net Amount Recognized	$(36,656)	$(32,621)
Accumulated Other Comprehensive Loss:		
Unrecognized Transition Obligation	$ 653	$ 871
Corporate Items Prior to Holding Company Formation:		
Unrecognized Transition Obligation	--	52
Unrecognized Prior Service Cost	--	26
Unrecognized Net Actuarial Gain	--	(64)
Total Accumulated Other Comprehensive Loss	$ 653	$ 885
Deferred Income Taxes:		
Otter Tail Power Company Portion	$ 436	$ 582
Corporate Portion Prior to Holding Company Formation	--	8
Total Deferred Income Taxes	$ 436	$ 590

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 Otter Tail Power Company Portion 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 Otter Tail Power Company Portion of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 31,749	$ 29,832
Service Cost (Net of Medicare Part D Subsidy)	909	872
Interest Cost (Net of Medicare Part D Subsidy)	1,921	1,801
Benefit Payments (Net of Medicare Part D Subsidy)	(3,113)	(3,392)
Participant Premium Payments	1,859	1,815
Actuarial Loss	3,331	821
Projected Benefit Obligation at December 31	$ 36,656	$ 31,749

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
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Transition Obligation	363
Total Estimated Amortization	$ 931

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

9. 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:

Long-Term Debt--The fair value of OTP's long-term debt is estimated based on the current rates available to OTP for the issuance of debt. OTP's long-term debt subject to variable interest rates of $68.4 million and OTP's notes payable to parent company, Otter Tail Corporation, approximate fair value.

	December 31, 2009		December 31, 2008	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$(354,425)	$(314,567)	$(256,790)	$(229,404)

10. 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	492,902	467,855
Electric Plant Net of Accumulated Depreciation	820,113	737,792
Construction Work in Progress	11,104	25,547
Net Electric Plant	831,217	763,339
Other Property		
Land	776	902
Net Plant	$ 831,993	$ 764,241

The estimated service lives for rate-regulated properties is 5 to 65 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

11. Income Taxes

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

(in thousands)	2009	2008
Tax Computed at Federal Statutory Rate	$ 12,154	$ 16,156
Increases (Decreases) in Tax from:		
State Income Taxes Net of Federal Income Tax Benefit	1,584	1,967
Differences Reversing in Excess of Federal Rates	893	1,089
Federal Production Tax Credit	(6,533)	(3,234)
Tax Depreciation - Treasury Grant for Wind Farms	(3,169)	--
Allowance for Funds Used During Construction - Equity	(1,113)	(975)
Investment Tax Credit Amortization	(992)	(1,125)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(870)	(369)
Dividend Received/Paid Deduction	(683)	(718)
Permanent and Other Differences	(625)	135
Total Income Tax Expense	$ 646	$ 12,926
Overall Effective Federal and State Income Tax Rate	1.9%	28.0%
Income Tax Expense Includes the Following:		
Current Federal Income Taxes	$ (35,666)	$ (18,475)
Current State Income Taxes	2,723	(1,581)
Deferred Federal Income Taxes	42,500	32,212
Deferred State Income Taxes	(516)	5,498
Federal Production Tax Credit	(6,533)	(3,234)
Investment Tax Credit Amortization	(992)	(1,125)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(870)	(369)
Total	$ 646	$ 12,926

OTP'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	22,041	22,438
Differences Related to Property	10,738	9,581
Net Operating Loss Carryforward	7,529	1,643
Federal Production Tax Credits	6,533	--
Amortization of Tax Credits	4,966	4,946
Vacation Accrual	1,312	1,320
Other	1,605	2,093
Total Deferred Tax Assets	$ 112,915	$ 77,923
Deferred Tax Liabilities		
Differences Related to Property	$(203,597)	$(149,981)
Related to North Dakota Wind Tax Credits	(15,132)	(9,090)
Transfer to Regulatory Asset	(5,808)	(7,045)
Excess Tax over Book Pension	(2,898)	(2,530)
Renewable Resource Rider Accrued Revenue	(2,300)	(1,971)
Impact of State Net Operating Losses on Federal Taxes	(2,060)	--
Other	(4,458)	424
Total Deferred Tax Liabilities	$(236,253)	$(170,193)
Deferred Income Taxes	$(123,338)	$ (92,270)

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	$ 65
Increases Related to Tax Positions	--
Uncertain Positions Resolved in 2009	(65)
Balance at December 31, 2009	$ --

Otter Tail Corporation and its subsidiaries, including OTP, file a consolidated U.S. federal income tax return and various state and foreign income tax returns. As of December 31, 2009 Otter Tail Corporation is no longer subject to U.S. federal income tax examinations by tax authorities for years before 2006. As of December 31, 2009 Otter Tail Corporation's earliest open tax year in which an audit can be initiated by state taxing authorities in Otter Tail Corporation's major operating jurisdictions is 2005 for Minnesota and 2006 for North Dakota. OTP classifies interest and penalties on tax uncertainties as components of the provision for income taxes.

12. Asset Retirement Obligations (AROs)

OTP's AROs are related to 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. OTP 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. OTP 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 OTP'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	$ --	$ --

13. Quantitative and Qualitative Disclosures about Market Risk

At December 31, 2009 OTP had exposure to market risk associated with interest rates because we had $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.

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.

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.