NOTES TO FINANCIAL STATEMENTS

(1) Nature of Operations

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas to approximately 665,000 customers in Montana, South Dakota and Nebraska. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have generated and distributed electricity and distributed natural gas in Montana since 2002.

The Financial Statements for the periods included herein have been prepared by NorthWestern Corporation (NorthWestern, we or us), pursuant to the rules and regulations of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that may affect the reported amounts of assets, liabilities, revenues and expenses during the reporting period. Actual results could differ from those estimates. Events occurring subsequent to December 31, 2010, have been evaluated as to their potential impact to the Financial Statements through the date of issuance.

Variable Interest Entities

Effective January 1, 2010, we adopted new accounting guidance which modified the consolidation model in previous guidance and expanded the disclosures related to variable interest entities (VIE). An entity is considered to be a VIE when its total equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support, or its equity investors, as a group, lack the characteristics of having a controlling financial interest. A reporting company is required to consolidate a VIE as its primary beneficiary, which means it has a controlling financial interest, when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance, and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. This revised guidance changes how a company determines when an entity that is insufficiently capitalized or is not controlled through voting (or similar) rights should be consolidated. The determination of whether a company is required to consolidate an entity is based on, among other things, an entity's purpose and design and a company's ability to direct the activities of the entity that most significantly impact the entity's economic performance.

Certain long-term purchase power and tolling contracts may be considered variable interests. We have various long-term purchase power contracts with other utilities and certain Qualifying Facility (QF) plants. We identified one QF contract that may constitute a VIE. We entered into a power purchase contract in 1984 with this 35 MW coal-fired QF to purchase substantially all of the facility's capacity and electrical output over a substantial portion of its estimated useful life. We absorb a portion of the facility's variability through annual changes to the price we pay per MWH (energy payment). After making exhaustive efforts, we have been unable to obtain the information from the facility necessary to determine whether the facility is a VIE or whether we are the primary beneficiary of the facility. The contract with the facility contains no provision which legally obligates the facility to release this information. We have accounted for this QF contract as an executory contract. Based on the current contract terms with this QF, our estimated gross contractual payments aggregate approximately $442.1 million through 2024. For further discussion of our gross QF liability, see Note 18. During the years ended December 31, 2010 and 2009, purchases from this QF were approximately $21.5 million and $20.1 million, respectively.

(2) Significant Accounting Policies

Financial Statement Presentation

The financial statements are presented on the basis of the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts. This report differs from GAAP due to FERC requiring the presentation of subsidiaries on the equity method of accounting, which differs from Statement of Financial Accounting Standards

No. 94 "Consolidation of All Majority-Owned Subsidiaries" (SFAS No. 94). SFAS No. 94 requires that all majority-owned subsidiaries be consolidated (see Note 3). The other significant differences consist of the following:

- Comparative statements of net income per share are not presented;
- Removal costs of transmission and distribution assets are reflected in the Balance Sheets as a component of accumulated depreciation of $222.1 million and $209.2 million as of December 31, 2010 and December 31, 2009, respectively, in accordance with regulatory treatment as compared to regulatory liabilities for GAAP purposes;
- Goodwill is reflected in the balance sheets as a utility plant adjustment of $355.1 million as of December 31, 2010 and December 31, 2009, respectively, in accordance with regulatory treatment, as compared to goodwill for GAAP purposes (see Note 6);
- The write-down of plant values associated with the 2002 acquisition of the Montana operations is reflected in the Balance Sheets as a component of accumulated depreciation of $147.6 million for December 31, 2010 and December 31, 2009, respectively, in accordance with regulatory treatment as compared to plant for GAAP purposes;
- The current portion of gas stored underground is reflected in the Balance Sheets as current and accrued assets, as compared to materials and supplies for GAAP purposes;
- Current and long-term debt is classified in the Balance Sheets as all long-term debt in accordance with regulatory treatment, while GAAP presentation reflects current and long-term debt on separate lines;
- Accumulated deferred tax assets and liabilities are classified in the Balance Sheets as gross deferred debits and credits, respectively, while GAAP presentation reflects either a net deferred tax asset or liability; and
- GAAP revenue differs from FERC revenue primarily due to the equity method of accounting as discussed above, netting of electric purchases and sales for resale in revenue for the GAAP presentation as compared to a gross presentation for FERC purposes, and the classification of regulatory amortizations in revenue for GAAP as compared to expense for FERC purposes. The following table reconciles GAAP revenues to FERC revenues by segment for the twelve months ended December 31, 2010.

	Total	Electric	Natural Gas	Other
	(in millions)			
GAAP Revenues	$ 1,110.7	$ 790.7	$ 318.7	$ 1.3
Revenue from equity investments	(2.1)	-	(2.1)	-
Grossing revenues / power purchases	32.4	32.4	-	-
Regulatory amortizations	(30.8)	(21.5)	(9.3)	-
Other	4.6	5.8	(0.7)	(0.5)
FERC Revenues	$ 1,114.8	$ 807.4	$ 306.6	$ 0.8

Use of Estimates

The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Estimates are used for such items as long-lived asset values and impairment charges, long-lived asset useful lives, tax provisions, asset retirement obligations, uncollectible accounts, our QF obligation, environmental costs, unbilled revenues and actuarially determined benefit costs. We revise the recorded estimates when we get better information or when we can determine actual amounts. Those revisions can affect operating results.

Revenue Recognition

Customers are billed monthly on a cycle basis. To match revenues with associated expenses, we accrue unbilled revenues for electrical and natural gas services delivered to customers, but not yet billed at month-end.

Cash Equivalents

We consider all highly liquid investments with maturities of three months or less at the time of purchase to be cash equivalents.

Accounts Receivable, Net

Accounts receivable are net of allowances for uncollectible accounts of $2.9 million and $2.8 million at December 31, 2010 and December 31, 2009, respectively. Receivables include unbilled revenues of $69.4 million and $72.3 million at December 31, 2010 and December 31, 2009, respectively.

Inventories

Inventories are stated at average cost. Inventory consisted of the following (in thousands):

	December 31,	
	2010	2009
Fuel stock	$ 5,994	$ 5,651
Materials and supplies	20,604	20,180
Gas stored underground (including the non-current portion reflected in utility plant)	56,199	53,571
	$ 82,797	$ 79,402

Regulation of Utility Operations

Our regulated operations are subject to the provisions of Accounting Standards Codification (ASC) 980, Regulated Operations (ASC 980). Regulated accounting is appropriate provided that (i) rates are established by or subject to approval by independent, third-party regulators, (ii) rates are designed to recover the specific enterprise's cost of service, and (iii) in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be charged to and collected from customers.

Our Financial Statements reflect the effects of the different rate making principles followed by the jurisdictions regulating us. The economic effects of regulation can result in regulated companies recording costs that have been, or are expected to be, allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as regulatory assets and recorded as expenses in the periods when those same amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (regulatory liabilities).

If we were required to terminate the application of these provisions to our regulated operations, all such deferred amounts would be recognized in the Statement of Income at that time. This would result in a charge to earnings, net of applicable income taxes, which could be material. In addition, we would determine any impairment to the carrying costs of deregulated plant and inventory assets.

Derivative Financial Instruments

We account for derivative instruments in accordance with ASC 815, *Derivatives and Hedging*. All derivatives are recognized in the Balance Sheets at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair-value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash-flow hedge). For fair-value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash-flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in accumulated other comprehensive income (AOCI) and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For other derivative contracts that do not qualify or are not designated for hedge accounting, changes in the fair value of the derivatives are recognized in earnings each period. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Statement of Cash Flows, depending on the underlying nature of the hedged items.

Revenues and expenses on contracts that qualify are designated as normal purchases and normal sales and are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but on an accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time, and price is not tied to an unrelated underlying derivative. As part of our regulated electric and gas operations, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the exceptions, the fair value of the related contract would be reflected as an asset or liability and immediately recognized through earnings. See Note 7, Risk Management and Hedging Activities for further discussion of our derivative activity.

Utility Plant

Utility plant is stated at original cost, including contracted services, direct labor and material, allowance for funds used during construction (AFUDC), and indirect charges for engineering, supervision and similar overhead items. All expenditures for maintenance and repairs of utility plant are charged to the appropriate maintenance expense accounts. A betterment or replacement of a unit of plant is accounted for as an addition and retirement of utility plant. At the time of such a retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal. Also included in utility plant are assets under capital lease, which are stated at the present value of minimum lease payments.

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to net interest charges, while the equity component is included in other income. We determine the rate used to compute AFUDC in accordance with a formula established by the FERC. This rate averaged 8.2% and 8.4% for Montana for 2010 and 2009, respectively, and 8.2% and 8.5% for South Dakota for 2010 and 2009, respectively. Interest capitalized totaled $11.0 million for the year ended December 31, 2010 and $3.2 million for the year ended December 31, 2009 for Montana and South Dakota combined.

We capitalize preliminary survey and investigation charges related to the determination of the feasibility of transmission or generation utility projects in other deferred debits. Upon commencement of construction, these costs are transferred to construction work in process, and upon completion, these costs will be transferred to utility plant. These costs totaled approximately $2.3 million and $11.4 million as of December 31, 2010 and 2009, respectively. In addition, our subsidiary, Mountain States Transmission Intertie, LLC has capitalized $16.7 million of preliminary survey and investigation charges as of December 31, 2010, which is reflected in the investment in subsidiary companies in our balance sheet. Capitalized costs are charged to operating expense if the development of the project is no longer feasible.

We may require contributions in aid of construction from customers when we extend service. Amounts used from these contributions to fund capital additions were $1.9 million and $2.6 million for the years ended December 31, 2010 and 2009, respectively.

We record provisions for depreciation at amounts substantially equivalent to calculations made on a straight-line method by applying various rates based on useful lives of the various classes of properties (ranging from three to 40 years) determined from engineering studies. As a percentage of the depreciable utility plant at the beginning of the year, our provision for depreciation of utility plant was approximately 3.2% and 3.2% for 2010 and 2009, respectively.

Depreciation rates include a provision for our share of the estimated costs to decommission three coal-fired generating plants at the end of the useful life of each plant. The annual provision for such costs is included in depreciation expense, while the accumulated provisions are included in accumulated depreciation.

Income Taxes

Exposures exist related to various tax filing positions, which may require an extended period of time to resolve and may result in income tax adjustments by taxing authorities. We have reduced deferred tax assets or established liabilities based on our best estimate of future probable adjustments related to these exposures. On a quarterly basis, we evaluate exposures in light of any additional information and make adjustments as necessary to reflect the best estimate of the future outcomes. We believe our deferred tax assets and established liabilities are appropriate for estimated exposures; however, actual results may differ from these estimates. The resolution of tax matters in a particular future period could have a material impact on our Statement of Income and provision for income taxes.

Environmental Costs

We record environmental costs when it is probable we are liable for the costs and we can reasonably estimate the liability. We may defer costs as a regulatory asset if we have prior regulatory authorization for recovery of these costs from customers in future rates. Otherwise, we expense the costs. If an environmental expense is related to facilities we currently use, such as pollution control equipment, then we capitalize and depreciate the costs over the remaining life of the asset, assuming the costs are recoverable in future rates or future cash flows.

Our remediation cost estimates are based on the use of an environmental consultant, our experience, our assessment of the current situation and the technology currently available for use in the remediation. We regularly adjust the recorded costs as we revise estimates and as remediation proceeds. If we are one of several designated responsible parties, then we estimate and record only our share of the cost. We treat any future costs of restoring sites where operation may extend indefinitely as a capitalized cost of plant retirement. The depreciation expense levels we can recover in rates include a provision for these estimated removal costs.

Emission Allowances

We have sulfur dioxide (SO2) emission allowances and each allowance permits a generating unit to emit one ton of SO2 during or after a specified year. We have approximately 3,200 excess SO2 emission allowances per year for years 2017 through 2031, however these allowances have no carrying value in our Financial Statements and the market for these years is presently illiquid. These emission allowances are not subject to regulatory jurisdiction. When excess SO2 emission allowances are sold, we reflect the gain in operating income and cash received is reflected as an investing activity.

Accounting Standards Issued

There have been no new recent accounting pronouncements or changes in accounting pronouncements during the year ended December 31, 2010 that are of significance, or potential significance, to us.

Accounting Standards Adopted

In June 2009, the Financial Accounting Standards Board issued authoritative guidance to amend the manner in which entities evaluate whether consolidation is required for VIEs. The model for determining which enterprise has a controlling financial interest and is the primary beneficiary of a VIE has changed significantly under the new guidance. Furthermore, this guidance requires that companies continually evaluate VIEs for consolidation rather than assessing based upon the occurrence of triggering events. This revised guidance also requires enhanced disclosures about how a company's involvement with a VIE affects its financial statements and exposure to risks. This guidance became effective for us on January 1, 2010. The impact of the adoption and relevant disclosure are included in Note 1 - Nature of Operations. The adoption of this guidance did not impact our results of operations, cash flows or financial position.

(3) Equity Investments

The following table presents our equity investments reflected in the investments in associated companies on the Balance Sheets (in thousands):

	December 31, 2010	December 31, 2009
Canadian Montana Pipeline Corporation	$ 2,280	$ 2,136
Clark Fork & Blackfoot, LLC	(7,272)	(7,842)
Mountain States Transmission Intertie, LLC	14,615	-
Natural Gas Funding Trust	1,661	1,643
NorthWestern Services, LLC	(10,401)	(10,702)
NorthWestern Investments, LLC	96,369	95,934
Risk Partners Assurance, Ltd.	2,880	2,961
Total Investments in Subsidiary Companies	$ 100,132	$ 84,130

(4) Utility Plant

The following table presents the major classifications of our net utility plant (in thousands):

	December 31, 2010	December 31, 2009
Land and improvements	$ 57,193	$ 46,816
Building and improvements	152,310	146,439
Storage, distribution, and transmission	2,271,236	2,180,325
Generation	370,495	189,840
Construction work in process	34,704	112,452
Other equipment	414,777	426,621
	3,300,715	3,102,493
Less accumulated depreciation	(1,461,694)	(1,404,111)
	$ 1,839,021	$ 1,698,382

Plant and equipment under capital lease were $31.9 million and $34.0 million as of December 31, 2010 and December 31, 2009, respectively, which included $31.1 million and $33.2 million as of December 31, 2010 and 2009, respectively, related to a long-term power supply contract with the owners of a natural gas fired peaking plant, which has been accounted for as an obligation under capital lease.

Jointly Owned Electric Generating Plant

We have an ownership interest in four electric generating plants, all of which are coal fired and operated by other companies. We have an undivided interest in these facilities and are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated. Our interest in each plant is reflected in the Balance Sheets on a pro rata basis and our share of operating expenses is reflected in the Statements of Income. The participants each finance their own investment.

Information relating to our ownership interest in these facilities is as follows (in thousands):

	Big Stone (SD)	Neal #4 (IA)	Coyote (ND)	Colstrip Unit 4 (MT)
December 31, 2010				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 58,283	$ 29,897	$ 45,050	$ 284,770
Accumulated depreciation	40,201	22,443	30,114	54,402
December 31, 2009				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 58,021	$ 29,885	$ 44,156	$ 281,279
Accumulated depreciation	38,609	21,729	29,083	46,714

(5) Asset Retirement Obligations

We recognize a liability for the legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event. We have identified asset retirement obligations (ARO), liabilities related to our electric and natural gas transmission and distribution assets that have been installed on easements over property not owned by us. The easements are generally perpetual and only require remediation action upon abandonment or cessation of use of the property for the specified purpose. The ARO liability is not estimable for such easements as we intend to utilize these properties indefinitely. In the event we decide to abandon or cease the use of a particular easement, an ARO liability would be recorded at that time.

Our regulated utility operations have, however, previously recognized removal costs of transmission and distribution assets as a component of depreciation in accordance with regulatory treatment. Generally, the accrual of future non-ARO removal obligations is not required. However, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. These amounts do not represent legal retirement obligations. As of December 31, 2010 and December 31, 2009, we have recognized accrued removal costs of $222.1 million and $209.2 million, respectively, which are classified as accumulated depreciation. In addition, for our generation properties, we have accrued decommissioning costs since the generating units were first put into service in the amount of $15.4 million and $14.9 million as of December 31, 2010 and December 31, 2009, respectively, which are classified as accumulated depreciation.

The liabilities associated with conditional AROs are adjusted on an ongoing basis due to the passage of new laws and regulations and revisions to either the timing or amount of estimates of undiscounted cash flows and estimates of cost escalation factors. We have recorded a conditional asset retirement obligation of $5.3 million as of December 31, 2010 and 2009, respectively, which increases our utility plant and asset retirement obligations. This is primarily related to Department of Transportation requirements to cut, purge and cap retired natural gas pipeline segments. We measure the liability at fair value when incurred and capitalize a corresponding amount as part of the book value of the related assets. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the ARO is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period and recorded as a regulatory asset until the settlement of the liability.

The following table presents the change in our gross conditional ARO (in thousands):

	December 31,	
	2010	2009
Liability at January 1, 2010	$ 6,688	$ 7,160
Accretion expense	518	480
Liabilities incurred	76	113
Liabilities settled	(35)	(1,048)
Revisions to cash flows	(66)	(17)
Liability at December 31, 2010	$ 7,181	$ 6,688

(6) Utility Plant Adjustments

Utility plant adjustments are not amortized; rather, they are evaluated for impairment at least annually. We evaluated our utility plant adjustments during the fourth quarters of 2010 and 2009 and determined that they were not impaired.

(7) Risk Management and Hedging Activities

Nature of Our Business and Associated Risks

We are exposed to certain risks related to the ongoing operations of our business, including the impact of market fluctuations in the price of electricity and natural gas commodities and changes in interest rates. Commodity price risk is a significant risk due to our minimal ownership of natural gas reserves and our reliance on market purchases to fulfill a portion of our electric supply requirements within the Montana market. Several factors influence price levels and volatility. These factors include, but are not limited to, seasonal changes in demand, weather conditions, available generating assets within regions, transportation availability and reliability within and between regions, fuel availability, market liquidity, and the nature and extent of current and potential federal and state regulations.

Objectives and Strategies for Using Derivatives

To manage our exposure to fluctuations in commodity prices we routinely enter into derivative contracts, such as fixed-price forward purchase and sales contracts. The objective of these transactions is to fix the price for a portion of anticipated energy purchases to supply our customers. These types of contracts are included in our electric and natural gas supply portfolios and are used to manage price volatility risk by taking advantage of seasonal fluctuations in market prices. While we may incur gains or losses on individual contracts, the overall portfolio approach is intended to provide price stability for consumers; therefore, these commodity costs are included in our cost tracking mechanisms. We do not maintain a trading portfolio, and our derivative transactions are only used for risk management purposes. In addition, we may use interest rate swaps to manage our interest rate exposures associated with new debt issuances or to manage our exposure to fluctuations in interest rates on variable rate debt.

Accounting for Derivative Instruments

We evaluate new and existing transactions and agreements to determine whether they are derivatives. The permitted accounting treatments include: normal purchase normal sale; cash flow hedge; fair value hedge; and mark-to-market. Mark-to-market accounting is the default accounting treatment for all derivatives unless they qualify, and we specifically designate them, for one of the other accounting treatments. Derivatives designated for any of the elective accounting treatments must meet specific, restrictive criteria both at the time of designation and on an ongoing basis. The changes in the fair value of recognized derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and the type of hedge transaction.

Normal Purchases and Normal Sales

We have applied the normal purchase and normal sale scope exception (NPNS) to most of our contracts involving the physical purchase and sale of gas and electricity at fixed prices in future periods. During our normal course of business, we enter into full-requirement energy contracts, power purchase agreements and physical capacity contracts, which qualify for NPNS. All of these contracts are accounted for using the accrual method of accounting; therefore, there were no amounts recorded in the Financial Statements at December 31, 2010 and 2009. Revenues and expenses from these contracts are reported on a gross basis in the appropriate revenue and expense categories as the commodities are received or delivered.

Mark-to-Market Accounting

Certain contracts for the purchase of natural gas associated with our gas utility operations do not qualify for NPNS. These are typically forward purchase contracts for natural gas where we lock in a fixed price; however the contracts are settled financially and we do not take physical delivery of the natural gas. We use the mark-to-market method of accounting for these derivative contracts as we do not elect hedge accounting. Upon settlement of these contracts, associated proceeds or costs are refunded to or collected from our customers consistent with regulatory requirements; therefore we record a regulatory asset or liability based on changes in market value.

The following table represents the fair value and location of derivative instruments subject to mark-to-market accounting (in thousands). For more information on the determination of fair value see Note 9.

		December 31,	
Mark-to-Market Transactions	**Balance Sheet Location**	**2010**	**2009**
Natural gas net derivative liability	Current Accrued Assets/Liabilities	$ 29,712	$ 23,661

The following table represents the net change in fair value for these derivatives (in thousands):

	Unrealized (loss) gain recognized in Regulatory Assets	
	December 31,	
Derivatives Subject to Regulatory Deferral	**2010**	**2009**
Natural gas	$ (6,051)	$ 5,495

Credit Risk

We are exposed to credit risk primarily through buying and selling electricity and natural gas to serve customers. Credit risk is the potential loss resulting from counterparty non-performance under an agreement. We manage credit risk with policies and procedures for, among other things, counterparty analysis and exposure measurement, monitoring and mitigation. We may request collateral or other security from our counterparties based on the assessment of creditworthiness and expected credit exposure. It is possible that volatility in commodity prices could cause us to have material credit risk exposures with one or more counterparties.

We enter into commodity master enabling agreements with our counterparties to mitigate credit exposure, as these agreements reduce the risk of default by allowing us or our counterparty the ability to make net payments. The agreements generally are: (1) Western Systems Power Pool agreements - standardized power purchase and sales contracts in the electric industry; (2) International Swaps and Derivatives Association agreements - standardized financial gas and electric contracts; (3) North American Energy Standards Board agreements - standardized physical gas contracts; and (4) Edison Electric Institute Master Purchase and Sale Agreements - standardized power sales contracts in the electric industry.

Many of our forward purchase contracts contain provisions that require us to maintain an investment grade credit rating from each of the major credit rating agencies. If our credit rating were to fall below investment grade, the counterparties could require immediate payment or demand immediate and ongoing full overnight collateralization on contracts in net liability positions.

The following table presents, as of December 31, 2010, the aggregate fair value of forward purchase contracts that do not qualify for NPNS that contain credit risk-related contingent features. If the credit risk-related contingent features underlying these agreements were triggered as of December 31, 2010, the collateral posting requirements would be as follows (in thousands):

Contracts with Contingent Feature	Fair Value Liability	Posted Collateral	Contingent Collateral
Credit rating	$ 19,627	$ —	$ 19,627

Interest Rate Swaps Designated as Cash Flow Hedges

If we enter into contracts to hedge the variability of cash flows related to forecasted transactions that qualify as cash flow hedges, the changes in the fair value of such derivative instruments are reported in other comprehensive income. The relationship between the hedging instrument and the hedged item must be documented to include the risk management objective and strategy and, at inception and on an ongoing basis, the effectiveness of the hedge in offsetting the changes in the cash flows of the item being hedged. Gains or losses accumulated in other comprehensive income are reclassified to earnings in the periods in which earnings are affected by the variability of the cash flows of the related hedged item. Any ineffective portion of all hedges would be recognized in current-period earnings. Cash flows related to these contracts are classified in the same category as the transaction being hedged.

We have used interest rate swaps designated as cash flow hedges to manage our interest rate exposures associated with new debt issuances. These swaps were designated as cash-flow hedges with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in AOCI. We reclassify these gains from AOCI into interest on long-term debt during the periods in which the hedged interest payments occur. The following table shows the effect of these derivative instruments on the Financial Statements (in thousands):

Cash Flow Hedges	Amount of Gain Remaining in AOCI as of December 31, 2010	Location of Gain Reclassified from AOCI to Income	Amount of Gain Reclassified from AOCI into Income during the Year Ended December 31, 2010
Interest rate contracts	$ 9,277	Interest on long-term debt	$ 1,188

We expect to reclassify approximately $1.2 million of pre-tax gains on these cash-flow hedges from AOCI into interest on long-term debt during the next twelve months. These gains relate to swaps previously terminated, and we have no current interest rate swaps outstanding.

(8) Related Party Transactions

Accounts receivable from and payables to associated companies primarily include intercompany billings for direct charges, overhead, and income tax obligations. The following table reflects our accounts receivable from and accounts payable to associated companies (in thousands):

	December 31, 2010	December 31, 2009
Accounts Receivable from Associated Companies:		
Clark Fork & Blackfoot, LLC	$ 7,273	$ 7,190
Mountain States Transmission Intertie, LLC	2,096	-
NorthWestern Investments, LLC	157	867
NorthWestern Services, LLC	2,892	2,552
Risk Partners Assurance, Ltd.	18	18
	$ 12,436	$ 10,627
Accounts Payable to Associated Companies:		
Canadian Montana Pipeline Corporation	$ 2,184	$ 2,039
Natural Gas Funding Trust	61	43
	$ 2,245	$ 2,082

(9) Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (i.e., an exit price). Measuring fair value requires the use of market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, corroborated by market data, or generally unobservable. Valuation techniques are required to maximize the use of observable inputs and minimize the use of unobservable inputs.

A fair value hierarchy that prioritizes the inputs used to measure fair value, and requires fair value measurements to be categorized based on the observability of those inputs has been established by the applicable accounting guidance. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3 inputs). The three levels of the fair value hierarchy are as follows:

- Level 1 – Unadjusted quoted prices available in active markets at the measurement date for identical assets or liabilities;
- Level 2 – Pricing inputs, other than quoted prices included within Level 1, which are either directly or indirectly observable as of the reporting date; and
- Level 3 – Significant inputs that are generally not observable from market activity.

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. The table below sets forth by level within the fair value hierarchy the gross components of our assets and liabilities measured at fair value on a recurring basis. Normal purchases and sales transactions are not included in the fair values by source table as they are not recorded at fair value. See Note 7 - Risk Management and Hedging Activities for further discussion.

December 31, 2010	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Margin Cash Collateral Offset	Total Net Fair Value
			(in thousands)		
Other Special Deposits	$ 3,330	—	—	—	$ 3,330
Rabbi trust investments	5,495	—	—	—	5,495
Derivative asset (1)	—	1,620	—	—	1,620
Derivative liability (1)	—	(31,332)	—	—	(31,332)
Net derivative position	—	(29,712)	—	—	(29,712)
Total	**$ 8,825**	**$ (29,712)**	**$ —**	**$ —**	**$ (20,887)**
December 31, 2009					
Temp Cash investments	$ 3,000	—	—	—	$ 3,000
Other Special Deposits	3,073	—	—	—	3,073
Derivative asset (1)	—	972	—	—	972
Derivative liability (1)	—	(24,633)	—	—	(24,633)
Net derivative position	—	(23,661)	—	—	(23,661)
Total	**$ 6,073**	**$ (23,661)**	**$ —**	**$ —**	**$ (17,588)**

(1) The changes in the fair value of these derivatives are deferred as a regulatory asset or liability until the contracts are settled. Upon settlement, associated proceeds or costs are passed through the applicable cost tracking mechanism to customers.

We present our derivative assets and liabilities on a net basis in the Balance Sheets. The table above disaggregates our net derivative assets and liabilities on a gross contract-by-contract basis as required and classifies each individual asset or liability within the appropriate level in the fair value hierarchy, regardless of whether a particular contract is eligible for netting against other contracts. These gross balances are intended solely to provide information on sources of inputs to fair value and do not represent our actual credit exposure or net economic exposure. Increases and decreases in the gross components presented in each of the levels in this table also do not indicate changes in the level of derivative activities. Rather, the primary factors affecting the gross amounts are commodity prices.

Temporary cash investments and other special deposits represent amounts held in money market mutual funds. Rabbi trust assets represent assets held for non-qualified deferred compensation plans, which consist of our common stock and actively traded mutual funds with quoted prices in active markets. Fair value for the commodity derivatives was determined using internal models based on quoted forward commodity prices. We consider nonperformance risk in our valuation of derivative instruments by analyzing the credit standing of our counterparties and considering any counterparty credit enhancements (e.g., collateral). The fair value measurement of liabilities also reflects the nonperformance risk of the reporting entity, as applicable. Therefore, we have factored the impact of our credit standing as well as any potential credit enhancements into the fair value measurement of both derivative assets and derivative liabilities. Consideration of our own credit risk did not have a material impact on our fair value measurements.

Financial Instruments

The estimated fair value of financial instruments is summarized as follows (in thousands):

	December 31, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt (including current portion)	$ 1,058,025	$ 1,126,336	$ 971,001	$ 1,016,777

The estimated fair value amounts have been determined using available market information and appropriate valuation methodologies; however, considerable judgment is necessarily required in interpreting market data to develop estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we would realize in a current market exchange.

We determined fair values for debt based on interest rates that are currently available to us for issuance of debt with similar terms and remaining maturities, except for publicly traded debt, for which fair value is based on market prices for the same or similar issues or upon the quoted market prices of U.S. treasury issues having a similar term to maturity, adjusted for our bond issuance rating and the present value of future cash flows.

(10) Long-Term Debt

Long-term debt consisted of the following (in thousands):

		December 31,	
	Due	2010	2009
Unsecured Debt:			
Unsecured Revolving Line of Credit	2012	$ 153,000	$ 66,000
Secured Debt:			
Mortgage bonds—			
South Dakota—6.05%	2018	55,000	55,000
South Dakota—5.01%	2025	64,000	—
Montana—6.04%	2016	150,000	150,000
Montana—6.34%	2019	250,000	250,000
Montana—5.71%	2039	55,000	55,000
Montana—5.01%	2025	161,000	—
South Dakota & Montana—5.875%	2014	—	225,000
Pollution control obligations—			
Montana—4.65%	2023	170,205	170,205
Other Long Term Debt:			
Discount on Notes and Bonds	—	(180)	(204)
		$ 1,058,025	$ 971,001

Unsecured Revolving Line of Credit

Our $250 million unsecured revolving line of credit is scheduled to expire on June 30, 2012, and does not amortize. The facility bears interest at either prime plus a credit spread, ranging from 1.25% to 3.0%, or LIBOR plus a credit spread, ranging from 2.25% to 4.0%. As of December 31, 2010, the applicable LIBOR spread was 2.75%, resulting in a borrowing rate of 3.01%. A total of nine banks participate in the facility, with no one bank providing more than 14% of the total availability. As of December 31, 2010 we had $0.5 million in letters of credit and $153.0 million of borrowings outstanding. The weighted average interest rate on the outstanding revolving credit facility borrowings was 2.8% as of December 31, 2010.

Commitment fees for the unsecured revolving line of credit were $0.8 million and $0.7 million for the years ended December 31, 2010 and 2009, respectively.

The credit facility includes covenants that require us to meet certain financial tests, including a maximum debt to capitalization ratio not to exceed 65%. The facility also contains covenants which, among other things, limit our ability to engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, and enter into transactions with affiliates. A default on the South Dakota or Montana First Mortgage Bonds would trigger a cross default on the credit facility; however a default on the credit facility would not trigger a default on any other obligations.

Secured Debt

First Mortgage Bonds and Pollution Control Obligations

The South Dakota Mortgage Bonds are a series of general obligation bonds issued under our South Dakota indenture. All of such bonds are secured by substantially all of our South Dakota and Nebraska electric and natural gas assets.

The Montana First Mortgage Bonds and Montana Pollution Control Obligations are secured by substantially all of our Montana electric and natural gas assets.

Financing Activities

On May 27, 2010 we issued $161 million aggregate principal amount of Montana First Mortgage Bonds at a fixed interest rate of 5.01% maturing in May 1, 2025. At the same time, we also issued $64 million aggregate principal amount of South Dakota First Mortgage Bonds at a fixed interest rate of 5.01% maturing May 1, 2025. The bonds are secured by our electric and natural gas assets in the respective jurisdictions. The bonds were issued in transactions exempt from the registration requirements of the Securities Act of 1933, as amended. We used the proceeds to redeem our 5.875%, $225 million Senior Secured Notes due 2014.

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt during the next five years are zero in 2011, $153.0 million in 2012, and zero in 2013, 2014. and 2015.

As of December 31, 2010, we are in compliance with our financial debt covenants.

(11) Income Taxes

In 2009, we received approval from the Internal Revenue Service (IRS) to change our tax accounting method related to costs to repair and maintain utility assets. This allowed us to take a current tax deduction for a significant amount of repair costs that were previously capitalized for tax purposes. These repair costs are capitalized and depreciated for book purposes. We record a deferred income tax liability as we flow the temporary timing differences between book and tax treatment through to our customers in the form of lower rates. A regulatory asset is established to reflect that future increases in taxes payable will be recovered from customers as the temporary differences reverse. Due to this regulatory treatment, we recorded an income tax benefit of approximately $10.7 million and $16.6 million during the years ended December 31, 2010 and 2009, respectively. The 2009 deduction consisted of approximately $8.7 million and $7.9 million related to the 2009 and 2008 tax years, respectively. For years prior to 2008, we are amortizing the deduction over the remaining life of the assets. This change in tax accounting method increased and extended our net operating loss carryforwards.

As discussed above, our regulatory tax accounting method provides for the flow-through of certain state tax adjustments, including accelerated depreciation. In September 2010, the Small Business Jobs Act of 2010 was signed into law extending bonus depreciation. This act provides a bonus tax depreciation deduction ranging from 50% to 100% for qualified property acquired or constructed and placed into service during 2010 through 2012. We recorded a bonus depreciation related tax benefit of approximately $2.3 million and $1.1 million during the years ended December 31, 2010 and 2009, respectively.

Deferred income taxes relate primarily to the difference between book and tax methods of depreciating property, amortizing tax-deductible goodwill, the difference in the recognition of revenues and expenses for book and tax purposes, certain natural gas and electric costs which are deferred for book purposes but expensed currently for tax purposes, and net operating loss carry forwards.

The components of the net deferred income tax liability recognized in our Balance Sheets are related to the following temporary differences (in thousands):

	December 31,	
	2010	**2009**
Excess tax depreciation	(223,511)	(191,458)
Regulatory assets	(9,234)	(4,479)
Regulatory liabilities	550	709
Unbilled revenue	10,403	3,058
Unamortized investment tax credit	1,075	1,305
Compensation accruals	5,329	2,040
Reserves and accruals	(8,400)	(19,245)
Utility plant adjustments amortization	(77,193)	(68,434)
Net operating loss (NOL) carryforward	84,309	111,439
AMT credit carryforward	7,067	5,604
Valuation allowance	(653)	(3,264)
Other, net	(172)	709
	(210,430)	(162,016)

A valuation allowance is recorded when a company believes that it will not generate sufficient taxable income of the appropriate character to realize the value of its deferred tax assets. We have a valuation allowance against certain state NOL carryforwards as we do not believe these assets will be realized. For the year ended December 31, 2010, we increased our valuation allowance by approximately $0.7 million against certain state NOL carryforwards as we believe they will expire before we can use them due primarily to the extension of bonus depreciation.

At December 31, 2010 we estimate our total federal NOL carryforward to be approximately $434.2 million. If unused, our federal NOL carryforwards will expire as follows: $290.6 million in 2025; $104.1 million in 2028; and $39.5 million 2029. We estimate our state NOL carryforward as of December 31, 2010 is approximately $358.1 million. If unused, our state NOL carryforwards will expire as follows: $16.7 million in 2011; $229.9 million in 2012; $80.6 million in 2015; and $30.9 million in 2016. Management believes it is more likely than not that sufficient taxable income will be generated to utilize these NOL carryforwards except as noted above.

We have elected under Internal Revenue Code 46(f)(2) to defer investment tax credit benefits and amortize them against expense and customer billing rates over the book life of the underlying plant.

Uncertain Tax Positions

We recognize tax positions that meet the more-likely-than-not threshold as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. The change in unrecognized tax benefits is as follows (in thousands):

	2010	2009
Unrecognized Tax Benefits at January 1	$ 122,844	$ 115,105
Gross increases - tax positions in prior period	—	9,960
Gross decreases - tax positions in prior period	(5,707)	(2,221)
Gross increases - tax positions in current period	6,202	—
Gross decreases - tax positions in current period	(2,480)	—
Unrecognized Tax Benefits at December 31	$ 120,859	$ 122,844

Our unrecognized tax benefits include approximately $80.4 million related to tax positions as of December 31, 2010 and 2009, respectively that if recognized, would impact our annual effective tax rate. We do not anticipate total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitations within the next twelve months.

Our policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. During the years ended December 31, 2010 and 2009, we have not recognized expense for interest or penalties, and do not have any amounts accrued at December 31, 2010 and 2009, respectively, for the payment of interest and penalties.

Our federal tax returns from 2000 forward remain subject to examination by the Internal Revenue Service.

(12) Accumulated Other Comprehensive Income

The following table displays the components of AOCI, which is included in proprietary capital on the Balance Sheets (in thousands).

	Net Unrealized Gains on Hedging Instruments	Pension and Other Benefits	Other	Total
Balances December 31, 2008	$ 11,653	$ 713	$ (12)	$ 12,354
Reclassification of net gains on hedging instruments from OCI to net income	(1,188)	—	—	(1,188)
Pension and postretirement medical liability adjustment, net of tax of $1,088	—	(1,737)	—	(1,737)
Foreign currency translation	—	—	296	296
Balances December 31, 2009	10,465	(1,024)	284	9,725
Reclassification of net gains on hedging instruments from OCI to net income	(1,188)	—	—	(1,188)
Pension and postretirement medical liability adjustment, net of tax of $75	—	(134)	—	(134)
Foreign currency translation	—	—	111	111
Balance at December 31, 2010	$ 9,277	$ (1,158)	$ 395	$ 8,514

(13) Operating Leases

We lease vehicles, office equipment and facilities under various long-term operating leases. At December 31, 2010 future minimum lease payments for the next five years under non-cancelable lease agreements are as follows (in thousands):

2011	$ 1,866
2012	1,483
2013	547
2014	280
2015	139

Lease and rental expense incurred was $2.0 million and $1.8 million for the years ended December 31, 2010 and 2009, respectively.

(14) Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

We sponsor and/or contribute to pension and postretirement health care and life insurance benefit plans for eligible employees, which includes two cash balance pension plans. The plan for our South Dakota and Nebraska employees is referred to as the NorthWestern pension plan, and the plan for our Montana employees is referred to as the NorthWestern Energy pension plan.

We utilize a number of accounting mechanisms that reduce the volatility of reported pension costs. Differences between actuarial assumptions and actual plan results are deferred and are recognized into earnings only when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the market-related value of plan assets. If necessary, the excess is amortized over the average remaining service period of active employees. The Plan's funded status is recognized as an asset or liability in our financial statements. See Note 16 for further discussion on how these costs are recovered through rates charged to our customers.

Plan Amendment

In 2009, we amended our postretirement medical plan to: (i) cap the company contribution toward the premium cost for coverage; (ii) provide a company contribution toward the premium cost for coverage to our South Dakota and Nebraska retirees; and (iii) change eligibility provisions for the company contributions from age 50 with 5 years of service to age 60 with 20 years of service for employees terminating on or after January 1, 2011. Previously, only our Montana retirees received a company contribution.

In 2008, we amended our NorthWestern Corporation and NorthWestern Energy pension plans to close the plans to new employees effective January 1, 2009. New employees are eligible to participate in the defined contribution plan.

Benefit Obligation and Funded Status

Following is a reconciliation of the changes in plan benefit obligations and fair value and a statement of the funded status (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2010	2009	2010	2009
Change in Benefit Obligation:				
Obligation at beginning of period	$ 415,278	$ 388,659	$ 32,347	$ 44,323
Service cost	9,361	8,270	483	993
Interest cost	24,090	23,705	1,803	3,149
Plan amendments	—	—	—	(25,427)
Actuarial loss	51,730	13,962	4,758	14,191
Gross benefits paid	(21,669)	(19,318)	(3,423)	(4,882)
Benefit obligation at end of period	$ 478,790	$ 415,278	$ 35,968	$ 32,347
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 391,429	$ 242,228	$ 15,298	$ 12,421
Return on plan assets	48,392	75,619	1,903	2,877
Employer contributions	10,000	92,900	3,423	4,882
Gross benefits paid	(21,669)	(19,318)	(3,423)	(4,882)
Fair value of plan assets at end of period	$ 428,152	$ 391,429	$ 17,201	$ 15,298
Funded Status	$ (50,638)	$ (23,849)	$ (18,767)	$ (17,049)
Unrecognized net actuarial (gain) loss	—	—	—	—
Unrecognized prior service cost	—	—	—	—
Accrued benefit cost	$ (50,638)	$ (23,849)	$ (18,767)	$ (17,049)
Amounts recognized in the balance sheet consist of:				
Current liability	—	—	(1,078)	(1,028)
Noncurrent liability	(50,638)	(23,849)	(17,689)	(16,021)
Net amount recognized	$ (50,638)	$ (23,849)	$ (18,767)	$ (17,049)
Amounts recognized in regulatory assets consist of:				
Transition obligation	—	—	—	—
Prior service (cost) credit	(1,487)	(1,734)	25,230	27,332
Net actuarial loss	(71,749)	(38,711)	(12,549)	(9,908)
Amounts recognized in AOCI consist of:				
Transition obligation	—	—	—	—
Prior service cost	—	—	(1,755)	(1,905)
Net actuarial gain	—	—	(395)	21
Total	$ (73,236)	$ (40,445)	$ 10,531	$ 15,540

The total projected benefit obligation and fair value of plan assets for the pension plans with projected benefit obligations in excess of plan assets were as follows (in millions):

	Pension Benefits December 31, 2010	Pension Benefits December 31, 2009
Projected benefit obligation	$ 478.8	$ 415.3
Accumulated benefit obligation	475.7	413.2
Fair value of plan assets	428.2	391.4

Net Periodic Cost

The components of the net costs for our pension and other postretirement plans are as follows (in thousands):

	Pension Benefits December 31,			Other Postretirement Benefits December 31,		
	2010	2009	2008	2010	2009	2008
Components of Net Periodic Benefit Cost						
Service cost	$ 9,361	$ 8,270	$ 8,405	$ 483	$ 993	$ 563
Interest cost	24,090	23,705	22,875	1,803	3,149	2,367
Expected return on plan assets	(29,839)	(22,383)	(27,212)	(1,186)	(994)	(1,316)
Amortization of prior service cost	246	246	246	(1,952)	—	—
Recognized actuarial loss (gain)	140	4,058	(818)	984	277	(599)
Net Periodic Benefit Cost	$ 3,998	$ 13,896	$ 3,496	$ 132	$ 3,425	$ 1,015

We estimate amortizations from regulatory assets into net periodic benefit cost during 2011 will be as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
Prior service cost	$ 246	$ (1,952)
Accumulated gain	2,371	825

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2010 and 2009. The actuarial assumptions used to compute the net periodic pension cost and postretirement benefit cost are based upon information available as of the beginning of the year, specifically, market interest rates, past experience and management's best estimate of future economic conditions. Changes in these assumptions may impact future benefit costs and obligations. In computing future costs and obligations, we must make assumptions about such things as employee mortality and turnover, expected salary and wage increases, discount rate, expected return on plan assets, and expected future cost increases. Two of these items generally have the most impact on the level of cost: (1) discount rate and (2) expected rate of return on plan assets.

For 2010 and 2009, we set the discount rate using a yield curve analysis, which projects benefit cash flows into the future and then discounts those cash flows to the measurement date using a yield curve. This is done by constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year, projected benefit cash flow from our plans.

In determining the expected long-term rate of return on plan assets, we review historical returns, the future expectations for returns for each asset class weighted by the target asset allocation of the pension and postretirement portfolios, and long-term inflation assumptions. During 2010, we revised our target asset allocation from 60% equity securities, and 40% fixed-income securities to 50% equity securities, and 50% fixed-income securities. Considering this information and future expectations for asset returns, we reduced our expected long-term rate of return on assets assumption from 7.75% to 7.25% for 2011.

The health care cost trend rates are established through a review of actual recent cost trends and projected future trends. Our retiree medical trend assumptions are the best estimate of expected inflationary increases to our healthcare costs. Due to the relative size of our retiree population (under 800 members), the assumptions used are based upon both nationally expected trends and our specific expected trends. Our average increase remains consistent with the nationally expected trends.

The weighted-average assumptions used in calculating the preceding information are as follows:

	Pension Benefits			Other Postretirement Benefits		
	December 31,			December 31,		
	2010	2009	2008	2010	2009	2008
Discount rate	5.00-5.25	5.75-6.00%	6.25%	4.00-5.00	4.75-6.00%	6.00-6.25%
Expected rate of return on assets	7.75	8.00	8.00	7.75	8.00	8.00
Long-term rate of increase in compensation levels (nonunion)	3.58	3.58	3.58	3.58	3.58	3.55
Long-term rate of increase in compensation levels (union)	3.50	3.50	3.50	3.50	3.50	3.50

The postretirement benefit obligation is calculated assuming that health care costs increased by 9.25% in 2010 and the rate of increase in the per capita cost of covered health care benefits thereafter was assumed to decrease gradually by .25% per year to an ultimate trend of 4.5% by the year 2029.

Assumed health care cost trend rates have had a significant effect on the amounts reported for the costs each year as well as on the accumulated postretirement benefit obligation. With our 2009 plan amendment to cap the company contribution toward the premium cost, future health care cost trend rates are expected to have a minimal impact on company costs and the accumulated postretirement benefit obligation.

Investment Strategy

Our investment goals with respect to managing the pension and other postretirement assets are to meet current and future benefit payment needs while maximizing total investment returns (income and appreciation) after inflation within the constraints of diversification, prudent risk taking, and the Prudent Man Rule of the Employee Retirement Income Security Act of 1974. Each plan is diversified across asset classes to achieve optimal balance between risk and return and between income and growth through capital appreciation. Our investment philosophy is based on the following:

- Each Plan should be substantially fully invested as long-term cash holdings reduce long-term rates of return;
- It is prudent to diversify each Plan across the major asset classes;
- Equity investments provide greater long-term returns than fixed income investments, although with greater short-term volatility;

- Fixed income investments of the Plans should strongly correlate with the interest rate sensitivity of the Plan's aggregate liabilities in order to hedge the risk of change in interest rates negatively impacting the overall funded status;
- Allocation to foreign equities increases the portfolio diversification and thereby decreases portfolio risk while providing for the potential for enhanced long-term returns;
- Active management can reduce portfolio risk and potentially add value through security selection strategies;
- A portion of plan assets should be allocated to passive, indexed management to provide for greater diversification and lower cost; and
- It is appropriate to retain more than one investment manager, provided that such managers offer asset class or style diversification.

Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

The most important component of an investment strategy is the portfolio asset mix, or the allocation between the various classes of securities available. The mix of assets is based on an optimization study that identifies asset allocation targets in order to achieve the maximum return for an acceptable level of risk, while minimizing the expected contributions and pension and postretirement expense. In the optimization study, assumptions are formulated about characteristics, such as expected asset class investment returns, volatility (risk), and correlation coefficients among the various asset classes, and making adjustments to reflect future conditions expected to prevail over the study period. Based on this, the target asset allocation established, within an allowable range of plus or minus 5%, is as follows:

	Pension Benefits		Other Benefits	
	December 31,		December 31,	
	2010	2009	2010	2009
Domestic debt securities	40.0%	40.0%	40.0%	40.0%
International debt securities	10.0	—	10.0	—
Domestic equity securities	40.0	50.0	40.0	50.0
International equity securities	10.0	10.0	10.0	10.0

The actual allocation by plan is as follows:

	NorthWestern Energy Pension		NorthWestern Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2010	2009	2010	2009	2010	2009
Cash and cash equivalents	—%	—%	—%	—%	—%	—%
Domestic debt securities	37.5	38.9	37.0	39.1	39.1	36.9
International debt securities	10.2	—	10.5	—	—	—
Domestic equity securities	41.9	51.2	41.8	51.0	50.7	52.5
International equity securities	10.4	9.9	10.7	9.9	10.2	10.6
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Generally, the asset mix will be rebalanced to the target mix as individual portfolios approach their minimum or maximum levels. Debt securities consist of U.S. as well as international instruments. Core domestic portfolios can be invested in government, corporate, asset-backed and mortgage-backed obligation securities. The portfolio may invest in high yield securities, however, the average quality must be rated at least "investment grade" by rating agencies. Performance of fixed income investments shall be measured by both traditional investment benchmarks as well as relative changes in the present value of the plans liabilities. Equity investments consist primarily of U.S.

stocks including large, mid and small cap stocks, which are diversified across investment styles such as growth and value. Non-U.S. equities are utilized with exposure to developing and emerging markets. Derivatives, options and futures are permitted for the purpose of reducing risk but may not be used for speculative purposes.

Our plan assets are primarily invested in common collective trusts (CCTs), which are invested in equity and fixed income securities. In accordance with our investment policy, these pooled investment funds must have an adequate asset base relative to their asset class and be invested in a diversified manner and have a minimum of three years of verified investment performance experience or verified portfolio manager investment experience in a particular investment strategy and have management and oversight by an investment advisor registered with the SEC. Investments in a collective investment vehicle are valued by multiplying the investee company's net asset value per share with the number of units or shares owned at the valuation date. Net asset value per share is determined by the trustee. Investments held by the CCT, including collateral invested for securities on loan, are valued on the basis of valuations furnished by a pricing service approved by the CCT's investment manager, which determines valuations using methods based on quoted closing market prices on national securities exchanges, or at fair value as determined in good faith by the CCT's investment manager if applicable. The funds do not contain any redemption restrictions. The direct holding of NorthWestern Corporation stock is not permitted; however, any holding in a diversified mutual fund or collective investment fund is permitted. In addition, the NorthWestern Corporation pension plan assets also include a participating group annuity contract in the John Hancock General Investment Account, which consists primarily of fixed-income securities. The participating group annuity contract is valued based on discounted cash flows of current yields of similar contracts with comparable duration based on the underlying fixed income investments.

The fair value of our plan assets at December 31, 2010 by asset category are as follows (in thousands):

Asset Category	Total	Quoted Market Prices in Active Markets for Identical Assets Level 1	Significant Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Pension Plan Assets				
Cash and cash equivalents	$ 47	$ —	$ 47	$ —
Equity securities: (1)				
US small/mid cap growth	15,768	—	15,768	—
US small/mid cap value	16,124	—	16,124	—
US large cap growth	48,012	—	48,012	—
US large cap value	46,668	—	46,668	—
US large cap passive	52,688	—	52,688	—
Non-US core	44,751	—	44,751	—
Fixed income securities:(2)				
US core opportunistic	65,449	—	65,449	—
US passive	35,596	—	35,596	—
Long duration	49,083	—	49,083	—
Ultra long duration	—	—	—	—
Non-US passive	43,653	—	43,653	—
Participating group annuity contract	10,313	—	10,313	—
	$ 428,152	$ —	$ 428,152	$ —
Other Postretirement Benefit Plan Assets				
Cash and cash equivalents	$ 4	$ —	$ 4	$ —
Equity securities: (1)				
US small/mid cap growth	806	—	806	—
US small/mid cap value	829	—	829	—
S&P 500 index	6,029	—	6,029	—
US large cap growth	346	—	346	—
US large cap value	334	—	334	—
US large cap passive	378	—	378	—
Non-US core	1,758		1,758	—
Fixed income securities: (2)				
Passive bond market	1,073	—	1,073	—
US core opportunistic	4,683	—	4,683	—
US passive	272	—	272	—
Long duration	377	—	377	—
Ultra long duration	—	—	—	—
Non-US passive	312	—	312	—
	$ 17,201	$ —	$ 17,201	$ —

The fair value of our plan assets at December 31, 2009 by asset category are as follows (in thousands):

Asset Category	Total	Quoted Market Prices in Active Markets for Identical Assets Level 1	Significant Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Pension Plan Assets				
Cash and cash equivalents	$ 45	$ —	$ 45	$ —
Equity securities: (1)				
US small/mid cap growth	17,533	—	17,533	—
US small/mid cap value	17,414	—	17,414	—
US large cap growth	53,835	—	53,835	—
US large cap value	52,561	—	52,561	—
US large cap passive	58,937	—	58,937	—
Non-US core	38,709	—	38,709	—
Fixed income securities:(2)				
US core opportunistic	29,240	—	29,240	—
US passive	16,419	—	16,419	—
Long duration	92,325	—	92,325	—
Ultra long duration	3,278	—	3,278	—
Non-US passive	—	—	—	—
Participating group annuity contract	11,133	—	11,133	—
	$ 391,429	$ —	$ 391,429	$ —
Other Postretirement Benefit Plan Assets				
Cash and cash equivalents	$ 4	$ —	$ 4	$ —
Equity securities: (1)				
US small/mid cap growth	837	715	122	—
US small/mid cap value	810	689	121	—
S&P 500 index	5,238	—	5,238	—
US large cap growth	375	—	375	—
US large cap value	367	—	367	—
US large cap passive	410	—	410	—
Non-US core	1,623	1,354	269	—
Fixed income securities: (2)				
Passive bond market	1,008	—	1,008	—
US core opportunistic	3,786	3,565	221	—
US passive	120	—	120	—
Long duration	694	—	694	—
Ultra long duration	26	—	26	—
Non-US passive	—	—	—	—
	$ 15,298	$ 6,323	$ 8,975	$ —

(1) This category consists of active and passive managed equity funds, which are invested in multiple strategies to diversify risks and reduce volatility.

(2) This category consists of investment grade bonds of issuers from diverse industries, debt securities issued by international, national, state and local governments, and asset-backed securities. This includes both active and

passive managed funds.

For further discussion of the three levels of the fair value hierarchy see Note 9.

Cash Flows

Due to the unprecedented volatility in equity markets, we experienced plan asset market gains during 2009 in excess of 20%, and plan asset market losses during 2008 in excess of 30%, which impact our planned levels of contributions. In accordance with the Pension Protection Act of 2006 (PPA), and the relief provisions of the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), which was signed into law on December 23, 2008, we are required to meet minimum funding levels in order to avoid required contributions and benefit restrictions. We have elected to use asset smoothing provided by the WRERA, which allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of funding requirements.

Based on the assumptions allowed under the PPA, WRERA, Treasury guidance and IRS guidance, and the significant contributions made during 2009, we estimate that we will not have a minimum annual required contribution for 2011. We do expect to contribute approximately $11.7 million to our pension plans during 2011. Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact these funding requirements.

Due to the regulatory treatment of pension costs in Montana, expense is calculated using the average of our actual and estimated funding amounts from 2005 through 2012, therefore changes in our funding estimates creates increased volatility to earnings. As a result of the significant increase in unfunded status as of December 31, 2008, we reviewed our funding strategy for the plans, and significantly increased our 2009 cash funding in order to decrease the volatility of these plans to our long-term results of operations and liquidity as follows:

	2010	2009	2008
NorthWestern Energy Pension Plan (MT)	$ 9,000	$ 80,600	$ 31,140
NorthWestern Pension Plan (SD)	1,000	12,300	1,594
	$ 10,000	$ 92,900	$ 32,734

We estimate the plans will make future benefit payments to participants as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2011	$ 22,916	$ 3,899
2012	23,538	3,734
2013	25,331	3,782
2014	26,296	3,767
2015	28,147	3,750
2016-2020	162,181	16,050

Defined Contribution Plan

Our defined contribution plan permits employees to defer receipt of compensation as provided in Section 401(k) of the Internal Revenue Code. Under the plan, employees may elect to direct a percentage of their gross compensation to be contributed to the plan. We contribute various percentage amounts of the employee's gross compensation contributed to the plan. Matching contributions for the year ended December 31, 2010 and 2009 were $6.0 million and $5.8 million, respectively.

(15) Stock-Based Compensation

We grant stock-based awards through our 2005 Long-Term Incentive Plan (LTIP), which includes service based restricted stock awards and performance share awards. As of December 31, 2010, there were 408,578 shares of common stock remaining available for grants. The remaining vesting period for awards previously granted ranges from one to three years if the service and/or performance requirements are met. Nonvested shares do not receive dividend distributions. The long-term incentive plan provides for accelerated vesting in the event of a change in control.

We account for our share-based compensation arrangements by recognizing compensation costs for all share-based awards over the respective service period for employee services received in exchange for an award of equity or equity-based compensation. The compensation cost is based on the fair value of the grant on the date it was awarded.

Restricted Stock and Performance Share Awards

Restricted stock awards vest within five years after the date of grant. The fair value of restricted stock is measured based upon the closing market price of our common stock as of the date of grant. Performance share awards are typically payable at the end of a three-year performance period if the specified performance criteria are met.

Performance share awards were granted under the 2005 LTIP during 2010 and 2009. With these awards, shares will vest if, at the end of the three-year performance period, we have achieved certain performance goals and the individual remains employed by us. The exact number of shares issued will vary from 0% to 200% of the target award, depending on actual company performance relative to the performance goals. These awards contain both a market and performance based component. The performance goals for these awards are independent of each other and equally weighted, and are based on two metrics: (i) cumulative net income and return on equity growth; and (ii) total shareholder return (TSR) relative to a peer group. The fair value of the net income component is estimated based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends, multiplied by an estimated performance multiple determined on the basis of historical experience, which is subsequently trued up at vesting based on actual performance. The fair value of the TSR portion is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. The risk-free interest rate was based on the U.S. Treasury yield of a three-year bond at the time of grant. The expected term of the performance shares is three years based on the performance cycle. Expected volatility was based on the historical volatility for the peer group. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest.

The following summarizes the significant assumptions used to determine the fair value of performance shares and related compensation expense as well as the resulting estimated fair value of performance shares granted:

	2010	2009
Risk-free interest rate	1.38%	1.37%
Expected life, in years	3	3
Expected volatility	27.2% to 51.6%	25.1% to 46.5%
Dividend yield	5.4%	5.6%

A summary of nonvested shares as of December 31, 2010, and changes during the year ended December 31, 2010 are as follows:

	Performance Share Awards		Restricted Stock Awards	
	Shares	Weighted-Average Grant-Date Fair Value	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	78,346	$ 21.53	69,954	$ 34.37
Granted	108,372	19.66	5,000	26.22
Vested	—	—	(56,968)	34.26
Forfeited	(6,779)	21.29	(2,098)	28.07
Remaining nonvested grants	179,939	$ 20.41	15,888	$ 30.84

We recognized compensation expense of $1.6 million and $1.8 million for the years ended December 31, 2010 and 2009, respectively, and a related income tax benefit (expense) of $0.2 million and $(0.6) million for the years ended December 31, 2010 and 2009, , respectively. As of December 31, 2010, we had $2.0 million of unrecognized compensation cost related to the nonvested portion of outstanding awards, which is reflected in other aid-in capital in our Balance Sheets. The cost is expected to be recognized over a weighted-average period of 1.7 years. The total fair value of shares vested was $1.4 million and $4.0 million for the years ended December 31, 2010 and 2009, respectively.

Director's Deferred Compensation

Nonemployee directors may elect to defer up to 100% of any qualified compensation that would be otherwise payable to him or her, subject to compliance with our 2005 Deferred Compensation Plan for Nonemployee Directors and Section 409A of the Internal Revenue Code. The deferred compensation may be invested in NorthWestern stock or in designated investment funds. Compensation deferred in a particular month is recorded as a deferred stock unit (DSU) on the first of the following month based on the closing price of NorthWestern stock or the designated investment fund. The DSUs are marked-to-market on a quarterly basis with an adjustment to director's compensation expense. Based on the election of the nonemployee director, following separation from service on the Board, other than on account of death, he or she shall be paid a distribution either in a lump sum or in approximately equal installments over a designated number of years (not to exceed 10 years). During the years ended December 31, 2010 and 2009, DSUs issued to members of our Board totaled 36,831 and 42,870, respectively. Total compensation expense attributable to the DSUs during the years ended December 31, 2010 and 2009 was approximately $1.3 million and $1.1 million, respectively.

(16) Regulatory Assets and Liabilities

We prepare our financial statements in accordance with the provisions of ASC 980, as discussed in Note 2. Pursuant to this pronouncement, certain expenses and credits, normally reflected in income as incurred, are deferred and recognized when included in rates and recovered from or refunded to the customers. Regulatory assets and liabilities are recorded based on management's assessment that it is probable that a cost will be recovered or that an obligation has been incurred. Accordingly, we have recorded the following major classifications of regulatory assets and liabilities that will be recognized in expenses and revenues in future periods when the matching revenues are collected or refunded. These regulatory items have corresponding assets and liabilities that will be paid for or refunded in future periods. Because these costs are recovered as paid, they do not earn a return. We have specific orders to cover approximately 97% of our regulatory assets and 100% of our regulatory liabilities.

	Note Reference	Remaining Amortization Period	December 31, 2010		December 31, 2009	
Pension	14	Undetermined	$	94,500	$	87,934
Postretirement benefits	14	Undetermined		9,104		6,191
Environmental clean-up	18	Various		15,438		14,631
Energy supply derivatives	7	1 Year		29,721		23,812
Income taxes	11	Plant Lives		71,374		47,241
Other		Various		29,460		20,789
Total regulatory assets			**$**	**249,597**	**$**	**200,598**
Gas storage sales		29 Years	$	12,092	$	12,513
Supply costs		1 Year		8,203		6,355
Energy supply derivatives	7	1 Year		9		2,044
State & local taxes & fees		1 Year		805		6,012
Other		Various		1,656		3,565
Total regulatory liabilities			**$**	**22,765**	**$**	**30,489**

Pension and Postretirement Benefits

We recognize the unfunded portion of plan benefit obligations in the Balance Sheets, which is remeasured at each year end, with a corresponding adjustment to regulatory assets/liabilities as the costs associated with these plans are recovered in rates. The portion of the regulatory asset related to our Montana pension plan will amortize as cash funding amounts exceed accrual expense under GAAP. The South Dakota Public Utilities Commission (SDPUC) allows recovery of pension costs on an accrual basis. The Montana Public Service Commission (MPSC) allows recovery of postretirement benefit costs on an accrual basis.

Environmental clean-up

Environmental clean-up costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss the specific sites and clean-up requirements further in Note 18. Environmental clean-up costs are typically recoverable in customer rates when they are actually incurred. We record changes in the regulatory asset consistent with changes in our environmental liabilities. When cost projections become known and measurable we coordinate with the appropriate regulatory authority to determine a recovery period.

Income Taxes

Tax assets primarily reflect the effects of plant related temporary differences such as removal costs, capitalized interest and contributions in aid of construction that we will recover or refund in future rates. We amortize these amounts as temporary differences reverse.

State & Local Taxes & Fees (Montana Property Tax Tracker)

Under Montana law, we are allowed to track the increases in the actual level of state and local taxes and fees and recover these amounts. The MPSC has authorized recovery of approximately 60% of the estimated increase in our local taxes and fees (primarily property taxes) as compared to the related amount included in rates during our last general rate case.

Gas Storage Sales

A regulatory liability was established in 2000 and 2001 based on gains on cushion gas sales in Montana. This gain is being flowed to customers over a period that matches the depreciable life of surface facilities that were added to maintain deliverability from the field after the withdrawal of the gas. This regulatory liability is a reduction of rate base.

(17) Regulatory Matters

Montana General Rate Case

In October 2009, we filed a request with the MPSC for an annual electric transmission and distribution revenue increase of $15.5 million, and an annual natural gas transmission, storage and distribution revenue increase of $2.0 million. The MPSC approved interim rates, subject to refund, beginning July 8, 2010. In September 2010, we and the Montana Consumer Counsel (MCC) filed a joint Stipulation and Settlement Agreement (Stipulation) regarding the revenue requirement portion of the rate filing, including a net increase in base electric and natural gas rates of approximately $6.7 million, and a proposed authorized rate of return of 7.92%. An increase in base electric rates of $7.7 million;

In December 2010, we received a final order approving our Stipulation regarding the revenue requirement portion of the rate filing with an additional MPSC requirement to implement a modified lost revenue adjustment mechanism (previously proposed as a decoupling mechanism), and an inclining block rate structure for electric energy supply customers. Key provisions of the final order are as follows:

- An increase in base electric rates of $6.4 million;
- A decrease in base natural gas rates of approximately $1.0 million; and
- An authorized return on equity of 10.0% and 10.25% for base electric and natural gas rates, respectively.
- The overall authorized rates of return are based on the equity percentages above, long-term debt cost of 5.76% and a capital structure of 52% debt and 48% equity.

The authorized return on equity for base electric rates was reduced from the stipulated return on equity of 10.25% to 10.0% due to the modified lost revenue adjustment mechanism. This change in return on equity reduced the electric revenue requirement increase from $7.7 million to $6.4 million. The final approved electric and natural gas revenue requirements are lower than those approved by the MPSC's interim order, therefore we must rebate the difference to customers over a six-month period beginning January 1, 2011. We have recognized revenue and implemented rates consistent with the MPSC's final order; however, we have appealed the MPSC's decision to the Montana district court due to the required implementation of a modified lost revenue adjustment mechanism and the related reduction in return on equity and the block rate design. In addition, the MPSC has continued to discuss potential modifications to the final order and we cannot predict the outcome. We will continue to support the Stipulation as agreed to by the parties.

Montana Electric and Natural Gas Supply Trackers

Rates for our Montana electric and natural gas supply are set by the MPSC. Each year we submit electric and natural gas tracker filings for recovery of supply costs for the 12-month period ended June 30 and for the projected supply costs for the next 12-month period. The MPSC reviews such filings and makes its cost recovery determination based on whether or not our electric and natural gas energy supply procurement activities were prudent. If the MPSC subsequently determines that a procurement activity was imprudent, then it may disallow such costs.

A hearing was held in January 2011 and we expect to receive a final order during the second quarter of 2011. The MCC is challenging approximately $1.9 million of supply costs related to the inclusion of our interest in Colstrip Unit 4 in the tracker.

A stipulation with the MCC regarding our 2009 and 2010 annual natural gas cost tracker filings was approved by the MPSC in December 2010. The stipulation includes agreed upon limits on our use of fixed-price swaps to mitigate natural gas price volatility and requires us to investigate the possibility of using natural gas call options as an alternative hedging tool. Also, the MPSC found that our natural gas costs for the actual time periods covered were prudently incurred.

Montana Property Tax Tracker

In December 2010, we filed our annual property tax tracker (including other state/local taxes and fees) with the MPSC for an automatic rate adjustment, which reflected 60% of the change in 2010 actual property taxes and estimated property taxes for 2011. We received a final order approving the filing in February 2011.

Mill Creek Generating Station (MCGS)

In August 2008, we filed a request with the MPSC for advanced approval to construct a 150 MW natural gas fired facility. In May 2009, the MPSC issued an order granting approval to construct the facility, authorizing a return on equity of 10.25% and a preliminary cost of debt of 6.5%, with a capital structure of 50% equity and 50% debt. In addition, the MPSC determined the $81 million cost for the turbines is prudent, with the remainder of the project costs to be submitted to the MPSC for review and approval once construction of the facility is complete. Construction began in June 2009, and the plant achieved commercial operation on January 1, 2011. We filed a request for interim rates with the MPSC in October 2010 based on the total estimated MCGS construction costs of approximately $202 million. The MPSC approved our interim request to include these costs in our monthly electric supply rates effective January 1, 2011. The interim order reflected the actual cost of debt relating to the MCGS at 6.07%. The cost of the MCGS replaces our current contract costs for regulating reserve service. We are required to make a compliance filing with the MPSC by March 31, 2011 reflecting the actual construction costs of MCGS. As a result of the lower than estimated construction costs, lower debt rates, and the estimated impact of bonus depreciation, we expect the final revenue requirement approved by the MPSC will be lower than the interim amount approved, with the difference refunded to customers. Total project costs through December 31, 2010 were approximately $183 million.

Our FERC Open Access Transmission Tariff (OATT) allows for recovery of ancillary costs to our customers, including the regulating reserve service described above to be provided by the MCGS under Schedule 3 (Regulation and Frequency Response). We submitted a filing to the FERC related to this project in April 2010 and requested that the revised tariff sheets become effective on January 1, 2011 in order to reflect the cost of service for the MCGS under the OATT in Schedule 3. On October 15, 2010, FERC issued an order granting interim rates, subject to refund. A hearing is scheduled for March 2011.

Transmission Investment Projects

In January 2009, we filed a request with the FERC seeking negotiated rates for the proposed Mountain States Transmission Intertie (MSTI) project and to directly assign the cost of the Collector Project to the generators. The request for negotiated rates for MSTI was not for specific rates; rather, it was for confirmation from the FERC that MSTI would satisfy the FERC's negotiated rate criteria. As a transmission export project in a region that lacks a Regional Transmission Organization (RTO), MSTI would have no readily available regional tariff through which to recover costs and thereby mitigate project development risk. The request was based on a rate approach that FERC had approved for similar projects in the region, which would provide us with the flexibility to meet market demand from primarily new renewable generation resources in Montana and to insulate our native load customers from the costs and risks of the project. FERC issued an order in May 2009 denying our request for negotiated rates, and encouraged us to meet our needs by pursuing the MSTI project on a cost-of-service basis by requesting appropriate waivers under our OATT. As to the Collector Project, FERC approved our proposal to directly assign the cost of the project to the generators. This also has the effect of insulating native load customers from the cost of the project. While FERC deferred ruling on our request for tariff waivers, FERC specifically found the proposed Collector Project open season process to be a reasonable means of accommodating a large number of interconnection requests in the queue.

In March 2010, we initiated open season processes for the proposed MSTI line and Collector Project to identify potential interest for new transmission capacity on these paths due to the changing nature of generation projects. The open seasons are designed to identify potential interest for new transmission capacity on these paths due to the changing nature of generation projects while providing for a staged level of commitment by prospective users and ensuring that the projects have sufficient contracts with credit-worthy shippers to support financing. Customers can revoke open season requests at any time up to the point of an executed service agreement. Under our original timeline, we anticipated completing the open season processes by the end of 2010. During 2010, a lawsuit was filed against the Montana Department of Environmental Quality (MDEQ) by Jefferson County, Montana, regarding the County's ability to be more involved in the siting and routing of MSTI. On September 8, 2010, the Montana District Court agreed with Jefferson County and (i) required the MDEQ to consult with Jefferson County in the preparation of the environmental impact statement (EIS) concerning the project and (ii) enjoined the MDEQ from releasing the draft EIS until that consultation occurs. In January 2011, MDEQ appealed the decision to the Montana Supreme Court. In February 2011, we also appealed the decision to the Montana Supreme Court. In addition to this lawsuit, due to general economic conditions, lack of clarity around federal legislation on renewables and uncertainty in the California renewable standards we have extended the open season processes for the proposed MSTI and Collector Projects until December 31, 2011. We have capitalized approximately $16.7 million of preliminary survey and investigative costs associated with the MSTI transmission project. If our efforts to complete MSTI are not successful we may have to write-off all or a portion these costs, which could have a material adverse effect on our results of operations.

(18) Commitments and Contingencies

Qualifying Facilities Liability

In Montana we have certain contracts with Qualifying Facilities, or QFs. The QFs require us to purchase minimum amounts of energy at prices ranging from $65 to $167 per MWH through 2029. Our estimated gross contractual obligation related to the QFs is approximately $1.3 billion through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $1.0 billion through 2029. The present value of the remaining QF liability is recorded in our Balance Sheets. The following summarizes the change in the QF liability (in thousands):

	December 31,	
	2010	2009
Beginning QF liability	$ 165,839	$ 162,841
Unrecovered amount	(1,198)	(9,366)
Interest expense	12,681	12,364
Ending QF liability	$ 177,322	$ 165,839

The following summarizes the estimated gross contractual obligation less amounts recoverable through rates (in thousands):

	Gross Obligation	Recoverable Amounts	Net
2011	$ 65,323	$ 54,357	$ 10,966
2012	67,111	54,904	12,207
2013	69,816	55,462	14,354
2014	72,354	56,025	16,329
2015	74,135	56,598	17,537
Thereafter	985,267	740,592	244,675
Total	$ 1,334,006	$ 1,017,938	$ 316,068

Long Term Supply and Capacity Purchase Obligations

We have entered into various commitments, largely purchased power, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 20 years. Costs incurred under these contracts were approximately $417.2 million and, $433.7 million for the years ended December 31, 2010 and 2009, respectively. As of December 31, 2010, our commitments under these contracts are $346.2 million in 2011, $242.9 million in 2012, $211.5 million in 2013, $134.1 million in 2014, $96.6 million in 2015, and $629.9 million thereafter. These commitments are not reflected in our Financial Statements.

Environmental Liabilities

Our liability for environmental remediation obligations is estimated to range between $29.3 million to $38.9 million. As of December 31, 2010, we have a reserve of approximately $32.4 million, which has not been discounted. Environmental costs are recorded when it is probable we are liable for the remediation and we can reasonably estimate the liability. Over time, as specific laws are implemented and we gain experience in operating under them, a portion of the costs related to such laws will become determinable, and we may seek authorization to recover such costs in rates or seek insurance reimbursement as applicable; therefore, we do not expect these costs to have a material adverse effect on our financial position or ongoing operations.

Manufactured Gas Plants - Approximately $27.8 million of our environmental reserve accrual is related to manufactured gas plants. A formerly operated manufactured gas plant located in Aberdeen, South Dakota, has been identified on the Federal Comprehensive Environmental Response, Compensation, and Liability Information System list as contaminated with coal tar residue. We are currently investigating, characterizing, and initiating remedial actions at the Aberdeen site pursuant to work plans approved by the South Dakota Department of Environment and Natural Resources. Our current reserve for remediation costs at this site is approximately $14.1 million, and we estimate that approximately $8.9 million of this amount will be incurred during the next five years.

We also own sites in North Platte, Kearney and Grand Island, Nebraska on which former manufactured gas facilities were located. During 2005, the Nebraska Department of Environmental Quality (NDEQ) conducted Phase II investigations of soil and groundwater at our Kearney and Grand Island sites. On March 30, 2006 and May 17, 2006, the NDEQ released to us the Phase II Limited Subsurface Assessment performed by the NDEQ's environmental consulting firm for Kearney and Grand Island, respectively. We have conducted limited additional site investigation, assessment and monitoring work at Kearney and Grand Island. At present, we cannot determine with a reasonable degree of certainty the nature and timing of any risk-based remedial action at our Nebraska locations.

In addition, we own or have responsibility for sites in Butte, Missoula and Helena, Montana on which former manufactured gas plants were located. An investigation conducted at the Missoula site did not require entry into the MDEQ voluntary remediation program, but required preparation of a groundwater monitoring plan. The Butte and Helena sites were placed into the MDEQ's voluntary remediation program for cleanup due to excess regulated pollutants in the groundwater. We have conducted additional groundwater monitoring at the Butte and Missoula sites and, at this time, we believe natural attenuation should address the conditions at these sites; however, additional groundwater monitoring will be necessary. In Helena, we continue limited operation of an oxygen delivery system implemented to enhance natural biodegradation of pollutants in the groundwater and we are currently evaluating limited source area treatment/removal options. Monitoring of groundwater at this site is ongoing and will be necessary for an extended time. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of risk-based remedial action at the Helena site or if any additional actions beyond monitored natural attenuation will be required.

Global Climate Change

There are national and international efforts to address global climate change and the contribution of emissions of greenhouse gases (GHG) including, most significantly, carbon dioxide. This concern has led to increased interest in legislation at the federal level, actions at the state level, as well as litigation relating to GHG emissions.

Specifically, coal-fired plants have come under scrutiny due to their emissions of carbon dioxide. We have joint ownership interests in four electric generating plants, all of which are coal fired and operated by other companies. We have undivided interests in these facilities and are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated. In addition, a significant portion of the electric supply we procure in the market is generated by coal-fired plants.

In September 2009, the U.S. Court of Appeals for the Second Circuit ruled that several states and public interest groups could sue five electric utility companies under federal common law for allegedly causing a public nuisance as a result of their emissions of greenhouse gases. The decision was appealed in the U.S. Supreme Court, which has granted certiorari and is expected to hear the case this year. In October 2009, the U.S. Court of Appeals for the Fifth Circuit ruled that individuals damaged by Hurricane Katrina could sue a variety of companies that emit carbon dioxide, including electric utilities, for allegedly causing a public nuisance that contributed to their damages. In May 2010, due to a lack of quorum, the Court of Appeals for the Fifth Circuit dismissed its decision, which essentially reinstated the district court's dismissal of the claim. The U.S. Supreme Court has denied the plaintiffs' request to order the Fifth Circuit to hear the appeal. Additional litigation in federal and state courts over these issues is continuing.

National Legislation - Numerous bills have been introduced in Congress that address climate change from different perspectives, including direct regulation of GHG emissions and the establishment of Federal Renewable Portfolio Standards. We cannot predict when or if Congress will pass legislation containing climate change provisions.

The U.S. Environmental Protection Agency (EPA) issued a finding during 2009 that GHG emissions endanger the public health and welfare. The EPA's finding indicated that the current and projected levels of six GHG emissions - carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride contribute to climate change. In a related matter, in June 2010, the EPA also adopted rules that would phase in requirements for all new or modified "stationary sources," such as power plants, that emit 100,000 tons of greenhouse gases per year or modified sources that increase emissions by 75,000 tons per year to obtain permits incorporating the "best available control technology" for such emissions. These thresholds are effective January 2, 2011, apply for six years and will be reviewed by the U.S. EPA for future applicability thereafter. Under the regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case-by-case basis.

Interstate Transport - On July 6, 2010, the EPA published its proposed Transport Rule as the replacement to the Clean Air Interstate Act (CAIR) that had been remanded by a Federal court decision due to a number of legal deficiencies. The proposed Transport Rule is the first of a number of significant regulations that the EPA expects to issue that will impose more stringent requirements relating to air, water and waste controls on electric generating units. Beginning with the proposed Transport Rule, the air requirements are expected to be implemented through a series of increasingly stringent regulations relating to conventional air pollutants (e.g., nitrogen oxide (NO_x), sulfur dioxide (SO_2) and particulate matter) as well as hazardous air pollutants (HAPs) (e.g., acid gases, mercury and other heavy metals). Under the proposal, the first phase of the NO_x and SO_2 emissions reductions under the proposed Transport Rule would commence in 2012, with further reductions of SO_2 emissions proposed to become effective in 2014.

Coal Combustion Residuals (CCRs) - In June 2010, the EPA proposed two approaches to regulating the disposal and management of CCRs under the Resource Conservation and Recovery Act (RCRA). CCRs include fly ash, bottom ash and scrubber wastes. Under one approach, the EPA would regulate CCRs as a hazardous waste under Subtitle C of RCRA. This approach would have very significant impacts on any coal-fired plant, and would require plants to retrofit their operations to comply with full hazardous waste requirements from the generation of CCRs and associated waste waters through transportation and disposal. This could also have a negative impact on the beneficial use of CCRs and the current markets. The second approach would regulate CCRs as a solid waste under Subtitle D of RCRA. This approach would only affect disposal and most significantly affect any wet disposal operations. Under this approach, many of the current markets for beneficial uses of CCRs would not be affected. Currently, the plant operator of Colstrip Unit 4 expects it could be significantly impacted by either approach. We cannot predict at this time the final requirements of the EPA's Transport Rule or CCR regulations and what impact, if any, they would have on our facilities, but the costs could be significant.

In June 2010, the EPA adopted rules that would phase in requirements for all new or modified stationary sources such as power plants, that emit 100,000 tons of GHGs per year or modified sources that increase emissions by 75,000 tons per year to obtain permits incorporating the "best available control technology" for such emissions. These thresholds are effective January 2, 2011, apply for six years and will be reviewed by the EPA for future applicability thereafter. Under the regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case-by-case basis. Requirements to reduce GHG emissions from stationary sources could cause us to incur material costs of compliance. In addition, there is a gap between the possible requirements and the current capabilities of technology. The EPA has indicated that carbon capture and sequestration is not currently feasible as a GHG emission control technology. To the extent that such technology does become feasible, we can provide no assurance that it will be suitable or cost-effective for installation at the generation facilities in which we have a joint interest. We believe future legislation and regulations that affect carbon dioxide emissions from power plants are likely, although technology to efficiently capture, remove and sequester carbon dioxide emissions may not be available within a timeframe consistent with the implementation of such requirements.

Clean Air Mercury Rule - Citing its authority under the Clean Air Act, in 2005, the EPA issued the Clean Air Act Mercury Regulations (CAMR) affecting coal-fired power plants. Since CAMR was overturned by a 2008 decision by the U.S. Circuit Court, the EPA is now proceeding to develop standards imposing Maximum Achievable Control Technology (MACT) for mercury emissions and other hazardous air pollutants from electric generating units. Under a recent approved settlement, the EPA is required to issue final MACT standards by November 2011 and compliance is statutorily required three years later. In order to develop these standards, the EPA has collected information from coal- and oil-fired electric utility steam generating units. The costs of complying with the final MACT standards are not currently determinable, but could be significant.

Regional Haze and Visibility - The Clean Air Visibility Rule was issued by the EPA in June 2005, to address regional haze or regionally-impaired visibility caused by multiple sources over a wide area. The rule requires the use of Best Available Retrofit Technology (BART) for certain electric generating units to achieve emissions reductions from designated sources that are deemed to contribute to visibility impairment in Class I air quality areas. The South Dakota Department of Environment and Natural Resources (DENR) has proposed a draft Regional Haze State Implementation Plan (SIP), which recommends SO_2 and particulate matter emission control technology and emission rates that generally follow the EPA rules. We have a 23.4% joint interest in Big Stone, which is potentially subject to these emission reduction requirements. At the request of the DENR, the plant operator submitted an analysis of control technologies that should be considered BART to achieve emissions reductions consistent with both the EPA and DENR rules. In addition to scrubbers that were included in the analysis, the DENR recommended Selective Catalytic Reduction technology for NO_x emission reduction instead of the plant operator recommended separated over-fire air. We are working with the joint owners to evaluate BART options. Based upon current engineering estimates, capital expenditures for these BART technologies are currently estimated to be approximately \$500 - \$550 million for Big Stone (our share is 23.4%).

The DENR proposes to require that BART be installed and operating as expeditiously as practicable, but no later than five years from the EPA's approval of the South Dakota Regional Haze SIP, which was filed in January 2011. We cannot predict the timing of the EPA's approval. We will not incur any costs unless the EPA approves the South Dakota Regional Haze SIP and the plant operator's plan for emissions reduction technology is accepted. We will seek to recover any such costs through the ratemaking process. The SDPUC has historically allowed timely recovery of the costs of environmental improvements; however, there is no precedent on a project of this size.

In addition, we have been notified by the operator of the Neal #4, of which we have an 8% ownership, that the plant will require a scrubber similar to the Big Stone project to comply with the Clean Air Act. Capital expenditures are currently estimated to be approximately \$220 million (our share is 8%), and are scheduled to commence in 2011 and be spread over the next three years.

While we cannot predict the impact of any legislation until final, if legislation or regulations are passed at the federal or state levels imposing mandatory reductions of carbon dioxide and other GHGs on generation facilities, the cost to us and/or our customers could be significant. Our incremental capital expenditures projections include amounts related to our share of the BART technologies at Big Stone and Neal #4 based on current estimates. Impacts could include future capital expenditures for environmental equipment beyond what is currently planned, financing costs related to additional capital expenditures and the purchase of emission allowances from market sources. We believe the cost of purchasing carbon emissions credits, or alternatively the proceeds from the sale of any excess carbon emissions credits would be included in our supply trackers and passed through to customers.

Other

We continue to manage equipment containing polychlorinated biphenyl (PCB) oil in accordance with the EPA's Toxic Substance Control Act regulations. We will continue to use certain PCB-contaminated equipment for its remaining useful life and will, thereafter, dispose of the equipment according to pertinent regulations that govern the use and disposal of such equipment.

We routinely engage the services of a third-party environmental consulting firm to assist in performing a comprehensive evaluation of our environmental reserve. Based upon information available at this time, we believe that the current environmental reserve properly reflects our remediation exposure for the sites currently and previously owned by us. The portion of our environmental reserve applicable to site remediation may be subject to change as a result of the following uncertainties:

- We may not know all sites for which we are alleged or will be found to be responsible for remediation; and

- Absent performance of certain testing at sites where we have been identified as responsible for remediation, we cannot estimate with a reasonable degree of certainty the total costs of remediation.

Legal Proceedings

Colstrip Energy Limited Partnership

In December 2006 and June 2007, the MPSC issued orders relating to certain QF long-term rates for the period July 1, 2003, through June 30, 2006. Colstrip Energy Limited Partnership (CELP) is a QF with which we have a power purchase agreement through June 2024. Under the terms of the power purchase agreement with CELP, energy and capacity rates were fixed through June 30, 2004 (with a small portion to be set by the MPSC's determination of rates in the annual avoided cost filing), and beginning July 1, 2004 through the end of the contract, energy and capacity rates are to be determined each year pursuant to a formula, with the rates to be used in that formula derived from the annual MPSC QF rate review. CELP initially appealed the MPSC's orders and then, in July 2007, filed a complaint against NorthWestern and the MPSC in Montana district court, which contested the MPSC's orders. CELP disputed inputs into the underlying rates used in the formula, which initially are calculated by us and reviewed by the MPSC on an annual basis, to calculate energy and capacity payments for the contract years 2004-2005 and 2005-2006. CELP claimed that NorthWestern breached the power purchase agreement causing damages, which CELP asserted to be approximately $23 million for contract years 2004-2005 and 2005-2006. The parties stipulated that NorthWestern would not implement the final derived rates resulting from the MPSC orders, pending an ultimate decision on CELP's complaint. The Montana district court, on June 30, 2008, granted both a motion by the MPSC to bifurcate, having the effect of separating the issues between contract/tort claims against us and the administrative appeal of the MPSC's orders and a motion by us to refer the claims against us to arbitration. The order also stayed the appellate decision pending a decision in the arbitration proceedings. Arbitration was held in June 2009 and the arbitration panel entered its interim award in August 2009, holding that although NorthWestern failed to use certain data inputs required by the power purchase agreement, CELP was entitled to neither damages for contract years 2004-2005 or 2005-2006, nor to recalculation of the underlying MPSC filings for those years, effectively finalizing CELP's contract rates for those years. We requested clarification from the arbitration panel as to its intent regarding the applicable rates. On November 2, 2009, we received the final award from the arbitration panel which confirmed that the filed rates for 2004-2005 and 2005-2006 are not required to be recalculated. In affirming its interim award, the arbitration panel also denied CELP's request for attorney fees, holding that each party would be responsible for its own fees. On June 15, 2010, the Montana district court confirmed the final arbitration panel award and denied CELP's motion to vacate, modify or correct the award. CELP has appealed the decision to the Montana Supreme Court (MSC). We participated in a court-ordered mediation with CELP on September 13, 2010, but were unable to resolve the claims. All appellate briefs have been submitted to the Montana Supreme Court and the matter awaits either a decision on the merits by the MSC or for the MSC to set the matter for oral argument. On October 31, 2010, NorthWestern filed with the MPSC, consistent with the direction of the arbitration panel, for a determination of the inputs that will be used to calculate contract rates for periods subsequent to June 30, 2006. Due to the uncertainty around resolution of this matter, we currently are unable to predict its outcome. In addition, settlement discussions concerning these claims are ongoing.

Gonzales

We are a defendant - along with the Montana Power Company (MPC) and pre-bankruptcy NorthWestern Corporation (NOR) - in an action (Gonzales Action) pending in the Montana Second Judicial District Court, Butte-Silver Bow County (Montana State Court), alleging fraud, constructive fraud and violations of the Unfair Claim Settlement Practices Act all arising out of the adjustment of workers' compensation claims. Putnam and Associates, the third party administrator of such workers' compensation claims, also is a defendant.

The Gonzales Action was first filed on December 18, 1999, against MPC (NOR acquired MPC in 2002) and was stayed due to the chapter 11 bankruptcy filing of NOR. On August 10, 2005, the Bankruptcy Court approved a "Bankruptcy Settlement Stipulation" which permitted the Gonzales Action to proceed, assigned to plaintiffs NOR's interest in MPC's insurance policies (to the extent applicable to the allegations made by plaintiffs), released NOR from any and all obligations to the plaintiffs concerning such claims, and preserved plaintiffs' right to pursue claims arising after November 1, 2004, relating to the adjustment of workers' compensation claims. To date, no insurance carrier has indicated that coverage is available for any of the claims.

On September 30, 2009, the Montana State Court granted the plaintiffs' motions to file a sixth amended complaint and partially granted the plaintiffs motion for class certification. The Montana State Court excluded the fraud claims from its class certification. The new complaint seeks to hold us jointly and severally liable for the acts of MPC and NOR and alleges that we negligently/intentionally sabotaged plaintiffs' ability to recover under the MPC insurance policies. Plaintiffs seek compensatory and punitive damages from all defendants. Due to the individual nature of the claims, we believe the class certification was improper under Montana law, and we continue to believe that the new complaint violates the bankruptcy stipulation.

We and Putnam and Associates have agreed to settle the Gonzales Action and have executed a settlement agreement which remains subject to the approval of the Montana State Court. We paid the settlement agreement amount of $2.5 million to the Clerk of the Montana State Court in full satisfaction of all Gonzales Action claims. The Clerk of the Montana State Court will hold these funds pending final Montana State Court approval of the settlement, which could take approximately 12 months.

Maryland Street

On March 16, 2009, Monsignor John F. McCarthy, the duly appointed personal representative for the Estate of his brother, Father James C. McCarthy, filed a wrongful death lawsuit against NorthWestern and one of our employees in the District Court of Butte-Silver Bow County, Montana for injuries that Fr. McCarthy received in an April 2007 natural gas explosion at his residence. The lawsuit alleges negligence and strict liability with respect to the maintenance and operation of the natural gas distribution system that served the residence. Fr. McCarthy died in November 2007, allegedly because of injuries sustained in the explosion. The plaintiff seeks unspecified compensatory and punitive damages and other equitable relief, costs and attorneys' fees. Following mediation on January 27, 2011, we settled the lawsuit pending completion of certain conditions, which we anticipate will be satisfied within the next 60 days. If the matter is resolved as contemplated, it would not have a material impact on our financial position, results of coperations or cash flows.

Bozeman Explosion

On March 5, 2009, a natural gas explosion occurred in downtown Bozeman, Montana, resulting in one fatality, the destruction of or damage to several buildings and the businesses in them, and damage to other nearby properties and businesses. Twenty-six lawsuits have been filed against NorthWestern in the District Court of Gallatin County, Montana, and a number of additional claims not currently in litigation also have been made against us. We have approximately $150 million of insurance coverage available for known and potential claims arising from the explosion. We tendered our self-insured retention under those policies to our insurance carriers, who accepted the tender and assumed the defense and handling of the existing and potential additional lawsuits and claims arising from the incident.

Mediation of the eleven largest lawsuits was held during the week of November 8, 2010. Settlement was reached in eight of those cases, including the wrongful death case, and we subsequently have settled a number of the other smaller cases and claims. There are currently three substantial and seven relatively small property damage cases pending. The court has scheduled trial of one of the unspecified remaining larger property damage cases for June 20, 2011. While we cannot predict an outcome, we intend to continue vigorously defending against the lawsuits.

Sierra Club

On June 10, 2008, the Sierra Club filed a complaint in the U.S. District Court for the District of South Dakota (Northern Division) (South Dakota Federal District Court) against us and two other co-owners (the Defendants) of Big Stone Generating Station. The complaint alleged certain violations of the (i) Prevention of Significant Deterioration and (ii) New Source Performance Standards provisions of the Clean Air Act and certain violations of the South Dakota State Implementation Plan. On March 31, 2009, the South Dakota Federal District Court entered a Memorandum Opinion and Order granting Defendants' Motion to Dismiss the Sierra Club Complaint. The Sierra Club appealed that decision to the Eighth Circuit Court of Appeals (Court of Appeals), which affirmed the decision on August 26, 2010. The Sierra Club did not file a writ of certiorari with the U.S. Supreme Court within the required period of time, and, as a result, the matter is concluded.

We are also subject to various other legal proceedings, governmental audits and claims that arise in the ordinary course of business. In the opinion of management, the amount of ultimate liability with respect to these other actions will not materially affect our financial position, results of operations, or cash flows.

(19) Common Stock

We have 250,000,000 shares authorized consisting of 200,000,000 shares of common stock with a $0.01 par value and 50,000,000 shares of preferred stock with a $0.01 par value. Of these shares, 2,265,957 shares of common stock are reserved for the incentive plan awards. For further detail of grants under this plan see Note 15 - Stock-Based Compensation.

Repurchase of Common Stock

Shares tendered by employees to us to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock awards totaled 14,453 and 30,684 during the years ended December 31, 2010 and 2009, respectively, and are reflected in treasury stock. These shares were credited to treasury stock based on their fair market value on the vesting date.