Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Retained Earnings Statement

	(A)	(B)
Line No.	Description	12 Months Ended December 31, 2007
1	Balance at Beginning of Period	$ 127,412,721
2	Net Income	24,497,584
3	Total Before Deductions	151,910,305
4	Dividends Paid/Declared and Other	
5	Preferred Dividends	735,500
6	Common Stock Dividends	27,824,110
7	Total Dividends	28,559,610
8	Balance at End of Period	$ 123,350,695

Reconciliation of Cash and Cash Equivalents
With Balance Sheet Accounts:
Account 136 – Temporary Cash Investment, contains amounts which are considered cash equivalents.

	2007	2006
Cash Equivalents	$ 22,435,436	$ 303,042

Reconciliation	2007	2006
Cash – Account 131	$ 23,367	$ 43,413
Working Fund – Account 135	22,405	22,880
Cash Equivalent – Account 136 (Above)	22,435,436	303,042
	$ 22,481,208	$ 369,335
Supplemental Disclosure of Cash Flow Information:		
Cash Paid During the year for:		
Interest (Net of Amount Capitalized)	$ 8,079,857	$ 9,949,634
Income Taxes	$ 9,367,086	$ 23,322,815

Otter Tail Power Company
Notes to Comparative Financial Statements
For the years ended December 31, 2007 and 2006

1. Summary of Significant Accounting Policies

Regulation and Statement of Financial Accounting Standards No. 71
As a regulated entity, the Company accounts for the financial effects of regulation in accordance with SFAS No. 71. This statement 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, the Company defers utility debt redemption premiums and amortizes such costs over the original life of the reacquired bonds. See note 3 for further discussion.

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

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. 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 tax 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. The amount of interest capitalized on electric utility plant was $2,257,000 in 2007 and $952,000 in 2006. 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 2.78% in 2007and 2.82% in 2006. 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 comparative balance sheets include the Company'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, 2007 and 2006 comparative balance sheets:

(in thousands)	Big Stone Plant	Coyote Station
December 31, 2007		
Electric Plant in Service	$ 136,493	$ 147,724
Accumulated Depreciation	(72,342)	(83,417)
Net Plant	$ 64,151	$ 64,307
December 31, 2006		
Electric Plant in Service	$ 124,965	$ 147,319
Accumulated Depreciation	(75,872)	(80,336)
Net Plant	$ 49,093	$ 66,983

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

Recoverability of Long-Lived Assets
The Company reviews its long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. The Company determines potential impairment by comparing the carrying value 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 values, the Company would determine whether an impairment loss should be recognized. An impairment loss would be quantified by comparing the amount by which the carrying value exceeds the fair value of the asset, where fair value is based on the discounted cash flows expected to be generated by the asset.

Income Taxes
Comprehensive interperiod income tax allocation is used for substantially all book and tax temporary differences. Deferred income taxes arise for all temporary differences between the book and tax basis of assets and liabilities. Deferred taxes are recorded using the tax rates scheduled by tax law to be in effect in the periods when the temporary differences reverse. The Company amortizes tax credits over the estimated lives of related property. Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109,* was issued in June 2006. FIN No. 48 clarifies the accounting for uncertain tax positions in accordance with SFAS No. 109, *Accounting for Income Taxes.* The Company adopted FIN No. 48 on January 1, 2007 and has recognized, in its comparative 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 December 31, 2007. The term "more-likely-than-not" means a likelihood of more than 50%.

Revenue Recognition
In the case of derivative instruments, such as the electric utility's forward energy contracts, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended and interpreted. 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.

Electric customers' meters are read 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.

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

The Company's unrealized gains and losses on forward energy contracts that do not meet the definition of capacity contracts are marked to market and reflected on a net basis in electric revenue on the Company's comparative statement of income. Under SFAS No. 133 as amended and interpreted, the Company's forward energy contracts that do not meet the definition of a capacity contract and are subject to unplanned netting do not qualify for the normal purchase and sales exception from mark-to-market accounting. The Company is required to mark to market these forward energy contracts and recognize changes in the fair value of these contracts as components of income over the life of the contracts. See note 4 for further discussion.

Use of Estimates
The Company uses estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, unbilled electric revenues, valuations of forward energy contracts, residual load adjustments related to purchase and sales transactions processed through the Midwest Independent Transmission System Operator (MISO) that are pending settlement and actuarially determined benefits costs and liabilities. As better information becomes available (or actual amounts are known), the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

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

Investments
The balance of investments at December 31, 2007 consists of $30,000 in investments accounted for under the equity method, $500,000 of investments accounted under the cost method and $655,000 related to participation in economic development loan pools accounted for under the cost method. The balance of investments at December 31, 2006 consists of $29,000 in investments accounted for under the equity method, $500,000 of investments accounted for under the cost method and $569,000 related to participation in economic development loan pools accounted for under the cost method. (See further discussion under note 9.)

Inventories
The Electric operation inventories are reported at average cost. Inventories consist of plant materials, fuel, and operating supplies.

New Accounting Standards

FIN No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109,* was issued by the FASB in June 2006. FIN No. 48 clarifies the accounting for uncertain tax positions in accordance with SFAS No. 109, *Accounting for Income Taxes*. The Company adopted FIN No. 48 on January 1, 2007 and has recognized, in its comparative 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 December 31, 2007. The term "more-likely-than-not" means a likelihood of more than 50%. FIN No. 48 also provides guidance on new disclosure requirements, reporting and accrual of interest and penalties, accounting in interim periods and transition. Only tax positions that meet the "more-likely-than-not" threshold on the reporting date may be recognized. See note 11 for additional discussion.

SFAS No. 157, *Fair Value Measurements,* was issued by the FASB in September 2006. SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 will be effective for fiscal years beginning after November 15, 2007. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements where fair value is the relevant measurement attribute. Accordingly, this statement does not require any new fair value measurements. Other than additional footnote disclosures related to the use of fair value measurements in the areas of derivatives, goodwill and asset impairment evaluations and financial instruments, the Company does not expect the adoption of SFAS No. 157 to have a significant impact on its comparative balance sheet, income statement or statement of cash flows.

SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans,* was issued by the FASB in September 2006 and became effective for the Company in 2006. The information included in this footnote pertains to both Otter Tail Power Company and Otter Tail Corporation. Information for Otter Tail Power Company has not been quantified and, therefore, is not available. SFAS No. 158 requires employers to recognize, on a prospective basis, the funded status of their defined benefit pension and other postretirement plans on their comparative balance sheet and to recognize, as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits and transition assets or obligations that have not been recognized as components of net periodic benefit cost. SFAS No. 158 also requires additional disclosures in the notes to financial statements. SFAS No. 158 did not change the amount of net periodic benefit expense recognized in an entity's income statement. The Company determined the balance of unrecognized net actuarial losses, prior service costs and the SFAS No. 106 transition obligation related to regulated utility activities would be subject to recovery through rates as those balances are amortized to expense and the related benefits are earned. Therefore, the Company charged those unrecognized amounts to regulatory asset accounts under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, rather than to Accumulated Other Comprehensive Loss in equity as prescribed by SFAS No. 158. Application of this standard had the following effects on the Company's December 31, 2006 comparative balance sheet:

(in thousands)	2006
Decrease in Executive Survivor and Supplemental Retirement Plan Intangible Asset	$ (767)
Increase in Regulatory Assets (for the unrecognized portions of net actuarial losses, prior service costs and transition obligations that are subject to recovery through electric rates)	36,736
Increase in Pension Benefit and Other Postretirement Liability	(34,714)
Increase in Deferred Tax Liability	(502)
Decrease in Accumulated Other Comprehensive Loss (for the unrecognized portions of net actuarial losses, prior service costs and transition obligations that are not subject to recovery through electric rates) (increase to equity)	(753)

The adoption of this standard did not affect compliance with debt covenants maintained in the Company's financing agreements.

SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement No. 115,* was issued by the FASB in February 2007. SFAS No. 159 provides companies with an option to measure, at specified election dates, many financial instruments and certain other items at fair value that are not currently measured at fair value. A company that adopts SFAS No. 159 will report unrealized gains and losses in earnings at each subsequent reporting date on items for which the fair value option has been elected. This statement also establishes presentation and disclosure requirements to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. As of December 31, 2007 the Company had not opted, nor does it currently plan to opt, to apply fair value accounting to any financial instruments or other items that it is not currently required to account for at fair value.

SFAS No. 141 (revised 2007), Businesses Combinations (SFAS No. 141(R)), was issued by the FASB in December 2007. SFAS No. 141(R) replaces SFAS No. 141, *Business Combinations,* and will apply prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008—January 1, 2009 for the Company. SFAS No. 141(R) applies to all transactions or other events in which an entity (the acquirer) obtains control of one or more businesses (the acquiree). In addition to replacing the term "purchase method of accounting" with "acquisition method of accounting," SFAS No. 141(R) requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions. This guidance will replace SFAS No. 141's cost-allocation process, which requires the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. SFAS No. 141's guidance results in not recognizing some assets and liabilities at the acquisition date, and it also results in measuring some assets and liabilities at amounts other than their fair values at the acquisition date. For example, SFAS No. 141 requires the acquirer to include the costs incurred to effect an acquisition (acquisition-related costs) in the cost of the acquisition that is allocated to the assets acquired and the liabilities assumed. SFAS No. 141(R) requires those costs to be expensed as incurred. In addition, under SFAS No. 141, restructuring costs that the acquirer expects but is not obligated to incur are recognized as if they were a liability assumed at the acquisition date. SFAS No. 141(R) requires the acquirer to recognize those costs separately from the business combination.

2. Rate and Regulatory Matters

Minnesota

General Rate Case--The electric utility filed a general rate case in Minnesota on October 1, 2007 requesting an interim rate increase of 5.41% effective November 30, 2007 and a final total rate increase of approximately 11%. However, the electric utility is proposing to share asset-based wholesale margins through the FCA, so the final overall customer impact would be an increase of approximately 6.7%. The electric utility's interim rate request was approved and will remain in effect for all Minnesota customers until the Minnesota Public Utilities Commission (MPUC) makes a final determination on the final request, which is expected by August 1, 2008. If the MPUC approves final rates that are lower than interim rates, the electric utility will refund Minnesota customers the difference with interest.

Capacity Expansion 2020 (CapX 2020) Mega Certificate of Need--On August 16, 2007 the eleven CapX 2020 utilities asked the MPUC to determine the need for three 345-kilovolt transmission lines. These lines would help ensure continued reliable electricity service in Minnesota and the surrounding region by upgrading and expanding the high-voltage transmission network and providing capacity for more wind energy resources to be developed in southern and western Minnesota, eastern North Dakota and South Dakota. The proposed lines would span more than 600 miles and represent one of the largest single transmission initiatives in the region in several years. The MPUC is expected to decide if the lines are needed by early 2009. The MPUC would determine routes for the new lines in separate proceedings. Portions of the lines 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 complete (expected in 2009 or 2010), construction will begin. The lines would be expected to be completed three or four years later. Great River Energy and Xcel Energy are leading the project, and Otter Tail Power Company and eight other utilities are involved in permitting, building and financing. The electric utility's 2008 – 2012 capital budgets include $67 million for CapX 2020 expenditures.

Renewable Energy Standards, Conservation and Renewable Resource Riders--In February 2007, the Minnesota legislature passed a renewable energy standard requiring the electric utility 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. Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards.

Under the Next Generation Energy Act passed by the Minnesota legislature in May 2007, an automatic adjustment mechanism was established to allow Minnesota electric utilities to recover charges incurred to satisfy the requirements of the renewable energy standards. The MPUC is now authorized to approve a rate schedule rider to recover the costs of qualifying renewable energy projects to 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 in an integrated resource plan or certificate of need proceeding before the MPUC. Renewable resource costs eligible for recovery may include return or investment, depreciation, operation and maintenance costs, taxes, renewable energy delivery costs and other related expenses. The electric utility has requested approval of a renewable resource rider that would allow recovery of eligible and prudently incurred costs for its qualifying renewable energy project investments. The proposed rider would cover the Minnesota jurisdictional portion of such eligible costs. The electric utility expects to receive MPUC approval of its proposed rider in 2008.

In addition, the Minnesota Public Utilities Act provides a similar mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new electric transmission facilities. The MPUC may approve a tariff to recover the Minnesota jurisdictional costs of new transmission facilities that have been previously approved by the MPUC in a certificate of need proceeding or certified by the MPUC as a Minnesota priority transmission project. Such transmission cost recovery riders would allow a return on investments at the level approved in the utility's last general rate case. The electric utility is also preparing to file a proposed rider to recover its share of costs of transmission infrastructure upgrades projects. The electric utility currently expects to file its transmission cost recovery tariff and receive MPUC approval during 2008.

Recovery of MISO Costs--In December 2005, the MPUC issued an order denying the electric utility's request to allow recovery of certain MISO-related costs through the FCA in Minnesota retail rates and requiring a refund of amounts previously collected pursuant to an interim order issued in April 2005. The electric utility recorded a $1.9 million reduction in revenue and a refund payable in December 2005 to reflect the refund obligation. On February 9, 2006 the MPUC decided to reconsider its December 2005 order. The MPUC's final order was issued on February 24, 2006 requiring jurisdictional investor-owned utilities in the state to participate with the Minnesota Department of Commerce (MNDOC) and other parties in a proceeding that would evaluate suitability of recovery of certain MISO Day 2 energy market costs through the FCA. The February 24, 2006 order eliminated the refund provision from the December 2005 order and allowed that any MISO-related costs not recovered through the FCA may be deferred for a period of 36 months, with possible recovery through base rates in the utility's next general rate case. As a result, the electric utility recognized $1.9 million in revenue and reversed the refund payable in February 2006. The Minnesota utilities and other parties submitted a final report to the MPUC in July 2006.

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. That 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. According to the order, a utility may, in its next rate case, seek to recover schedule 16 and 17 costs at an appropriate level of base rate recovery, provided it shows those costs were prudently incurred, reasonable, resulted in benefits justifying recovery and not already recovered through other rates. Also, a utility may seek to recover schedule 16 and 17 costs and associated amortizations through interim rates pending the resolution of a general rate case, subject to final MPUC approval. Pursuant to this December 20, 2006 order, the electric utility 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. As of December 31, 2007 the electric utility had refunded $407,000 of the $446,000 and deferred $855,000 in MISO schedule 16 and 17 costs. The electric utility has also requested recovery of the deferred costs and recovery of the ongoing costs in its pending general rate case. The Residential and Small Business Utilities Division of the Office of the Attorney General (RUD-OAG) has appealed the December 20, 2006 order to the Minnesota Court of Appeals.

Minnesota Annual Automatic Adjustment Report on Energy Costs (AAA Report)--The MNDOC and the electric utility 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 the sale of Financial Transmission Rights (FTRs) not needed for retail load. For the period July 1, 2005 through June 30, 2007 the electric utility 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. The electric utility 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. The electric utility also agreed to modifications to the MISO Day 2 cost allocations that were resolved in the MPUC's December 20, 2006 order. The electric utility agreed to make some of those modifications retroactive back to January 1, 2007. The MPUC accepted the electric utility's refund offer and modifications and closed this docket on February 6, 2008. In December 2007, the electric utility 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.

Claims of Improper Regulatory Filings--In September 2004, the Company provided a letter to the MPUC summarizing issues and conclusions of an internal investigation completed by the Company related to claims of allegedly improper regulatory filings brought to the attention of the Company by certain individuals. On November 30, 2004 the electric utility filed a report with the MPUC responding to these claims. In 2005, the Energy Division of the MNDOC, the RUD-OAG and the claimants filed comments in response to the report, to which the electric utility filed reply comments. A hearing before the MPUC was held on February 28, 2006. As a result of the hearing, the electric utility agreed that within 90 days it would file a revised Regulatory Compliance Plan, an updated Corporate Cost Allocation Manual and documentation of the definitions of its chart of accounts. The electric utility filed these documents with the MPUC in the second quarter of 2006. The electric utility received comments on its filings from the MNDOC and the claimants and filed reply comments in August 2006.

The MNDOC recommended accepting the revised Regulatory Compliance Plan and the chart of accounts definition. The electric utility filed supplemental comments related to its Corporate Allocation Manual in November 2006. The electric utility also agreed to file a general rate case in Minnesota on or before October 1, 2007. At a MPUC hearing on January 25, 2007 all remaining open issues were resolved. The MPUC accepted the electric utility's compliance filing with minor changes, agreed to allow the electric utility to calculate corporate cost allocations as proposed, determined not to conduct any further review at this time and required the electric utility to include all of the Company's short-term debt in its calculations of allowance for funds used during construction. The electric utility agreed to provide the MPUC the results of the current FERC operational audit when available, compare the corporate allocation method to a commonly accepted methodology in the next rate case, and provide the results of the Company's investigation relating to a 2007 hotline complaint. The Company recorded a noncash charge to Other Income and Deductions of $3.3 million in 2006 related to the disallowance of a portion of capitalized costs of funds used during construction from the electric utility's rate base. On December 12, 2007 the MPUC issued its order closing the investigation subject to the Company's continuing responsibility to file the report on its FERC operational audit as soon as it becomes available and subject to any further development of the record required in the electric utility's pending general rate case.

North Dakota
In February 2005, the electric utility filed a petition with the North Dakota Public Service Commission (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 the electric utility and an intervener representing several large industrial customers in North Dakota. When the MISO Day 2 energy market began in April 2005, the characterization of some of the electric utility's energy costs changed, though the essential nature of those costs did not. Fuel and purchased energy costs incurred to serve retail customers are recoverable through the FCA in North Dakota. Under the approved settlement agreement, the electric utility will refund to North Dakota customers the schedule 16 and 17 costs collected through the FCA since April 2005. The electric utility can defer recognition of these costs and request recovery of them in its next general rate case. Purchase Power – Electric System Use expense was reduced and an offsetting regulatory asset was established for the amount of the refund. The refund amount of $493,000 was credited to North Dakota customers through the FCA beginning in October 2007. Also as part of the settlement, the electric utility agreed to file a general rate case in North Dakota between November 1 and December 31, 2008. As of December 31, 2007 the electric utility had deferred $576,000 in MISO schedule 16 and 17 costs in North Dakota pending the allowed recovery of those costs in its next rate case.

Federal
Revenue Sufficiency Guarantee (RSG) Charges--On April 25, 2006 the FERC issued an order requiring MISO to refund to customers, with interest, amounts related to real-time RSG charges that were not allocated to day-ahead virtual supply offers in accordance with MISO's Transmission and Energy Markets Tariff (TEMT) going back to the commencement of MISO Day 2 markets in April 2005. On May 17, 2006 the FERC issued a Notice of Extension of Time, permitting MISO to delay compliance with the directives contained in its April 2006 order, including the requirement to refund to customers the amounts due, with interest, from April 1, 2005 and the requirement to submit a compliance filing. The Notice stated that the order on rehearing would provide the appropriate guidance regarding the timing of compliance filing. On October 26, 2006 the FERC issued an order on rehearing of the April 25, 2006 order, stating it would not require refunds related to real-time RSG charges that had not been allocated to day-ahead virtual supply offers in accordance with MISO's TEMT going back to the commencement of the MISO Day 2 market in April 2005. However, the FERC ordered prospective allocation of RSG charges to virtual transactions consistent with the TEMT to prevent future inequity and directed MISO to propose a charge that assesses RSG costs to virtual supply offers based on the RSG costs that virtual supply offers cause within 60 days of the October 26, 2006 order. On December 27, 2006 the FERC issued an order granting rehearing of the October 26, 2006 order.

On March 15, 2007 the FERC issued an order denying requests for rehearing of the RSG rehearing order dated October 27, 2006. In the March 15, 2007 order on rehearing, the FERC stated that its findings in the April 25, 2006 RSG order that virtual offers should share in the allocation of RSG costs, per the terms of the currently effective tariff, served as notice to market participants that virtual offers, for those market participants withdrawing energy, were liable for RSG charges. FERC clarified that the RSG rehearing order's waiver of refunds applies to the period before that order, from market start-up in April 2005 until April 24, 2006. After that date, virtual supply offers are liable for RSG costs and therefore, to the extent virtual supply offers were not assessed RSG costs, refunds are due for the period starting April 25, 2006.

On November 5, 2007 the FERC issued two orders related to the RSG proceeding. In the first order, the FERC accepted the MISO's April 17, 2007 RSG compliance filing to comply with the FERC's March 15, 2007 RSG order. The compliance reinserted language requiring the actual withdrawal of energy by market participants, restored the MISO's original TEMT language allocating RSG costs to virtual transactions, revised the effective date for allocation to imports, provided an explanation of its efforts to reflect partial-hour revenue determinations in its software development, and revised several definitions. The second related RSG order issued by FERC on

November 5, 2007 was its order on rehearing on its April 25, 2006 order in which it rejected the MISO's proposal to remove references to virtual supply from the TEMT provisions related to calculating RSG charges (FERC Docket Nos. ER04-691-084 and ER04-691-086). In this order, the FERC denied the requests for rehearing of the RSG second rehearing order (the electric utility was one of the parties that sought rehearing) and FERC denied all requests for rehearing of the RSG compliance order.

In the RSG compliance order, the FERC rejected the MISO's proposal to allocate costs based on net virtual offers, i.e., virtual offers minus virtual bids, and clarified that the currently effective tariff, which allocates RSG costs to virtual supply offers, remains in effect. In the RSG second rehearing order, the FERC clarified that for those market participants withdrawing energy, to the extent virtual supply offers were not assessed RSG costs, refunds were due for the period starting April 25, 2006.

The electric utility recorded a $1.7 million ($1.0 million net-of-tax) charge to earnings in the first quarter of 2007 based on an internal estimate of the net impact of MISO reallocating RSG charges in response to the FERC order on rehearing. In May 2007, MISO informed affected market participants of the impact of reallocating charges based on its interpretation of the FERC order on rehearing. Based on MISO's interpretation of the order on rehearing, the electric utility estimated the reallocation of charges would not have a significant impact on earnings previously recognized by the electric utility. Accordingly, the electric utility revised its first quarter estimated charge of $1.7 million ($1.0 million net-of-tax) to zero in the second quarter of 2007. The electric utility is awaiting FERC's response to MISO's December 5, 2007 RSG compliance filing and cannot determine what financial impact, if any, the filing will have on the Company's comparative results of operations. However, MISO has stated there will be no additional resettlements related to this matter.

Transmission Practices Audit--The Division of Operation Audits of the FERC Office of Market Oversight and Investigations (OMOI) commenced an audit of the electric utility's transmission practices in 2005. The purpose of the audit is to determine whether and how the electric utility's transmission practices are in compliance with the FERC's applicable rules and regulations and tariff requirements and whether and how the implementation of the electric utility's waivers from the requirements of Order No. 889 and Order No. 2004 restricts access to transmission information that would benefit the electric utility's off-system sales. The Division of Operation Audits of the OMOI has not issued an audit report. The Company cannot predict if the results of the audit will have any impact on the Company's comparative financial statements.

Big Stone II Project

On June 30, 2005 the electric utility 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. The three primary agreements are the Participation Agreement, the Operation and Maintenance Agreement and the Joint Facilities Agreement. Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., Southern Minnesota Municipal Power Agency and Western Minnesota Municipal Power Agency are parties to all three agreements. In September 2007, Great River Energy and Southern Minnesota Municipal Power Agency withdrew from the project. The five remaining project participants decided to downsize the proposed plant's nominal generating capacity from 630 megawatts to between 500 and 580 megawatts. New procedural schedules have been established in the various project-related proceedings, which will take into consideration the optimal plant configuration decided on by the remaining participants. NorthWestern Corporation, one of the co-owners of the existing Big Stone Plant, is an additional party to the Joint Facilities Agreement.

The electric utility and the coalition of six other electric providers filed an application for a Certificate of Need for the Minnesota portion of the Big Stone II transmission line project on October 3, 2005 and filed an application for a Route Permit for the Minnesota portion of the Big Stone II transmission line project with the MPUC on December 9, 2005. Evidentiary hearings were conducted in December 2006 and all parties submitted legal briefs. The Administrative Law Judges (ALJs) on August 15, 2007 recommended approval of the Certificate of Need subject to potential conditions. The electric utility and project participants addressed the ALJs' recommended potential conditions in an August 31, 2007 proposed settlement agreement with the MNDOC that was entered into the record of the Certificate of Need/Route Permit dockets. The MPUC had not acted on the applications or the proposed settlement agreement when Great River Energy and Southern Minnesota Municipal Power Agency withdrew from the project. On October 19, 2007 the MPUC requested that the ALJs recommence proceedings in the matter and that the remaining project participants file testimony describing and supporting a revised Big Stone II project. The remaining five participants filed testimony on November 13, 2007. On December 3, 2007 the ALJs issued an order refining the scope of the additional proceedings. Evidentiary hearings were held on January 23-25, 2008. The electric utility anticipates the ALJs will issue their report and recommendation in March 2008 and the MPUC will decide the matters in April 2008. The electric utility's integrated resource plan (IRP) includes generation from Big Stone II beginning in 2013 to accommodate load growth and to replace expiring purchased power contracts and older coal-fired base-load generation units scheduled for retirement. In addition to approval of the Certificate of Need/Route Permit applications for the transmission line project, approval of this IRP is pending with the MPUC.

A filing in North Dakota for an advanced determination of prudence of Big Stone II was made by the electric utility in November 2006. Evidentiary hearings were held in June 2007. The NDPSC decision was delayed because of the change in ownership of the project. The administrative law judge in the matter scheduled supplemental hearings in April 2008.

The electric utility and the coalition of six other electric providers filed an Energy Conversion Facility Siting Permit Application for Big Stone II with the South Dakota Public Utilities Commission (SDPUC) on July 21, 2005. The permit was granted by the SDPUC on July 14, 2006 but was appealed by a group of interveners on the basis that carbon dioxide concerns had not been adequately addressed. In February 2007, a South Dakota circuit court judge issued an opinion affirming the decision of the SDPUC to grant the siting permit for Big Stone II. The permit was appealed to the South Dakota Supreme Court. On January 16, 2008 the South Dakota Supreme Court unanimously affirmed the SDPUC's decision to grant Big Stone II project participants a site permit. A permit application for the South Dakota portion of the transmission line for Big Stone II was filed with the SDPUC on January 16, 2006 and was approved by the SDPUC on January 2, 2007.

As of December 31, 2007 the electric utility has capitalized $8.2 million in costs related to the planned construction of Big Stone II. Should approvals of permits not be received on a timely basis, the project could be at risk. If the project is abandoned for permitting or other reasons, these capitalized costs and others incurred in future periods may be subject to expense and may not be recoverable.

3. Regulatory Assets and Liabilities

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

(in thousands)	December 31, 2007	December 31, 2006
Regulatory Assets:		
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pension and Other Postretirement Benefits	$ 26,933	$ 36,736
Accrued Cost-of-Energy Revenue	19,452	10,735
Deferred Income Taxes	8,733	11,712
Reacquisition Premiums	3,745	2,694
MISO Schedule 16 and 17 Deferred Administrative Costs - MN	855	541
Deferred Marked-to-Market Losses	771	--
MISO Schedule 16 and 17 Deferred Administrative Costs - ND	576	--
Deferred Conservation Program Costs	518	1,036
Accumulated ARO Accretion/Depreciation Adjustment	345	249
Plant Acquisition Costs	107	151
Total Regulatory Assets	$ 62,035	$ 63,854
Regulatory Liabilities:		
Accumulated Reserve for Estimated Removal Costs	$ 12,317	$ 13,093
Deferred Income Taxes	4,502	5,228
Deferred Marked-to-Market Gains	271	--
Gain on Sale of Division Office Building	145	151
Total Regulatory Liabilities	$ 17,235	$ 18,472
Net Regulatory Asset Position	$ 44,800	$ 45,382

The regulatory asset related to the unrecognized transition obligation on postretirement medical benefits and prior service costs and actuarial losses on pension and other postretirement benefits represents benefit costs that will be subject to recovery through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs were required to be recognized as components of Accumulated Other Comprehensive Loss in equity under SFAS No. 158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans,* adopted in December 2006, but were determined to be eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates. Accrued Cost-of-Energy Revenue included in Accrued Utility and Cost-of-Energy Revenues will be recovered over the next nine months. The regulatory assets and liabilities related to Deferred Income Taxes result from changes in statutory tax rates accounted for in accordance with SFAS No. 109, *Accounting for Income Taxes.* Reacquisition Premiums included in Unamortized Debt Expense are being recovered from electric utility customers over the remaining original lives of the reacquired debt issues, the longest of which is 24.7 years. MISO Schedule 16 and 17 Deferred Administrative Costs – MN were excluded from recovery through the FCA in Minnesota in a December 2006 order issued by the MPUC. The MPUC ordered the electric utility to refund MISO schedule 16 and 17 charges that had been recovered through the FCA since the inception of MISO Day 2 markets in April 2005, but allowed for deferral and possible recovery of those costs through rates established in the electric utility's Minnesota general rate case filed on October 1, 2007. All deferred marked-to-market losses and gains are related to forward purchases of energy scheduled for delivery in January and February of 2008. MISO Schedule 16 and 17 Deferred Administrative Costs - ND were excluded from recovery through the FCA in North Dakota in an August 2007 order issued by the NDPSC. The NDPSC ordered the electric utility to refund MISO schedule 16 and 17 charges that had been recovered through the FCA since the inception of MISO Day 2 markets in April 2005, but allowed for deferral and possible recovery of those costs through rates established in the electric utility's next general rate case in North Dakota scheduled to be filed in November or December of 2008. Deferred

Conservation Program Costs represent mandated conservation expenditures recoverable through retail electric rates over the next 1.5 years. Plant Acquisition Costs will be amortized over the next 2.4 years. The Accumulated Reserve for Estimated Removal Costs is reduced for actual removal costs incurred. The remaining regulatory assets and liabilities are being recovered from, or will be paid to, electric customers over the next 30 years.

If for any reason, the Company's regulated businesses cease to meet the criteria for application of SFAS No. 71 for all or part of their operations, the regulatory assets and liabilities that no longer meet such criteria would be removed from the comparative balance sheet and included in the comparative statement of income as an extraordinary expense or income item in the period in which the application of SFAS No. 71 ceases.

4. Forward Energy Contracts Classified as Derivatives

Electricity Contracts
All of the electric utility'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. The electric utility'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. The electric utility'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. The electric utility 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.

5. Capital Stock

The Company is a division of Otter Tail Corporation.

6. Commitments and Contingencies

At December 31, 2007 the electric utility had commitments under contracts in connection with construction programs aggregating approximately $35,835,000. For capacity and energy requirements, the electric utility has agreements extending through 2032 at annual costs of approximately $23,111,000 in 2008, $22,929,000 in 2009, $11,377,000 in 2010, $5,565,000 in 2011 and $5,565,000 in 2012, and $93,286,000 for the years beyond 2012.

The electric utility has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. These contracts expire in 2010 and 2016. In total, the electric utility is committed to the minimum purchase of approximately $183,209,000 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.

The amounts of future operating lease payments are as follows in thousands:

2008	$ 2,560
2009	2,560
2010	2,203
2011	1,446
2012	951
Later years	3,206
Total	$12,926

The electric future operating lease payments are primarily related to coal rail-car leases. Rent expense was $2,461,000 for 2007 and $1,828,000 for 2006.

The Company is a party to litigation arising in the normal course of business. The Company regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. The Company believes the effect on its comparative results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of December 31, 2007 will not be material.

7. Short-Term and Long-Term Borrowings

Short-Term Debt
As of December 31, 2007 the Company had no short-term debt outstanding. As of December 31, 2006 the Company had $3.9 million in short-term debt outstanding at an interest rate of 5.7%. The average interest rate paid on short-term debt was 5.9% in 2007 and 5.7% in 2006.

Otter Tail Corporation, dba Otter Tail Power Company and U.S. Bank National Association have a Credit Agreement (the Electric Utility Credit Agreement) providing for a separate $75 million line of credit. This line of credit is an unsecured revolving credit facility that the electric utility can draw on to support the working capital needs and other capital requirements of its electric operations. Borrowings under this line of credit bear interest at LIBOR plus 0.4%, subject to adjustment based on the ratings of the Company's senior unsecured debt. The Electric Utility Credit Agreement contains a number of restrictions on the business of the electric utility, 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 Electric Utility Credit is subject to renewal on September 1, 2008. As of December 31, 2007 no money was borrowed under the Electric Utility Credit Agreement.

Long-Term Debt
At closings completed in August 2007 and October 2007, the Company issued $93 million aggregate principal amount of its senior unsecured notes, in a private placement transaction, to the purchasers named in a note purchase agreement (the 2007 Note Purchase Agreement) dated August 20, 2007. These notes were issued in four series: $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017 (the Series A Notes); $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022 (the Series B Notes); $17 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027 (the Series C Notes); and $13 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (the Series D Notes). On August 20, 2007, $12 million aggregate principal amount of the Series C Notes and $13 million aggregate principal amount of the Series D Notes were issued and sold pursuant to the 2007 Note Purchase Agreement. The net proceeds from this initial closing were used to repay borrowings under the Company's $150 million line of credit that was terminated on October 2, 2007. The remaining $5 million aggregate principal amount of the Series C Notes as well as the Series A Notes and the Series B Notes, were issued and sold by the Company at a second closing on October 1, 2007. The net proceeds from the second closing were used to retire $40 million aggregate principal amount of the Company's 5.625% Series of Insured Senior Notes due October 1, 2017 and $20 million aggregate principal amount of the Company's 6.80% Series of Senior Notes due October 1, 2032 on October 15, 2007, to pay down lines of credit and to fund capital expenditures.

In February 2007 the Company entered into a note purchase agreement (the Cascade Note Purchase Agreement) with Cascade Investment L.L.C. (Cascade) pursuant to which the Company agreed to issue to Cascade, in a private placement transaction, $34.6 million aggregate principal amount of the Company's senior notes due November 30, 2017 (the Cascade Note). On December 14, 2007 the Company issued the Cascade Note. The Cascade Note bears interest at a rate of 5.778% per annum. The terms of the Cascade Note Purchase Agreement are substantially similar to the terms of the note purchase agreement entered into in connection with the issuance of the Company's $36 million 6.63% senior notes due December 1, 2011 (the 2001 Note Purchase Agreement). The proceeds of this financing were used to redeem the Company's $34.6 million 6.375% Senior Debentures due December 1, 2007.

Each of the Cascade Note Purchase Agreement, the 2007 Note Purchase Agreement, and the 2001 Note Purchase Agreement states the Company may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. Each of the Cascade Note Purchase Agreement and the 2001 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require the Company to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the respective note purchase agreements. The 2007 Note Purchase Agreement states the Company 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 the Company.

The 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and the Cascade Note Purchase Agreement contain a number of restrictions on the businesses of the Company and its subsidiaries. In each case these include restrictions on the ability of the Company and certain of its subsidiaries to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties.

The Company's Grant County and Mercer County Pollution Control Refunding Revenue Bonds require that the Company grant to Ambac Assurance Corporation, under a financial guaranty insurance policy relating to the bonds, a security interest in the assets of the electric utility if the rating on the Company's senior unsecured debt is downgraded to Baa2 or below (Moody's) or BBB or below (Standard & Poor's).

The aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2007 for each of the next five years are $0 for 2008, $0 for 2009, $0 for 2010, $36,000,000 for 2011 and $10,400,000 for 2012.

Financial Covenants

The Electric Utility Credit Agreement, the 2001 Note Purchase Agreement, the Cascade Note Purchase Agreement, and the 2007 Note Purchase Agreement contain covenants by the Company not to permit its debt-to-total capitalization ratio to exceed 60% or permit its interest and dividend coverage ratio (or in the case of the Cascade Note Purchase Agreement, the Company's interest coverage ratio) to be less than 1.5 to 1. The note purchase agreements further restrict the Company from allowing its priority debt to exceed 20% of total capitalization. The Company was in compliance with all of the covenants under its financing agreements as of December 31, 2007.

8. Pension Plan and Other Postretirement Benefits

The information included in this footnote pertains to both Otter Tail Power Company and Otter Tail Corporation. Information for Otter Tail Power Company has not been quantified and, therefore, is not available.

The following footnote reflects the adoption of SFAS No. 158, *Accounting for Defined Benefit Pension and Other Postretirement Plans,* in December 2006. The Company determined that the balance of unrecognized net actuarial losses, prior service costs and the SFAS No. 106 transition obligation related to regulated utility activities would be subject to recovery through rates as those balances are amortized to expense and the related benefits are earned. Therefore, the Company charged those unrecognized amounts to regulatory asset accounts under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, rather than to Accumulated Other Comprehensive Losses in equity as prescribed by SFAS No. 158.

Pension Plan

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

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

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

Components of net periodic pension benefit cost:

(in thousands)	2007	2006
Service Cost--Benefit Earned During the Period	$ 4,837	$ 5,057
Interest Cost on Projected Benefit Obligation	10,790	10,435
Expected Return on Assets	(12,948)	(12,288)
Amortization of Prior-Service Cost	742	742
Amortization of Net Actuarial Loss	1,091	1,844
Net Periodic Pension Cost	$ 4,512	$ 5,790

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

(in thousands)	2007	2006
Regulatory Assets:		
Unrecognized Prior Service Cost	$ (4,018)	$ (4,748)
Unrecognized Actuarial Loss	(17,115)	(21,771)
Total Regulatory Assets	(21,133)	(26,519)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	(120)	(132)
Unrecognized Actuarial Loss	(511)	(606)
Total Accumulated Other Comprehensive Loss	(631)	(738)
Prepaid Pension Cost	7,493	8,005
Net Amount Recognized – Noncurrent Liability	$ (14,271)	$ (19,252)

Funded status as of December 31:

(in thousands)	2007	2006
Accumulated Benefit Obligation	$(154,373)	$(153,816)
Projected Benefit Obligation	$(185,206)	$(186,760)
Fair Value of Plan Assets	170,935	167,508
Funded Status	$ (14,271)	$ (19,252)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's benefit obligations and prepaid pension cost over the two-year period ended December 31, 2007:

(in thousands)	2007	2006
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ 167,508	$ 146,982
Actual Return on Plan Assets	8,013	24,856
Discretionary Company Contributions	4,000	4,000
Benefit Payments	(8,586)	(8,330)
Fair Value of Plan Assets at December 31	$ 170,935	$ 167,508
Estimated Asset Return	4.85%	17.24%
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 186,760	$ 181,587
Service Cost	4,837	5,057
Interest Cost	10,790	10,435
Benefit Payments	(8,586)	(8,330)
Actuarial Gain	(8,595)	(1,989)
Projected Benefit Obligation at December 31	$ 185,206	$ 186,760
Reconciliation of Prepaid Pension Cost:		
Prepaid Pension Cost at January 1	$ 8,005	$ 9,795
Net Periodic Pension Cost	(4,512)	(5,790)
Discretionary Company Contributions	4,000	4,000
Prepaid Pension Cost at December 31	$ 7,493	$ 8,005

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

	2007	2006
Discount Rate	6.25%	6.00%
Rate of Increase in Future Compensation Level	3.75%	3.75%

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

	2007	2006
Discount Rate	6.00%	5.75%
Long-Term Rate of Return on Plan Assets	8.50%	8.50%
Rate of Increase in Future Compensation Level	3.75%	3.75%

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

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

The Company bases actuarial determination of pension plan expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation calculation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related valuation calculation recognizes gain 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 2008 net periodic pension cost is 8.50%.

Measurement Dates:	2007	2006
Net Periodic Pension Cost	January 1, 2007	January 1, 2006
End of Year Benefit Obligations	January 1, 2007 projected to December 31, 2007	January 1, 2006 projected to December 31, 2006
Market Value of Assets	December 31, 2007	December 31, 2006

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 2008 are:

(in thousands)	2008
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 720
Amortization of Unrecognized Actuarial Loss	103
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	22
Amortization of Unrecognized Actuarial Loss	3
Total Estimated Amortization	$ 848

Cash flows--The Company is not required to make a contribution to the pension plan in 2008.

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

(in thousands)	2008	2009	2010	2011	2012	Years 2013-2017
	$8,917	$9,073	$9,234	$9,641	$10,103	$59,365

The Company's pension plan asset allocations at December 31, 2007 and 2006, by asset category are as follows:

Asset Allocation	2007	2006
Large Capitalization Equity Securities	47.1%	49.3%
Small Capitalization Equity Securities	10.7%	11.6%
International Equity Securities	10.4%	10.6%
Total Equity Securities	68.2%	71.5%
Cash and Fixed-Income Securities	31.8%	28.5%
	100.0%	100.0%

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

- The Plan is managed to operate in perpetuity.
- The Plan will meet the pension benefit obligation payments of the Company.
- The Plan's assets should be invested with the objective of meeting current and future payment requirements while minimizing annual contributions and their volatility.

- The asset strategy reflects the desire to meet current and future benefit payments while considering a prudent level of risk and diversification.

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

The asset allocation strategy contains guideline percentages, at market value, of the total Plan invested in various asset classes. The strategic target allocation 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 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.

The Company's Retirement Plans Administrative Committee monitors actual asset allocations and directs contributions and withdrawals toward maintaining the targeted allocation percentages listed in the table below.

Asset Allocation	Strategic Target	Tactical Range
Large capitalization equity securities	48%	40%-55%
Small capitalization equity securities	12%	9%-15%
International equity securities	10%	5%-15%
Total equity securities	70%	60%-80%
Fixed-income securities	30%	20%-40%

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

On December 19, 2006 the Board of Directors of the Company approved an amendment to the ESSRP effective January 1, 2006. The Amendment amends the ESSRP to provide that for each of the Company's Chief Executive Officer and Corporate Secretary, the "Normal Retirement Benefit" (as defined in the ESSRP) will be determined based on "Final Average Earnings" rather than "Final Annual Salary" (defined as the base Salary (as defined in the ESSRP) and annual bonus paid to the participant during the 12 months prior to termination or death). The ESSRP defines "Final Average Earnings" as the average of the participant's total cash payments (Salary (as defined in the ESSRP) and annual incentive bonus) paid during the highest consecutive 42 months in the 10 years prior to the date as of which the Final Average Earnings are determined.

Components of net periodic pension benefit cost:

(in thousands)	2007	2006
Service Cost--Benefit Earned During the Period	$ 626	$ 426
Interest Cost on Projected Benefit Obligation	1,451	1,303
Amortization of Prior-Service Cost	67	71
Amortization of Net Actuarial Loss	540	473
Net Periodic Pension Cost	$ 2,684	$ 2,273

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

(in thousands)	2007	2006
Regulatory Assets:		
Unrecognized Prior Service Cost	$ 435	$ 496
Unrecognized Actuarial Loss	4,841	5,796
Total Regulatory Assets	5,276	6,292
Projected Benefit Obligation Liability – Net Amount Recognized	(25,158)	(24,783)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	266	271
Unrecognized Actuarial Loss	2,954	3,162
Total Accumulated Other Comprehensive Loss	3,220	3,433
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$ (16,662)	$ (15,058)

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, 2007 and a statement of the funded status as of December 31 of both years:

(in thousands)	2007	2006
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ --	$ --
Actual Return on Plan Assets	--	--
Employer Contributions	1,079	1,124
Benefit Payments	(1,079)	(1,124)
Fair Value of Plan Assets at December 31	$ --	$ --
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 24,783	$ 23,271
Service Cost	626	426
Interest Cost	1,451	1,303
Benefit Payments	(1,079)	(1,124)
Plan Amendments	--	(53)
Actuarial (Gain) Loss	(623)	960
Projected Benefit Obligation at December 31	$ 25,158	$ 24,783
Reconciliation of Funded Status:		
Funded Status at December 31	$ (25,158)	$ (24,783)
Unrecognized Net Actuarial Loss	7,795	8,958
Unrecognized Prior Service Cost	701	767
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$ (16,662)	$ (15,058)

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

	2007	2006
Discount Rate	6.25%	6.00%
Rate of Increase in Future Compensation Level	4.70%	4.71%

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

	2007	2006
Discount Rate	6.00%	5.75%
Rate of Increase in Future Compensation Level	4.71%	4.69%

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 2008 are:

(in thousands)	2008
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 42
Amortization of Unrecognized Actuarial Loss	298
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	25
Amortization of Unrecognized Actuarial Loss	182
Total Estimated Amortization	$ 547

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)	2008	2009	2010	2011	2012	Years 2013-2017
	$1,109	$1,114	$1,113	$1,206	$1,258	$6,755

Other Postretirement Benefits

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

Components of net periodic postretirement benefit cost:

(in thousands)	2007	2006
Service Cost--Benefit Earned During the Period	$ 1,098	$ 1,319
Interest Cost on Projected Benefit Obligation	2,565	2,556
Amortization of Transition Obligation	748	748
Amortization of Prior-Service Cost	(206)	(305)
Amortization of Net Actuarial Loss	177	556
Expense Decrease Due to Medicare Part D Subsidy	(1,233)	(1,543)
Net Periodic Postretirement Benefit Cost	$ 3,149	$ 3,331

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

(in thousands)	2007	2006
Regulatory Asset:		
Unrecognized Transition Obligation	$ 3,658	$ 4,414
Unrecognized Prior Service Cost	1,781	1,588
Unrecognized Net Actuarial Gain	(4,915)	(2,077)
Net Regulatory Asset	524	3,925
Projected Benefit Obligation Liability – Net Amount Recognized	(30,488)	(32,254)
Accumulated Other Comprehensive Loss:		
Unrecognized Transition Obligation	83	75
Unrecognized Prior Service Cost	40	27
Unrecognized Net Actuarial Gain	(111)	(35)
Accumulated Other Comprehensive Loss	12	67
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$ (29,952)	$ (28,262)

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, 2007:

(in thousands)	2007	2006
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ --	$ --
Actual Return on Plan Assets	--	--
Company Contributions	1,459	2,051
Benefit Payments (Net of Medicare Part D Subsidy)	(3,127)	(3,625)
Participant Premium Payments	1,668	1,574
Fair Value of Plan Assets at December 31	$ --	$ --
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 32,254	$ 36,757
Service Cost (Net of Medicare Part D Subsidy)	890	1,110
Interest Cost (Net of Medicare Part D Subsidy)	1,776	1,779
Benefit Payments (Net of Medicare Part D Subsidy)	(3,127)	(3,625)
Participant Premium Payments	1,668	1,574
Actuarial Gain	(2,973)	(5,341)
Projected Benefit Obligation at December 31	$ 30,488	$ 32,254
Reconciliation of Accrued Postretirement Cost:		
Accrued Postretirement Cost at January 1	$ (28,262)	$ (26,982)
Expense	(3,149)	(3,331)
Net Company Contribution	1,459	2,051
Accrued Postretirement Cost at December 31	$ (29,952)	$ (28,262)

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

	2007	2006
Discount Rate	6.25%	6.00%

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

	2007	2006
Discount Rate	6.00%	5.75%

Assumed healthcare cost-trend rates as of December 31:

	2007	2006
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	8.00%	9.00%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	9.00%	10.00%
Rate at Which the Cost-Trend Rate is Assumed to Decline	5.00%	5.00%
Year the Rate Reaches the Ultimate Trend Rate	2012	2012

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 2007 would have the following effects:

(in thousands)	1 point increase	1 point decrease
Effect on the Postretirement Benefit Obligation	$ 2,804	$(2,423)
Effect on Total of Service and Interest Cost	$ 358	$ (293)
Effect on Expense	$ 418	$ (544)

Measurement dates:	2007	2006
Net Periodic Postretirement Benefit Cost	January 1, 2007	January 1, 2006
End of Year Benefit Obligations	January 1, 2007 projected to December 31, 2007	January 1, 2006 projected to December 31, 2006

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 2008 are:

(in thousands)	2008
Decrease in Regulatory Assets:	
Amortization of Transition Obligation	$ 732
Amortization of Unrecognized Prior Service Cost	205
Amortization of Unrecognized Actuarial Gain	(200)
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Transition Obligation	16
Amortization of Unrecognized Prior Service Cost	5
Amortization of Unrecognized Actuarial Gain	(4)
Total Estimated Amortization	$ 754

Cash flows--The Company expects to contribute $2.2 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2008. The Company expects to receive a Medicare Part D subsidy from the Federal government of approximately $386,000 in 2008. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

(in thousands)	2008	2009	2010	2011	2012	Years 2013-2017
	$2,213	$2,266	$2,310	$2,294	$2,403	$13,263

Leveraged Employee Stock Ownership Plan
The Company has a leveraged employee stock ownership plan for the benefit of all its electric utility employees. Contributions made by the Company were $733,000 for 2007 and $738,000 for 2006.

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:

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

Other Investments--The carrying amount approximates fair value. A portion of other investments is in financial instruments that have variable interest rates that reflect fair value.

Long-Term Debt--The fair value of the Company's long-term debt is estimated based on the current rates available to the Company for the issuance of debt. About $10.4 million of the Company's long-term debt, which is subject to variable interest rates, approximates fair value.

(in thousands)	December 31, 2007		December 31, 2006	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Short-Term Investments	$ 22,481	$ 22,481	$ 369	$ 369
Other Investments	1,185	1,185	1,098	1,098
Long-Term Debt	(199,890)	(206,028)	(166,975)	(173,245)

10. Property, Plant and Equipment

(in thousands)	December 31, 2007	December 31, 2006
Electric Plant		
Production	$ 439,541	$ 360,304
Transmission	191,949	189,683
Distribution	322,107	307,825
General	75,320	72,877
Electric Plant	1,028,917	930,689
Less Accumulated Depreciation and Amortization	446,475	433,657
Electric Plant Net of Accumulated Depreciation	582,442	497,032
Construction Work in Progress	33,772	18,502
Net Electric Plant	$ 616,214	$ 515,534

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

(years)	Service Life Range Low	High
Electric Fixed Assets:		
Production Plant	34	62
Transmission Plant	40	55
Distribution Plant	15	55
General Plant	5	65

11. Income Taxes

The information included in this footnote pertains to both Otter Tail Power Company and Otter Tail Corporation. Information for Otter Tail Power Company has not been quantified and, therefore, is not available.

The total income tax expense differs from the amount computed by applying the federal income tax rate (35 percent in 2007 and 2006) to net income before total income tax expense for the following reasons:

	2007	2006
	(in thousands)	
Tax computed at federal statutory rate	$ 10,879	$ 12,257
Increases (decreases) in tax from:		
State income taxes net of federal income tax benefit	987	1,094
Investment tax credit amortization	(1,137)	(1,146)
Depreciation differences--flow-through method reversal		
Timing differences reversing in excess of federal rates	929	1,271
Dividends received/paid deduction	(714)	(718)
Affordable housing tax credits	(285)	(839)
Section 199 deduction	(327)	(205)
Permanent and other differences	(267)	135
Total income tax expense	$ 10,065	$ 11,849
Overall effective federal and state income tax rate	32.3%	32.2%

	2007	2006
	(in thousands)	
Income tax expense includes the following:		
Charges (credits) related to operations:		
Current federal income taxes	$ 6,043	$ 11,786
Current state income taxes	(863)	1,830
Deferred federal income taxes	2,701	(484)
Deferred state income taxes	733	(8)
Investment tax credit amortization	(1,136)	(1,145)
Total	7,478	11,979
Charges (credits) related to other income and deductions:		
Current federal income taxes	2,146	2,529
Current state income taxes	131	668
Affordable housing tax credits	(285)	(839)
Deferred federal income taxes	(847)	(2,093)
Deferred state income taxes	1,442	(395)
Total income tax expense	$ 10,065	$ 11,849

The Company's deferred tax assets and liabilities were composed of the following on December 31, 2007 and 2006:

	2007	2006
	(in thousands)	
Deferred tax assets		
Amortization of tax credits	$ 4,505	$ 5,231
Vacation accrual	1,258	1,230
Operating reserves	27,103	24,819
Differences related to property	8,270	7,253
Transfer to regulatory liability/(asset)	(261)	(308)
Related to ND Wind Tax Credit	12,999	-

Other	678	688
Total deferred tax assets	54,552	38,913
Deferred tax liabilities		
Differences related to property	(109,710)	(103,635)
Excess tax over book pension	(2,953)	(3,153)
Transfer to regulatory asset	(8,471)	(11,404)
Related to ND Wind Tax Credit	(4,340)	-
Other	(377)	128
Total deferred tax liabilities	(125,851)	(118,064)
Deferred income taxes	$ (71,299)	$ (79,151)

On January 1, 2007 the Company adopted the provisions of FIN No. 48. The cumulative effect of adoption of FIN No. 48, which is reported as an adjustment to the beginning balance of retained earnings, was $118,000. As of the date of adoption,, the total amount of unrecognized tax benefits for uncertain tax positions was $1,874,000. The amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate was $575,000 as of January 1, 2007.

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

(in thousands)	Total
Balance at January 1, 2007	$ 1,874
Increases Related to Current Year Tax Positions	198
Expiration of the Statute of Limitations for the Assessment of Taxes	(1,566)
Balance at December 31, 2007	$ 506

The balance of unrecognized tax benefits as of December 31, 2007 would reduce our effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2007 is not expected to change significantly within the next 12 months. The Company and its subsidiaries file a comparative U.S. federal income tax return and various state and foreign income tax returns. As of December 31, 2007 the Company is no longer subject to U.S. federal income tax examinations by tax authorities for years before 2004. As of December 31, 2007 the Company's earliest open tax year in which an audit can be initiated by state taxing authorities in the Company's major operating jurisdictions is 2003 for Minnesota and 2004 for North Dakota. Amounts accrued for interest and penalties on tax uncertainties as of December 31, 2007 were not material.

12. Asset Retirement Obligations (AROs)

The Company's AROs are related to coal-fired generation plants and 27 wind turbines erected near Langdon, North Dakota and include site restoration, closure of ash pits, and removal of storage tanks, structures, generators and asbestos. The Company has legal obligations associated with the retirement of a variety of other long-lived tangible assets used in electric operations where the estimated settlement costs are individually and collectively immaterial. The Company has no assets legally restricted for the settlement of any of its AROs.

During 2007, the Company recorded new obligations related to the removal of 27 wind turbines erected near Langdon, North Dakota and restoration of the tower sites but did not make any revisions to previously recorded obligations.

During 2006, the Company did not record any new obligation or make any revisions to previously recorded obligations. The Company settled a legal obligation for removal of asbestos at unit one of its Hoot Lake generating plant.

Reconciliations of carrying amounts of the present value of the Company's legal AROs, capitalized asset retirement costs and related accumulated depreciation and a summary of settlement activity for the years ended December 31, 2007 and 2006 are presented in the following table:

(in thousands)	2007	2006
Asset Retirement Obligations		
Beginning Balance	$ 1,335	$ 1,524
New Obligations Recognized	1,024	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Accrued Accretion	88	85
Settlements	--	(274)
Ending Balance	$ 2,447	$ 1,335
Asset Retirement Costs Capitalized		
Beginning Balance	$ 285	$ 349
New Obligations Recognized	1,024	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Settlements	--	(64)
Ending Balance	$ 1,309	$ 285
Accumulated Depreciation - Asset Retirement Costs Capitalized		
Beginning Balance	$ 178	$ 234
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Accrued Depreciation	7	8
Settlements	--	(64)
Ending Balance	$ 185	$ 178
Settlements		
Original Capitalized Asset Retirement Cost - Retired	$ --	$ 64
Accumulated Depreciation	--	(64)
Asset Retirement Obligation	$ --	$ 274
Settlement Cost	--	(222)
Gain on Settlement – Deferred Under Regulatory Accounting	$ --	$ 52

13. Quantitative and Qualitative Disclosures About Market Risk

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, 2007 we had $10.4 million of long-term debt subject to variable interest rates. 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, 2007, annualized interest expense on variable rate long-term debt and pre-tax earnings would change by approximately $104,000.

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

The electric utility has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of December 31, 2007 the electric utility had recognized, on a pretax basis, $632,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity. 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 the electric utility's forward contracts for the purchases and sales of electricity are determined by survey of counterparties or brokers used by the electric utility'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. Prices are benchmarked to forward price curves and indices acquired from a third party price forecasting service. Of the forward energy sales contracts that are marked to market as of December 31, 2007, 97.6% are offset by forward energy purchase contracts in terms of volumes and delivery periods, with $56,000 in unrealized gains recognized on the open sales contracts.

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. Exposure to price risk on any open positions as of December 31, 2007 was not material.
The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity on our comparative balance sheet as of December 31, 2007 and the change in our comparative balance sheet position from December 31, 2006 to December 31, 2007:

(in thousands)	December 31, 2007
Current Asset – Marked-to-Market Gain	$ 5,210
Regulatory Asset – Deferred Marked-to-Market Loss	771
Total Assets	5,981
Current Liability – Marked-to-Market Loss	(5,078)
Regulatory Liability – Deferred Marked-to-Market Gain	(271)
Total Liabilities	(5,349)
Net Fair Value of Marked-to-Market Energy Contracts	$ 632

(in thousands)	Year ended December 31, 2007
Fair Value at Beginning of Year	$ 203
Amount Realized on Contracts Entered into in 2006 and Settled in 2007	(203)
Changes in Fair Value of Contracts Entered into in 2006	--
Net Fair Value of Contracts Entered into in 2006 at Year End 2007	--
Changes in Fair Value of Contracts Entered into in 2007	632
Net Fair Value at End of Year	$ 632

The $632,000 in recognized but unrealized net gains on the forward energy purchases and sales marked to market on December 31, 2007 is expected to be realized on physical settlement as scheduled over the following quarters in the amounts listed:

(in thousands)	1st Quarter 2008	4th Quarter 2008	Total
Net Gain	$ 118	$ 514	$ 632

We have credit risk associated with the nonperformance or nonpayment by counterparties to our forward energy purchases and sales agreements. We have established guidelines and limits to manage credit risk associated with wholesale power purchases and sales. Specific limits are determined by a counterparty's financial strength. Our credit risk with our largest counterparty on delivered and marked-to-market forward contracts as of December 31, 2007 was $0.5 million. As of December 31, 2007 we had a net credit risk exposure of $1.5 million from eight counterparties with investment grade credit ratings and one counterparty that has not been rated by an external credit rating agency but has been evaluated internally and assigned an internal credit rating equivalent to investment grade. We had no exposure at December 31, 2007 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 $1.5 million credit risk exposure includes net amounts due to the electric utility 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, 2007. Individual counterparty exposures are offset according to legally enforceable netting arrangements.