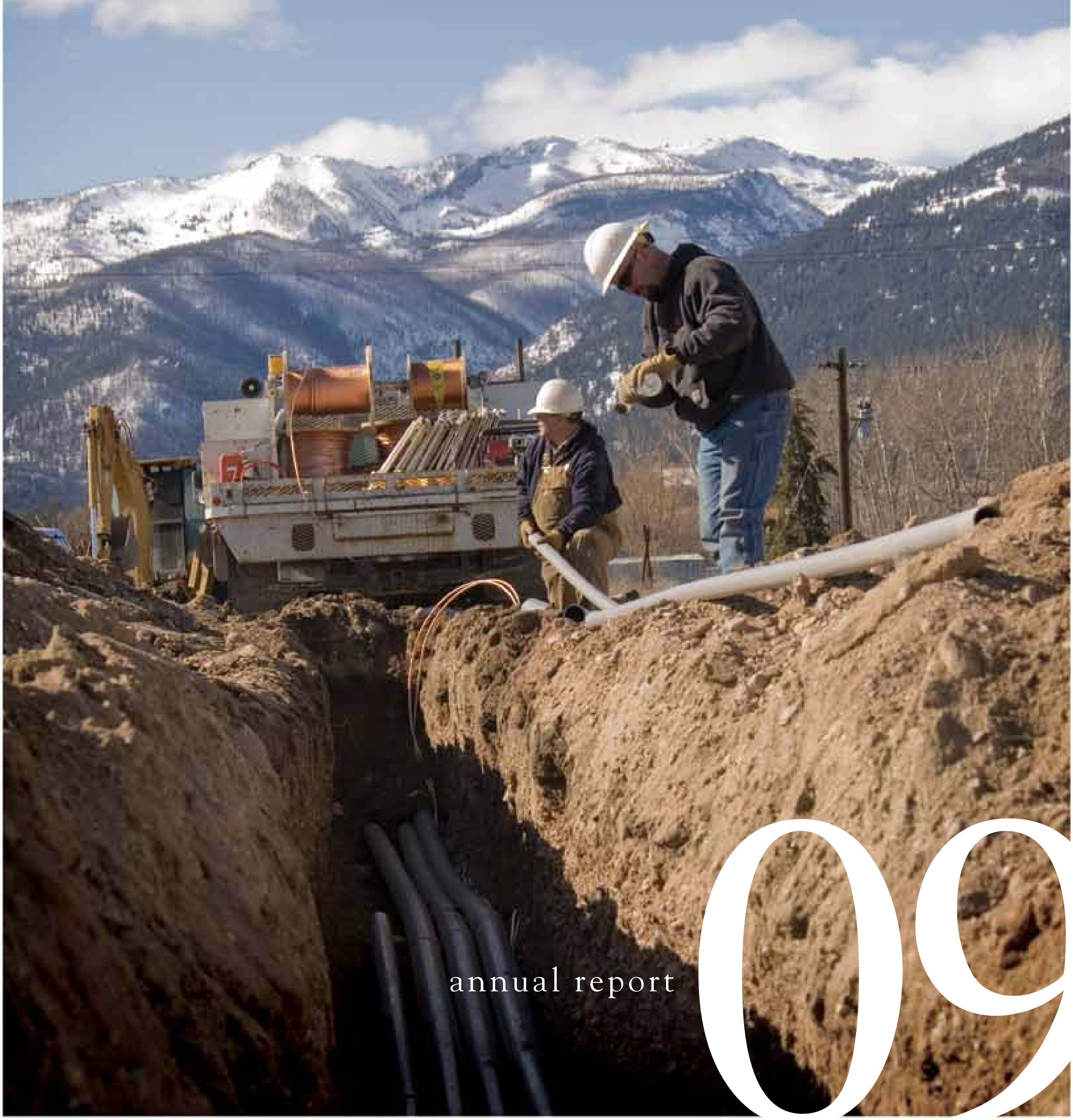


NorthWestern Energy

Delivering a Bright Future

NorthWestern Energy **AT A GLANCE**

ELECTRIC

montana

335,000 customers in 187 communities
7,000 miles of transmission lines
21,400 miles of distribution lines
Owns 222 net MW of power generation

south dakota

60,500 customers in 110 communities
3,300 miles of transmission and distribution lines
Owns 312 net MW of power generation

NATURAL GAS

montana

180,100 customers in 105 communities
4,100 miles of underground distribution pipelines
2,000 miles of intrastate transmission pipelines
17.75 Bcf of gas storage capacity

south dakota

43,600 customers in 60 communities
1,540 miles of distribution gas mains

nebraska

41,500 customers in 4 communities
760 miles of distribution pipelines

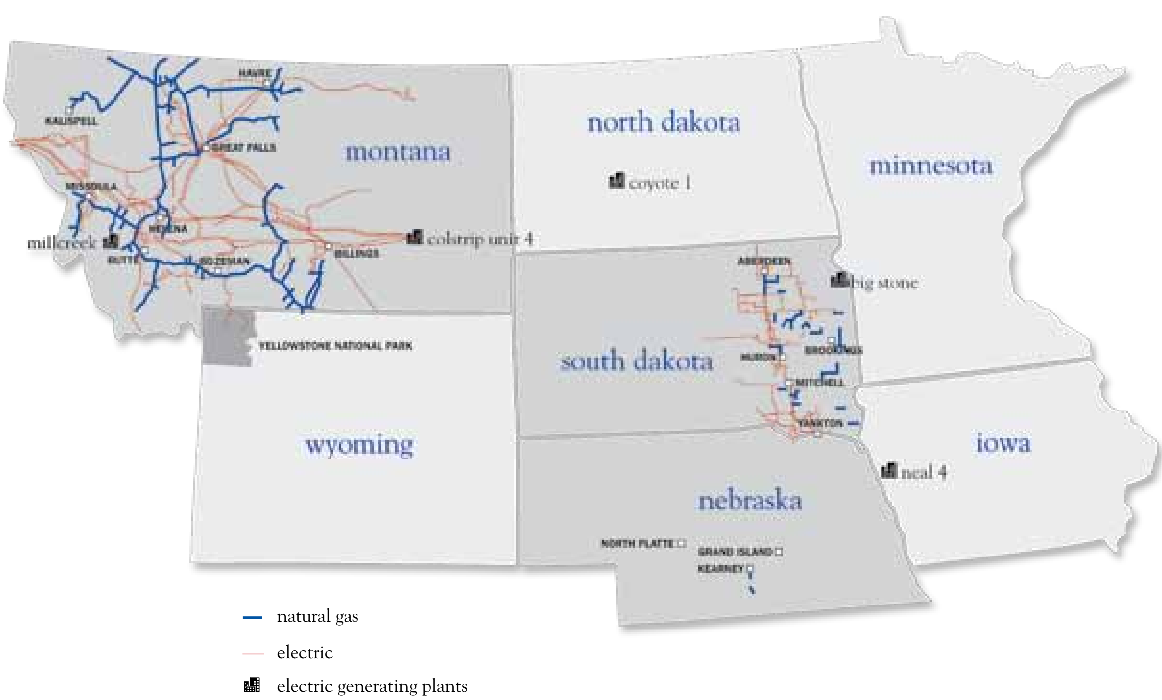
NorthWestern Energy provides electricity and natural gas in the Upper Midwest and Northwest, serving approximately 661,000 customers in Montana, South Dakota and Nebraska.

Our business consists of federal- and state-regulated electric and natural gas distribution and transmission and electric generation operations.

pictured on cover: Mike Depee and Don Provence work to install getaways at a new NorthWestern Energy substation near Victor, Montana.

– photographer: Susan Malee

NorthWestern Energy
Delivering a Bright Future



President and CEO Bob Rowe pauses briefly before returning to a work session of the company's Leadership NorthWestern program that was initiated in 2009 to provide employees with an opportunity to learn about the many facets of the company.
– photographer: Susan Malee

our message to **SHAREHOLDERS**

Vision and mission statements should define a business. Too often, they are dry and lifeless because they tend to be drafted by committee, with each word reflecting a delicate political balance based on a concern about how others may interpret it. An effective vision reflects a higher guiding purpose that drives all of the individuals who make up the whole. An effective mission reflects how they plan to achieve their purpose together.

When I asked our employees to share their insights into what it means to work at NorthWestern Energy, they often stated several key elements, including safe, sustainable, value, community and working together.

It was clear to me that our employees know NorthWestern Energy's vision and mission include something that is missing from many such statements — passion for a higher purpose. Therefore, I asked them over the course of the last year (in a number of settings) to help create new vision and mission statements. They do the important, complicated and sometimes dangerous work every day, so who better to help tell the story of what we do and how we do it. When employees presented their work to the leadership team, it was clear they had identified a shared higher purpose. The following vision and mission statements are the result of their work.

From the left, Bill Kendall of NewMech, Gene Scott of The Shaw Group and Bob Rowe of NorthWestern Energy check out construction progress at the Mill Creek Generating Station site located about seven miles east of Anaconda, Montana.
– photographer: Susan Malee

vision: *Enriching lives through a safe, sustainable energy future.*

mission: *Working together to deliver safe, reliable and innovative energy solutions that create value for customers, communities, employees and investors.*

These two statements are concise and speak clearly about the work we do. We also asked employees to describe how they live these words and those of our SERVICE values (safety, excellence, respect, value, integrity, community and environment) on a daily basis.

Nearly everyone's story reflected a sense of community, teamwork, perseverance and commitment. It is in this same spirit that we approach the coming year.

sustainable energy future

January 1, 2009, marked a turning point for our retail customers in Montana — the beginning of a return to a more vertically integrated utility that owns rate-based electricity supply, when our 30 percent ownership of Colstrip Unit 4 was placed into rate base by the Montana Public Service Commission, providing rate certainty and stability to customers. For most of the decade, our Montana customers have been subject to volatile electricity markets as a result of the state's failed "experiment" with deregulation and Montana Power's sale of its generation plants in 1999. We will likely always make market purchases of energy, but expect additional resources to be rate-based over time as it makes sense to do so for our customers.

In May, we received approval from the Montana Public Service Commission to proceed with construction of the Mill Creek Generating Station, which will provide needed regulating resources to balance and maintain the reliability of the company's regional transmission network. Construction began in August 2009 on the $200 million,

150-megawatt natural gas fired plant, which is planned to begin operation in December 2010.

In 2009, the Montana Legislature enabled NorthWestern Energy to own rate-based natural gas supply. We are evaluating potential opportunities that may provide a stable, secure source of fuel for our retail gas customers and for the Mill Creek plant.

As this report is finalized, there is still uncertainty over the future of federal environmental legislation, particularly so-called "cap and trade." We are positioning ourselves to better protect our customers in what we expect will be a carbon-constrained environment through additional acquisition or purchases of renewable energy.

Montana was one of the first states to adopt a Renewable Portfolio Standard. We are currently in a position to meet the 2010 milestone of 10 percent total energy supply from renewable resources, and are looking ahead to the next milestone of 15 percent in 2015. We made significant steps toward meeting South Dakota's voluntary renewable standard of 10 percent by 2015 with the purchase of all the power produced by the Titan 1 Wind Farm near Ree Heights — our first addition of wind energy to our South Dakota energy supply portfolio. We also have issued Requests for Information in both states with a goal of adding additional renewable energy projects to our existing portfolios. We have enhanced our emphasis on energy efficiency as a resource, along with identifying policies that will facilitate efficiency as a viable enterprise consistent with supply side investments.

create value

We produced a total shareholder return for 2009 of 17.6 percent, exceeding our peer average and the broad utility indices during a turbulent year. We are proud of this, particularly due to the prevailing uncertainty in the energy and financial markets throughout the year. NorthWestern Energy continued to act on initiatives to improve and grow in and around our service territories that are intended to provide sustainable value to our stakeholders and price stability to our customers.

pictured above: In June 2009 at its Missoula, Montana service center, NorthWestern Energy unveiled its fleet's first hybrid bucket truck that allows crews to shut down the diesel engine and use the vehicle's batteries to operate the bucket.
– photographer: Susan Malee

pictured below: The Titan 1 Wind Farm near Ree Heights, South Dakota went online in early December 2009 and generates five percent, or about 25 megawatts, of NorthWestern Energy's South Dakota load.
– photographer: Tom Glanzer

Renewable energy is a driving force behind our growth strategy. We believe it is poised to be the next big industry in our region. Montana and South Dakota possess high-value wind profiles and are leading contenders to supply much of the regional demand for wind power. This new generation needs new transmission lines, which is what we're working to develop.

In South Dakota, we're participating in two efforts aimed at tapping into this potential. We're collaborating with several other utilities and interested parties on the Green Power Express — a seven-state, 3,000-mile, 765-kV transmission line. We've also joined efforts with other regional entities working on the SMART Study, which is evaluating the long-term future transmission needs that may be necessary based on Midwestern demand for South Dakota wind power.

In Montana, where we already operate a regional transmission system, we have approximately 4,800 megawatts of potential new generation in queue seeking access to our system. We've proposed several projects to address these requests. In 2009, we collaborated with the other owners of the 500-kV Colstrip Transmission System and Bonneville Power to develop a plan to increase incremental export capacity by 500-700 megawatts. In 2010, we plan to continue this effort.

The Mountain States Transmission Intertie, a proposed 450-mile, 500-kV line from Townsend, Montana to Midpoint, Idaho, is in the permitting stage with the Draft Environmental Impact Statement expected to be released by the end of the first quarter of this year. If all goes as planned, we expect the line to be permitted and ready for construction in 2012 and in service by 2015.

Because large-scale wind generation is proposed mostly in areas that don't have enough installed transmission capacity, we're evaluating up to five new 230-kV transmission lines in Montana that would tie these wind facilities to NorthWestern Energy's existing system. NorthWestern Energy is expecting an Open Season for these facilities to occur in 2010. We will evaluate the responses we receive as we continue with project design and prioritization. All of the new lines we are evaluating would interconnect with the Colstrip Transmission System at a new substation (and soon-to-be regional energy hub) near Townsend, Montana.

A NorthWestern Energy crew works near Sarpy Creek in eastern Montana to replace transmission line spacers on a 115-mile stretch of the twin 500-kV electric transmission lines that run from Colstrip to Townsend.
– photographer: Don Scheidecker

We believe each of these projects would serve to enhance our federal- and state-regulated generation and transmission infrastructure while contributing to the growth of a new and exciting industry in our region.

safe, reliable, innovative energy solutions

Our distribution infrastructure — the thousands of miles of wires and pipes that carry energy from the substations and gate stations to homes and businesses — continues to perform very well. Over the past decade, we've learned how to translate the enormous amounts of data that we collect on system integrity and performance and use it to predict future performance. On the whole, our system reliability results are well above average compared with our peers.

Our customers are satisfied with their service according to the variety of surveys that we participate in throughout the year. We continue to show improvement in the JD Power and Associates utility rankings at a time when many of our peers and the industry as a whole are experiencing declines or remaining relatively flat. While this indicates that we are doing a good job today, we know we can do better both in terms of satisfaction and reliability.

To this end, we've been engaging our stakeholders in an intensive process that is intended to help us better understand how we can best align our long-term goals with those of our customers and policymakers and keep consistent with our vision and mission. We're particularly interested in the development of sound public policy that enables investment in appropriate new technology, infrastructure improvements and cost-effective renewable energy conservation measures. We want policy to be in step with and supportive of our customers' desire for reliable and affordable energy.

From the left, Andy Lesiak and Kelly DeJonge install a strainer on a gas riser at the company's new meter set on the campus of the University of Nebraska – Kearney. – *photographer: Dan Wolf*

We're part of a regional working group that will be evaluating various Smart Grid applications over the next few years to better understand how we can deploy this new technology affordably and effectively to customers in our service territories. We serve an area that most consider rural, where long lines, tough terrain and weather present daunting challenges. We're working with our stakeholders to understand whether and how to enhance the network for both our urban and rural customers, while at the same time laying the necessary foundation for more widespread deployment of Smart Grid technology as the value propositions become clearer on both sides of the meter and the technology stabilizes.

Commendably, many utilities have come to embrace energy efficiency and conservation. It's worth remembering that we have been actively engaged in this effort in our Montana service territory for more than 20 years, and we've continued to build upon our successes. In 2009, our Demand Side Management (DSM) programs delivered an annual savings of almost 6 megawatts in Montana, which exceeded our goal for the year. We know it will be harder to maintain those results in the coming years due to the ongoing recession and the fact that we've already achieved so much. That said, we've once again set aggressive targets for 2010, and we're excited to launch our first-ever program offerings in South Dakota, based upon our considerable expertise in DSM.

Lawrence Moran installs armor rod to the conductor before connecting it to the insulator as part of the 69-kV line relocation project south of Missoula, Montana.
– photographer: Susan Malee

working together

NorthWestern Energy is the sum of more than 1,300 individuals who work together to deliver results for the customers we serve, the communities we live and invest in and the shareholders who make it possible.

March 5, 2009, was one of the worst days we have ever experienced in our nearly century of service. An explosion in downtown Bozeman, Montana took the life of a member of the community and destroyed a half-block on one of the American West's most iconic Main Streets. Our employees in Bozeman and elsewhere responded immediately following the incident and in subsequent days with professionalism and compassion, reminding us that the most difficult experiences often bring out the best in people.

We continue to do our best to conduct ourselves as an ethical business and an important and committed member of the Bozeman community. We listened to the fears, concerns and suggestions of the people who were affected, and we developed a response plan to assist with the downtown's recovery as the area's property owners rebuild and the community continues to heal.

Toward the latter half of the year, the ongoing recession brought employees together in a spirit of teamwork to find ways that we could manage expenses without sacrificing service quality or reliability. Our employees helped us find innovative and resourceful ways to save money, and to do so safely. In 2009, our employees did an outstanding job of keeping themselves and their co-workers safe — a marked improvement from just a few short years ago. We started the first work day of 2010 by recognizing our team's safety success and affirming our commitment to safe work.

We're also working together and investing in human potential with the Leadership NorthWestern program, now starting its second year. Each year this effort brings together a cross-section of employees in an intensive program designed to expand their leadership potential through exposure to all aspects of the company. The members of the Class of 2009 are now emerging leaders across our broad service territory, and helping to knit us closer together.

enriching lives

There's more to life than work. Our employees are proud to deliver essential services, providing comfort, warmth and energy to our customers, and critical infrastructure for vital and growing communities. We're not just a company. We're an essential member of the community.

Our employees give their time and expertise both on and off the job. They have logged thousands of hours serving their communities in a variety of ways, from coaching Little League and refereeing hockey games to volunteering at shelters for homeless people and animals.

NorthWestern Energy contributed more than $850,000 to local charitable organizations and economic development projects in the communities that we serve. At a time when many companies have scaled back, we've proudly been able to increase our local donations program over 2008. In 2009, we launched our first companywide initiative to engage employees in support of the March of Dimes Walk for Babies. We're building upon this initiative in 2010 with sponsorship of the American Cancer Society's Relay for Life.

KEMA employees load a truck with thousands of weatherization kits for distribution to eligible Montana customers during NorthWestern Energy's 36 give-away events and eight home weatherization expos held in the fall of 2009.
– photographer: Susan Malee

In Montana, we held more than 40 weatherization events that provided qualifying customers with the tools necessary to make their homes more comfortable and energy efficient. While this was funded through our DSM program, many employees gave up their weekends to staff events held around the state. This year, in addition to weatherization kits, we gave away carbon monoxide detectors to natural gas customers who attended the Home Energy Expos.

Sometimes enriching life experiences are mutual, as in the experience of one employee who worked several of the events. The employee, Claudia, helped distribute hundreds of carbon monoxide detectors — an important job. The tears welling up in the eyes of a struggling new mom as she expressed gratitude for helping to provide a safer environment for her infant allowed Claudia to realize the contribution that each of us can make in our community, by doing our jobs well and going above and beyond when the need and the opportunity exist.

This is the contribution we strive to achieve each day for you.

Sincerely,

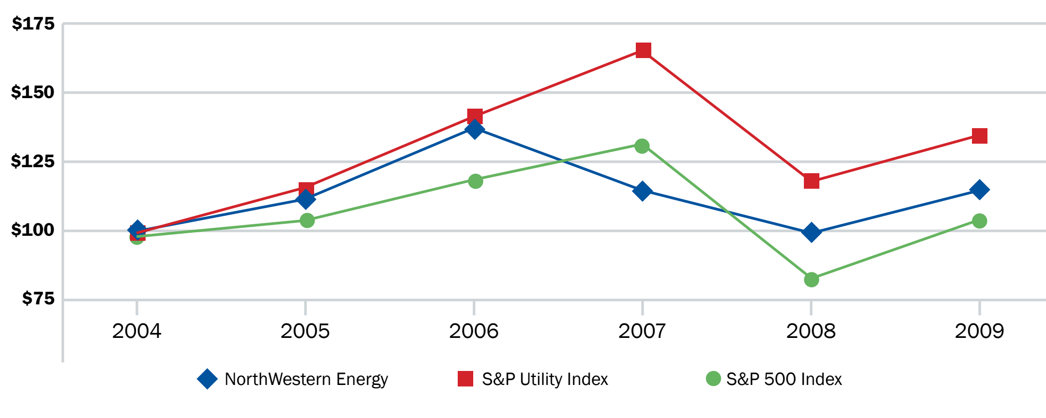
Robert C. Rowe
President and CEO

financial HIGHLIGHTS

	2009	2008	% Change
Gross Margin	$568,224	$562,053	1.1 %
Net Income	$73,420	$67,601	8.6 %
Earnings Per Diluted Common Share	$2.02	$1.77	14.1 %
Dividends Declared Per Average Common Share	$1.34	$1.32	1.5 %
Debt Outstanding	$987,419	$862,056	14.5 %
Total Debt to Total Capitalization Ratio	55.6%	53.0%	4.8 %
Capital Expenditures	$189,360	$124,563	52.0 %
Number of Customers	661,000	656,000	0.8 %
Number of Employees	1,354	1,385	(2.2)%
Retail Volumes Delivered			
Electric (megawatt hours)	9,958	10,164	(2.0)%
Natural Gas (dekaterms)	32,124	32,263	(0.4)%

total SHAREHOLDER RETURN

The following graph assumes $100 was invested in our common stock on December 31, 2004 and compares the share price performance with the S&P Utility Index and the S&P 500 Index for the years ending December 31, 2005, 2006, 2007, 2008 and 2009. Total return is computed assuming reinvestment of dividends.



	2004	2005	2006	2007	2008	2009
NorthWestern Energy	$100.00	$113.85	$134.61	$116.90	$98.18	$115.48
S&P 500 Index	$100.00	$104.91	$121.48	$128.16	$80.74	$102.11
S&P Utility Index	$100.00	$116.84	$141.36	$168.76	$119.86	$134.12

credit RATINGS

	Fitch	Moody's	S&P
Senior Secured	BBB+	A3	A- (Montana) BBB+ (South Dakota)
Senior Unsecured	BBB	Baa2	BBB
Outlook	Stable	Positive	Stable

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

☒ **ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2009

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number: 1-10499

NORTHWESTERN CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**46-0172280**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
3010 W. 69th Street, Sioux Falls, South Dakota	**57108**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 605-978-2900

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

(Title of each class)	(Name of each exchange on which registered)
Common Stock, $0.01 par value	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the past 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company (as defined in Rule 12b-2 of the Exchange Act).
Large Accelerated Filer ☒ Accelerated Filer ☐ Non-accelerated Filer ☐ Smaller Reporting Company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The aggregate market value of the voting and non-voting common stock held by nonaffiliates of the registrant was $818,036,000 computed using the last sales price of $22.76 per share of the registrant's common stock on June 30, 2009, the last business day of the registrant's most recently completed second fiscal quarter.

As of February 5, 2010, 36,005,742 shares of the registrant's common stock, par value $0.01 per share, were outstanding.

Documents Incorporated by Reference
Certain sections of our Proxy Statement for the 2010 Annual Meeting of Shareholders are incorporated by reference into Part III of this Form 10-K

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

On one or more occasions, we may make statements in this Annual Report on Form 10-K regarding our assumptions, projections, expectations, targets, intentions or beliefs about future events. All statements other than statements of historical facts, included or incorporated by reference in this Annual Report, relating to management's current expectations of future financial performance, continued growth, changes in economic conditions or capital markets and changes in customer usage patterns and preferences are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934.

Words or phrases such as “anticipates," “may," “will," “should," “believes," “estimates," “expects," “intends," “plans," “predicts," “projects," “targets," “will likely result," “will continue" or similar expressions identify forward-looking statements. Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. We caution that while we make such statements in good faith and believe such statements are based on reasonable assumptions, including without limitation, management's examination of historical operating trends, data contained in records and other data available from third parties, we cannot assure you that we will achieve our projections. Factors that may cause such differences include, but are not limited to:

- potential adverse federal, state, or local legislation or regulation or adverse determinations by regulators could have a material adverse effect on our liquidity, results of operations and financial condition;
- changes in availability of trade credit, creditworthiness of counterparties, usage, commodity prices, fuel supply costs or availability due to higher demand, shortages, weather conditions, transportation problems or other developments, may reduce revenues or may increase operating costs, each of which could adversely affect our liquidity and results of operations;
- unscheduled generation outages or forced reductions in output, maintenance or repairs, which may reduce revenues and increase cost of sales or may require additional capital expenditures or other increased operating costs; and
- adverse changes in general economic and competitive conditions in the U.S. financial markets and in our service territories.

We have attempted to identify, in context, certain of the factors that we believe may cause actual future experience and results to differ materially from our current expectation regarding the relevant matter or subject area. In addition to the items specifically discussed above, our business and results of operations are subject to the uncertainties described under the caption “Risk Factors" which is part of the disclosure included in Part I, Item 1A of this Annual Report.

From time to time, oral or written forward-looking statements are also included in our reports on Forms 10-Q and 8-K, Proxy Statements on Schedule 14A, press releases, analyst and investor conference calls, and other communications released to the public. We believe that at the time made, the expectations reflected in all of these forward-looking statements are and will be reasonable. However, any or all of the forward-looking statements in this Annual Report on Form 10-K, our reports on Forms 10-Q and 8-K, our Proxy Statements on Schedule 14A and any other public statements that are made by us may prove to be incorrect. This may occur as a result of assumptions, which turn out to be inaccurate or as a consequence of known or unknown risks and uncertainties. Many factors discussed in this Annual Report on Form 10-K, certain of which are beyond our control, will be important in determining our future performance. Consequently, actual results may differ materially from those that might be anticipated from forward-looking statements. In light of these and other uncertainties, you should not regard the inclusion of any of our forward-looking statements in this Annual Report on Form 10-K or other public communications as a representation by us that our plans and objectives will be achieved, and you should not place undue reliance on such forward-looking statements.

We undertake no obligation, to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. However, your attention is directed to any further disclosures made on related subjects in our subsequent annual and periodic reports filed with the Securities and Exchange Commission (SEC) on Forms 10-K, 10-Q and 8-K and Proxy Statements on Schedule 14A.

Unless the context requires otherwise, references to “we,” “us,” “our,” “NorthWestern Corporation,” “NorthWestern Energy,” and “NorthWestern” refer specifically to NorthWestern Corporation and its subsidiaries.

GLOSSARY

Accounting Standards Codification (ASC) - The single source of authoritative nongovernmental GAAP, which supersedes all existing accounting standards.

Allowance for Funds Used During Construction (AFUDC) - A regulatory accounting convention that represents the estimated composite interest costs of debt and a return on equity funds used to finance construction. The allowance is capitalized in the property accounts and included in income.

Base-Load - The minimum amount of electric power or natural gas delivered or required over a given period of time at a steady rate. The minimum continuous load or demand in a power system over a given period of time usually is not temperature sensitive.

Base-Load Capacity - The generating equipment normally operated to serve loads on an around-the-clock basis.

Competitive Transition Charges - Out of market energy costs associated with the change of an industry from a regulated, bundled service to a competitive open-access service.

Cushion Gas - The natural gas required in a gas storage reservoir to maintain a pressure sufficient to permit recovery of stored gas.

Deregulation - In the energy industry, the process by which regulated markets become competitive markets, giving customers the opportunity to choose their energy supplier.

Environmental Protection Agency (EPA) - A Federal agency charged with protecting the environment.

Federal Energy Regulatory Commission (FERC) - The Federal agency that has jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas transmission and related services pricing, oil pipeline rates and gas pipeline certification.

Franchise - A special privilege conferred by a unit of state or local government on an individual or corporation to occupy and use the public ways and streets for benefit to the public at large. Local distribution companies typically have exclusive franchises for utility service granted by state or local governments.

GAAP - Accounting principles generally accepted in the United States of America.

Hedging - Entering into transactions to manage various types of risk (e.g. commodity risk).

Hinshaw Exemption - A pipeline company (defined by the Natural Gas Act (NGA) and exempted from FERC jurisdiction under the NGA) defined as a regulated company engaged in transportation in interstate commerce, or the sale in interstate commerce for resale, of natural gas received by that company from another person within or at the boundary of a state, if all the natural gas so received is ultimately consumed within such state. A pipeline company with a Hinshaw exemption may receive a certificate authorizing it to transport natural gas out of the state in which it is located, without giving up its Hinshaw exemption.

Lignite Coal - The lowest rank of coal, often referred to as brown coal, used almost exclusively as fuel for steam-electric power generation. It has high inherent moisture content, sometimes as high as 45 percent. The heat content of lignite ranges from 9 to 17 million Btu per ton on a moist, mineral-matter-free basis.

Midcontinent Area Power Pool (MAPP) - A voluntary association of electric utilities and other electric industry participants that acts as a regional transmission group, responsible for facilitating open access of the transmission system and a generation reserve sharing pool to meet regional demand.

Midwest Independent Transmission System Operator (MISO) - The MISO is a nonprofit organization created in compliance with FERC as a Regional Transmission Organization, to improve the flow of electricity in the regional marketplace and to enhance electric reliability. Additionally, MISO is responsible for managing the energy markets, managing transmission constraints, managing the day-ahead, real-time and financial transmission rights markets and managing the ancillary market.

Montana Consumer Counsel (MCC) - A Montana state constitution established advocate for public utility and transportation consumers, which represents them before the MPSC, state and federal courts, and administrative agencies in matters concerning public utility regulation.

Montana Public Service Commission (MPSC) - The state agency that regulates public utilities doing business in Montana.

Nebraska Public Service Commission (NPSC) - The state agency that regulates public utilities doing business in Nebraska.

North American Electric Reliability Corporation (NERC) - NERC oversees eight regional reliability entities and encompasses all of the interconnected power systems of the contiguous United States. NERC's major responsibilities include developing standards for power system operation, monitoring and enforcing compliance with those standards, assessing resource adequacy, and providing educational and training resources as part of an accreditation program to ensure power system operators remain qualified and proficient.

Open Access - Non-discriminatory, fully equal access to transportation or transmission services offered by a pipeline or electric utility.

Open Access Transmission Tariff (OATT) -The OATT, which is established by the FERC, defines the terms and conditions of point-to-point and network integration transmission services offered by us, and requires that transmission owners provide open, non-discriminatory access on their transmission system to transmission customers.

Open Season - A period of time in which potential customers can bid for services, and during which such customers are treated equally regarding priority in the queue for service.

Peak Load - A measure of the maximum amount of energy delivered at a point in time.

Qualifying Facility (QF) - As defined under the Public Utility Regulatory Policies Act of 1978, a QF sells power to a regulated utility at a price determined by a public service commission that is intended to be equal to that which the utility would otherwise pay if it were to build its own power plant or buy power from another source.

Regional Transmission Organization (RTO) - An independent entity, which is established to have “functional control" over utilities' transmission systems, to expedite transmission of electricity. RTO's typically operate markets within their territories.

Securities and Exchange Commission (SEC) - The U.S. agency charged with protecting investors, maintaining fair, orderly and efficient markets and facilitating capital formation.

South Dakota Public Utilities Commission (SDPUC) - The state agency that regulates public utilities doing business in South Dakota.

Sub-bituminous Coal - A coal whose properties range from those of lignite to those of bituminous coal and used primarily as fuel for steam-electric power generation. Sub-bituminous coal contains 20 to 30 percent inherent moisture by weight. The heat content of sub-bituminous coal ranges from 17 to 24 million Btu per ton on a moist, mineral-matter-free basis.

Tariffs - A collection of the rate schedules and service rules authorized by a federal or state commission. It lists the rates a regulated entity will charge to provide service to its customers as well as the terms and conditions that it will follow in providing service.

Test Period - In a rate case, a test period is used to determine the cost of service upon which the utility's rates will be based. A test period consists of a base period of twelve consecutive months of recent actual operational experience, adjusted for changes in revenues and costs that are known and are measurable with reasonable accuracy at the time of the rate filing and which will typically become effective within nine months after the last month of actual data utilized in the rate filing.

Tolling Contract - An arrangement whereby a party moves fuel to a power generator and receives kilowatt hours (kWh) in return for a pre-established fee.

Transmission - The flow of electricity from generating stations over high voltage lines to substations. The electricity then flows from the substations into a distribution network.

Western Area Power Administration (WAPA) - One of five federal power-marketing administrations and electric transmission agencies established by Congress.

Western Electricity Coordination Council (WECC) - WECC is one of eight regional electric reliability councils under NERC.

Measurements:

Billion Cubic Feet (Bcf) - A unit used to measure large quantities of gas, approximately equal to 1 trillion Btu.

British Thermal Unit (Btu) - a basic unit used to measure natural gas; the amount of natural gas needed to raise the temperature of one pound of water by one degree Fahrenheit.

Degree-Day - A measure of the coldness / warmness of the weather experienced, based on the extent to which the daily mean temperature falls below or above a reference temperature.

Dekatherm - A measurement of natural gas; ten therms or one million Btu.

Kilovolt (kV) - A unit of electrical power equal to one thousand volts.

Megawatt (MW) - A unit of electrical power equal to one million watts or one thousand kilowatts.

Megawatt Hour (MWH) - One million watt-hours of electric energy. A unit of electrical energy which equals one megawatt of power used for one hour.

Part I

ITEM 1. BUSINESS

OVERVIEW

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas to approximately 661,000 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.

We were incorporated in Delaware in November 1923. Our Annual Report on Form 10-K, our Quarterly Reports on Form 10-Q, our Current Reports on Form 8-K and amendments to such reports filed or furnished pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, along with our annual report to shareholders and other information related to us, are available, free of charge, on our Internet website as soon as reasonably practicable after we electronically file those documents with, or otherwise furnish them to, the SEC. This information is available in print to any shareholder who requests it. Requests should be directed to: Investor Relations, NorthWestern Corporation, 3010 W. 69th Street, Sioux Falls, South Dakota 57108 and our telephone number is (605) 978-2900. We maintain an Internet website at http://www.northwesternenergy.com. Our Internet website and the information contained therein or connected thereto are not intended to be incorporated by reference into this Annual Report on Form 10-K and should not be considered a part of this Annual Report on Form 10-K.

We operate our business in the following reporting segments:

- Regulated electric operations;
- Regulated natural gas operations;
- All other, which primarily consists of a remaining unregulated natural gas contract, the wind down of our captive insurance subsidiary and our unallocated corporate costs.

SIGNIFICANT DEVELOPMENTS

Effective January 1, 2009, our joint ownership interest in Colstrip Unit 4 was placed into Montana utility rate base due to an MPSC order and is reflected in our regulated operations as a component of electric supply. Previously, this asset was reflected in our unregulated electric segment. We have not revised the presentation of the prior years segmented financial results due to the nature of the transfer of the asset from unregulated to the regulated business. For financial information regarding these segments, see Note 19 to the Consolidated Financial Statements.

We began construction in June 2009 on the Mill Creek Generating Station, which will provide regulating resources to balance our transmission system in Montana to maintain reliability and enable wind power to be integrated onto the network to meet renewable energy portfolio needs. The project is estimated to cost approximately $202 million and is scheduled to be operational by December 31, 2010. In addition, we have proposed three major transmission projects in Montana – the Colstrip Upgrade, Collector Project and MSTI – to facilitate development of new generation. The Colstrip Upgrade involves an expansion of the existing Colstrip 500 kV system including an additional substation and related electrical equipment to increase westbound capacity out of Montana by more than 500 MW. The Collector Project consists of up to five new transmission lines in Montana that would connect new generation, primarily wind farms, to our existing transmission system and to the proposed MSTI line. All of the new proposed wind generation that would be served by the Collector Project would be located in Montana. MSTI is a proposed 500kV transmission line from southwestern Montana to southeastern Idaho. For further discussion of these projects, see the Strategy section in Management's Discussion and Analysis of Financial Condition and Results of Operations.

REGULATED ELECTRIC OPERATIONS

MONTANA

Our regulated electric utility business in Montana includes generation, transmission and distribution. Our service territory covers approximately 107,600 square miles, representing approximately 73% of Montana's land area, and includes a population of approximately 786,000 according to the 2000 census. We deliver electricity to approximately 335,000 customers in 187 communities and their surrounding rural areas, 15 rural electric cooperatives and in Wyoming to the Yellowstone National Park. In 2009, by category, residential, commercial and industrial, and other sales accounted for approximately 33%, 46%, and 21%, respectively, of our Montana regulated electric utility revenue. We also transmit electricity for nonregulated entities owning generation facilities, other utilities and power marketers serving the Montana electricity market. The total control area peak demand was approximately 1,766 MWs, the average daily load was approximately 1,216 MWs, and more than 10.6 million MWHs were supplied during the year ended December 31, 2009.

Our Montana electric transmission system consists of approximately 7,000 miles of transmission lines, ranging from 50 to 500 kV, 272 circuit segments and approximately 125,000 transmission poles with associated transformation and terminal facilities, and extends throughout the western two-thirds of Montana from Colstrip in the east to Thompson Falls in the west. Our 500 kV transmission system, which is jointly owned, 230 kV and 161 kV facilities form the key assets of our Montana transmission system. Lower voltage systems, which range from 50 kV to 115 kV, provide for local area service needs. The system has interconnections with five major nonaffiliated transmission systems located in the WECC area, as well as one interconnection to a nonaffiliated system that connects with the MAPP region. With these interconnections, we transmit power to and from diverse interstate transmission systems, including those operated by Avista Corporation; Idaho Power Company; PacifiCorp; the Bonneville Power Administration; and WAPA.

Our Montana electric distribution system consists of approximately 21,400 miles of overhead and underground distribution lines and 336 transmission and distribution substations.

Electric Supply

Our joint ownership interest in Colstrip Unit 4 is expected to supply approximately 13% of our Montana base-load requirements through 2010 and approximately 25% thereafter. During 2009, we purchased the remaining quantity of our Montana capacity and energy requirements from third parties. Our annual electric supply load requirements average approximately 730 MWs. We currently have under contract approximately 75% of the energy requirements necessary to meet our projected load requirements through June 30, 2010, with approximately 74% at fixed prices. For the period July 1, 2010 through June 30, 2011, we have under contract approximately 76% of our projected load requirements, with approximately 75% at fixed prices. Remaining customer load requirements are met with market purchases. Specifically, we have a seven-year power purchase agreement with PPL Montana for 325 MWs of on-peak supply and 175 MWs of off-peak supply through June 2010 and decreasing volumes thereafter through June 2014. We also purchase power under several QF contracts entered into under the Public Utility Regulatory Policies Act of 1978, which provide a total of 114 MWs of contracted capacity. We have several other long and medium-term power purchase agreements including contracts for 148 MWs of wind generation and 14 MWs of seasonal base-load hydro supply, with an additional 13 MW of seasonal hydro under contract and expected to begin commercial operation in 2011. We file a biennial Electric Supply Resource Procurement Plan with the MPSC which guides future resource acquisition activities. We expect to file the next plan in April 2010.

Renewable portfolio standards enacted in Montana require that a certain portion of our electric supply be obtained from renewable sources, including wind, biomass, solar and small hydroelectric. The requirements are currently 5%, increasing to 10% by 2010 and 15% by 2015. Based on our current projections, we believe we will meet these requirements. Approximately 8% of our electric supply requirements for 2009 were from renewable resources. The amounts in excess of the annual requirements can be carried forward to future periods. In addition to the general renewable requirements, beginning in 2012, under a separate Community Renewable Energy Project provision, we are required to purchase output from community projects that total approximately 45 MWs in nameplate capacity.

Our electric supply purchases are being recovered through an electricity cost tracking process pursuant to which rates are adjusted on a monthly basis for electricity loads and electricity costs for the upcoming 12-month period. On an annual basis, rates are adjusted to include any differences in the previous tracking year's actual to estimated information, for recovery in the subsequent tracking year. The MPSC reviews the prudency of our electric supply procurement activities as part of the annual electric tracker filing.

FERC Regulation

We are subject to the jurisdiction of, and regulation by, the FERC with respect to rates for electric transmission service in interstate commerce and electricity sold at wholesale rates, the issuance of certain securities, incurrence of certain long-term debt, and compliance with mandatory reliability regulations, among other things.

In Montana, we sell transmission service across our system under terms, conditions and rates defined in our OATT, on file with FERC. We are required to provide retail transmission service in Montana under MPSC approved tariffs for customers still receiving “bundled" service and under the OATT for other wholesale transmission customers such as cooperatives. In 2007, FERC issued Order No. 890, Preventing Undue Discrimination and Preference in Transmission Service (Order 890). FERC Order 890 contained many changes to the OATT, and a number of items which all FERC jurisdictional entities, including us, were to comply with under various time frames defined by Order 890. We met or have approved mitigation plans for each of the compliance tasks by the dates specified by Order 890.

In January 2009, we filed a request with the FERC seeking negotiated rates for the proposed 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 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.

NERC Reliability - The Energy Policy Act of 2005 added a requirement for FERC to certify an Electric Reliability Organization (ERO) to develop mandatory and enforceable electric system reliability standards. FERC has certified the NERC as the ERO to develop these standards subject to FERC review and approval. On March 16, 2007, FERC issued Order 693, Mandatory Reliability Standards for the Bulk-Power System, which imposes penalties of up to $1.0 million per day per violation for failure to comply with new electric reliability standards. FERC initially approved 83 reliability standards developed by NERC. The 83 standards comprise over 550 requirements and sub-requirements. We must comply with the standards and requirements, which apply to the NERC functions for which we have registered in both the MRO (Midwest Reliability Organization) for our South Dakota operations and the WECC for our Montana operations. WECC has responsibility for monitoring and enforcing compliance with the FERC approved mandatory reliability standards within the western interconnection of the United States. Additional standards continue to be developed and will be adopted in the future. We expect that the existing standards will change often as a result of modifications, guidance and clarification following industry implementation and ongoing audits and enforcement.

We completed our compliance audit for our Montana operations under the compliance monitoring and enforcement program of the WECC during 2009. In connection with the compliance audit, WECC found no violations of the applicable standards. Since June 2007, we have identified and self-reported violations of 32 requirements to WECC. All but nine of these violations were dismissed or were subject to expedited dispositions with no penalties. During the fourth quarter of 2009, we reached a settlement agreement with WECC addressing six of the remaining nine violations for a total penalty of $80,000, which has been accrued. The settlement is pending formal NERC and FERC approval. The remaining three violations all relate to one standard and this standard is pending a NERC interpretation. We also filed mitigation plans for two potential violations with the MRO for our South Dakota operations. We have completed the mitigation measures in compliance with the plans and expect to hear from the MRO during the first half of 2010 of any further action. We expect our compliance with NERC standards will be audited at least every three years.

The Area Control Error Diversity Interchange (ADI) between the Idaho Power Company, PacifiCorp and our control areas was implemented during the first quarter of 2007. The ADI allows the participating utilities to net their control error balances across the participating utilities, rather than requiring each utility to balance on a one-to-one basis, which allows the utilities to stay in balance as a group (and make less generation level movements (regulating service) to stay in balance), thereby reducing the costs of staying in compliance with NERC's requirements. Since the initial implementation, thirteen additional Balancing Authorities (BAs) have signed the ADI agreement. Seven BAs have fully implemented the system and two BAs are expected to complete implementation in early 2010. The remaining four are expected to complete implementation in the third quarter of 2010. The BAs are located in the Pacific Northwest and Southwest regions of the WECC Interconnection.

MPSC Regulation

Our Montana operations are subject to the jurisdiction of the MPSC with respect to rates, terms and conditions of service, accounting records, electric service territorial issues and other aspects of our operations, including when we issue, assume, or guarantee securities in Montana, or when we create liens on our regulated Montana properties.

Montana's Electric Utility Industry Restructuring and Customer Choice Act was passed in 1997, which provided for deregulation and allowed for customer choice and competition among suppliers. During 2007, the Montana legislature passed House Bill 25 (HB 25), labeled *The Generation Reintegration Act*, which became effective October 1, 2007. This bill largely removed the remaining remnants of deregulation from Montana law that began in 1997 by eliminating customer choice for all customers except for the largest industrial customers using more than five MWs, and permits utilities to build and own electric generation assets that would be included in utility cost of service. In addition, the bill provided for a timely advanced approval process for electric supply resource projects and requires carbon offsets to reduce carbon dioxide emissions.

Mill Creek Generating Station - In August 2008, we filed a request with the MPSC for advanced approval to construct a 150 MW natural gas fired facility. The Mill Creek Generating Station, estimated to cost approximately $202 million, will provide energy supply and transmission regulating resources to balance our transmission system in Montana. 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 is scheduled to be operational by December 31, 2010.

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 request was based on a 2008 test period, a return on equity of 10.9%, an equity ratio of 49.45% and rate base of $632.2 million and $256.6 million for electric and natural gas, respectively.

In November 2009, the MPSC issued a determination that the rate case filing did not meet the MPSC's applicable minimum filing requirements, related to allocated cost of service and rate design. We submitted a supplemental filing on January 15, 2010 to meet the MPSC's minimum filing requirements, which was accepted as compliant on February 2, 2010. We have agreed to extend the timeframe by which the MPSC must issue a final order concerning the general rate filing by 90 days to October 11, 2010. We requested interim rate adjustments, which may be authorized during the processing of the filing if the MPSC finds it meets the established criteria. Final rate adjustments would become effective upon the issuance of a final order on this matter.

Cost Recovery Clauses

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. 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.

On May 30, 2008, we filed an annual electric supply cost tracker request with the MPSC for any unrecovered actual electric supply costs for the 12-month period ended June 30, 2008 and for the projected electric supply costs for the 12-month period ended June 30, 2009. On June 27, 2008, the MPSC issued an interim order approving recovery of our projected electric supply costs. On May 29, 2009, we filed an annual electric supply cost tracker request with the MPSC for any unrecovered actual electric supply costs for the 12-month period ended June 30, 2009 and for the projected electric supply costs for the 12-month period ended June 30, 2010. On June 26, 2009, the MPSC issued an interim order approving recovery of our projected electric supply costs. Our annual electric supply cost tracker requests for the 12-month periods ended June 30, 2008 and June 30, 2009 were combined and are still pending final approval of the MPSC. The MCC disputed (1) our ability to use financial swaps in purchasing electricity supply, (2) the recovery of certain labor costs associated with real-time schedulers and (3) our estimated revenues associated with demand side management for our Colstrip Unit 4 generation asset. During the fourth quarter of 2009, we entered into a settlement with the MCC agreeing to (a) withdraw our request to use financial swaps, (b) remove approximately $100,000 in labor costs and (c) remove approximately $83,000 of calculated lost revenues from the tracker. On February 3, 2010, the MPSC conducted a hearing to review the filings and resulting settlement and scheduled additional briefing for March 2010.

On June 2, 2009, we filed an annual gas cost tracker request with the MPSC for any unrecovered actual gas costs for the 12-month period ended June 30, 2009, and for the projected gas costs for the 12-month period ending June 30, 2010. On June 24, 2009, the MPSC issued an interim order, approving recovery of our projected gas costs pending its review. No procedural schedule has been established for this request.

Montana Property Tax Tracker **-** In December 2009, 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 2009 actual property taxes and estimated property taxes for 2010. This filing also included an adjustment for property taxes related to Colstrip Unit 4. In our 2008 filing requesting to include our interest in Colstrip Unit 4 in utility rate base, we estimated base property taxes would be approximately $5.5 million, by multiplying the rate base value by the latest known mill levy. This filing was approved by the MPSC. Actual 2009 Colstrip Unit 4 related property taxes were approximately $2.1 million and we proposed refunding 60% of the change to customers, consistent with previous MPSC orders. In January 2010, the MPSC issued an order requiring us to reset the base rates for Colstrip, effectively requiring us to refund 100% of the change in property taxes from our original 2008 filing. While we have accounted for our property tax tracker consistent with the MPSC's January 2010 order, we are disputing various aspects of the order and have filed a Motion for Reconsideration with the MPSC.

SOUTH DAKOTA

Our South Dakota electric utility business operates as a vertically integrated generation, transmission and distribution utility. We have the exclusive right to serve an area in South Dakota comprised of 25 counties with a combined population of approximately 99,900 according to the 2000 census. We provide retail electricity to more than 60,500 customers in 110 communities in South Dakota. In 2009, by category, residential, commercial and industrial, wholesale, and other sales accounted for approximately 39%, 55%, 5% and 1%, respectively, of our South Dakota electric utility revenue. Peak demand was approximately 284 MWs, the average daily load was approximately 162 MWs, and more than 1.42 million MWHs were supplied during the year ended December 31, 2009.

Residential, commercial and industrial services are generally bundled packages of generation, transmission, distribution, meter reading, billing and other services. In addition, we provide wholesale transmission of electricity to a number of South Dakota municipalities, state government agencies and agency buildings. For these wholesale sales, we are responsible for the transmission of contracted electricity to a substation or other distribution point, and the purchaser is responsible for further distribution, billing, collection and other related functions. We also provide sales of electricity to resellers, primarily including power pools or other utilities. Sales to power pools fluctuate from year to year depending on a number of factors, including the availability of excess short-term generation and the ability to sell excess power to other utilities in the power pool.

Our transmission and distribution network in South Dakota consists of approximately 3,300 miles of overhead and underground transmission and distribution lines as well as 123 substations. We have interconnection and pooling arrangements with the transmission facilities of Otter Tail Power Company; Montana-Dakota Utilities Co.; Xcel Energy Inc.; and WAPA. We have emergency interconnections with the transmission facilities of East River Electric Cooperative, Inc. and West Central Electric Cooperative. These interconnection and pooling arrangements enable us to arrange purchases or sales of substantial quantities of electric power and energy with other pool members and to participate in the efficiency benefits of pool arrangements.

Direct competition does not presently exist within our South Dakota service territory for the supply and delivery of electricity, except with regard to certain new large load customers with demand in excess of two MWs. The SDPUC, pursuant to the South Dakota Public Utilities Act, assigned the South Dakota service territory to us effective March 1976. Pursuant to that law, we have the exclusive right, other than as previously noted, to provide fully bundled services, as described above, to all present and future electric customers within our assigned territory for so long as the service provided is adequate. We are not aware of any allegations of inadequate service since assignment in 1976. The assignment of a service territory is perpetual under current South Dakota law; however, the local government of each of the municipalities we serve does have the right to condemn our facilities and establish a municipal utility distribution system.

Electric Supply

Most of the electricity that we supply to customers in South Dakota is generated by power plants that we own jointly with unaffiliated parties. In addition, we have several wholly owned peaking/standby generating units at seven locations throughout our service territory. Details of our generating facilities are described further in the chart below. Each of the jointly owned plants is subject to a joint management structure. We are not the operator of any of these plants. Except as otherwise noted, we are entitled to a proportionate share of the electricity generated in our jointly owned plants and are responsible for a proportionate share of the operating expenses, based upon our ownership interest. Most of the power allocated to us from these facilities is distributed to our South Dakota customers. During periods of lower demand, electricity in excess of our load requirements is sold in the competitive wholesale market. In 2009, this was approximately 14% of our share of the power generated. We use market purchases and internal peaking generation to provide peak supply in excess of our base-load capacity.

Name and Location of Plant	Fuel Source	Our Ownership Interest	Our Share of 2009 Peak Summer Demonstrated Capacity (MW)	% of Total 2009 Peak Summer Demonstrated Capacity
Big Stone Plant, located near Big Stone City in northeastern South Dakota	Sub-bituminous coal	23.4%	110.54	35.4%
Coyote I Electric Generating Station, located near Beulah, North Dakota	Lignite coal	10.0	42.70	13.7
Neal Electric Generating Unit No. 4, located near Sioux City, Iowa	Sub-bituminous coal	8.7	56.83	18.2
Miscellaneous combustion turbine units and small diesel units (used only during peak periods)	Combination of fuel oil and natural gas	100.0	102.14	32.7
Total Capacity			312.21	100.0%

Legislation passed in 2008 in South Dakota established a voluntary renewable and recycled energy objective for retail providers of electricity. The objective states that 10% of all electricity sold at retail within South Dakota by 2015 be obtained from renewable energy and recycled energy sources. In December 2008, we entered into a 20-year power purchase agreement for 25 MWs of electric supply from the Titan I Wind Project in Hand County, South Dakota. Under this agreement, at the end of the fourth and fifth contract year we have an option to purchase the project. In addition, if additional capacity is built we have the first right of refusal to purchase the output. The commercial operation date was November 25, 2009. This power is expected to cover approximately 5% of our load and is the first renewable source of energy to be made available to customers in South Dakota. We are in the process of conducting Request for Proposals (RFP) for additional renewable resources in South Dakota in order to meet this objective.

MidAmerican provided 71 MWs of firm capacity during the summer months of 2009 and we have an agreement with them to supply firm capacity of 74 MWs in 2010, 77 MWs in 2011 and 80 MWs in 2012, pending transmission availability. We are a member of the MAPP, which is an area power pool arrangement consisting of utilities and power suppliers having transmission interconnections located in a nine-state area in the North Central region of the United States and in two Canadian provinces. The terms and conditions of the MAPP agreement and transactions between MAPP members are subject to the jurisdiction of the FERC.

We have a resource plan that includes estimates of customer usage and programs to provide for economic, reliable and timely supply of energy. We continue to update our load forecast to identify the future electric energy needs of our customers, and we evaluate additional generating capacity requirements on an ongoing basis. This forecast shows customer peak demand growing modestly, which will result in the need to add peaking capacity in the future; however, we believe we have adequate base-load generation capacity to meet customer supply needs through at least 2015. We are undergoing an evaluation of our needs for base-load supply beyond that point based on our current load forecast.

Coal was used to generate approximately 99% of the electricity utilized for South Dakota operations for the year ended December 31, 2009. Our natural gas and fuel oil peaking units provided the balance of generating capacity. We have no interests in nuclear generating plants. The fuel for our jointly owned base-load generating plants is provided through supply contracts of various lengths with several coal companies. Coyote is a mine-mouth generating facility. Neal #4 and Big Stone receive their fuel supply via rail. Continuing upward pressure on coal prices and transportation costs could result in increases in costs to our customers due to mechanisms to recover fuel adjustments in our rates. The average cost, inclusive of transportation costs, by type of fuel burned is shown below for the periods indicated:

	Cost per Million Btu for the Year Ended December 31,			
Fuel Type – Generating Station	**2009**	**2008**	**2007**	**Percent of 2009 MWH Generated**
Sub-bituminous-Big Stone	$ 1.85	$ 1.77	$ 1.55	51.8%
Lignite-Coyote	1.19	1.18	1.06	19.5
Sub-bituminous-Neal	1.37	1.24	1.15	28.3
Natural Gas	5.44	8.52	7.41	0.2
Oil	15.82	19.34	13.11	0.2

During the year ended December 31, 2009, the average delivered cost per ton of fuel burned for our base-load plants was $30.41 at Big Stone, $16.41 at Coyote and $19.64 at Neal #4. The average delivered cost by type of fuel burned varies between generation facilities due to differences in transportation costs and owner purchasing power for coal supply. Changes in our fuel costs are passed on to customers through the operation of the fuel adjustment clause in our South Dakota tariffs.

The Big Stone facility currently burns sub-bituminous coal from the Powder River Basin delivered under a contract through 2010. Big Stone is in process of submitting a request for proposal for coal supply through 2012. Neal #4 also receives sub-bituminous coal from the Powder River Basin delivered under multiple firm and spot contracts with terms of up to several years in duration. The Coyote facility has a contract for the supply of lignite coal that expires in 2016.

The South Dakota Department of Environment and Natural Resources has given approval for Big Stone to burn a variety of alternative fuels, including tire-derived fuel and refuse-derived fuel. In 2009, approximately 0.3% of the fuel consumption at Big Stone was derived from alternative fuels.

Although we have no firm contract for the supply of diesel fuel or natural gas for our electric peaking units, we have historically been able to purchase diesel fuel requirements from local suppliers and have enough diesel fuel in storage to satisfy our current requirements. We have been able to use excess capacity from our natural gas operations as the fuel source for our gas peaking units.

We must pay fees to third parties to transmit the power generated at our Big Stone, Coyote, and Neal #4 plants to our South Dakota transmission system. We have a 10-year agreement, expiring December 31, 2010, with WAPA for transmission services, including transmission of electricity from Big Stone, Coyote, and Neal #4 to our South Dakota service areas through seven points of interconnection on WAPA's system. We anticipate renewing this agreement with WAPA in advance of the expiration date. Transmission services under this agreement, and our costs for such services, are variable and depend upon a number of factors, including the respective parties' system peak demand and the number of our transmission assets that are integrated into WAPA's system. In 2009, our costs for services under this contract totaled approximately $6.1 million. Our tariffs in South Dakota generally allow us to pass through these transmission costs to our customers.

FERC Regulation

Our South Dakota transmission operations underlie the MISO system and are part of the WAPA Control Area. The Coyote and Big Stone power plants, of which we are a joint owner, are connected directly to the MISO system, and we have ownership rights in the transmission lines from these plants to our distribution system. We have negotiated a settlement as a grandfathered agreement with MISO and the other Big Stone and Coyote power plant joint owners related to providing MISO with the information it needs to operate its system, while exempting us from assignment of MISO operational costs. We are not participating in the MISO markets directly, but continue to utilize WAPA to handle our scheduling and power marketing activities who does utilize the MISO market. MISO provides the reliability coordinator functions for MAPP. We updated the South Dakota OATT to accommodate the required planning functions that rely heavily on MAPP's planning process and MAPP's coordination with MISO.

See the "Montana - FERC Regulation" section for a discussion of the NERC compliance requirements also applicable to our South Dakota operations.

SDPUC Regulation

Our South Dakota operations are subject to SDPUC jurisdiction with respect to rates, terms and conditions of service, accounting records, electric service territorial issues and other aspects of our operations. Our retail electric rates, approved by the SDPUC, provide several options for residential, commercial and industrial customers, including dual-fuel, interruptible, special all-electric heating, and other special rates, as well as various incentive riders to encourage business development. An adjustment clause provides for quarterly adjustment based on differences in the delivered cost of energy, delivered cost of fuel, ad valorem taxes paid and commission-approved fuel incentives. The adjustment goes into effect upon filing, and is deemed approved within 10 days after the information filing unless the SDPUC staff requests changes during that period.

REGULATED NATURAL GAS OPERATIONS

<u>MONTANA</u>

We distribute natural gas to approximately 180,100 customers in 105 Montana communities. We also serve several smaller distribution companies that provide service to approximately 32,000 customers. Our natural gas distribution system consists of approximately 4,100 miles of underground distribution pipelines. We transmit natural gas in Montana from production receipt points and storage facilities to distribution points and other nonaffiliated transmission systems. We transported natural gas volumes of approximately 40 Bcf, and our peak capacity was approximately 335,000 dekatherms per day during the year ended December 31, 2009.

Our natural gas transmission system consists of more than 2,000 miles of pipeline, which vary in diameter from two inches to 20 inches, and serve more than 130 city gate stations. We have connections in Montana with five major, nonaffiliated transmission systems: Williston Basin Interstate Pipeline, NOVA Gas Transmission Ltd., Colorado Interstate Gas, Encana and Havre Pipeline. Seven compressor sites provide more than 42,000 horsepower, capable of moving more than 325,000 dekatherms per day. In addition, we own and operate a pipeline border crossing through our wholly owned subsidiary, Canadian-Montana Pipe Line Corporation.

We own and operate three working natural gas storage fields in Montana with aggregate working gas capacity of approximately 17.75 Bcf and maximum aggregate daily deliverability of approximately 195,000 dekatherms.

We have nonexclusive municipal franchises to transport and distribute natural gas in the Montana communities we serve. The terms of the franchises vary by community, but most are for 30 to 50 years. During the next five years, 19 of our municipal franchises, which account for approximately 79,900 customers, are scheduled to expire. Our policy is to seek renewal of a franchise in the last year of its term.

Natural Gas Supply

We supply natural gas to customers that have not chosen other suppliers. Our natural gas supply requirements are fulfilled through third-party fixed-term purchase contracts and short-term market purchases. Our portfolio approach to natural gas supply is intended to enable us to maintain a diversified supply of natural gas sufficient to meet our supply requirements. We benefit from direct access to suppliers in the major natural gas producing regions in the United States, primarily the Rockies (Colorado), Mid-Continent, Panhandle (Texas/Oklahoma), Montana, and Alberta, Canada. These suppliers also provide us with market insight, which assists us in making procurement decisions. Our Montana natural gas supply requirements for the year ended December 31, 2009, were approximately 21 Bcf. We have contracted with several major producers and marketers with varying contract durations to provide the anticipated supply to meet ongoing requirements.

Natural gas is used primarily for residential and commercial heating. As a result, the demand for natural gas depends upon weather conditions. Natural gas is a commodity that is subject to market price fluctuations. Our gas supply purchases are also recovered through a gas cost tracking process, which provides for the adjustment of rates on a monthly basis to reflect changes in gas prices. On an annual basis rates are adjusted to include any differences in the previous tracking year's actual to estimated information, for recovery in the subsequent tracking year. The MPSC reviews the prudency of our gas procurement activities as part of this annual gas tracking filing.

We filed a Biennial Natural Gas Procurement Plan in December 2008. This gas plan provides the MPSC the blueprint we will follow in procuring natural gas supply to meet our gas supply needs and reliability requirements and the implementation of hedging strategies to reduce price volatility.

FERC Regulation

FERC Order No. 636 requires that all companies with interstate natural gas pipelines separate natural gas supply and production services from interstate transportation service and underground storage services. The effect of the order was that natural gas distribution companies, such as us, and individual customers purchase natural gas directly from producers, third parties and various gas-marketing entities and transport it through interstate pipelines. We have established transportation rates on our transmission and distribution systems to allow customers to have supply choices. Our transportation tariffs have been designed to make us economically indifferent as to whether we sell and transport natural gas or merely deliver it for the customer.

Our natural gas transportation pipelines are generally not subject to the jurisdiction of the FERC, although we are subject to state regulation. We conduct limited interstate transportation in Montana that is subject to FERC jurisdiction, but through a Hinshaw Exemption the FERC has allowed the MPSC to set the rates for this interstate service.

MPSC Regulation

Our Montana operations are subject to the jurisdiction of the MPSC with respect to natural gas rates, terms and conditions of service, accounting records, and other aspects of our operations.

Montana General Rate Case – See “Regulated Electric Operations – Montana - MPSC Regulation – Montana General Rate Case” for a discussion of the Montana general rate filing.

SOUTH DAKOTA AND NEBRASKA

We provide natural gas to approximately 85,100 customers in 60 South Dakota communities and four Nebraska communities. We have approximately 2,300 miles of underground distribution pipelines in South Dakota and Nebraska. In South Dakota, we also transport natural gas for five gas-marketing firms and three large end-user accounts, currently serving 85 customers through our distribution systems. In Nebraska, we transport natural gas for three gas-marketing firms and one end-user account, servicing eight customers through our distribution system. We delivered approximately 22.2 Bcf of third-party transportation volume on our South Dakota distribution system and approximately 2.1 Bcf of third-party transportation volume on our Nebraska distribution system during 2009.

We have nonexclusive municipal franchises to purchase, transport and distribute natural gas in the South Dakota and Nebraska communities we serve. The maximum term permitted under Nebraska law for these franchises is 25 years while the maximum term permitted under South Dakota law is 20 years. Our policy is to seek renewal of a franchise in the last year of its term. During the next five years, 47 of our South Dakota and Nebraska municipal franchises, which account for approximately 59,700 customers, are scheduled to expire.

In South Dakota and Nebraska, we are subject to competition for natural gas supply. In addition, competition currently exists for commodity sales to large volume customers and for delivery in the form of system by-pass, alternative fuel sources such as propane and fuel oil and, in some cases, duplicate providers. We do not face material competition from alternative natural gas supply companies in the communities we serve in South Dakota and Nebraska.

Competition in the natural gas industry may result in the further unbundling of natural gas services. Separate markets may emerge for the natural gas commodity, transmission, distribution, meter reading, billing and other services currently provided by utilities. At present, it is unclear when or to what extent further unbundling of utility services will occur.

Natural Gas Supply

Our South Dakota natural gas supply requirements for the year ended December 31, 2009, were approximately 6.25 Bcf. We have contracted with Tenaska Marketing Ventures, Inc. in South Dakota to manage transportation, storage and procurement of supply to minimize cost and price volatility to our customers.

Our Nebraska natural gas supply requirements for the year ended December 31, 2009, were approximately 5.4 Bcf. Our Nebraska natural gas supply, storage and pipeline requirements are fulfilled primarily through a third-party contract with ONEOK Energy Services Co., which expires June 30, 2010. We are currently evaluating vendors for this contract.

To supplement firm gas supplies in South Dakota and Nebraska, we also contract for firm natural gas storage services to meet the heating season and peak day requirements of our natural gas customers. We also maintain and operate one propane-air gas peaking unit with a peak daily capacity of approximately 4,140 Mcf. These plants provide an economic alternative to pipeline transportation charges to meet the peaks caused by customer demand on extremely cold days.

Natural gas is used primarily for residential and commercial heating. As a result, the demand for natural gas depends upon weather conditions. Natural gas is a commodity that is subject to market price fluctuations. Purchase adjustment clauses contained in South Dakota and Nebraska tariffs allow us to pass through increases or decreases in gas supply and interstate transportation costs on a timely basis, so we are generally allowed to pass these changes in natural gas prices through to our customers.

FERC Regulation

Our natural gas transportation pipelines are generally not subject to the jurisdiction of the FERC, although we are subject to state regulation. We have capacity agreements with interstate pipelines that are subject to FERC jurisdiction.

SDPUC Regulation

Our South Dakota operations are subject to the jurisdiction of the SDPUC with respect to rates, terms and conditions of service, accounting records and other aspects of our natural gas distribution operations in South Dakota. A purchased gas adjustment provision in our natural gas rate schedules permits the monthly adjustment of charges to customers to reflect increases or decreases in purchased gas, gas transportation and ad valorem taxes.

Our retail natural gas tariffs, approved by the SDPUC, include gas transportation rates for transportation through our distribution systems by customers and natural gas marketers from the interstate pipelines at which our systems take delivery to the end-user's premises. Such transporting customers nominate the amount of natural gas to be delivered daily. Usage for these customers is monitored daily through electronic metering equipment by us and balanced against respective supply agreements.

NPSC Regulation

Our Nebraska natural gas rates and terms and conditions of service for residential and smaller commercial customers are regulated by the NPSC. High volume customers are not subject to such regulation but can file complaints if they allege discriminatory treatment. Under the Nebraska State Natural Gas Regulation Act, a regulated natural gas utility may propose a change in rates to its regulated customers, if it files an application for a rate increase with the NPSC and with the communities in which it serves customers. The utility may negotiate with those communities for a settlement with regard to the rate change, or it may proceed to have the NPSC review the filing and make a determination.

Subsequent to the 2004 enactment of the State Natural Gas Regulation Act, our tariffs have been accepted by the NPSC, and the NPSC has adopted certain rules governing the terms and conditions of service of regulated natural gas utilities. Our retail natural gas tariffs provide residential, general service and commercial and industrial options, as well as firm and interruptible transportation service. A purchased gas adjustment clause provides for adjustments based on changes in gas supply and interstate pipeline transportation costs.

SEASONALITY AND CYCLICALITY

Our electric and gas utility businesses are seasonal businesses, and weather patterns can have a material impact on operating performance. Because natural gas is used primarily for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our market areas, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Demand for electricity is often greater in the summer and winter months for cooling and heating, respectively. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. When we experience unusually mild winters or summers in the future, these weather patterns could adversely affect our results of operations, financial condition and liquidity.

ENVIRONMENTAL

The operation of electric generating, transmission and distribution facilities, and gas transportation and distribution facilities, along with the development (involving site selection, environmental assessments, and permitting) and construction of these assets, are subject to extensive federal, state, and local environmental and land use laws and regulations. Our activities involve compliance with diverse laws and regulations that address emissions and impacts to air and water, and protection of natural resources. We continuously monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are promulgated, our policy is to assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance.

Our environmental exposure includes a number of components, including remediation expenses related to the cleanup of current or former properties, and costs to comply with changing environmental regulations related to our operations. At present, the majority of our environmental reserve relates to the remediation of former manufactured gas plant (MGP) sites owned by us. We use a combination of site investigations and monitoring to formulate an estimate of environmental remediation costs for specific sites. Our monitoring procedures and development of actual remediation plans depend not only on site specific information but also on coordination with the different environmental regulatory agencies in our respective jurisdictions, therefore, while remediation exposure exists, it may be many years before costs become fixed and reliably determinable.

Our liability for environmental remediation obligations is estimated to range between $22.4 million to $44.1 million. As of December 31, 2009, we have a reserve of approximately $31.9 million. 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 consolidated financial position or ongoing operations. There can be no assurance, however, of regulatory recovery.

Global Climate Change

We have a joint 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. In addition, a significant portion of the electric supply we procure in the market is generated by coal-fired plants.

There is a growing concern nationally and internationally about global climate change and the contribution of emissions of greenhouse gases 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 greenhouse gas emissions. Recently, two federal courts of appeal reinstated nuisance claims against emitters of carbon dioxide, including several utility companies, alleging that such emissions contribute to global warming.

Specifically, coal-fired plants have come under scrutiny due to their emissions of carbon dioxide, and in September 2009, the U.S. Court of Appeals for the Second Circuit reversed a federal district court's decision and 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. In October 2009, the U.S. Court of Appeals for the Fifth Circuit reversed a federal district court and 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. Additional litigation in federal and state courts over these issues is continuing.

In addition to litigation during 2009, the EPA issued a finding that greenhouse gas emissions endanger the public health and welfare. The EPA's finding indicated that the current and projected levels of six greenhouse gas emissions – carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride contribute to climate change. In a related matter, the EPA also proposed rules that would require all new or modified "stationary sources," such as power plants, that emit 25,000 tons of greenhouse gases per year to obtain permits incorporating the "best available control technology" for such emissions.

In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, a bill introduced by Rep. Henry Waxman and Rep. Edward Markey and popularly known as the Waxman-Markey bill. The bill would regulate greenhouse gas emissions by instituting a cap-and-trade-system, in which an economy-wide cap on U.S. greenhouse gas emissions would be established starting in 2012 with a cap 3% below the baseline 2005 level. The cap would steeply decline over time until in 2050 it reaches 83% below the baseline level. Emission allowances, which are rights to emit greenhouse gases, would be both allocated for free and auctioned. In addition, the draft legislation contains a renewable energy standard of 25% by the year 2025 and an energy efficiency mandate for electric and natural gas utilities, as well as other requirements. Pending in the U.S. Senate is the Clean Energy Jobs and American Power Act introduced by Sens. John Kerry and Barbara Boxer, known as the Kerry-Boxer bill. The Kerry-Boxer bill also proposes to regulate greenhouse gas emissions by instituting a cap-and-trade-system, with primarily the same target levels proposed by the Waxman-Markey bill; however, the Kerry-Boxer bill is more aggressive in its 2020 target – a reduction to 20% below 2005 levels by 2020 (versus 17% in Waxman-Markey). Although the Waxman-Markey bill is widely viewed as the most probable climate change bill to be enacted into law, the prospects for passage of a similar bill by the U.S. Senate are uncertain.

Other nations have agreed to regulate emissions of greenhouse gases pursuant to the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol," an international treaty pursuant to which participating countries (not including the United States) have agreed to reduce their emissions of greenhouse gases to below 1990 levels by 2012. At the end of 2009, an international conference to develop a successor to the Kyoto Protocol issued a document known as the Copenhagen Accord. Pursuant to the Copenhagen Accord, the United States submitted a greenhouse gas emission reduction target of 17% compared to 2005 levels.

The Montana Governor's office has joined the Western Regional Climate Initiative (WCI) and is expected to participate in any greenhouse gas emission control regulations that are adopted by the WCI. The WCI, which has a goal of reducing carbon dioxide emissions 15% below the 2005 levels by 2020, currently is developing greenhouse gas emission allocations, offsets, and reporting recommendations.

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 greenhouse gases on generation facilities, the cost to us and / or our customers could be significant. We are proactively involved in analyzing the impacts of current legislative efforts on our customers and shareholders and are participating in public policy forums related to these issues.

In September 2009, the EPA announced the adoption of the first comprehensive national system for reporting emissions of carbon dioxide and other greenhouse gases produced by major sources in the United States. The new reporting requirements will apply to suppliers of fossil fuel and industrial chemicals, manufacturers of motor vehicles and engines, as well as large direct emitters of greenhouse gases with emissions equal to or greater than a threshold of 25,000 metric tons per year, which includes certain of our facilities. The effective date for gathering the data is January 2010 with the first mandatory reporting due in March 2011.

Clean Air Act - The Clean Air Act Amendments of 1990 and subsequent amendments stipulate limitations on sulfur dioxide and nitrogen oxide emissions from coal-fired power plants and motor vehicles. We comply with existing emission requirements through purchase of sub-bituminous coal, and we believe that we are in compliance with all presently applicable environmental protection requirements and regulations.

In September 2009, the EPA proposed rules to reduce greenhouse gas emissions from light-duty vehicles. Final adoption of the proposed standards for light-duty vehicles is contingent on the EPA first finalizing its proposed endangerment finding for greenhouse gas emissions from motor vehicles.

Clean Air Mercury Rule - In March 2005, the EPA issued the Clean Air Mercury Regulations (CAMR) to reduce the emissions of mercury from coal-fired facilities through a market-based cap-and-trade program. Although the U.S. Court of Appeals for the District of Columbia Circuit struck down CAMR, the state of Montana has finalized its own rules more stringent than CAMR's 2018 cap that require every coal-fired generating plant in the state to achieve reduction levels by 2010. Chemical injection technologies were installed at Colstrip Unit 4 during the fourth quarter of 2009 to meet these requirements, and our share of the capital cost was approximately $1.0 million, with ongoing annual operating costs estimated to be approximately $1.5 million. If the enhanced chemical injection technologies are not sufficient to meet the required levels of reduction, then adsorption/absorption technology with fabric filters would be required, which could represent a material cost. We are continuing to work with the other Colstrip owners to assess compliance with these reduction levels.

There is a gap between proposed emissions reduction levels and the current capabilities of technology, as there is no currently available commercial scale technology that would achieve the proposed reduction levels. Such technology may not be available within a timeframe consistent with the implementation of climate change legislation or at all. To the extent that such technology does become available, 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 is not presently available on a commercial scale.

The proposed regulations and/or current litigation related to global climate change could have a material impact on our future capital expenditures and results of operations, but the costs are not determinable at this time. Our current capital expenditures projections do not include significant amounts related to environmental projects. 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. For more information on environmental contingencies, see Note 17 - Commitments and Contingencies, in the Notes to Consolidated Financial Statements.

EMPLOYEES

As of December 31, 2009, we had 1,354 employees. Of these, 1,037 employees were in Montana and 317 were in South Dakota or Nebraska. Of our Montana employees, 405 were covered by six collective bargaining agreements involving five unions. All six of these agreements were renegotiated in 2008 for terms of four years. In addition, our South Dakota and Nebraska operations had 186 employees covered by the System Council U-26 of the International Brotherhood of Electrical Workers. This collective bargaining agreement expired on December 31, 2009, and a tentative agreement has been reached. We consider our relations with employees to be in good standing.

Executive Officers

Executive Officer	Current Title and Prior Employment	Age on Feb. 6, 2010
Robert C. Rowe	President, Chief Executive Officer and Director since August 2008. Prior to joining NorthWestern, Mr. Rowe was a co-founder and senior partner at Balhoff, Rowe & Williams, LLC, a specialized national professional services firm providing financial and regulatory advice to clients in the telecommunications and energy industries (January 2005-August, 2008); and served as Chairman and Commissioner of the Montana Public Service Commission (1993–2004).	54
Brian B. Bird	Vice President, Chief Financial Officer and Treasurer since May 2009, formerly Vice President and Chief Financial Officer since December 2003. Prior to joining NorthWestern, Mr. Bird was Chief Financial Officer and Principal of Insight Energy, Inc., a Chicago-based independent power generation development company (2002-2003). Previously, he was Vice President and Treasurer of NRG Energy, Inc., in Minneapolis, MN (1997-2002). Mr. Bird serves on the board of directors of a NorthWestern subsidiary.	47
Patrick R. Corcoran	Vice President-Government and Regulatory Affairs since December 2004; formerly Vice President-Regulatory Affairs since February 2002; formerly Vice President-Regulatory Affairs for the former Montana Power Company (2000-2002).	58
David G. Gates	Vice President-Wholesale Operations since September 2005; formerly Vice President-Transmission Operations since May 2003; formerly Executive Director-Distribution Operations since January 2003; formerly Executive Director-Distribution Operations for the former Montana Power Company (1996-2002). Mr. Gates serves on the board of directors of a NorthWestern subsidiary.	53

Executive Officer	Current Title and Prior Employment	Age on Feb. 6, 2010
Kendall G. Kliewer	Vice President and Controller since August 2006; Controller since June 2004; formerly Chief Accountant since November 2002. Prior to joining NorthWestern, Mr. Kliewer was a Senior Manager at KPMG LLP (1999-2002).	40
Curtis T. Pohl	Vice President-Retail Operations since September 2005; formerly Vice President-Distribution Operations since August 2003; formerly Vice President-South Dakota/Nebraska Operations since June 2002; formerly Vice President-Engineering and Construction since June 1999. Mr. Pohl serves on the board of directors of a NorthWestern subsidiary.	45
Bobbi L. Schroeppel	Vice President, Customer Care, Communications and Human Resources since May 2009, formerly Vice President-Customer Care and Communications since September 2005; formerly Vice President-Customer Care since June 2002; formerly Director-Staff Activities and Corporate Strategy since August 2001; formerly Director-Corporate Strategy since June 2000.	41

Officers are elected annually by, and hold office at the pleasure of the Board, and do not serve a "term of office" as such. Miggie E. Cramblit, Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer, terminated her employment with NorthWestern effective January 5, 2010. The Board appointed Timothy P. Olson to act as interim general counsel and corporate secretary, effective upon Ms. Cramblit's departure and until the Board appoints a permanent replacement.

ITEM 1A. RISK FACTORS

You should carefully consider the risk factors described below, as well as all other information available to you, before making an investment in our common stock or other securities.

Economic conditions and instability in the financial markets could negatively impact our business.

Our operations are impacted by local, national and worldwide economic conditions. The consequences of a prolonged recession may include a lower level of economic activity and uncertainty regarding energy prices and the capital and commodity markets. A lower level of economic activity has resulted in a decline in energy consumption and a decrease in customers' ability to pay their accounts, which may adversely affect our liquidity, results of operations and future growth. While our territories have been less impacted than other parts of the country, during 2009 we experienced declines in electric and natural gas usage per customer and lower electric transmission sales, due in part to the recession. In addition, demand for our Montana transmission capacity is impacted by market conditions in states to the South and West of our service territory, which have been more significantly impacted by the economic downturn.

Access to the capital and credit markets, at a reasonable cost, is necessary for us to fund our operations, including capital requirements. We rely on a revolving credit facility for short-term liquidity needs due to the seasonality of our business, and on capital markets to raise capital for growth projects that are not otherwise provided by operating cash flows. Instability in the financial markets may increase the cost of capital, limit our ability to draw on our revolving credit facility and/or raise capital. If we are unable to obtain the liquidity needed to meet our business requirements on favorable terms, we may defer growth projects and/or capital expenditures.

We are subject to extensive governmental laws and regulations that affect our industry and our operations, which could have a material adverse effect on our liquidity and results of operations.

We are subject to regulation by federal and state governmental entities, including the FERC, MPSC, SDPUC and NPSC. Regulations can affect allowed rates of return, recovery of costs and operating requirements. For example, in our 2008 proceeding related to Colstrip Unit 4, the MPSC approved a 10% return on equity and 6.5% cost of debt for the expected 34-year life of the plant. In addition, existing regulations may be revised or reinterpreted, new laws, regulations, and interpretations thereof may be adopted or become applicable to us and future changes in laws and regulations may have a detrimental effect on our business.

Our rates are approved by our respective commissions and are effective until new rates are approved. The outcome of our Montana electric and natural gas rate case filed in 2009 could have a significant impact on our liquidity and results of operations. The filing is based upon a 2008 test period, and we anticipate a final determination on the filing during the fourth quarter of 2010, which creates a delay between the timing of when such costs are incurred and when the costs are recovered from customers. This lag can adversely impact our cash flows. In addition, supply costs are recovered through adjustment charges that are periodically reset to reflect current and projected costs. Inability to recover costs in rates or adjustment clauses could have a material adverse effect on our liquidity and results of operations.

We are also subject to the jurisdiction of FERC with regard to electric system reliability standards. We must comply with the standards and requirements established, which apply to the NERC functions for which we have registered in both the Midwest Reliability Organization for our South Dakota operations and the WECC for our Montana operations. To the extent we are deemed to not be compliant with these standards, we could be subject to fines or penalties.

We are subject to extensive environmental laws and regulations and potential environmental liabilities, which could result in significant costs and liabilities.

We are subject to extensive laws and regulations imposed by federal, state, and local government authorities in the ordinary course of operations with regard to the environment, including environmental laws and regulations relating to air and water quality, solid waste disposal, and other environmental considerations. We believe that we are in compliance with environmental regulatory requirements and that maintaining compliance with current requirements will not materially affect our financial position or results of operations; however, possible future developments, including the promulgation of more stringent environmental laws and regulations, and the timing of future enforcement proceedings that may be taken by environmental authorities could affect the costs and the manner in which we conduct our business and could require us to make substantial additional capital expenditures.

There is a growing concern nationally and internationally about global climate change and the contribution of emissions of greenhouse gases 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 greenhouse emissions, including a U.S. Supreme Court decision holding that the EPA relied on improper factors in deciding not to regulate carbon dioxide emissions from motor vehicles under the Clean Air Act and two federal courts of appeal have reinstated nuisance claims against emitters of carbon dioxide, including several utility companies, alleging that such emissions contribute to global warming. Increased pressure for carbon dioxide emissions reduction also is coming from investor organizations. If legislation or regulations are passed at the federal or state levels imposing mandatory reductions of carbon dioxide and other greenhouse gases on generation facilities, the cost to us of such reductions could be significant.

Many of these environmental laws and regulations create permit and license requirements and provide for substantial civil and criminal fines which, if imposed, could result in material costs or liabilities. We cannot predict with certainty the occurrence of private tort allegations or government claims for damages associated with specific environmental conditions. We may be required to make significant expenditures in connection with the investigation and remediation of alleged or actual spills, personal injury or property damage claims, and the repair, upgrade or expansion of our facilities to meet future requirements and obligations under environmental laws.

To the extent that our environmental liabilities are greater than our reserves or we are unsuccessful in recovering anticipated insurance proceeds under the relevant policies or recovering a material portion of remediation costs in our rates, our results of operations and financial position could be adversely affected.

We are subject to physical and financial risks associated with climate change.

Physical risks from climate change could include changes in weather conditions, such as an increase in changes in precipitation and extreme weather events. Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions are affected by climate change, our customers' energy use could increase or decrease depending on the duration and magnitude of the changes. Increased energy use due to weather changes may require us to invest in additional electric generation assets, transmission and other infrastructure to serve increased loads. Decreased energy use due to weather changes could result in decreased revenues. Extreme weather conditions in general increase the stress on our system. Weather conditions outside of our service territories could have an impact on our results of operations through impacts to the market prices for supply and transmission capacity. We purchase and sell electric and natural gas supply depending upon system needs and market opportunities. Extreme weather conditions creating high energy demand on our own and/or other systems may raise market prices as we buy short-term energy to serve our own system. Severe weather impacts our service territories, primarily through thunderstorms, tornadoes and snow or ice storms. To the extent the frequency of extreme weather events increase, this could increase our cost of providing service. Changes in precipitation resulting in droughts or water shortages could adversely affect our ability to provide electricity to customers, as well as increase the price they pay for energy. We may not recover all costs related to mitigating these physical and financial risks.

To the extent climate change impacts a region's economic health, it also may impact our revenues. Our financial performance is tied to the health of the regional economies we serve. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods, has an impact on the economic health of our communities. The cost of additional regulatory requirements, such as a tax on greenhouse gases or additional environmental regulation, would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

To the extent our incurred supply costs are deemed imprudent by the applicable state regulatory commissions, we would under recover our costs, which could adversely impact our results of operations and liquidity.

Our wholesale costs for electricity and natural gas are recovered through various pass-through cost tracking mechanisms in each of the states we serve. The rates are established based upon projected market prices or contract obligations. As these variables change, we adjust our rates through our monthly trackers. To the extent our energy supply costs are deemed imprudent by the applicable state regulatory commissions, we would under recover our costs, which could adversely impact our results of operations.

We are required to procure our entire natural gas supply and a large portion of our Montana electric supply pursuant to contracts with third-party suppliers. In light of this reliance on third-party suppliers, we are exposed to certain risks in the event a third-party supplier is unable to satisfy its contractual obligation. If this occurred, then we might be required to purchase gas and/or electricity supply requirements in the energy markets, which may not be on commercially reasonable terms, if at all. If prices were higher in the energy markets, it could result in a temporary material under recovery that would reduce our liquidity.

Poor investment performance of plan assets of our defined benefit pension and post-retirement benefit plans, in addition to other factors impacting these costs, could unfavorably impact our results of operations and liquidity.

Our costs for providing defined benefit retirement and postretirement benefit plans are dependent upon a number of factors, including rate of return on plan assets, discount rates, other actuarial assumptions, and government regulation. 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%. Without sustained growth in the plan assets over time and depending upon the other factors noted above, the costs of such plans reflected in our results of operations and financial position and cash funding obligations may change significantly from projections.

Our plans for future expansion through transmission grid expansion, the construction of power generation facilities and capital improvements to current assets involve substantial risks. Failure to adequately execute and manage significant construction plans, as well as the risk of recovering such costs, could materially impact our results of operations and liquidity.

We have proposed capital investment projects in excess of $1 billion. The completion of these projects, which are primarily investments in electric transmission projects and electric generation projects, is subject to many construction and development risks, including, but not limited to, risks related to financing, regulatory recovery, obtaining and complying with terms of permits, escalating costs of materials and labor, meeting construction budgets and schedules, and environmental compliance. In addition, there are projects proposed by other parties that may result in direct competition to our proposed transmission expansion.

Our proposed capital investment projects are based on assumptions regarding future growth and resulting power demand that may not be realized. The timing and extent of the recovery of the economy, and its impact on demand cannot be predicted. Additionally, our customers may undertake further individual energy conservation measures, which could decrease the demand for electricity. We may increase our transmission and/or baseload capacity and have excess capacity if anticipated growth levels are not realized. The resulting excess capacity could exceed our obligation to serve retail customers or demand for transmission capacity and, as a result, may not be recoverable from customers.

The construction of new generation and expansion of our transmission system will require a significant amount of capital expenditures. We cannot provide certainty that adequate external financing will be available to support these projects. Additionally, borrowings incurred to finance construction may adversely impact our leverage, which could increase our cost of capital. We may pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with these projects, but we cannot be certain we will be able to successfully negotiate any such arrangement. Furthermore, joint ventures or joint ownership arrangements also present risks and uncertainties, including those associated with sharing control over the construction and operation of a facility and reliance on the other party's financial or operational strength.

We have filed for and received advanced approval from the MPSC to construct the Mill Creek Generating Station. The MPSC determined the cost of the gas turbines is prudent, with the remainder of the project costs to be submitted for review upon completion of construction. A portion of these future costs could potentially be deemed imprudent, which we would not be able to recover from customers.

Should our efforts be unsuccessful, we could be subject to additional costs, termination payments under committed contracts, and/or the write-off of investments in these projects. As of December 31, 2009, we have capitalized approximately $84.7 million in construction work in progress associated with the Mill Creek Generating Station and $11.4 million in preliminary survey and investigative costs associated with transmission projects.

Our obligation to include a minimum annual quantity of power in our Montana electric supply portfolio at an agreed upon price per MWh could expose us to material commodity price risk if certain QFs under contract with us do not perform during a time of high commodity prices, as we are required to supply any quantity deficiency. In addition, we are subject to price escalation risk with one of our largest QF contracts.

As part of a previous stipulation with the MPSC and other parties, we agreed to include a minimum annual quantity of power in our Montana electric supply portfolio at an agreed upon price per MWh. The annual minimum energy requirement is achievable under normal QF operations, including normal periods of planned and forced outages. Furthermore, we will not realize commodity price risk unless any required replacement energy cost is in excess of the total amount recovered under the QF obligation.

However, to the extent the supplied QF power for any year does not reach the minimum quantity set forth in the settlement, we are obligated to secure the quantity deficiency from other sources. The anticipated source for any quantity deficiency is the wholesale market which, in turn, would subject us to commodity price volatility.

In addition, we are subject to price escalation risk with one of our largest QF contracts due to variable contract terms. In estimating our QF liability, we have estimated an annual escalation rate of 1.9% over the term of the contract (through June 2024). To the extent the annual escalation rate exceeds 1.9%, our results of operations and financial position could be adversely affected.

Our jointly owned electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased power purchase costs.

Operation of electric generating facilities involves risks, which can adversely affect energy output and efficiency levels. Most of our generating capacity is coal-fired. We rely on a limited number of suppliers of coal for our regulated generation, making us vulnerable to increased prices for fuel as existing contracts expire or in the event of unanticipated interruptions in fuel supply. We are a captive rail shipper of the Burlington Northern Santa Fe Railway for shipments of coal to the Big Stone Plant (our largest source of generation in South Dakota), making us vulnerable to railroad capacity and operational issues and/or increased prices for coal transportation from a sole supplier. Operational risks also include facility shutdowns due to breakdown or failure of equipment or processes, labor disputes, operator error and catastrophic events such as fires, explosions, floods, and intentional acts of destruction or other similar occurrences affecting the electric generating facilities. The loss of a major regulated generating facility would require us to find other sources of supply, if available, and expose us to higher purchased power costs.

Seasonal and quarterly fluctuations of our business could adversely affect our results of operations and liquidity.

Our electric and natural gas utility business is seasonal, and weather patterns can have a material impact on our financial performance. Demand for electricity and natural gas is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our market areas, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. In the event that we experience unusually mild winters or cool summers in the future, our results of operations and financial position could be adversely affected. In addition, exceptionally hot summer weather or unusually cold winter weather could add significantly to working capital needs to fund higher than normal supply purchases to meet customer demand for electricity and natural gas.

We must meet certain credit quality standards. If we are unable to maintain investment grade credit ratings, our liquidity, access to capital and operations could be materially adversely affected.

A downgrade of our credit ratings to less than investment grade could adversely affect our liquidity. Certain of our credit agreements and other credit arrangements with counterparties require us to provide collateral in the form of letters of credit or cash to support our obligations if we fall below investment grade. Also, a downgrade below investment grade could hinder our ability to raise capital on favorable terms and increase our borrowing costs.

Our secured credit ratings are also tied to our ability to invest in unregulated ventures due to an existing stipulation with the MPSC and MCC, which establishes diminishing limits for such investment at certain credit rating levels. The stipulation does not limit investment in unregulated ventures so long as we maintain credit ratings on a secured basis of at least BBB+ (S&P) and Baa1 (Moody's). For a further discussion of how a lack of liquidity and access to adequate capital could affect our operations, please see the Risk Factor above, "Economic conditions and instability in the financial markets could negatively impact our business."

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 2. PROPERTIES

NorthWestern's corporate support office is located at 3010 West 69th Street, Sioux Falls, South Dakota 57108, where we lease approximately 20,000 square feet of office space, pursuant to a lease that expires on December 1, 2012.

Our operational support office for our Montana operations is owned by us and located at 40 East Broadway Street, Butte, Montana 59701. We own or lease other facilities throughout the state of Montana. Our operational support office for our South Dakota and Nebraska operations is owned by us and located at 600 Market Street W., Huron, South Dakota 57350. Substantially all of our South Dakota and Nebraska facilities are owned.

Substantially all of our Montana electric and natural gas assets are subject to the lien of our Montana First Mortgage Bond indenture. Substantially all of our South Dakota and Nebraska electric and natural gas assets are subject to the lien of our South Dakota Mortgage Bond indenture. For further information regarding our operating properties, including generation and transmission, see the descriptions included in Item 1.

ITEM 3. LEGAL PROCEEDINGS

We discuss details of our legal proceedings in Note 17, Commitments and Contingencies, to the Consolidated Financial Statements. Some of this information is about costs or potential costs that may be material to our financial results.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of our security holders during the quarter ended December 31, 2009.

Part II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED SHAREHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock, which is traded under the ticker symbol NWE, is listed on the New York Stock Exchange (NYSE). As of February 5, 2010, there were approximately 883 common stockholders of record.

Dividends

We pay dividends on our common stock after our Board of Directors (Board) declares them. The Board reviews the dividend quarterly and establishes the dividend rate based upon such factors as our earnings, financial condition, capital requirements, debt covenant requirements and/or other relevant conditions. Although we expect to continue to declare and pay cash dividends on our common stock in the future, we cannot assure that dividends will be paid in the future or that, if paid, the dividends will be paid in the same amount as during 2009. Quarterly dividends were declared and paid on our common stock during 2009 as set forth in the table below.

QUARTERLY COMMON STOCK PRICE RANGES AND DIVIDENDS

	Prices		
	High	Low	Cash Dividends Paid
2009—			
Fourth Quarter	$ 26.85	$ 23.61	$ 0.335
Third Quarter	24.94	22.58	0.335
Second Quarter	23.49	20.00	0.335
First Quarter	25.39	18.48	0.335
2008—			
Fourth Quarter	$ 25.49	$ 17.24	$ 0.33
Third Quarter	26.30	23.74	0.33
Second Quarter	26.72	23.78	0.33
First Quarter	29.32	24.22	0.33

On February 5, 2010, the last reported sale price on the NYSE for our common stock was $24.24.

Securities Authorized for Issuance under Equity Compensation Plans

The following table presents summary information about our equity compensation plans, including our long-term incentive plan. The table presents the following data on our plans as of the close of business on December 31, 2009:

i. The aggregate number of shares of our common stock subject to outstanding stock options, warrants and rights;

ii. The weighted average exercise price of those outstanding stock options, warrants and rights; and

iii. The number of shares that remain available for future option grants, excluding the number of shares to be issued upon the exercise of outstanding options, warrants and rights described in (i) above.

For additional information regarding our stock long-term incentive plans and the accounting effects of our stock-based compensation, please see Note 13 to our Consolidated Financial Statements included in Item 8 herein.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders			
None			
Equity compensation plans not approved by security holders			
New Incentive Plan (1)	—		1,259,465
Total	—		1,259,465

(1) Upon our emergence from bankruptcy in 2004, a New Incentive Plan was established pursuant to our Plan of Reorganization, which set aside 2,265,957 shares for the new Board to establish equity-based compensation plans for employees and directors. As the New Incentive Plan was established by provisions of the Plan of Reorganization, shareholder approval was not required. During 2005 the NorthWestern Corporation 2005 Long-Term Incentive Plan was established under the New Incentive Plan, under which 815,074 shares have been distributed to officers and employees and 191,418 shares have been used for Board compensation.

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data has been derived from our consolidated financial statements and should be read in conjunction with the consolidated financial statements and notes thereto and with “Management's Discussion and Analysis of Financial Condition and Results of Operations" and other financial data included elsewhere in this report. The historical results are not necessarily indicative of results to be expected for any future period.

FIVE-YEAR FINANCIAL SUMMARY

	Year Ended December 31,				
	2009	2008	2007	2006	2005
Financial Results (in thousands, except per share data)					
Operating revenues	$ 1,141,910	$ 1,260,793	$ 1,200,060	$ 1,132,653	$ 1,165,750
Income from continuing operations (1)	73,420	67,601	53,191	37,482	61,547
Basic earnings per share from continuing operations	2.03	1.78	1.45	1.06	1.73
Diluted earnings per share from continuing operations	2.02	1.77	1.44	1.00	1.71
Dividends declared & paid per common share	1.34	1.32	1.28	1.24	1.00
Financial Position					
Total assets	$ 2,795,132	$ 2,762,037	$ 2,547,380	$ 2,395,937	$ 2,400,403
Long-term debt and capital leases, including current portion	1,024,186	900,047	846,368	747,117	742,970
Ratio of earnings to fixed charges	2.3	2.7	2.4	2.0	2.4

(1) Income from continuing operations includes reorganization items for the year ended December 31, 2005.

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

The following discussion and analysis should be read in conjunction with “Item 6 Selected Financial Data" and our consolidated financial statements and related notes contained elsewhere in this Annual Report on Form 10-K. For additional information related to our industry segments, see Note 19 to the Consolidated Financial Statements, which is included in Item 8 herein. For information regarding our revenues, net income and assets; see our Consolidated Financial Statements included in Item 8.

OVERVIEW

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas to approximately 661,000 customers in Montana, South Dakota and Nebraska. As you read this discussion and analysis, refer to our Consolidated Statements of Income, which present the results of our operations for 2009, 2008 and 2007. Following is a brief overview of highlights for 2009, and a discussion of our strategy and outlook.

SUMMARY

Significant achievements for the year ended December 31, 2009 include:

- Improvement in net income of approximately $5.8 million as compared with 2008, due primarily to
    - obtaining Internal Revenue Service (IRS) approval of a tax accounting method change to deduct repairs that would have previously been capitalized, resulting in an income tax benefit of $16.6 million during 2009, and
    - the transfer of Colstrip Unit 4 to utility rate base, resulting in improved gross margin of $13.8 million;
- Successfully accessed the capital markets to refinance existing maturities and to finance the Mill Creek Generating Station project and capital expenditures;
    - Issuance of $250 million, 6.34% Montana First Mortgage Bonds with a 10 year term
    - Issuance of $55 million, 5.71% Montana First Mortgage Bonds with a 30 year term.
    - Amended our revolving credit facility to increase the availability to $250 million from $200 million and extended the maturity date to June 30, 2012;
- Received approval from the MPSC to construct the 150 MW Mill Creek Generating Station project with a 50% debt and 50% equity capital structure, return on equity at 10.25% and debt at 6.5%; and
- Upgrade of our senior secured and unsecured credit ratings by Moody’s Investors Service (Moody’s).

Repairs Tax Deduction

In December 2008, we filed a request with the IRS to change our accounting method related to costs to repair and maintain utility assets. The IRS approved our request in September 2009, which allows us to take a current tax deduction for a significant amount of repair costs that were previously capitalized for tax purposes. For regulatory purposes, we flow these current tax deductions through to our customers. Due to this regulatory treatment, we recorded an income tax benefit of approximately $16.6 million during the year ended December 31, 2009 to reflect this change in tax accounting method, of which approximately $8.7 million and $7.9 million related to the 2009 and 2008 tax years, respectively. Our effective tax rate was 17.2% for 2009, as compared with 37.3% and 37.8% for 2008 and 2007, respectively. The 2009 rate reflects the impact of the change in tax accounting method for repairs for both 2008 and 2009, as well as lower 2009 taxable income. We expect our effective tax rate for 2010 to be approximately 30%. See Note 9 – Income Taxes, in the Notes to Consolidated Financial Statements for further discussion.

Colstrip Unit 4

In January 2009, as approved by the MPSC in 2008, we placed our joint ownership interest in Colstrip Unit 4, which had previously been an unregulated asset, into utility rate base at a value of $407 million. The MPSC order included a capital structure of 50% equity and 50% debt, an authorized return on equity of 10% and cost of debt of 6.5%, which are set for 34 years based on the estimated useful life of the plant. Our interest in Colstrip Unit 4 is expected to supply approximately 13% of our base-load requirements through 2010 and approximately 25% thereafter (upon expiration of an existing power sale agreement) and will help provide rate stability for our customers. The generation related costs and return on rate base related to Colstrip Unit 4 are included in customer rates as part of our annual electric supply tracker filing.

STRATEGY

We are focused on growing through investing in our core utility business and earning a reasonable return on invested capital, while providing safe, reliable service. In response to growing customer demand and aging infrastructure, we continue to make significant maintenance capital investments in our system in excess of our depreciation, which is the amount of these costs we recover through rates. These investments reflect our focus on maintaining our system reliability, and allow us to pursue the deployment of newer technology that promotes the efficient use of electricity, including smart grid. See the “Capital Requirements" discussion below for further detail on planned maintenance capital expenditures. We are considering opportunities consistent with our load growth for the ownership and/or development of rate-base electric generation facilities, which help to stabilize our customers’ energy costs while providing us the opportunity to grow our rate-base and earn a return on investment.

In addition to the organic load growth in our service territories we also have a number of growth opportunities due to legislative changes that allow us to invest in electric generation and gas reserves in Montana on a regulated basis, and the increased focus on renewable energy. We are considering opportunities consistent with our load growth for the ownership and/or development of electric generation facilities, which help to stabilize our customers’ energy costs while providing us the opportunity to grow our rate base and earn a return on investment. In addition, our service territories have some of the best wind resources in the country, and we are focusing on leveraging our unique geographic position to pursue the construction of the associated transmission facilities required to support this renewable expansion.

Montana General Rate Case

Rate cases are a key component of our earnings growth and achieving our financial objectives. 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 request was based on a 2008 test period, a return on equity of 10.9%, an equity ratio of 49.45% and rate base of $632.2 million and $256.6 million for electric and natural gas, respectively.

In November 2009, the MPSC issued a determination that the rate case filing did not meet the MPSC’s applicable minimum filing requirements, related to allocated cost of service and rate design. We submitted a supplemental filing on January 15, 2010 to meet the MPSC’s minimum filing requirements, which was accepted as compliant on February 2, 2010. We have agreed to extend the timeframe by which the MPSC must issue a final order concerning the general rate filing by 90 days to October 11, 2010. We requested interim rate adjustments, which may be authorized during the processing of the filing if the MPSC finds it meets the established criteria. Final rate adjustments would become effective upon the issuance of a final order on this matter.

Distribution System Investment

As part of our commitment to maintain high level reliability and system performance we continue to evaluate the condition of our distribution assets to address aging infrastructure through our asset management process. We are working on various solutions taking a proactive and pragmatic approach to replace these assets while also evaluating the implementation of additional technologies to prepare the overall system for smart grid applications. We are in the initial phases of analyzing the value of implementing additional smart grid technologies. In 2010 we expect to implement a smart grid pilot project as part of an overall regional smart grid demonstration project, which has been accepted for 50% funding by the Department of Energy under the American Recovery and Reinvestment

Act of 2009. This project involves testing various smart grid applications in four urban circuits in Helena, Montana and one rural circuit in the Georgetown Lake area of Montana. We anticipate spending up to $5 million over three to five years as we gather information and gain a better understanding of the costs versus benefits that could then be applied on a larger scale to the rest of our distribution infrastructure. We have also formed an Infrastructure Stakeholder Group to assist us as we consider possible future scenarios for investment in our distribution system and evaluate the potential impacts of different scenarios to rates and future service quality. While the projected capital amounts needed under the various scenarios are currently uncertain, we expect to continue investing amounts in excess of our annual depreciation.

Generation Investment

Mill Creek Generating Station - In August 2008, we filed a request with the MPSC for advanced approval to construct a 150 megawatt natural gas fired facility. The Mill Creek Generating Station, estimated to cost approximately $202 million, will provide regulating resources to balance our transmission system in Montana to maintain reliability and enable wind power to be integrated onto the network to meet renewable energy portfolio needs. 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 is scheduled to be operational by December 31, 2010. As of December 31, 2009, we have capitalized approximately $84.7 million in construction work in progress related to this project.

Wind Generation – We are currently conducting a Request for Information in Montana and Request for Proposals in South Dakota for additional renewable resources for the respective electric supply portfolios. Both efforts are designed to assure we meet the required renewables portfolio standard of 15% by 2015 in Montana and the renewable energy objective of 10% by 2015 in South Dakota. We have expressed a preference for an equity ownership position rather than power purchase agreements in these requests. Upon receiving responses to these requests we will further evaluate wind related capital expenditure projections.

Transmission Investment

Due to the abundance of natural resources in Montana, significant electric generation projects, particularly wind generation, are in development by various parties. Uncertainty surrounding global climate change and environmental concerns related to new coal-fired generation development is changing the mix of the potential sources of new generation in the region. State renewable portfolio standards are increasing the region's reliance on wind generation and Montana has one of the best wind regimes in the country. Our Montana transmission assets are strategically located between these renewable generation resources and the population base desiring them, which should allow us to take advantage of the potential transmission grid expansion in the west.

In Montana, we have begun development on three significant electric transmission projects:

- an expansion of the existing Colstrip 500 kV system that would increase capacity by 500-700 MWs, of which we assume a 30% joint ownership; and
- a 230 kV Collector Project in central Montana designed to aggregate renewables and facilitate their access to markets; and
- a new 500 kV transmission line from southwestern Montana to southeastern Idaho with a potential capacity of 1,500 MWs.

All of the current joint owners of the existing Colstrip 500 kV transmission line from Colstrip, Montana to mid-Columbia, as well as the Bonneville Power Authority, are working to develop an upgrade to the system, which involves an additional substation and related electrical equipment to increase westbound capacity out of Montana by more than 500 MWs. We anticipate completing the technical analysis for the project in 2010. If constructed, we expect the upgrade to be completed by the end of 2012.

The Collector Project consists of up to five new transmission lines in Montana that would connect new generation, primarily wind farms, to our existing transmission system and to the proposed MSTI line. All of the new proposed wind generation that would be served by the Collector Project would be located in Montana. The proposed new 500 kV transmission line between southwestern Montana and southeastern Idaho is known as MSTI. The transmission line's main purpose will be to meet requests for transmission service from customers and relieve constraints on the high-voltage transmission system in the region. An initial siting study identified several reasonable alternatives for the route and we have selected a preferred, as well as two alternative routes.

In January 2009, we filed a request with the FERC seeking negotiated rates for the proposed 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 satisfies the FERC's negotiated rate criteria. As a transmission export project in a region that lacks a RTO, MSTI has 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.

We are planning to conduct open seasons for both MSTI and the Collector Project during the first half of 2010 to identify potential interest for new transmission capacity on this path due to the changing nature of generation projects. The results of the open season will be used to size the projects according to customer demand. The open season process is intended to ensure 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. Based on our current timeline, we anticipate the Collector Project and MSTI line will be in service by 2014 and 2015, respectively.

Construction on these projects cannot commence until all local, state and federal permits/regulatory requirements are met. We expect the administrative routing decision on the combined environmental impact statement from the Montana Department of Environmental Quality and Bureau of Land Management for the MSTI project in the second quarter of 2010, with a final Record of Decision in late 2010. Due to the uncertainty surrounding the proposed generation, certain aspects of our proposed transmission development projects are scaleable and thus can be built out to more closely match the timing of new generation and loads. The first step in any of these growth opportunities is to obtain regulatory support prior to making substantial investment. To avoid excessive risk for us, it is critical to reduce regulatory uncertainty before making large capital investments. In addition, we are contemplating a strategic partner for the MSTI project for ownership up to 50%. We have capitalized approximately $11.4 million of preliminary survey and investigative costs associated with proposed transmission projects, which include approximately $11.2 million for the MSTI transmission project and approximately $0.2 million for the Colstrip 500 kV upgrade. We currently estimate aggregate capital expenditures related to these transmission projects to range between approximately $20 and $25 million in 2010.

ECONOMIC CONDITIONS AND OUTLOOK

The recent capital and credit market crisis is adversely affecting the US and global economies, which can lead to adverse impacts on our business. Slower economic growth could lead to lower demand for electricity and gas, resulting in a decrease in sales volumes to our commercial, industrial and residential customers. In addition, customers may not be able to pay, or may delay payment of their bills. Each of the significant growth opportunities described above are elective, which allows us to be flexible in adjusting to changing economic conditions by deferring the timing of, or reducing the scale of the projects. In addition, in response to the change in economic conditions, we have reviewed our access to liquidity in the credit and capital markets, counterparty creditworthiness, and the funding requirements of our employee benefit plans.

Outlook - The current weak economic conditions have resulted, and we believe likely will continue into 2010, in weaker customer demand, among other things. While customer counts increased, retail residential and commercial electric volumes were relatively flat. In addition, industrial volumes declined, however, our margins are minimally impacted by changes in industrial demand due to our rate structure. The weak economy also contributed reduced pricing for wholesale sales and decreased demand for transmission capacity, which we expect to continue into 2010.

Liquidity – We believe we have sufficient liquidity despite the volatility in the credit and capital markets. We use our revolving credit facility to manage the variability in our cash flows due to the seasonality of our business, and were able to increase the size of this credit facility during 2009. We closely monitor the financial institutions associated with our credit facility, and have had no exposure to the banks that have failed or were purchased in distressed transactions.

We believe our cash flows from operations and existing borrowing capacity should be sufficient to fund our operations, service existing debt, pay dividends, and fund capital expenditures (excluding strategic growth opportunities). We may defer planned capital expenditures to maintain sufficient liquidity in response to changing economic conditions. To fund our strategic growth opportunities we intend to utilize available cash flow, debt capacity that would allow us to maintain investment grade ratings (50-55% debt to total capital ratio), and if necessary additional equity financing. We do not anticipate the need for equity financing until we proceed further with transmission or a combination of other investment opportunities. We currently expect to continue targeting a long-term dividend payout ratio of 60 – 70 % of net income; however, there can be no assurance that we will be able to meet this target. See the “Liquidity and Capital Resources” section for further discussion.

Counterparty Credit Risk – We are exposed to counterparty credit risk related to the ability of our counterparties to meet their contractual payment obligations, and the potential non-performance of counterparties to deliver contracted commodities or services at the contracted price. We have risk management policies in place to limit our transactions to high quality counterparties, and continue to monitor closely the status of our counterparties, and will take action, as appropriate, to further manage this risk. This includes, but is not limited to, requiring letters of credit or prepayment terms.

Defined Benefit Pension Plans – 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%. We remeasure our benefit obligations annually using a December 31 measurement date, and use this information to project our cash funding requirements. Pension costs in Montana are included in expense using the average of our actual and estimated funding amounts from 2005 through 2012 based on an MPSC accounting order. Therefore, changes in our funding estimates create increased volatility to earnings. Our Montana pension expense totaled $28.4 million in 2009 as compared with $30.6 million in 2008 and $22.0 million in 2007. Based on current projections, we expect annual expense to be approximately $28.4 million through 2012. 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:

	2009	2008	2007
NorthWestern Energy Pension Plan (MT).........	$ 80,600	$ 31,140	$ 21,966
NorthWestern Corporation Pension Plan (SD)..	12,300	1,594	672
	$ 92,900	$ 32,734	$ 22,638

For further discussion of our sensitivity to plan asset returns and other assumptions for these plans, see the “Critical Accounting Policies” section. For further discussion of the impact of the additional cash funding in 2009, see the “Liquidity and Capital Resources” section. For discussion of the plan’s funded status, see Note 12-Employee Benefit Plans, in the Notes to Consolidated Financial Statements.

RESULTS OF OPERATIONS

Our consolidated results include the results of our divisions and subsidiaries constituting each of our business segments. The overall consolidated discussion is followed by a detailed discussion of gross margin by segment.

NON-GAAP FINANCIAL MEASURE

The following discussion includes financial information prepared in accordance with generally accepted accounting principles (GAAP), as well as another financial measure, Gross Margin, that is considered a "non-GAAP financial measure." Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that exclude (or include) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. Gross Margin (Revenues less Cost of Sales) is a non-GAAP financial measure due to the exclusion of depreciation from the measure. The presentation of Gross Margin is intended to supplement investors' understanding of our operating performance. Gross Margin is used by us to determine whether we are collecting the appropriate amount of energy costs from customers to allow recovery of operating costs. Our Gross Margin measure may not be comparable to other companies' Gross Margin measure. Furthermore, this measure is not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

Factors Affecting Results of Operations

Our revenues may fluctuate substantially with changes in supply costs, which are generally collected in rates from customers. In addition, various regulatory agencies approve the prices for electric and natural gas utility service within their respective jurisdictions and regulate our ability to recover costs from customers.

Revenues are also impacted to a lesser extent by customer growth and usage, the latter of which is primarily affected by weather. Very cold winters increase demand for natural gas and to a lesser extent, electricity, while warmer than normal summers increase demand for electricity, especially among our residential and commercial customers. We measure this effect using degree-days, which is the difference between the average daily actual temperature and a baseline temperature of 65 degrees. Heating degree-days result when the average daily temperature is less than the baseline. Cooling degree-days result when the average daily temperature is greater than the baseline. The statistical weather information in our regulated segments represents a comparison of this data.

OVERALL CONSOLIDATED RESULTS

Year Ended December 31, 2009 Compared with Year Ended December 31, 2008

	Year Ended December 31,			
	2009	2008	Change	% Change
	(in millions)			
Operating Revenues				
Regulated Electric	$ 782.3	$ 774.2	$ 8.1	1.0%
Regulated Natural Gas	354.5	416.7	(62.2)	(14.9)
Unregulated Electric	—	77.7	(77.7)	(100.0)
Other	6.7	30.0	(23.3)	(77.7)
Eliminations	(1.6)	(37.8)	36.2	95.8
	$ 1,141.9	$ 1,260.8	$ (118.9)	(9.4)%

	Year Ended December 31,			
	2009	2008	Change	% Change
	(in millions)			
Cost of Sales				
Regulated Electric	$ 356.7	$ 410.4	$ (53.7)	(13.1)%
Regulated Natural Gas	210.0	271.7	(61.7)	(22.7)
Unregulated Electric	—	23.5	(23.5)	(100.0)
Other	7.0	29.1	(22.1)	(75.9)
Eliminations	—	(36.0)	36.0	100.0
	$ 573.7	$ 698.7	$ (125.0)	(17.9)%

	Year Ended December 31,			
	2009	2008	Change	% Change
	(in millions)			
Gross Margin				
Regulated Electric	$ 425.6	$ 363.8	$ 61.8	17.0%
Regulated Natural Gas	144.5	145.0	(0.5)	(0.3)
Unregulated Electric	—	54.2	(54.2)	(100.0)
Other	(0.3)	0.9	(1.2)	(133.3)
Eliminations	(1.6)	(1.8)	0.2	11.1
	$ 568.2	$ 562.1	$ 6.1	1.1%

Consolidated gross margin in 2009 was $568.2 million, an increase of $6.1 million, or 1.1%, from gross margin in 2008. Primary components of this change include the following:

	Gross Margin 2009 vs. 2008
	(in millions)
Transfer of Colstrip Unit 4 to regulated electric	$ 68.0
2008 Unregulated electric	(54.2)
Net Colstrip Unit 4 increase to gross margin	13.8
Operating expenses recovered in supply trackers	4.0
Montana property tax tracker	2.9
Regulated electric wholesale	(4.6)
Regulated electric transmission capacity	(3.3)
QF supply costs	(2.6)
Loss on capacity contract	(1.5)
Other	(2.6)
Increase in Consolidated Gross Margin	**$ 6.1**

The transfer of our interest in Colstrip Unit 4 to Montana utility rate base contributed approximately $68.0 million to gross margin. Prior to the transfer of Colstrip Unit 4, all of our Montana electric supply costs were based on power purchase agreements, which are passed through to customers at actual cost with no return component. Results of operations of this plant were reflected in our unregulated electric segment through December 31, 2008, which impacts the comparability of our segmented results. The absence of Colstrip Unit 4 from our unregulated electric segment reduced gross margin by approximately $54.2 million as compared with the same period of 2008.

Consolidated margin also increased due to higher revenues for operating, general and administrative expenses primarily related to costs incurred for customer efficiency programs, which are recovered from customers through the supply trackers and therefore have no impact on operating income, and an increase in property taxes recovered compared with 2008. These increases in margin were offset in part by lower wholesale pricing and volumes, lower transmission capacity revenues due to decreased demand, higher QF related supply costs based on actual QF pricing and output, and a loss on a capacity contract included in our "other" segment. This capacity contract runs through October 2013 and was primarily used to serve one customer. The customer terminated their supply contract with us during the second quarter of 2009 and we have recorded a loss to reflect the change in the estimate of the market value for the capacity during the remaining term. Our remaining exposure related to this capacity contract is approximately $0.9 million as of December 31, 2009.

	Year Ended December 31,			
	2009	2008	Change	% Change
	(in millions)			
Operating Expenses (excluding cost of sales)				
Operating, general and administrative	$ 245.6	$ 226.1	$ 19.5	8.6%
Property and other taxes	79.6	80.6	(1.0)	(1.2)
Depreciation	89.0	85.1	3.9	4.6
	$ 414.2	$ 391.8	$ 22.4	5.7%

Consolidated operating, general and administrative expenses were $245.6 million in 2009 as compared to $226.1 million in 2008. Primary components of this change include the following:

	Operating, General, & Administrative Expenses 2009 vs. 2008 (in millions)
Insurance recoveries and settlements	$ 10.9
Insurance reserves	6.3
Jointly owned plant operations	4.4
Labor	4.4
Operating expenses recovered in supply trackers	4.0
Postretirement health care	2.8
Legal and professional fees	(6.8)
Fleet and materials expense	(2.9)
Stock based compensation	(1.4)
Bad debt expense	(0.9)
Other	(1.3)
Increase in Operating, General & Administrative Expenses	**$ 19.5**

The increase in operating, general and administrative expenses of $19.5 million was primarily due to the following:

- Lower insurance recoveries and litigation settlements as compared with 2008. During 2009, we received approximately $5.6 million of insurance recoveries related primarily to previously incurred Montana generation related environmental remediation costs. During 2008, we received $16.5 million of insurance reimbursements and litigation settlement proceeds related to costs incurred in prior years;
- Increased insurance reserves due to general liability and workers compensation matters;
- Increased plant operations costs due to scheduled maintenance and an unplanned outage at Colstrip Unit 4 for a rotor repair;

- Increased labor costs due primarily to compensation increases and severance costs;
- Higher operating, general and administrative expenses primarily related to costs incurred for customer efficiency programs, which are recovered from customers through supply trackers and therefore have no impact on operating income; and
- Increased postretirement health care costs due to plan asset market losses in 2008 and changes in actuarial assumptions. Postretirement healthcare costs totaled approximately $5.7 million during 2009 as compared with $2.9 million during 2008. We amended our postretirement healthcare plan during the fourth quarter of 2009 and we anticipate 2010 costs will decrease to approximately $1.0 million.

  These increases were partially offset by:

- Decreased legal and professional fees as 2008 included costs related to a proposed Colstrip Unit 4 transaction and other matters where we received insurance reimbursements or settlement proceeds;
- Decreased fleet and material expense primarily due to lower average fuel costs;
- Lower stock-based compensation due to the timing of equity grants and vesting criteria; and
- Lower bad debt expense based on lower average customer receivable balances and less days outstanding.

Property and other taxes were $79.6 million in 2009 as compared with $80.6 million in 2008.

Depreciation expense was $89.0 million in 2009 as compared with $85.1 million in 2008. This increase was primarily due to plant additions.

Consolidated operating income in 2009 was $154.0 million, as compared with $170.2 million in 2008. The decrease was primarily due to higher operating expenses, partially offset by the $6.1 million increase in gross margin discussed above.

Consolidated interest expense in 2009 was $67.8 million, an increase of $3.8 million, or 5.9%, from 2008. This increase was primarily due to increased debt outstanding. We expect interest expense for 2010 to be consistent with 2009 due to an increase in the amounts capitalized for the debt portion of allowance for funds used during construction (AFUDC), related to the Mill Creek Generating Station, offsetting an increase in debt outstanding.

Consolidated other income in 2009 was $2.5 million, an increase of $0.9 million from 2008. This increase was primarily due to capitalizing approximately $1.4 million of costs for the equity portion of AFUDC. We expect to capitalize approximately $8.1 million of AFUDC costs related to the Mill Creek Generating Station during 2010.

Consolidated income tax expense in 2009 was $15.3 million as compared with $40.2 million in 2008. The effective tax rate in 2009 was 17.2% as compared with 37.3% for the same period of 2008. These effective tax rates differ from the federal tax rate of 35% primarily due to the effects of tax credits, state income taxes, utility rate-making, and other permanent book-to-tax differences. The effective tax rate in 2009 was significantly impacted by a change in tax accounting method related to repair costs as discussed above in the MD&A “Overview” section. While we reflect an income tax provision in our financial statements, we expect our cash payments for income taxes will be minimal through at least 2014, based on our projected taxable income and anticipated use of consolidated net operating loss carryforwards (CNOLs).

Consolidated net income in 2009 was $73.4 million as compared with $67.6 million in 2008. The increase was primarily due to lower income tax expense, offset by lower operating income and higher interest expense as discussed above.

Year Ended December 31, 2008 Compared with Year Ended December 31, 2007

	Year Ended December 31,			
	2008	2007	Change	% Change
	(in millions)			
Operating Revenues				
Regulated Electric	$ 774.2	$ 736.7	$ 37.5	5.1%
Regulated Natural Gas	416.7	363.6	53.1	14.6
Unregulated Electric	77.7	74.2	3.5	4.7
Other	30.0	56.7	(26.7)	(47.1)
Eliminations	(37.8)	(31.1)	(6.7)	(21.5)
	$ 1,260.8	$ 1,200.1	$ 60.7	5.1%

	Year Ended December 31,			
	2008	2007	Change	% Change
	(in millions)			
Cost of Sales				
Regulated Electric	$ 410.4	$ 389.7	$ 20.7	5.3%
Regulated Natural Gas	271.7	236.0	35.7	15.1
Unregulated Electric	23.5	18.0	5.5	30.6
Other	29.1	54.2	(25.1)	(46.3)
Eliminations	(36.0)	(29.5)	(6.5)	(22.0)
	$ 698.7	$ 668.4	$ 30.3	4.5%

	Year Ended December 31,			
	2008	2007	Change	% Change
	(in millions)			
Gross Margin				
Regulated Electric	$ 363.8	$ 347.0	$ 16.8	4.8%
Regulated Natural Gas	145.0	127.6	17.4	13.6
Unregulated Electric	54.2	56.2	(2.0)	(3.6)
Other	0.9	2.5	(1.6)	(64.0)
Eliminations	(1.8)	(1.6)	(0.2)	(12.5)
	$ 562.1	$ 531.7	$ 30.4	5.7%

Consolidated gross margin in 2008 was $562.1 million, an increase of $30.4 million, or 5.7%, from gross margin in 2007. Primary components of this change included the following:

	Gross Margin 2008 vs. 2007
	(in millions)
Rate increases	$ 20.4
Regulated electric and gas volumes	6.9
Unregulated electric volumes	8.2
Regulated electric QF supply costs	5.0
Wholesale electric	2.6
Unregulated electric pricing and fuel supply costs	(10.2)
Montana property tax tracker	(8.6)
Other	6.1
Improvement in Gross Margin	**$ 30.4**

Our regulated electric and gas margin improved due to the combination of an increase in electric rates in Montana and gas rates in Montana, South Dakota and Nebraska, and an 11.7% increase in volumes in our regulated gas segment due primarily to colder winter weather. In addition, regulated electric QF supply costs were lower due to a combination of pricing and output, and electric wholesale margin improved from increased plant availability and higher average prices. Partly offsetting these increases was a reduction in revenues related to the recovery of our Montana property taxes in rates. The decrease was due to lower 2008 property taxes, a credit to customers related to the property tax settlement discussed below, and a change in calculation by the MPSC to reduce the allocation of property taxes to Montana electric retail customers. See additional discussion related to property taxes below. In addition, unregulated electric margin decreased due to lower average contract prices and higher fuel supply costs partially offset by higher volumes due to increased plant availability.

	Year Ended December 31,			
	2008	2007	Change	% Change
	(in millions)			
Operating Expenses (excluding cost of sales)				
Operating, general and administrative	$ 226.1	$ 221.6	$ 4.5	2.0%
Property and other taxes	80.6	87.6	(7.0)	(8.0)
Depreciation	85.1	82.4	2.7	3.3
	$ 391.8	$ 391.6	$ 0.2	0.1%

Consolidated operating, general and administrative expenses were $226.1 million in 2008 as compared to $221.6 million in 2007. Primary components of this change included the following:

	Operating, General, & Administrative Expenses 2008 vs. 2007
	(in millions)
2007 Environmental clean-up cost recovery	$ 12.6
Pension expense	8.4
Labor and benefits	7.3
Legal and professional fees	5.4
Insurance reimbursements and settlements	(16.5)
Operating lease expense	(14.4)
Other	1.7
Increase in Operating, General & Administrative Expenses	**$ 4.5**

The increase in operating, general and administrative expenses of $4.5 million was primarily due to the following:

- Lower environmental expense in 2007 due to a settlement to recover MGP clean-up costs in our South Dakota natural gas rate case;
- Higher pension expense related to our Montana plan as pension costs are included in expense on a pay as you go (cash funding) basis. With the revised MPSC pension accounting order, pension expense was approximately $30.6 million in 2008, as compared with $22.0 million in 2007, which reflects increased plan funding projections due to plan asset market losses during 2008;
- Increased labor and benefits costs due to a combination of compensation increases, severance costs and higher medical claims; and
- Higher legal and professional fees related to the Colstrip Unit 4 transaction and other matters where we obtained insurance reimbursements or settlement proceeds noted below.

Offsets to these increases included the following:

- The receipt in 2008 of insurance reimbursements and litigation settlement proceeds related to costs incurred in prior years; and
- Decreased operating lease expense due to the purchase of our previously leased interest in Colstrip Unit 4 during 2007.

Property and other taxes were $80.6 million in 2008 as compared with $87.6 million in 2007. This $7.0 million decrease was due to a $4.6 million property tax refund in Montana as a result of a settlement with the Montana Department of Revenue, and a reduction of approximately $2.4 million due to a lower property tax valuation in Montana as compared with 2007. We file annual property tax tracker filings in Montana to reflect a portion of property tax increases or decreases in customer rates. Our latest property tax tracker filing reflected the reductions noted above. In January 2009, the MPSC reviewed our filing and made various changes to allocation factors for the years 2007, 2008 and projections for 2009, which resulted in a lower property tax allocation to our Montana electric retail customers and a higher property tax allocation to electric FERC jurisdictional transmission customers (we do not have a property tax tracker for FERC jurisdictional purposes).

Depreciation expense was $85.1 million in 2008 as compared with $82.4 million in 2007. The increase was primarily due to the purchase of our previously leased interest in Colstrip Unit 4.

Consolidated operating income in 2008 was $170.2 million, as compared with $140.1 million in 2007. This $30.1 million increase was primarily due to the increase in gross margin.

Consolidated interest expense in 2008 was $64.0 million, an increase of $7.1 million, or 12.5%, from 2007. This increase was primarily related to the additional debt incurred with the purchase of our previously leased interest in Colstrip Unit 4.

Consolidated other income in 2008 was $1.6 million, a decrease of $0.8 million from 2007.

Consolidated income tax expense in 2008 was $40.2 million as compared with $32.4 million in 2007. Our effective tax rate for 2008 was 37.3% as compared to 37.8% for 2007.

Consolidated net income in 2008 was $67.6 million as compared with $53.2 million for the same period in 2007. This increase was primarily due to improved operating income, partly offset by higher interest and income tax expense as discussed above.

REGULATED ELECTRIC MARGIN

Year Ended December 31, 2009 Compared with Year Ended December 31, 2008

The following summarizes the regulated electric revenue, cost of sales, and gross margin for the years ended December 31, 2009 and 2008:

	Results			
	2009	2008	Change	% Change
	(in millions)			
Retail revenue	$ 660.7	$ 709.7	$ (49.0)	(6.9)%
Transmission	45.5	48.7	(3.2)	(6.6)
Wholesale	43.9	10.4	33.5	322.1
Regulatory Amortization and Other	32.2	5.4	26.8	496.3
Total Revenues	**782.3**	**774.2**	**8.1**	**1.0**
Total Cost of Sales	**356.7**	**410.4**	**(53.7)**	**(13.1)**
Gross Margin	**$ 425.6**	**$ 363.8**	**$ 61.8**	**17.0%**

	Revenues		Megawatt Hours (MWH)		Avg. Customer Counts	
	2009	2008	2009	2008	2009	2008
	(in thousands)					
Retail Electric						
Montana	$ 222,610	$ 236,921	2,317	2,285	268,492	266,100
South Dakota	43,971	45,199	523	513	48,258	47,967
Residential	**266,581**	**282,120**	**2,840**	**2,798**	**316,750**	**314,067**
Montana	270,558	289,209	3,161	3,190	60,445	59,595
South Dakota	63,004	65,608	877	872	11,659	11,492
Commercial	**333,562**	**354,817**	**4,038**	**4,062**	**72,104**	**71,087**
Industrial	35,902	46,504	2,899	3,122	71	71
Other	24,697	26,221	181	182	5,943	5,823
Total Retail Electric	**$ 660,742**	**$ 709,662**	**9,958**	**10,164**	**394,868**	**391,048**
Wholesale Electric						
Montana	$ 38,263	$ —	642	—	N/A	N/A
South Dakota	5,653	10,370	217	265	N/A	N/A
Total Wholesale Electric	**$ 43,916**	**$ 10,370**	**859**	**265**	**N/A**	**N/A**

	2009 as compared with:	
Cooling Degree-Days	2008	Historic Average
Montana	6% colder	4% warmer
South Dakota	25% colder	37% colder

The following summarizes the components of the changes in regulated electric margin for the years ended December 31, 2009 and 2008:

	Gross Margin 2009 vs. 2008
	(in millions)
Transfer of interest in Colstrip Unit 4 to regulated electric	$ 68.0
Montana property tax tracker	2.6
Operating expenses recovered in supply tracker	2.4
South Dakota wholesale	(4.6)
Transmission capacity	(3.3)
QF supply costs	(2.6)
Other	(0.7)
Improvement in Regulated Electric Gross Margin	**61.8**
Reduction in Unregulated Electric Gross Margin	(54.2)
Net Increase in Electric Gross Margin	**$ 7.6**

The net increase in gross margin is due primarily to the transfer of Colstrip Unit 4 to the regulated utility. Prior to the transfer of Colstrip Unit 4, all of our Montana electric supply costs were based on power purchase agreements, which are passed through to customers at actual cost with no return component. Revenues from the sales of the output of this plant were reflected in our unregulated electric segment through December 31, 2008, which impacts the comparability of the results of our regulated electric segment. The absence of gross margin from our unregulated electric segment reduced gross margin by approximately $54.2 million as compared with 2008. In addition, we are continuing to fulfill a prior third party power purchase agreement, which is reflected as an increase in Montana wholesale revenues and volumes above. Also contributing to the increase in gross margin is an increase in property taxes recovered in revenues as compared with 2008; and higher revenues for operating, general and administrative expenses primarily related to customer efficiency programs, which are recovered from customers through the supply trackers and therefore have no impact on operating income.

This increase in gross margin was offset in part by lower South Dakota wholesale margin due to lower sales at lower average prices, lower transmission capacity revenues with less demand to transmit energy for others across our lines, and higher QF related supply costs based on actual QF pricing and output. In addition, average electric supply prices decreased resulting in decreased retail revenues and cost of sales in 2009 as compared with 2008, with no impact to gross margin. Regulatory amortizations increased due to changes in our electric supply and property tax trackers. These amortizations are offset in retail revenue; therefore they have no impact on gross margin.

Regulated wholesale electric volumes increased due to the 2009 transfer of Colstrip Unit 4 to the regulated utility discussed above. This increase in regulated wholesale electric volumes was offset in part by a decrease in South Dakota wholesale volumes from lower plant availability related to scheduled maintenance. We estimate our South Dakota wholesale volumes will increase by approximately 53 MWHs and margin will increase by approximately $1.8 million in 2010 due primarily to lower planned maintenance.

Year Ended December 31, 2008 Compared with Year Ended December 31, 2007

The following summarizes the regulated electric revenue, cost of sales, and gross margin for the years ended December 31, 2008 and 2007:

	Results			
	2008	2007	Change	% Change
	(in millions)			
Retail revenue	$ 709.7	$ 668.8	$ 40.9	6.1%
Transmission	48.7	48.7	—	—
Wholesale	10.4	6.0	4.4	73.3
Regulatory Amortization and Other	5.4	13.2	(7.8)	(59.1)
Total Revenues	**774.2**	**736.7**	**37.5**	**5.1**
Total Cost of Sales	**410.4**	**389.7**	**20.7**	**5.3**
Gross Margin	**$ 363.8**	**$ 347.0**	**$ 16.8**	**4.8%**

	Revenues		Megawatt Hours (MWH)		Avg. Customer Counts	
	2008	2007	2008	2007	2008	2007
	(in thousands)					
Retail Electric						
Montana	$ 236,921	$ 221,046	2,285	2,235	266,100	262,481
South Dakota	45,199	42,062	513	505	47,967	47,713
Residential	**282,120**	**263,108**	**2,798**	**2,740**	**314,067**	**310,194**
Montana	289,209	277,875	3,190	3,213	59,595	58,319
South Dakota	65,608	58,341	872	827	11,492	11,336
Commercial	**354,817**	**336,216**	**4,062**	**4,040**	**71,087**	**69,655**
Industrial	46,504	44,473	3,122	2,992	71	71
Other	26,221	25,015	182	181	5,823	5,802
Total Retail Electric	**$ 709,662**	**$ 668,812**	**10,164**	**9,953**	**391,048**	**385,722**
Wholesale Electric						
Montana	$ —	$ —	—	—	N/A	N/A
South Dakota	10,370	5,965	265	155	N/A	N/A
Total Wholesale Electric	**$ 10,370**	**$ 5,965**	**265**	**155**	**N/A**	**N/A**

	2008 as compared with:	
Cooling Degree-Days	2007	Historic Average
Montana	42% colder	8% warmer
South Dakota	31% colder	16% colder

The following summarizes the components of the changes in regulated electric margin for the years ended December 31, 2008 and 2007:

	Gross Margin 2008 vs. 2007
	(in millions)
Montana jurisdiction transmission and distribution rate increase	$ 9.9
QF supply costs	5.0
Wholesale	2.6
Customer growth and colder winter weather	2.0
FERC jurisdiction transmission rate increase	1.1
Montana property tax tracker	(7.4)
Transmission volumes	(1.1)
Other	4.7
Improvement in Gross Margin	**$ 16.8**

Regulated electric margin increased $16.8 million primarily due to rate increases and lower QF supply costs. Although it was significantly cooler in the summer of 2008 as compared with 2007, our Montana residential customer usage related to air-conditioning is less sensitive to these changes. The net increase in customer usage is due to customer growth and colder winter weather. We recorded gains (reduced cost of sales) related to our QF liability of $5.9 million in 2008 and $0.9 million in 2007 as actual QF output and variable pricing terms were lower than our estimate. Wholesale margin also improved from increased plant availability and higher average prices. These increases were partly offset by a decrease in revenues related to the recovery of our Montana property taxes in rates. The decrease was due to lower 2008 property taxes, a credit to customers related to the property tax settlement and a change in calculation by the MPSC to reduce the allocation of property taxes to Montana electric retail customers.

Total retail electric volumes increased 211 MWHs, or 2.1%, due primarily to residential and commercial customer growth and an increase in industrial volumes. Wholesale electric volumes increased 110 MWHs, or 71.0%, due to increased plant availability.

REGULATED NATURAL GAS MARGIN

Year Ended December 31, 2009 Compared with Year Ended December 31, 2008

The following summarizes the regulated natural gas revenue, cost of sales, and gross margin for the years ended December 31, 2009 and 2008:

	Results			
	2009	2008	Change	% Change
	(in millions)			
Retail revenue	$ 310.1	$ 374.8	$ (64.7)	(17.3)%
Wholesale and other	44.4	41.9	2.5	6.0
Total Revenues	**354.5**	**416.7**	**(62.2)**	**(14.9)**
Total Cost of Sales	**210.0**	**271.7**	**(61.7)**	**(22.7)**
Gross Margin	**$ 144.5**	**$ 145.0**	**$ (0.5)**	**(0.3)%**

	Revenues		Dekatherms (Dkt)		Customer Counts	
	2009	2008	2009	2008	2009	2008
	(in thousands)					
Retail Gas						
Montana	$ 132,586	$ 161,393	13,291	13,426	156,714	155,409
South Dakota	32,462	37,057	2,925	2,975	36,815	36,620
Nebraska	28,531	33,164	2,674	2,717	36,458	36,466
Residential	**193,579**	**231,614**	**18,890**	**19,118**	**229,987**	**228,495**
Montana	66,516	81,262	6,733	6,754	21,929	21,703
South Dakota	26,567	31,318	3,315	3,104	5,837	5,780
Nebraska	20,760	26,910	2,903	2,962	4,504	4,532
Commercial	**113,843**	**139,490**	**12,951**	**12,820**	**32,270**	**32,015**
Industrial	1,650	2,406	170	207	295	303
Other	1,003	1,261	113	118	142	140
Total Retail Gas	**$ 310,075**	**$ 374,771**	**32,124**	**32,263**	**262,694**	**260,953**

	2009 as compared with:	
Heating Degree-Days	2008	Historic Average
Montana	1% warmer	Remained flat
South Dakota	Remained flat	3% colder
Nebraska	2% warmer	1% colder

The following summarizes the components of the changes in regulated natural gas margin for the years ended December 31, 2009 and 2008:

	Gross Margin 2009 vs. 2008
	(in millions)
Storage	$ (1.2)
Other	0.7
Reduction in Gross Margin	**$ (0.5)**

The decline in margin is primarily due to a decreased return on working gas due to lower average prices on gas in storage. Our wholesale and other revenues are largely gross margin neutral as they are offset by changes in cost of sales. In addition, average natural gas supply prices decreased, resulting in decreased retail revenues and cost of sales in 2009 as compared with 2008, with no impact to gross margin.

Overall retail natural gas volumes declined slightly. The increase in South Dakota commercial volumes was primarily related to higher grain drying requirements due to harvest conditions in our service territory.

Year Ended December 31, 2008 Compared with Year Ended December 31, 2007

The following summarizes the regulated natural gas revenue, cost of sales, and gross margin for the years ended December 31, 2008 and 2007:

	Results			
	2008	2007	Change	% Change
	(in millions)			
Retail revenue	$ 374.8	$ 307.0	$ 67.8	22.1%
Wholesale and other	41.9	56.6	(14.7)	(26.0)
Total Revenues	**416.7**	**363.6**	**53.1**	**14.6**
Total Cost of Sales	**271.7**	**236.0**	**35.7**	**15.1**
Gross Margin	**$ 145.0**	**$ 127.6**	**$ 17.4**	**13.6%**

	Revenues		Dekatherms (Dkt)		Customer Counts	
	2008	2007	2008	2007	2008	2007
	(in thousands)					
Retail Gas						
Montana	$ 161,393	$ 128,451	13,426	12,101	155,409	152,939
South Dakota	37,057	33,027	2,975	2,771	36,620	36,662
Nebraska	33,164	30,374	2,717	2,519	36,466	36,343
Residential	**231,614**	**191,852**	**19,118**	**17,391**	**228,495**	**225,944**
Montana	81,262	64,567	6,754	6,091	21,703	21,261
South Dakota	31,318	24,018	3,104	2,444	5,780	5,765
Nebraska	26,910	23,784	2,962	2,655	4,532	4,523
Commercial	**139,490**	**112,369**	**12,820**	**11,190**	**32,015**	**31,549**
Industrial	2,406	1,749	207	169	303	311
Other	1,261	991	118	144	140	140
Total Retail Gas	**$ 374,771**	**$ 306,961**	**32,263**	**28,894**	**260,953**	**257,944**

	2008 as compared with:	
Heating Degree-Days	**2007**	**Historic Average**
Montana	9% colder	1% colder
South Dakota	9% colder	2% colder
Nebraska	11% colder	2% colder

The following summarizes the components of the changes in regulated natural gas margin for the years ended December 31, 2008 and 2007:

	Gross Margin 2008 vs. 2007
	(in millions)
Colder weather and customer growth	$ 6.0
South Dakota and Nebraska jurisdictions transportation and distribution rate increase	4.3
Montana jurisdiction transportation and distribution rate increase	5.1
Montana property tax tracker	(1.2)
Other	3.2
Improvement in Gross Margin	**$ 17.4**

Regulated natural gas margin increased $17.4 million primarily due to increased volumes and rate increases. Volumes increased 11.7% primarily due to colder winter weather in all of our service territories, along with 1.2% customer growth. These increases were partly offset by a decrease in revenues related to our Montana property tax tracker as discussed above. In addition to the colder weather, the increase in South Dakota commercial volumes was also related to higher grain drying requirements due to harvest conditions in our service territory.

UNREGULATED ELECTRIC MARGIN

Year Ended December 31, 2008 Compared with Year Ended December 31, 2007

As discussed above in the "Overview" to the MD&A, in November 2008, the MPSC approved placing our joint ownership interest in Colstrip Unit 4 into our Montana utility rate base. Effective January 1, 2009, we no longer present an unregulated electric segment and the results of operations of our interest in Colstrip Unit 4 are reflected in the regulated electric segment as a component of electric supply.

The following summarizes the components of the changes in unregulated electric revenue, cost of sales, and gross margin for the years ended December 31, 2008 and 2007:

	Results			
	2008	2007	Change	% Change
	(in millions)			
Total Revenues	**$ 77.7**	**$ 74.2**	**$ 3.5**	**4.7%**
Total Cost of Sales	**23.5**	**18.0**	**5.5**	**30.6%**
Gross Margin	**$ 54.2**	**$ 56.2**	**$ (2.0)**	**(3.6)%**
% GM/Rev	**69.8%**	**75.7%**		

The following summarizes the components of the changes in unregulated electric margin for the years ended December 31, 2008 and 2007:

	Gross Margin 2008 vs. 2007
	(in millions)
Volumes	$ 8.2
Average prices	(6.8)
Fuel supply costs	(3.4)
Decline in Gross Margin	**$ (2.0)**

The decline in unregulated electric margin was primarily due to lower average prices on contracts and higher fuel supply costs partially offset by an increase in volumes from higher plant availability.

The following summarizes unregulated electric volumes for the years ended December 31, 2008 and 2007:

	Volumes MWH			
	2008	2007	Change	% Change
	(in thousands)			
Wholesale Electric	**1,812**	**1,638**	**174**	**10.6%**

Unregulated electric volumes increased from higher energy available to sell as compared with 2007 due to increased plant availability.

LIQUIDITY AND CAPITAL RESOURCES

We require liquidity to support and grow our business, and use our liquidity for working capital needs, capital expenditures, investments in or acquisitions of assets, to repay debt and, from time to time, to repurchase common stock. We anticipate that our ongoing liquidity requirements will be satisfied through a combination of operating cash flows, borrowings, and as necessary the issuance of debt or equity securities, consistent with our objective of maintaining a capital structure that will support a strong investment grade credit rating on a long-term basis. The amount of capital expenditures and dividends are subject to certain factors including the use of existing cash, cash equivalents and the receipt of cash from operations. A material adverse change in operations or available financing could impact our ability to fund our current liquidity and capital resource requirements, and we may defer capital expenditures as necessary.

We utilize our revolver availability to manage our cash flows due to the seasonality of our business, and utilize any cash on hand in excess of current operating requirements to invest in our business and reduce borrowings. As of December 31, 2009, our total net liquidity was approximately $185.2 million, including $4.3 million of cash and $180.9 million of revolving credit facility availability. A total of nine banks participate in our revolving credit facility, with no one bank providing more than 14% of the total availability. As of December 31, 2009, no bank has advised us of its intent to withdraw from the revolving credit facility or not to honor its obligations. To borrow from the revolving credit facility, we are required to maintain a maximum debt to capitalization ratio not to exceed 65%. At December 31, 2009, we were in compliance with this ratio. The revolving credit facility also contains default and related acceleration provisions related to default on other debt. As of February 5, 2010, our availability under our revolving credit facility was approximately $199.4 million.

Credit Ratings

Fitch Ratings (Fitch), Moody's Investors Service (Moody's) and Standard and Poor's Rating Group (S&P) are independent credit-rating agencies that rate our debt securities. These ratings indicate the agencies' assessment of our ability to pay interest and principal when due on our debt. As of February 6, 2010, our ratings with these agencies were as follows:

	Senior Secured Rating	Senior Unsecured Rating	Outlook
Fitch	BBB+	BBB	Stable
Moody's (1)	A3	Baa2	Positive
S&P	A- (MT) BBB+ (SD)	BBB	Stable

(1) Moody's upgraded our senior secured and senior unsecured credit ratings on March 6, 2009 from Baa2 toBaa1 and Baa3 to Baa2, respectively. On August 3, 2009, Moody's upgraded our senior secured credit rating from Baa1 to A3. These changes are reflected above.

In general, less favorable credit ratings make debt financing more costly and more difficult to obtain on terms that are economically favorable to us and impacts our trade credit availability. A security rating is not a recommendation to buy, sell or hold securities. Such rating may be subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

Capital Requirements

Our capital expenditures program is subject to continuing review and modification. Actual utility construction expenditures may vary from estimates due to changes in electric and natural gas projected load growth, changing business operating conditions and other business factors. We anticipate funding capital expenditures through cash flows from operations, available credit sources and future rate increases. Our estimated capital expenditures (excluding strategic growth opportunities discussed below) for the next five years is as follows (in thousands):

Year	Maintenance	Mill Creek Generating Station	Total
2010	$ 124,000	$ 114,000	$ 236,000
2011	140,000	—	142,000
2012	148,000	—	148,000
2013	146,000	—	146,000
2014	142,000	—	142,000

The increase in estimated maintenance capital expenditures from our historical amounts and previous projections reflects our need to address aging infrastructure to maintain reliability, as well as new capacity constraints which are dependent upon load growth projections. Our growth capital falls within the categories of transmission and generation.

Mill Creek Generating Station - We have entered into two key contracts related to the Mill Creek Generating Station. In July 2009, we entered into a gas turbine purchase agreement (Gas Turbine Agreement) with Pratt & Whitney Power Systems, Inc. The total contract price to be paid by us under the agreement is approximately $80.5 million. In July 2009, we also entered into an Engineering, Procurement and Construction Services Agreement (EPC Agreement) with NewMech Companies, Inc., for design, engineering, procurement, construction management and construction. The total contract price, assuming all conditions and covenants under the EPC Agreement are satisfied, is approximately $54.1 million. We are required to make monthly progress payments to NewMech under the EPC Agreement. These two contracts represent approximately 67% of the projected $202 million cost. We have paid approximately $56.4 million and $9.5 million under the Gas Turbine and EPC Agreements during 2009, respectively, which is included in construction work in progress. As of December 31, 2009 we have capitalized approximately $84.7 million in construction work in progress related to this project.

Strategic Growth Capital Expenditures - We have three significant transmission projects currently being contemplated, as discussed in the strategy section. The Colstrip 500 kV upgrade has a projected total capital cost of $125 million of which we assume a 30% ownership and an estimated completion date by the end of 2012. The MSTI project has an estimated cost of $1 billion with an anticipated completion date in 2015. Decisions whether to partner and/or resize the line due to demand would impact the ultimate capital expected from us. The capital requirements for the 230 kV collector system project are dependent upon the outcome of the open season in process that will determine the size of the project. Costs for this project could exceed $200 million. We currently estimate capital expenditures related to these projects to range between approximately $20 and $25 million in 2010. We are currently in the process of determining future capital needs related to additional distribution investment and wind generation opportunities. We do not expect capital expenditures related to these projects to be significant in 2010.

The timing of and commitment to these proposed strategic transmission growth projects is solely at our discretion. Significant financial commitments are not made until appropriate commercial assurances and regulatory approvals, as applicable, have been secured, thus limiting our risk to prudent levels.

Contractual Obligations and Other Commitments

We have a variety of contractual obligations and other commitments that require payment of cash at certain specified periods. The following table summarizes our contractual cash obligations and commitments as of December 31, 2009. See additional discussion in Note 17 – Commitments and Contingencies in the Notes to Consolidated Financial Statements.

	Total	2010	2011	2012	2013	2014	Thereafter
				(in thousands)			
Long-term Debt	$ 987,419	$ 6,123	$ 6,578	$ 69,792	$ —	$ 225,000	$ 679,926
Capital Leases	36,767	1,197	1,282	1,370	1,468	1,582	29,868
Future minimum operating lease payments	3,696	1,529	1,079	688	86	63	251
Estimated Pension and Other Postretirement Obligations (1)	51,000	13,800	13,800	13,800	4,800	4,800	N/A
Qualifying Facilities (2)	1,397,595	63,589	65,323	67,111	69,816	72,354	1,059,402
Supply and Capacity Contracts (3)	1,671,110	363,046	191,948	174,494	161,983	120,289	659,351
Other Purchase Obligations (4)	70,790	70,790	—	—	—	—	—
Contractual interest payments on debt (5)	520,326	55,574	55,187	53,702	52,512	52,512	250,839
Total Commitments (6)	$4,738,703	$ 575,648	$ 335,197	$ 380,957	$ 290,665	$ 476,600	$ 2,679,637

(1) We have estimated cash obligations related to our pension and other postretirement benefit programs for five years, as it is not practicable to estimate thereafter. These estimates reflect our expected cash contributions, which may be in excess of minimum funding requirements.

(2) 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 $1.4 billion. A portion of the costs incurred to purchase this energy is recoverable through rates authorized by the MPSC, totaling approximately $1.1 billion.

(3) We have entered into various purchase commitments, largely purchased power, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 19 years.

(4) This represents contractual purchase obligations related to the Mill Creek Generating Station construction project.

(5) Contractual interest payments includes our revolving credit facility, which has a variable interest rate. We have assumed an average interest rate of 3.23% on an estimated revolving line of credit balance of $66.0 million through maturity in June 2012.

(6) Potential tax payments related to uncertain tax positions are not practicable to estimate and have been excluded from this table.

Cash Flows

Factors Impacting our Liquidity

Supply Costs - Our operations are subject to seasonal fluctuations in cash flow. During the heating season, which is primarily from November through March, cash receipts from natural gas sales and transportation services typically exceed cash requirements. During the summer months, cash on hand, together with the seasonal increase in cash flows and utilization of our existing revolver, are used to purchase natural gas to place in storage, perform maintenance and make capital improvements.

The effect of this seasonality on our liquidity is also impacted by changes in the market prices of our electric and natural gas supply, which is recovered through various monthly cost tracking mechanisms. These energy supply tracking mechanisms are designed to provide stable and timely recovery of supply costs on a monthly basis during the July to June annual tracking period, with an adjustment in the following annual tracking period to correct for any under or over collection in our monthly trackers. Due to the lag between our purchases of electric and natural gas commodities and revenue receipt from customers, cyclical over and under collection situations arise consistent with the seasonal fluctuations discussed above; therefore we usually under collect in the fall and winter and over collect in the spring. Fluctuations in recoveries under our cost tracking mechanisms can have a significant effect on cash flow from operations and make year-to-year comparisons difficult.

As of December 31, 2009, we are under collected on our current Montana natural gas and electric trackers by approximately $19.8 million, as compared with an under collection of $10.5 million as of December 31, 2008, and an over collection of approximately $4.0 million as of December 31, 2007. This under collection is primarily due to the volatility of commodity prices.

Pension Plan Contributions – During the year ended December 31, 2009, we made contributions of $92.9 million to our qualified pension plans, as compared with $32.7 million in 2008. The 2009 contributions exceeded our minimum funding requirements by approximately $75.0 million and were made to improve the funded status of our plans as well as reduce future contribution requirements.

Financing Transactions - In March 2009, we received net proceeds of approximately $249.8 million from the issuance of Montana First Mortgage Bonds at a fixed interest rate of 6.34% maturing April 1, 2019. We used the proceeds to redeem our $100 million Colstrip Lease Holdings LLC term loan, repay outstanding borrowings on our revolving credit facility, repay other outstanding debt obligations of $31.7 million related to Colstrip Unit 4, fund a portion of the costs of the Mill Creek Generating Station project, and capital expenditures.

On June 30, 2009, we amended and restated our unsecured revolving line of credit scheduled to expire on November 1, 2009. The amended facility extends the term to June 30, 2012, and increases the aggregate principal amount available under the facility by $50 million to $250 million. The amended facility does not amortize and borrowings will bear interest based on a credit ratings grid. The ‘spread’ or ‘margin’ ranges from 2.25% to 4.0% over the London Interbank Offered Rate (LIBOR). As of December 31, 2009, the applicable spread was 3.0%. A total of nine banks participate in the new facility, with no one bank providing more than 14.0% of the total availability. The amended facility contains covenants substantially similar to the previous facility.

On October 15, 2009 we issued $55 million of Montana First Mortgage Bonds at a fixed interest rate of 5.71% maturing October 15, 2039. We used the proceeds to fund a portion of the costs of the Mill Creek Generating Station project and capital expenditures.

The following table summarizes our consolidated cash flows for 2009, 2008 and 2007.

	Year Ended December 31,		
	2009	2008	2007
Operating Activities			
Net income	$ 73.4	$ 67.6	$ 53.2
Non-cash adjustments to net income	137.5	132.3	113.1
Changes in working capital	(40.3)	(7.8)	26.9
Other noncurrent assets and liabilities	(53.8)	6.2	8.8
	116.8	**198.3**	**202.0**
Investing Activities			
Property, plant and equipment additions	(189.4)	(124.6)	(117.1)
Colstrip Unit 4 acquisition	—	—	(141.3)
Sale of assets	0.3	0.2	1.9
	(189.1)	**(124.4)**	**(256.5)**
Financing Activities			
Net borrowing of debt	125.0	54.6	46.5
Dividends on common stock	(48.2)	(49.8)	(47.3)
Treasury stock activity	(0.7)	(78.7)	(0.9)
Proceeds from exercise of warrants	—	—	68.8
Other	(10.8)	(1.5)	(1.7)
	65.3	**(75.4)**	**65.4**
Net (Decrease) Increase in Cash and Cash Equivalents	**$ (7.0)**	**$ (1.5)**	**$ 10.9**
Cash and Cash Equivalents, beginning of period	$ 11.3	$ 12.8	$ 1.9
Cash and Cash Equivalents, end of period	**$ 4.3**	**$ 11.3**	**$ 12.8**

Cash Flows Provided By Operating Activities

As of December 31, 2009, our cash and cash equivalents were $4.3 million as compared with $11.3 million at December 31, 2008. Cash provided by operating activities totaled $116.8 million for the year ended December 31, 2009 as compared with $198.3 million during 2008. This decrease in operating cash flows is primarily related to pension funding of $92.9 million, which was an increase of approximately $60.2 million as compared with 2008, payment of the Ammondson verdict in the fourth quarter of 2009 of approximately $26.7 million and a $10.8 million prepayment of a power purchase agreement, offset by lower commodity prices reflected in the change in accounts receivable, as well as decreased cash outflows for natural gas storage injections.

Our 2008 operating cash flows decreased by approximately $3.7 million as compared with 2007 due to the combination of a $14.5 million change in our supply tracker due to an under collected position as discussed above, an increase in accounts receivable of $18.5 million due to colder winter weather and higher average prices in December 2008, and increased pension funding of approximately $10.1 million. These decreases in operating cash flows were offset in part by higher net income, improved operating cash flows related to our Colstrip Unit 4 lease buyout of approximately $6.0 million, and the inclusion in 2007 operating cash flows of an additional semi-annual Colstrip Unit 4 lease payment of $16.1 million due to calendar timing.

Cash Flows Used In Investing Activities

Cash used in investing activities totaled $189.1 million during the year ended December 31, 2009, as compared with $124.4 million during 2008, and $256.5 million in 2007. During 2009, we invested $189.4 million in property, plant and equipment additions, including approximately $83.4 million related to Mill Creek Generating Station, as compared with $124.6 million in property, plant and equipment additions during 2008. During the same period in 2007, we used $141.3 million to complete the purchases of the Owner Participant interests in portions of the Colstrip Unit 4 generating facility, and $117.1 million for property, plant and equipment additions, partially offset by $1.9 million of proceeds received from the sale of assets.

Cash Flows Provided By (Used In) Financing Activities

Cash provided by financing activities totaled $65.3 million during 2009, as compared with cash used in financing activities of $75.4 million during 2008, and cash provided of $65.4 million during 2007. During 2009 we received net proceeds from the issuance of debt of $304.8 million (see “Financing Transactions” discussion above), made net debt repayments of $179.8 million, paid deferred financing costs of $10.8 million and paid dividends on common stock of $48.2 million. During 2008, cash used to repurchase shares under our previously announced plan was approximately $77.7 million. We had net borrowings on our revolving credit facility of $96.0 million, and debt repayments of $41.4 million. Dividends paid on common stock during 2008 were approximately $49.8 million.

During 2007, we received proceeds of $100 million from the issuance of debt, made debt repayments of $53.5 million and paid dividends on common stock of $47.3 million. In addition, we received proceeds during 2007 of $68.8 million from the exercise of warrants.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Management's discussion and analysis of financial condition and results of operations is based on our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. We base our estimates on historical experience and other assumptions that are believed to be proper and reasonable under the circumstances. We continually evaluate the appropriateness of our estimates and assumptions, including those related to goodwill, qualifying facilities liabilities, impairment of long-lived assets and revenue recognition, among others. Actual results could differ from those estimates.

We have identified the policies and related procedures below as critical to understanding our historical and future performance, as these polices affect the reported amounts of revenue and the more significant areas involving management's judgments and estimates.

Goodwill and Long-lived Assets

We assess the carrying value of our goodwill for impairment at least annually (October 1) and more frequently when indications of impairment exist. We calculate the fair value of our segments and reporting units by considering various factors, including valuation studies based primarily on a discounted cash flow methodology and published industry valuations and market data as supporting information. These calculations are dependent on subjective factors such as management’s estimate of future cash flows and the selection of appropriate discount and growth rates. These underlying assumptions and estimates are made as of a point in time; subsequent changes in these assumptions could result in a future impairment charge. We monitor for events or circumstances that may indicate an interim goodwill impairment test is necessary. Accounting standards require that if the fair value of a reporting unit is less than its carrying value including goodwill, an impairment charge for goodwill must be recognized in the financial statements. To measure the amount of an impairment loss, the implied fair value of the reporting unit's goodwill is compared with its carrying value.

We evaluate our property, plant and equipment for impairment if an indicator of impairment exists. If the sum of the undiscounted cash flows from a company's asset, without interest charges, is less than the carrying value of the asset, impairment must be recognized in the financial statements. If an asset is deemed to be impaired, then the amount of the impairment loss recognized represents the excess of the asset's carrying value as compared to its estimated fair value, based on management's assumptions and projections.

We believe that the accounting estimate related to determining the fair value of goodwill and long-lived assets, and thus any impairment, is a “critical accounting estimate" because: (i) it is highly susceptible to change from period to period since it requires company management to make cash flow assumptions about future revenues, operating costs and discount rates over an indefinite life; and (ii) recognizing an impairment could have a significant impact on the assets reported in our Consolidated Balance Sheets and our Consolidated Statements of Income. Management's assumptions about future margins and volumes require significant judgment because actual margins and volumes have fluctuated in the past and are expected to continue to do so. In estimating future margins, we use our internal budgets.

Qualifying Facilities Liability

Certain QF contracts under the Public Utility Regulatory Policies Act (PURPA) require us to purchase minimum amounts of energy at prices ranging from $65 to $167 per MWH through 2029. As of December 31, 2009, our estimated gross contractual obligation related to the QFs is approximately $1.4 billion. A portion of the costs incurred to purchase this energy is recoverable though rates authorized by the MPSC, totaling approximately $1.1 billion through 2029. We maintain a liability based on the net present value (discounted at 7.75%) of the difference between our estimated obligations under the QFs and the related amounts recoverable in rates.

There are ten contracts encompassed in the QF liability. Three of these contracts account for more than 98% of the output. The liability was established based on certain assumptions and projections over the contract terms related to pricing, estimated output and recoverable amounts. The estimated capacity factor for each QF and the estimated escalation rate for one of the contracts are key assumptions. The estimated capacity factors are primarily based on historical actual capacity factors. The estimated escalation rate for the one contract was based on a combination of historical actual results and market data available for future projections. Since the liability is based on projections over a 25-year period; actual QF output, changes in pricing, contract amendments and regulatory decisions relating to QFs could significantly impact the liability and our results of operations in any given year.

In assessing the liability each reporting period, we compare our assumptions to actual results and make adjustments as necessary for that period.

In December 2006, the MPSC issued an order finalizing certain QF rates for the periods July 1, 2003 through June 30, 2006. The result of this order could provide for a significant reduction to our QF liability, as it reduces the escalating energy and capacity rates for one contract that we utilize in determining the present value of our obligation. We are currently in litigation with a QF over this matter and we cannot predict the outcome of this litigation, therefore we have not changed our historical assumptions or reduced the liability. We will continue to assess the status of the litigation and do not anticipate changing our assumptions until we can determine a probable outcome. See Note 17 – Commitments and Contingencies in the Notes to Consolidated Financial Statements for further discussion of this litigation.

Revenue Recognition

Revenues are recognized differently depending on the various jurisdictions. For our South Dakota and Nebraska operations, consistent with historic treatment in the respective jurisdictions, electric and natural gas utility revenues are based on billings rendered to customers. For our Montana operations, operating revenues are recorded monthly on the basis of consumption or services rendered. Customers are billed on a monthly cycle basis. To match revenues with associated expenses, we accrue unbilled revenues for electric and natural gas services delivered to the customers but not yet billed at month-end. The calculation of unbilled revenue is affected by factors that include fluctuations in energy demand for the unbilled period, seasonality, weather, customer usage patterns, price in effect for each customer class and estimated transmission and distribution line losses. We base our estimate of unbilled revenue each period on the volume of energy delivered, as valued by the billing cycle and historical usage rates and growth by customer class for our service area. This figure is then adjusted for the projected impact of seasonal and weather variations.

Regulatory Assets and Liabilities

Our operations are subject to the provisions of ASC 980, *Accounting for the Effects of Certain Types of Regulation*. Our regulatory assets are the probable future revenues associated with certain costs to be recovered from customers through the ratemaking process, including our estimate of amounts recoverable for natural gas and electric supply purchases. Regulatory liabilities are the probable future reductions in revenues associated with amounts to be credited to customers through the ratemaking process. We determine which costs are recoverable by consulting previous rulings by state regulatory authorities in jurisdictions where we operate or other factors that lead us to believe that cost recovery is probable. This accounting treatment is impacted by the uncertainties of our regulatory environment, anticipated future regulatory decisions and their impact. If any part of our operations becomes no longer subject to the provisions of ASC 980, or facts and circumstances lead us to conclude that a recorded regulatory asset is no longer probable of recovery, we would record a charge to earnings, which could be material. In addition, we would need to determine if there was any impairment to the carrying costs of the associated plant and inventory assets.

While we believe that our assumptions regarding future regulatory actions are reasonable, different assumptions could materially affect our results. See Note 14 – Regulatory Assets and Liabilities in the Notes to Consolidated Financial Statements for further discussion.

Pension and Postretirement Benefit Plans

We sponsor and/or contribute to pension, postretirement health care and life insurance benefits for eligible employees. Our reported costs of providing pension and other postretirement benefits, as described in Note 12 to the Consolidated Financial Statements, are dependent upon numerous factors including the provisions of the plans, changing employee demographics, rate of return on plan assets and other economic conditions, and various actuarial calculations, assumptions, and accounting mechanisms. As a result of these factors, significant portions of pension and other postretirement benefit costs recorded in any period do not reflect (and are generally greater than) the actual benefits provided to plan participants. Due to the complexity of these calculations, the long-term nature of the obligations, and the importance of the assumptions utilized, the determination of these costs is considered a critical accounting estimate.

Assumptions

Key actuarial assumptions utilized in determining these costs include:

- Discount rates used in determining the future benefit obligations;
- Projected health care cost trend rates;
- Expected long-term rate of return on plan assets; and
- Rate of increase in future compensation levels.

We review these assumptions on an annual basis and adjust them as necessary. The assumptions 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.

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. Based on this analysis, in 2009 we reduced our discount rate on the NorthWestern Corporation pension plan from 6.25% to 5.75% and on the NorthWestern Energy pension plan from 6.25% to 6.00%.

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 long-term trend assumption is based upon our actuary's macroeconomic forecast, which includes assumed long-term nominal gross domestic product (GDP) growth plus the expected excess growth in national health expenditures versus GDP, the assumed impact of population growth and aging, and variations by healthcare sector. Based on this review, the health care cost trend rate used in calculating the accumulated postretirement benefit obligation remained unchanged from 2008, which was a 10% increase in health care costs in 2008, with a reset to 9.5% in 2009 and gradually decreasing each successive year by 0.25% until it reaches an ultimate trend of 4.5% annual increase in health care costs.

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 2009, we revised our target asset allocation from 70% equity securities, and 30% fixed-income securities to 60% equity securities, and 40% 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 8.00% to 7.75% for 2010. The assumed rate of increase in future compensation levels used to calculate benefit obligations was a weighted average of 3.50% for union and 3.55% - 3.58% for nonunion employees in 2009.

Cost Sensitivity

The following table reflects the sensitivity of pension costs to changes in certain actuarial assumptions (in thousands):

Actuarial Assumption	Change in Assumption	Impact on Pension Cost	Impact on Projected Benefit Obligation
Discount rate	0.25%	$ (997)	$ (11,390)
	(0.25)	1,001	11,697
Rate of return on plan assets	0.25	(700)	N/A
	(0.25)	700	N/A

Accounting Treatment

We recognize the funded status of each plan as an asset or liability in the Consolidated Balance Sheets. 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, which reduces the volatility of reported pension costs. If necessary, the excess is amortized over the average remaining service period of active employees.

Due to the various regulatory treatments of the plans, our financial statements reflect the effects of the different rate making principles followed by the jurisdiction regulating us. Pension costs in Montana and other postretirement benefit costs in South Dakota are included in rates on a pay as you go basis for regulatory purposes. Pension costs in South Dakota and other postretirement benefit costs in Montana are included in rates on an accrual basis for regulatory purposes. Regulatory assets have been recognized for the obligations that will be included in future cost of service.

Income Taxes

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. Deferred income tax assets and liabilities represent the future effects on income taxes from temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The probability of realizing deferred tax assets is based on forecasts of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. We establish a valuation allowance when it is more likely than not that all, or a portion of, a deferred tax asset will not be realized. 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 currently estimate that as of December 31, 2009, we have approximately $476 million of CNOLs to offset federal taxable income in future years. We believe our deferred tax assets and established liabilities are appropriate for estimated exposures; however, actual results may differ significantly from these estimates.

The interpretation of tax laws involves uncertainty. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows and adjustments to tax-related assets and liabilities could be material. The uncertainty and judgment involved in the determination and filing of income taxes is accounted for by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the financial statements. 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. We have unrecognized tax benefits of approximately $122.8 million as of December 31, 2009. The resolution of tax matters in a particular future period could have a material impact on our cash flows, results of operations and provision for income taxes.

NEW ACCOUNTING STANDARDS

See Note 2, Significant Accounting Policies, to the Consolidated Financial Statements, included in Item 8 herein for a discussion of new accounting standards.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

We are exposed to market risks, including, but not limited to, interest rates, energy commodity price volatility, and credit exposure. Management has established comprehensive risk management policies and procedures to manage these market risks.

Interest Rate Risk

We utilize various risk management instruments to reduce our exposure to market interest rate changes. These risks include exposure to adverse interest rate movements for outstanding variable rate debt and for future anticipated financings. All of our debt has fixed interest rates, with the exception of our revolving credit facility. The revolving credit facility bears interest at the lower of prime or available rates tied to the London Interbank Offered Rate (LIBOR) plus a credit spread, ranging from 2.25% to 4.0% over LIBOR. As of December 31, 2009, the applicable spread was 3.0%, resulting in a borrowing rate of 3.23%. Based upon amounts outstanding as of December 31, 2009, a 1% increase in the LIBOR would increase our annual interest expense by approximately $0.7 million.

Commodity Price Risk

Commodity price risk is a significant risk due to our lack of ownership of natural gas reserves and minimal ownership of regulated electric generation assets 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.

As part of our overall strategy for fulfilling our regulated electric supply requirements, we employ the use of market purchases, including forward purchase and sales contracts. 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.

Our “other” segment includes a pipeline capacity contract through October 2013 that was primarily used to serve natural gas supply to one customer. During the second quarter of 2009, this customer terminated their natural gas supply contract with us during their bankruptcy proceedings. As a result of the supply contract termination, we have excess capacity. We recognized a $1.5 million loss during the year ended December 31, 2009 based on our release of the excess capacity through October 2010 and our estimate of the market value for the excess capacity during the remaining term. Our remaining maximum exposure is approximately $0.9 million related to this contract. We have no other remaining capacity contracts outside of our regulated utility operations.

Counterparty Credit Risk

We are exposed to counterparty credit risk related to the ability of our counterparties to meet their contractual payment obligations, and the potential non-performance of counterparties to deliver contracted commodities or services at the contracted price. We have risk management policies in place to limit our transactions to high quality counterparties, and continue to monitor closely the status of our counterparties, and will take action, as appropriate, to further manage this risk. This includes, but is not limited to, requiring letters of credit or prepayment terms. There can be no assurance, however, that the management tools we employ will eliminate the risk of loss.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The consolidated financial information, including the reports of independent accountants, the quarterly financial information, and the financial statement schedules, required by this Item 8 is set forth on pages F-1 to F-48 of this Annual Report on Form 10-K and is hereby incorporated into this Item 8 by reference.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms and accumulated and reported to management, including the principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

We conducted an evaluation, under the supervision and with the participation of our principal executive officer and principal financial officer, of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934). Based on this evaluation our principal executive officer and principal financial officer have concluded that, as of December 31, 2009, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal controls over financial reporting for the three-months ended December 31, 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Controls over Financial Reporting

The management of NorthWestern is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control system was designed to provide reasonable assurance to our management and Board of Directors regarding the preparation and fair presentation of published financial statements.

All internal controls over financial reporting, no matter how well designed, have inherent limitations, including the possibility of human error and the circumvention or overriding of controls. Therefore, even effective internal control over financial reporting can provide only reasonable assurance with respect to financial statement preparation and presentation. Further, because of changes in conditions, the effectiveness of internal controls over financial reporting may vary over time.

Our management, including our chief executive officer and chief financial officer, assessed the effectiveness of our internal control over financial reporting as of December 31, 2009. In making its assessment of internal control over financial reporting, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control—Integrated Framework. Based on our evaluation, management concluded that, as of December 31, 2009, our internal control over financial reporting was effective based on those criteria.

Our independent registered public accounting firm has issued an attestation report on our internal control over financial reporting. Their report appears on page F-3.

ITEM 9B. OTHER INFORMATION

Not applicable.

Part III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item with respect to directors and corporate governance will be set forth in NorthWestern Corporation's Proxy Statement for its 2010 Annual Meeting of Shareholders, which is incorporated by reference. Information with respect to our Executive Officers is included in Item 1 to this report.

ITEM 11. EXECUTIVE COMPENSATION

Information required by this Item will be set forth in NorthWestern Corporation's Proxy Statement for its 2010 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED SHAREHOLDER MATTERS

Information required by this item will be set forth in NorthWestern Corporation's Proxy Statement for its 2010 Annual Meeting of Shareholders, which is incorporated by reference. Information with respect to issuance under equity compensation plans is included in Part II, Item 5 to this report.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information concerning relationships and related transactions of the directors and officers of NorthWestern Corporation and director independence will be set forth in NorthWestern Corporation's Proxy Statement for its 2010 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information concerning fees paid to the principal accountant for each of the last two years is contained in NorthWestern Corporation's Proxy Statement for its 2010 Annual Meeting of Shareholders, which is incorporated by reference.

Part IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

The following documents are filed as part of this report:

(1) Financial Statements.

The following items are included in Part II, Item 8 of this annual report on Form 10-K:

FINANCIAL STATEMENTS:

(2) Financial Statement Schedule

Schedule II, Valuation and Qualifying Accounts, is included in Part II, Item 8 of this annual report on Form 10-K. All other schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or the Notes thereto.

(3) Exhibits.

The exhibits listed below are hereby filed with the SEC, as part of this Annual Report on Form 10-K. Certain of the following exhibits have been previously filed with the SEC pursuant to the requirements of the Securities Act of 1933 or the Securities Exchange Act of 1934. Such exhibits are identified by the parenthetical references following the listing of each such exhibit and are incorporated by reference. We will furnish a copy of any exhibit upon request, but a reasonable fee may be charged to cover our expenses in furnishing such exhibit.

Exhibit Number	Description of Document
2.1(a)	Second Amended and Restated Plan of Reorganization of NorthWestern Corporation (incorporated by reference to Exhibit 2.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 20, 2004, Commission File No. 1-10499).
2.1(b)	Order Confirming the Second Amended and Restated Plan of Reorganization of NorthWestern Corporation (incorporated by reference to Exhibit 2.2 of NorthWestern Corporation's Current Report on Form 8-K, dated October 20, 2004, Commission File No. 1-10499).
3.1	Amended and Restated Certificate of Incorporation of NorthWestern Corporation, dated November 1, 2004 (incorporated by reference to Exhibit 3.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 20, 2004, Commission File No. 1-10499).
3.2	Amended and Restated By-Laws of NorthWestern Corporation, dated June 27, 2006 (incorporated by reference to Exhibit 3.1 of NorthWestern Corporation's Current Report on Form 8-K, dated June 27, 2006, Commission File No. 1-10499).
4.1(a)	General Mortgage Indenture and Deed of Trust, dated as of August 1, 1993, from NorthWestern Corporation to The Chase Manhattan Bank (National Association), as Trustee (incorporated by reference to Exhibit 4(a) of NorthWestern Corporation's Current Report on Form 8-K, dated August 16, 1993, Commission File No. 1-10499).
4.1(b)	Supplemental Indenture, dated as of November 1, 2004, by and between NorthWestern Corporation (formerly known as Northwestern Public Service Company) and JPMorgan Chase Bank (successor by merger to The Chase Manhattan Bank (National Association)), as Trustee under the General Mortgage Indenture and Deed of Trust dated as of August 1, 1993 (incorporated by reference to Exhibit 4.5 of NorthWestern Corporation's Current Report on Form 8-K, dated November 1, 2004, Commission File No. 1-10499).
4.1(c)	Eighth Supplemental Indenture, dated as of May 1, 2008, by and between NorthWestern Corporation and The Bank of New York, as trustee under the General Mortgage Indenture and Deed of Trust dated as of August 1, 1993 (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 10-Q for the quarter ended June 30, 2008, Commission File No. 1-10499).
4.2(a)	Indenture, dated as of November 1, 2004, between NorthWestern Corporation and U.S. Bank National Association, as trustee agent (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated November 1, 2004, Commission File No. 1-10499).
4.2(b)	Supplemental Indenture No. 1, dated as of November 1, 2004, by and between NorthWestern Corporation and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation's Current Report on Form 8-K, dated November 1, 2004, Commission File No. 1-10499).
4.2(c)	Purchase Agreement, dated March 23, 2009, among NorthWestern Corporation and Banc of America Securities LLC and J.P. Morgan Securities Inc., as representatives of several initial purchasers (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated March 23, 2009, Commission File No. 1-10499).
4.3	Loan Agreement, dated as of April 1, 2006, between NorthWestern Corporation and the City of Forsyth, Montana, related to the issuance of City of Forsyth Pollution Control Revenue Bonds Series 2006 (incorporated by reference to Exhibit 4.3(e) of the Company's Report on Form 10-K for the year ended December 31, 2006, Commission File No. 1-10499).
4.4(a)	First Mortgage and Deed of Trust, dated as of October 1, 1945, by The Montana Power Company in favor of Guaranty Trust Company of New York and Arthur E. Burke, as trustees (incorporated by reference to Exhibit 7(e) of The Montana Power Company's Registration Statement, Commission File No. 002-05927).

Exhibit Number	Description of Document
4.4(b)	Eighteenth Supplemental Indenture to the Mortgage and Deed of Trust, dated as of August 5, 1994 (incorporated by reference to Exhibit 99(b) of The Montana Power Company's Registration Statement on Form S-3, dated December 5, 1994, Commission File No. 033-56739).
4.4(c)	Twenty-First Supplemental Indenture to the Mortgage and Deed of Trust, dated as of February 13, 2002 (incorporated by reference to Exhibit 4(v) of NorthWestern Energy, LLC's Annual Report on Form 10-K for the year ended December 31, 2001, Commission File No. 001-31276).
4.4(d)	Twenty-Second Supplemental Indenture to the Mortgage and Deed of Trust, dated as of November 15, 2002 (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated February 10, 2003, Commission File No. 1-10499).
4.4(e)	Twenty-Third Supplemental Indenture to the Mortgage and Deed of Trust, dated as of February 1, 2002 (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation's Current Report on Form 8-K, dated February 10, 2003, Commission File No. 1-10499).
4.4(f)	Twenty-Fourth Supplemental Indenture, dated as of November 1, 2004, between NorthWestern Corporation and The Bank of New York and MaryBeth Lewicki, (incorporated by reference to Exhibit 4.4 of NorthWestern Corporation's Current Report on Form 8-K, dated November 1, 2004, Commission File No. 1-10499).
4.4(g)	Twenty-Fifth Supplemental Indenture, dated as of April 1, 2006, between NorthWestern Corporation and The Bank of New York and Ming Ryan, as trustees (incorporated by reference to Exhibit 4.4(n) of the Company's Report on Form 10-K for the year ended December 31, 2006, Commission File No. 1-10499).
4.4(h)	Twenty-Sixth Supplemental Indenture, dated as of September 1, 2006, between NorthWestern Corporation and The Bank of New York and Ming Ryan, as trustees (incorporated by reference to Exhibit 4.4 of NorthWestern Corporation's Current Report on Form 8-K, dated September 13, 2006, Commission File No. 1-10499).
4.4(i)	Twenty-seventh Supplemental Indenture, dated as of March 1, 2009, among NorthWestern Corporation and The Bank of New York Mellon (formerly The Bank of New York) and Ming Ryan, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation’s Current Report on Form 8-K, dated March 23, 2009, Commission File No. 1-10499).
4.4(j)	Twenty-eighth Supplemental Indenture, dated as of October 1, 2009, by and between NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, Commission File No. 1-10499).
4.5(a)	Natural Gas Funding Trust Indenture, dated as of December 22, 1998, between MPC Natural Gas Funding Trust, as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.7(a) of the Company's Report on Form 10-K for the year ended December 31, 2002, Commission File No. 1-10499).
4.5(b)	Natural Gas Funding Trust Agreement, dated as of December 11, 1998, among The Montana Power Company, Wilmington Trust Company, as trustee, and the Beneficiary Trustees party thereto (incorporated by reference to Exhibit 4.7(b) of the Company's Report on Form 10-K for the year ended December 31, 2002, Commission File No. 1-10499).
4.5(c)	Transition Property Purchase and Sale Agreement, dated as of December 22, 1998, between MPC Natural Gas Funding Trust and The Montana Power Company (incorporated by reference to Exhibit 4.7(c) of the Company's Report on Form 10-K for the year ended December 31, 2002, Commission File No. 1-10499).
4.5(d)	Transition Property Servicing Agreement, dated as of December 22, 1998, between MPC Natural Gas Funding Trust and The Montana Power Company (incorporated by reference to Exhibit 4.7(d) of the Company's Report on Form 10-K for the year ended December 31, 2002, Commission File No. 1-10499).
4.5(e)	Assumption Agreement regarding the Transition Property Purchase Agreement and the Transition Property Servicing Agreement, dated as of February 13, 2002, by The Montana Power, LLC to MPC Natural Gas Funding Trust (incorporated by reference to Exhibit 4.7(e) of the Company's Report on Form 10-K for the year ended December 31, 2002, Commission File No. 1-10499).
4.5(f)	Assignment and Assumption Agreement (Natural Gas Transition Documents), dated as of November 15, 2002, by and between NorthWestern Energy, LLC, as assignor, and NorthWestern Corporation, as assignee (incorporated by reference to Exhibit 4.7(f) of the Company's Report on Form 10-K for the year ended December 31, 2002, Commission File No. 1-10499).

Exhibit Number	Description of Document
10.1(a) †	NorthWestern Corporation 2005 Deferred Compensation Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.1(c) to NorthWestern Corporation's Annual Report on Form 10-K for the year ended December 31, 2004, Commission File No. 1-10499).
10.1(b) †	NorthWestern Corporation 2005 Long-Term Incentive Plan (incorporated by reference to Exhibit 2.1 of NorthWestern Corporation's registration statement on Form S-8, dated May 4, 2005, Commission File No. 333-124624).
10.1(c) †	Employment agreement with Robert C. Rowe, dated August 11, 2008 (incorporated by reference to Exhibit 10.1 to NorthWestern Corporation's Current Report on Form 8-K, dated August 19, 2008, Commission File No. 1-10499).
10.1(d) †	NorthWestern Corporation 2008 Key Employee Severance Plan (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 2, 2008, Commission File No. 1-10499).
10.1(e) †	NorthWestern Corporation 2005 Long-Term Incentive Plan, as amended October 31, 2007 (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Quarterly Report on Form 10-Q, dated October 30, 2008, Commission File No. 1-10499).
10.1(f) †	NorthWestern Energy 2009 Annual Incentive Plan (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated February 13, 2009, Commission File No. 1-10499).
10.1(g) †	Form of NorthWestern Corporation Long Term Performance Incentive Restricted Stock Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated February 13, 2009, Commission File No. 1-10499).
10.1(h) †	NorthWestern Corporation 2009 Officers Deferred Compensation Plan (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated April 22, 2009, Commission File No. 1-10499).
10.1(i) †	Waiver and Release of Miggie E. Cramblit executed January 5, 2010 (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated January 5, 2010, Commission File No.1-10499).
10.1(j) †	Consulting agreement with Miggie E. Cramblit, executed January 6, 2010 (incorporated by reference to Exhibit 10.2 of NorthWestern Corporation's Current Report on Form 8-K, dated January 5, 2010, Commission File No.1-10499).
10.2(a)	Purchase Agreement, dated September 6, 2006, among NorthWestern Corporation and Credit Suisse Securities (USA) LLC and Deutsche Bank Securities Inc., as representatives of several initial purchasers (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated September 13, 2006, Commission File No. 1-10499).
10.2(b)	Purchase Agreement, dated January 18, 2007, between NorthWestern Corporation and Mellon Leasing Corporation (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated March 13, 2007, Commission File No.1-10499).
10.2(c)	Purchase Agreement, dated October 30, 2007, between NorthWestern Corporation and SGE (New York) Associates (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 30, 2007, Commission File No.1-10499).
10.2(d)	Bond Purchase Agreement, dated May 1, 2008, between NorthWestern Corporation and initial purchasers (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, Commission File No. 1-10499).
10.2(e)	Purchase Agreement, dated March 23, 2009, among NorthWestern Corporation and Banc of America Securities LLC and J.P. Morgan Securities Inc., as representatives of several initial purchasers (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated March 23, 2009, Commission File No. 1-10499).
10.2(f)	Amended and Restated Credit Agreement, dated as of June 30, 2009, among NorthWestern Corporation, as borrower, the several banks and other financial institutions or entities from time to time parties to the Agreement, as lenders, Banc of America Securities LLC, as lead arranger; JP Morgan Chase Bank, N.A., as syndication agent; Union Bank, N.A. and U.S. Bank National Association, as co-documentation agents; and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated June 30, 2009, Commission File No. 1-10499)

Exhibit Number	Description of Document
10.2(g)	Purchase Agreement, dated July 2, 2009, between NorthWestern Corporation and Pratt & Whitney Power Systems, Inc. (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, Commission File No. 1-10499).
10.2(h)	Engineering, Procurement and Construction Agreement, dated July 27, 2009, between NorthWestern Corporation and NewMech Companies, Inc. (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, Commission File No. 1-10499).
10.2(i)*	Purchase Agreement, dated September 30, 2009, among NorthWestern Corporation and the initial purchasers named therein.
12.1*	Statement Regarding Computation of Earnings to Fixed Charges.
21*	Subsidiaries of NorthWestern Corporation.
23.1*	Consent of Independent Registered Public Accounting Firm
24*	Power of Attorney (included on the signature page of this Annual Report on Form 10-K)
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002
32.1*	Certification of Robert C. Rowe pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Brian B. Bird pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

† Management contract or compensatory plan or arrangement.

* Filed herewith.

All schedules for which provision is made in the applicable accounting regulations of the SEC are not required under the related instructions or are not applicable, and, therefore, have been omitted.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Annual Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized.

NORTHWESTERN CORPORATION

Dated: February 12, 2010

By: /s/ ROBERT C. ROWE
Robert C. Rowe
President and Chief Executive Officer

POWER OF ATTORNEY

We, the undersigned directors and/or officers of NorthWestern Corporation, hereby severally constitute and appoint Robert C. Rowe and Kendall G. Kliewer, and each of them with full power to act alone, our true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution and revocation, for each of us and in our name, place, and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file or cause to be filed the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, and hereby grant unto such attorneys-in-fact and agents, and each of them, the full power and authority to do each and every act and thing requisite and necessary to be done in and about the foregoing, as fully to all intents and purposes as each of us might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, or their respective substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report on Form 10-K has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ E. LINN DRAPER, JR. E. Linn Draper, Jr.	Chairman of the Board	February 12, 2010
/s/ ROBERT C. ROWE Robert C. Rowe	President, Chief Executive Officer and Director (Principal Executive Officer)	February 12, 2010
/s/ BRIAN B. BIRD Brian B. Bird	Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	February 12, 2010
/s/ KENDALL G. KLIEWER Kendall G. Kliewer	Vice President and Controller (Principal Accounting Officer)	February 12, 2010
/s/ STEPHEN P. ADIK Stephen P. Adik	Director	February 12, 2010
/s/ DOROTHY M. BRADLEY Dorothy M. Bradley	Director	February 12, 2010
/s/ DANA J. DYKHOUSE Dana J. Dykhouse	Director	February 12, 2010
Julia L. Johnson	Director	
/s/ PHILIP L. MASLOWE Philip L. Maslowe	Director	February 12, 2010
/s/ DENTON LOUIS PEOPLES Denton Louis Peoples	Director	February 12, 2010

INDEX TO FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of NorthWestern Corporation:

We have audited the accompanying consolidated balance sheets of NorthWestern Corporation (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2009 and 2008, and the related consolidated statements of income, common shareholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2009. Our audits also included the financial statement schedule listed in the index at Item 15. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2009 and 2008, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2009, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 12, 2010, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 12, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of NorthWestern Corporation:

We have audited the internal control over financial reporting of NorthWestern Corporation and subsidiaries (the "Company") as of December 31, 2009, based on criteria established in *Internal Control — Integrated Framework,* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying "Management's Report on Internal Control over Financial Reporting." Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control — Integrated Framework,* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2009, of the Company, and our report dated February 12, 2010, expressed an unqualified opinion on those consolidated financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 12, 2010

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

(in thousands, except per share amounts)

	Year Ended December 31, 2009	2008	2007
Revenues			
Electric	$ 781,186	$ 773,029	$ 735,513
Gas	353,977	416,070	362,800
Other	6,747	71,694	101,747
Total Revenues	1,141,910	1,260,793	1,200,060
Operating Expenses			
Cost of sales	573,686	698,740	668,405
Operating, general and administrative	245,618	226,164	221,566
Property and other taxes	79,582	80,602	87,581
Depreciation	89,039	85,071	82,415
Total Operating Expenses	987,925	1,090,577	1,059,967
Operating Income	153,985	170,216	140,093
Interest Expense	(67,760)	(63,952)	(56,942)
Other Income	2,499	1,558	2,428
Income Before Income Taxes	88,724	107,822	85,579
Income Tax Expense	(15,304)	(40,221)	(32,388)
Net Income	$ 73,420	$ 67,601	$ 53,191
Average Common Shares Outstanding	36,091	37,976	36,623
Basic Earnings per Average Common Share	$ 2.03	$ 1.78	$ 1.45
Diluted Earnings per Average Common Share	$ 2.02	$ 1.77	$ 1.44
Dividends Declared per Average Common Share	$ 1.34	$ 1.32	$ 1.28

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31, 2009	2008	2007
OPERATING ACTIVITIES:			
Net Income	$ 73,420	$ 67,601	$ 53,191
Items not affecting cash:			
Depreciation	89,039	85,071	82,415
Amortization of debt issue costs, discount and deferred hedge gain	2,168	2,444	1,617
Amortization of restricted stock	1,627	3,088	7,116
Equity portion of allowance for funds used during construction	(2,113)	(641)	(508)
Gain on rate case settlement	—	—	(12,636)
(Gain) loss on sale of assets	(287)	(214)	85
Deferred income taxes	47,014	42,587	34,994
Changes in current assets and liabilities:			
Restricted cash	1,119	(245)	1,354
Accounts receivable	11,913	(12,150)	6,311
Inventories	23,436	(7,155)	(3,096)
Prepaid energy supply costs	199	432	(772)
Other current assets	(866)	(1,768)	1,693
Accounts payable	(9,224)	3,218	12,123
Accrued expenses	(48,396)	(9,883)	(13,918)
Regulatory assets	1,109	9,248	1,221
Regulatory liabilities	(19,601)	10,522	21,929
Other noncurrent assets	(3,928)	28,348	23,662
Other noncurrent liabilities	(49,825)	(22,177)	(14,817)
Cash provided by operating activities	116,804	198,326	201,964
INVESTING ACTIVITIES:			
Property, plant, and equipment additions	(189,360)	(124,563)	(117,084)
Colstrip Unit 4 acquisition	—	—	(141,257)
Proceeds from sale of assets	326	200	1,842
Cash used in investing activities	(189,034)	(124,363)	(256,499)
FINANCING ACTIVITIES:			
Proceeds from exercise of warrants	—	—	68,834
Dividends on common stock	(48,186)	(49,833)	(47,286)
Issuance of long term debt	304,833	55,000	100,000
Repayment of long-term debt	(137,800)	(96,355)	(15,540)
Line of credit borrowings	348,000	254,000	623,001
Line of credit repayments	(390,000)	(158,000)	(661,001)
Treasury stock activity	(741)	(78,706)	(896)
Financing costs	(10,824)	(1,550)	(1,734)
Cash provided by (used in) provided by financing activities	65,282	(75,444)	65,378
(Decrease) Increase in Cash and Cash Equivalents	(6,948)	(1,481)	10,843
Cash and Cash Equivalents, beginning of period	11,292	12,773	1,930
Cash and Cash Equivalents, end of period	**$ 4,344**	**$ 11,292**	**$ 12,773**

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED BALANCE SHEETS

(in thousands, except per share amounts)

	Year Ended December 31, 2009	2008
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 4,344	$ 11,292
Restricted cash	13,608	14,727
Accounts receivable, net	143,759	155,672
Inventories	47,305	70,741
Regulatory assets	40,509	46,905
Prepaid energy supply	2,535	2,734
Deferred income taxes	1,239	685
Other	11,528	10,661
Total current assets	**264,827**	**313,417**
Property, plant, and equipment, net	1,964,121	1,839,699
Goodwill	355,128	355,128
Regulatory assets	182,382	233,102
Other noncurrent assets	28,674	20,691
Total assets	**$ 2,795,132**	**$ 2,762,037**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current maturities of capital leases	$ 1,197	$ 1,193
Current maturities of long-term debt	6,123	228,045
Accounts payable	92,923	94,685
Accrued expenses	165,127	215,431
Regulatory liabilities	29,622	49,223
Total current liabilities	**294,992**	**588,577**
Long-term capital leases	35,570	36,798
Long-term debt	981,296	634,011
Deferred income taxes	161,188	114,707
Noncurrent regulatory liabilities	238,332	222,969
Other noncurrent liabilities	296,730	401,442
Total liabilities	**2,008,108**	**1,998,504**
Commitments and Contingencies (Note 17)		
Shareholders' Equity:		
Common stock, par value $0.01; authorized 200,000,000 shares; issued and outstanding 39,566,846 and 36,003,434, respectively; Preferred stock, par value $0.01; authorized 50,000,000 shares; none issued	395	395
Treasury stock at cost	(90,228)	(89,487)
Paid-in capital	807,527	805,900
Retained earnings	59,605	34,371
Accumulated other comprehensive income	9,725	12,354
Total shareholders' equity	**787,024**	**763,533**
Total liabilities and shareholders' equity	**$ 2,795,132**	**$ 2,762,037**

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

(in thousands)

	Number of Common Shares	Number of Treasury Shares	Common Stock	Paid in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance at December 31, 2006	**35,968**	**330**	$ **360**	$ **727,327**	$ **(9,885)**	$ **10,698**	$ **14,271**	$ **742,771**
Net income			$ —	$ —	$ —	$ 53,191	$ —	$ 53,191
Other comprehensive income:								
Foreign currency translation adjustment							318	318
Reclassification of net gains on derivative instruments from OCI to net income,	—	—	—	—	—	—	(1,188)	(1,188)
Pension and postretirement medical liability adjustment, net of taxes of $133	—	—	—	—	—	—	347	347
Total comprehensive income								52,668
Treasury stock activity	—	33	—	—	(896)	—	—	(896)
Amortization of unearned restricted stock compensation	104	—	1	6,932	—	—	—	6,933
Warrants exercise	3,262	—	32	68,802	—	—	—	68,834
Dividends on common stock	—	—	—	—	—	(47,286)	—	(47,286)
Balance at December 31, 2007	**39,334**	**363**	**$ 393**	**$ 803,061**	**$ (10,781)**	**$ 16,603**	**$ 13,748**	**$ 823,024**
Net income	—	—	—	—	—	67,601	—	67,601
Other comprehensive income:								
Foreign currency translation adjustment	—	—	—	—	—	—	(410)	(410)
Reclassification of net gains on derivative instruments from OCI to net income	—	—	—	—	—	—	(1,188)	(1,188)
Pension and postretirement medical liability adjustment, net of taxes of $128	—	—	—	—	—	—	204	204
Total comprehensive income								66,207
Treasury stock activity	—	3,170	—	—	(78,706)	—	—	(78,706)
Issuance of restricted stock	2	—	—	58	—	—	—	58
Amortization of unearned restricted stock compensation	125	—	2	2,781	—	—	—	2,783
Dividends on common stock	—	—	—	—	—	(49,833)	—	(49,833)
Balance at December 31, 2008	**39,461**	**3,533**	**$ 395**	**$ 805,900**	**$ (89,487)**	**$ 34,371**	**$ 12,354**	**$ 763,533**
Net income	—	—	—	—	—	73,420	—	73,420
Other comprehensive income:								
Foreign currency translation adjustment	—	—	—	—	—	—	296	296
Reclassification of net gains on derivative instruments from OCI to net income	—	—	—	—	—	—	(1,188)	(1,188)
Pension and postretirement medical liability adjustment, net of taxes of $1,088	—	—	—	—	—	—	(1,737)	(1,737)
Total comprehensive income								70,791
Treasury stock activity	—	30	—	—	(741)	—	—	(741)
Issuance of restricted stock	8	—	—	184	—	—	—	184
Amortization of unearned restricted stock compensation	98	—	—	1,443	—	—	—	1,443
Dividends on common stock	—	—	—	—	—	(48,186)	—	(48,186)
Balance at December 31, 2009	**39,567**	**3,563**	**$ 395**	**$ 807,527**	**$ (90,228)**	**$ 59,605**	**$ 9,725**	**$ 787,024**

See Notes to Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Nature of Operations and Basis of Consolidation

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas to approximately 661,000 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 natural gas in Montana since 2002.

The consolidated 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 Securities and Exchange Commission (SEC). 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. The accompanying consolidated financial statements include our accounts together with those of our wholly and majority-owned or controlled subsidiaries. All intercompany balances and transactions have been eliminated from the consolidated financial statements. Events occurring subsequent to December 31, 2009, have been evaluated as to their potential impact to the Consolidated Financial Statements through February 12, 2010, the date of issuance.

(2) Significant Accounting Policies

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

For our South Dakota and Nebraska operations, as prescribed by the applicable regulatory authorities, electric and natural gas utility revenues are based on billings rendered to customers. For our Montana operations, as prescribed by the MPSC, operating revenues are recorded monthly on the basis of consumption or services rendered. 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.

Restricted Cash

Restricted cash consists primarily of funds held in trust accounts to satisfy the requirements of certain stipulation agreements and insurance reserve requirements.

Accounts Receivable, Net

Accounts receivable are net of allowances for uncollectible accounts of $2.8 million and $3.0 million at December 31, 2009 and December 31, 2008, respectively. Receivables include unbilled revenues of $72.3 million and $79.1 million at December 31, 2009 and December 31, 2008, respectively.

Inventories

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

	December 31,	
	2009	2008
Materials and supplies	$ 19,854	$ 18,907
Storage gas	27,451	51,834
	$ 47,305	$ 70,741

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 Consolidated Financial Statements reflect the effects of the different rate making principles followed by the jurisdiction 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 Consolidated Income Statements 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 Consolidated 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 OCI 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 Consolidated 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 6, Risk Management and Hedging Activities for further discussion of our derivative activity.

Property, Plant and Equipment

Property, plant and equipment are 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 property, plant and equipment are charged to the appropriate maintenance expense accounts. A betterment or replacement of a unit of property 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 plant and equipment 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 interest expense, 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 8.4%, 8.9%, and 8.7%, for Montana for 2009, 2008, and 2007 respectively, and 8.5%, 8.8%, and 8.7% for South Dakota for 2009, 2008, and 2007 respectively. Interest capitalized totaled $3.2 million for the year ended December 31, 2009, $0.9 million for the year ended December 31, 2008 and $0.8 million for the year ended December 31, 2007 for Montana and South Dakota combined.

We capitalize preliminary survey and investigation costs related to the determination of the feasibility of transmission or generation utility projects in other noncurrent assets. Upon commencement of construction, these costs are transferred to construction work in process, and upon completion, these costs will be transferred to utility plant in service. These costs totaled approximately $11.4 million and $6.7 million as of December 31, 2009 and 2008, respectively. 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 $2.6 million and $6.9 million for the years ended December 31, 2009 and 2008, 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%, 3.3%, and 3.5% for 2009, 2008, and 2007, 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 noncurrent regulatory liabilities.

Other Noncurrent Liabilities

Other noncurrent liabilities consisted of the following (in thousands):

	December 31, 2009	December 31, 2008
Pension and other employee benefits	$ 32,695	$ 139,306
Future QF obligation, net	165,839	162,841
Environmental	31,900	32,051
Customer advances	47,074	49,998
Other	19,222	17,246
	$ 296,730	$ 401,442

Insurance Subsidiary

Risk Partners Assurance, Ltd (Risk Partners) is a wholly owned non-United States insurance subsidiary established in 2001 to insure a portion of our worker's compensation, general liability and automobile liability risks. New policies have not been underwritten through this subsidiary since 2004. Claims that were incurred during that time period continue to be paid and managed by Risk Partners. Reserve requirements are established based on actuarial projections of ultimate losses. Any losses estimated to be paid within one year from the balance sheet date are classified as accrued expenses, while losses expected to be payable in later periods are included in other long-term liabilities. Risk Partners has purchased reinsurance policies through a third-party reinsurance company to transfer a portion of the insurance risk. Restricted cash held by this subsidiary was $5.8 million and $5.4 million as of December 31, 2009 and 2008, respectively.

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 Consolidated Income Statements 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 (SO_2) emission allowances and each allowance permits a generating unit to emit one ton of SO_2 during or after a specified year. We have approximately 3,200 excess SO_2 emission allowances per year for years 2017 through 2031, however these allowances have no carrying value in our Consolidated 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 other income and cash received is reflected as an investing activity.

Accounting Standards Issued

In June 2009, the Financial Accounting Standards Board (FASB) amended the accounting for variable interest entities, which is effective for us beginning January 1, 2010. 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. The statement includes the following significant provisions:

- requires an entity to qualitatively assess the determination of the primary beneficiary of a variable interest entity (VIE) based on whether the entity (1) has the power to direct matters that most significantly impact the activities of the VIE, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE,
- requires an ongoing reconsideration of the primary beneficiary instead of only upon certain triggering events,
- amends the events that trigger a reassessment of whether an entity is a VIE, and
- for an entity that is the primary beneficiary of a VIE, requires separate balance sheet presentation of (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

We are required to consolidate VIEs if we are the primary beneficiary, which means we have a controlling financial interest. 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 are evaluating our inventory of long-term purchase power and tolling contracts under this guidance. Under the previous guidance, we identified one QF contract that may constitute a VIE. We have accounted for this QF contract as an executory contract as we have been unable to obtain the necessary information from this QF in order to determine if it is a VIE and if so, whether we are the primary beneficiary. Based on the current contract terms with this QF, our estimated gross contractual payments aggregate approximately $468.4 million through 2025. For further discussion of our gross QF liability, see Note 17. During the years ended December 31, 2009, 2008 and 2007 purchases from this QF were approximately $20.1 million, $20.5 million, and $21.1 million, respectively. We will finalize our evaluation during the first quarter of 2010 to determine the impact of adoption, if any, on our financial position and results of operations.

Supplemental Cash Flow Information

	Year Ended December 31,		
	2009	2008	2007
Cash paid for			
Income taxes	$ 3	$ 111	$ 3,921
Interest	39,473	47,992	43,076
Significant non-cash transactions:			
Capital expenditures included in trade accounts payable	12,272	4,464	5,627
Assumption of debt related to Colstrip Unit 4 acquisitions	—	—	53,685
Additions to property, plant and equipment and capital lease obligations	—	—	2,400

(3) Property, Plant and Equipment

The following table presents the major classifications of our property, plant and equipment (in thousands):

	Estimated Useful Life	December 31, 2009	December 31, 2008
	(years)	(in thousands)	
Land and improvements	49 – 105	$ 46,118	$ 44,813
Building and improvements	26 – 71	99,578	95,658
Storage, distribution, and transmission	12 – 79	2,056,587	1,974,505
Generation	30 – 46	247,937	214,893
Plant acquisition adjustment	34	204,754	227,633
Other equipment	2 - 31	238,645	238,379
Construction work in process	—	114,779	12,599
		3,008,398	2,808,480
Less accumulated depreciation		(1,044,277)	(968,781)
		$ 1,964,121	$ 1,839,699

Plant and equipment under capital lease were $34.0 million and $36.2 million as of December 31, 2009 and December 31, 2008, respectively, which included $33.2 million and $35.2 million as of December 31, 2009 and 2008, 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 a capital lease.

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 Consolidated Balance Sheets on a pro rata basis and our share of operating expenses is reflected in the Consolidated 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, 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
December 31, 2008				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 58,026	$ 29,771	$ 43,406	$ 266,627
Accumulated depreciation	34,636	20,708	26,795	21,462

(4) 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, or 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. Accordingly, the recorded amounts of estimated future removal costs are considered regulatory liabilities. These amounts do not represent legal retirement obligations. As of December 31, 2009 and December 31, 2008, we have recognized accrued removal costs of $209.2 million and $194.3 million, respectively. In addition, for our generation properties, we have accrued decommissioning costs since the generating units were first put into service in the amount of $14.9 million and $14.3 million as of December 31, 2009 and December 31, 2008, respectively.

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 and $6.3 million, as of December 31, 2009 and 2008, respectively, which increases our property, plant and equipment and other noncurrent liabilities. 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 change in our gross conditional ARO during the year ended December 31, 2009, is as follows (in thousands):

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

(5) Goodwill

Goodwill by segment is as follows (in thousands):

	December 31, 2009	December 31, 2008
Regulated electric	$ 241,100	$ 241,100
Regulated natural gas	114,028	114,028
	$ 355,128	$ 355,128

Goodwill is not amortized; rather, it is evaluated for impairment at least annually. We evaluated our goodwill during the fourth quarters of 2009 and 2008 and determined that it was not impaired.

(6) 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 lack of ownership of natural gas reserves and minimal ownership of regulated electric generation assets 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 regulated 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 do not currently have any derivative transactions that are not 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. 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 permitted accounting treatments include: normal purchase normal sale; cash flow hedge; fair value hedge; and mark-to-market. 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, 2009 and 2008. 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 physical purchase of natural gas associated with our regulated gas utilities 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 7.

		December 31,	
Mark-to-Market Transactions	**Balance Sheet Location**	**2009**	**2008**
Regulated natural gas net derivative liability.....	Accrued Expenses	$ 23,661	$ 29,156

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

Derivatives Subject to Regulatory Deferral	Unrealized gain (loss) recognized in Regulatory Assets December 31, 2009	2008
Natural gas	$ 5,495	$ (23,436)

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 arrangements 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: Western Systems Power Pool agreements (WSPP) – standardized power sales contracts in the electric industry; (2) International Swaps and Derivatives Association agreements (ISDA) – standardized financial gas and electric contracts; (3) North American Energy Standards Board agreements (NAESB) – 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, it would be in violation of these provisions, and 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, 2009, the aggregate fair value of forward purchase contracts that do not qualify as normal purchases in a net liability position with credit risk-related contingent features, collateral posted, and the aggregate amount of additional collateral that we would be required to post with counterparties, if the credit risk-related contingent features underlying these agreements were triggered on December 31, 2009 (in thousands):

Contracts with Contingent Feature	Fair Value Liability	Posted Collateral	Contingent Collateral
Credit rating	$ 23,199	$ —	$ 23,199

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 Accumulated Other Comprehensive Income (AOCI). We reclassify these gains from AOCI into interest expense during the periods in which the hedged interest payments occur. The following table shows the effect of these derivative instruments on the Financial Statements:

Cash Flow Hedges	Amount of Gain Remaining in AOCI as of December 31, 2009	Location of Gain Reclassified from AOCI to Income	Amount of Gain Reclassified from AOCI into Income during the Year Ended December 31, 2009
Interest rate contracts	$ 10,464	Interest Expense	$ 1,188

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

(7) 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 6 for further discussion.

December 31, 2009	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)		
Cash equivalents	$ 3,000	$ —	$ —	$ —	$ 3,000
Restricted cash	12,942	—	—	—	12,942
Derivative asset (1)	—	972	—	—	972
Derivative liability (1)	—	(24,633)	—	—	(24,633)
Net derivative position	—	(23,661)	—	—	(23,661)
Total	**$ 15,942**	**$ (23,661)**	**$ —**	**$ —**	**$ (7,719)**
December 31, 2008					
Restricted cash	14,719	—	—	—	14,719
Derivative liability (1)	—	(29,156)	—	—	(29,156)
Total	**$ 14,719**	**$ (29,156)**	**$ —**	**$ —**	**$ (14,437)**

(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 Consolidated 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.

Cash equivalents and restricted cash represent amounts held in money market mutual funds. 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, 2009		December 31, 2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt (including current portion)	$ 987,419	$ 1,034,122	$ 862,056	$ 780,023

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

- The carrying amounts of cash, cash equivalents, and restricted cash approximate fair value due to the short maturity of the instruments.
- 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.

(8) Long-Term Debt and Capital Leases

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

		December 31,	
	Due	2009	2008
Unsecured Debt:			
Unsecured Revolving Line of Credit	2012	$ 66,000	$ 108,000
Secured Debt:			
Mortgage bonds—			
South Dakota—6.05%	2018	55,000	55,000
Montana—6.04%	2016	150,000	150,000
Montana—6.34%	2019	250,000	—
Montana—5.71%	2039	55,000	—
South Dakota & Montana—5.875%	2014	225,000	225,000
Pollution control obligations—			
Montana—4.65%	2023	170,205	170,205
Montana Natural Gas Transition Bonds— 6.20%	2012	16,493	22,355
Other Long Term Debt:			
Colstrip Unit 4 debt—13.25%	2010	—	31,666
Colstrip Lease Holdings, LLC—floating rate	2009	—	100,000
Discount on Notes and Bonds	—	(279)	(170)
		987,419	862,056
Less current maturities		(6,123)	(228,045)
		$ 981,296	$ 634,011
Capital Leases:			
Total Capital Leases	Various	$ 36,767	$ 37,991
Less current maturities		(1,197)	(1,193)
		$ 35,570	$ 36,798

Unsecured Revolving Line of Credit

On June 30, 2009, we amended and restated our unsecured revolving line of credit scheduled to expire on November 1, 2009. The amended facility extends the term to June 30, 2012, and increases the aggregate principal amount available under the facility by $50 million to $250 million. The amended facility does not amortize and borrowings will bear interest based on a credit ratings grid. A total of nine banks participate in the new facility, with no one bank providing more than 14% of the total availability. The amended facility contains covenants substantially similar to the previous facility.

The 'spread' or 'margin' ranges from 2.25% to 4.0% over the London Interbank Offered Rate (LIBOR). The facility bears interest at a rate of approximately 3.23%, which is 3.0% over LIBOR, as of December 31, 2009, and we had $3.1 million in letters of credit and $66 million of borrowings outstanding. The weighted average interest rate on the outstanding revolving credit facility borrowings was 2.9% as of December 31, 2009.

Commitment fees for the unsecured revolving line of credit were $0.7 million and $0.3 million for the years ended December 31, 2009 and 2008, respectively.

The credit facility includes covenants, which require us to meet certain financial tests, including a maximum debt to capitalization ratio not to exceed 65%. The amended and restated line of credit 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. The Montana Natural Gas Transition Bonds are secured by a specified component of future revenues meant to recover the regulatory assets known as a competitive transition charge. The principal payments amortize proportionately with the regulatory asset.

Financing Transactions

In March 2009, we issued $250 million of Montana First Mortgage Bonds at a fixed interest rate of 6.34% maturing April 1, 2019, which were discounted to yield 6.349%. The bonds are secured by our Montana electric and natural gas assets. The bonds were issued in a transaction exempt from registration under the Securities Act of 1933, as amended. We completed an offer to exchange these bonds for a like series of bonds registered under the Securities Act of 1933 during the third quarter of 2009. We used the proceeds to redeem our $100 million Colstrip Lease Holdings LLC term loan, repay outstanding borrowings on our revolving credit facility, repay other outstanding debt obligations of $31.7 million related to Colstrip Unit 4, fund a portion of the costs of the Mill Creek generation project, and fund future capital expenditures.

On October 15, 2009 we issued $55 million of Montana First Mortgage Bonds at a fixed interest rate of 5.71% maturing October 15, 2039. The bonds are secured by our Montana electric and natural gas assets. The transaction is exempt from the registration requirements of the Securities Act of 1933, as amended. We used the proceeds to fund a portion of the costs of the Mill Creek generation project and capital expenditures.

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt and capital leases, during the next five years are $7.3 million in 2010, $7.9 million in 2011, $71.2 million in 2012, $1.5 million in 2013 and $226.6 million in 2014.

As of December 31, 2009, we are in compliance with our financial debt covenants.

(9) Income Taxes

Income tax expense is comprised of the following (in thousands):

	Year Ended December 31,		
	2009	2008	2007
Federal			
Current	$ (448)	$ 863	$ 1,449
Deferred	15,077	37,916	28,586
Investment tax credits	(494)	(580)	(531)
State	1,169	2,022	2,884
	$ 15,304	$ 40,221	$ 32,388

The following table reconciles our effective income tax rate to the federal statutory rate:

	Year Ended December 31,		
	2009	2008	2007
Federal statutory rate	35.0%	35.0%	35.0%
State income, net of federal provisions	1.8	1.9	3.4
Amortization of investment tax credit	(0.5)	(0.5)	(0.7)
Depreciation of flow through items	0.1	(0.6)	(0.7)
2009 flow through repair deduction	(9.5)	—	—
Nondeductible professional fees	0.1	(0.4)	1.5
Prior year permanent return to accrual adjustments	(9.1)	0.2	(1.1)
Other, net	(0.7)	1.7	0.4
	17.2%	37.3%	37.8%

The 2009 effective tax rate reflects the impact of a change in tax accounting method for repairs for both 2008 and 2009, as well as lower 2009 taxable income. In December 2008, we filed a request with the Internal Revenue Service (IRS) to change our tax accounting method related to costs to repair and maintain utility assets. The IRS approved our request in September 2009, which 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 $16.6 million during the year ended December 31, 2009 to reflect this change in tax accounting method, of which approximately $8.7 million and $7.9 million related to the 2009 and 2008 tax years, respectively. The 2008 deduction is reflected as a prior year return to accrual adjustment in the table above. For years prior to 2008, we have not recorded a regulatory asset for the repairs deduction pending regulatory review. This change in tax accounting method will have the effect of increasing and extending our net operating loss carryforwards.

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 Consolidated Balance Sheets are related to the following temporary differences (in thousands):

	December 31,	
	2009	2008
Unbilled revenue	$ 2,937	$ 2,158
Compensation accruals	1,428	1,418
Regulatory assets	(3,195)	(2,012)
Reserves and accruals	(685)	(556)
Other, net	754	(323)
Current Deferred Tax Asset, net	**1,239**	**685**
Excess tax depreciation	(190,231)	(139,024)
Goodwill amortization	(68,434)	(59,674)
Pension liability	(54,546)	(34,605)
Flow through depreciation	(19,468)	(7,713)
Valuation allowance	(6,382)	(6,382)
Net operating loss (NOL) carryforward	113,858	65,432
Regulatory assets	24,880	16,049
Customer advances	18,541	19,693
Environmental liability	9,254	9,334
AMT credit carryforward	5,604	5,863
Other, net	5,736	16,320
Noncurrent Deferred Tax Liability, net	**(161,188)**	**(114,707)**
Deferred Tax Liability, net	**$ (159,949)**	**$ (114,022)**

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.

At December 31, 2009 we estimate our total federal NOL carryforward to be approximately $475.9 million. If unused, our federal NOL carryforwards will expire as follows: $171.0 million in 2023; $192.1 million in 2025; $88.1 million in 2028; and $24.7 million 2029. We estimate our state NOL carryforward as of December 31, 2009 is approximately $595.8 million. If unused, our state NOL carryforwards will expire as follows: $318.9 million in 2010; $33.8 million in 2011; $152.9 million in 2012; $70.5 million in 2015; and $19.7 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):

	2009	2008
Unrecognized Tax Benefits at January 1	$ 115,105	$ 111,124
Gross increases - tax positions in prior period	9,960	6,468
Gross decreases - tax positions in prior period	(2,221)	(2,487)
Unrecognized Tax Benefits at December 31	$ 122,844	$ 115,105

Our unrecognized tax benefits include approximately $85.1 million related to tax positions as of December 31, 2009 and 2008, 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, 2009 and 2008, we have not recognized expense for interest or penalties, and do not have any amounts accrued at December 31, 2009 and 2008, respectively, for the payment of interest and penalties.

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

(10) Accumulated Other Comprehensive Income

The following table displays the components of AOCI, which is included in Shareholder's Equity on the Consolidated Balance Sheets (in thousands).

	Net Unrealized Gains on Hedging Instruments	Pension and Other Benefits	Other	Total
Balances December 31, 2006	**$ 14,029**	**$ 162**	**$ 80**	**$ 14,271**
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 $133	—	347	—	347
Foreign currency translation	—	—	318	318
Balances December 31, 2007	**12,841**	**509**	**398**	**13,748**
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 $128	—	204	—	204
Foreign currency translation	—	—	(410)	(410)
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 $1,088	—	(1,737)	—	(1,737)
Foreign currency translation	—	—	296	296
Balance at December 31, 2009	**$ 10,465**	**$ (1,024)**	**$ 284**	**$ 9,725**

(11) Operating Leases

We lease vehicles, office equipment and facilities under various long-term operating leases. At December 31, 2009 future minimum lease payments for the next five years under non-cancelable lease agreements are as follows (in thousands):

2010	$ 1,529
2011	1,079
2012	688
2013	86
2014	63

Lease and rental expense incurred was $1.8 million, $2.1 million and $19.0 million for the years ended December 31, 2009, 2008 and 2007, respectively.

(12) 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 14 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,	
	2009	2008	2009	2008
Change in Benefit Obligation:				
Obligation at beginning of period	$ 388,659	$ 376,872	$ 44,323	$ 46,494
Service cost	8,270	8,405	993	563
Interest cost	23,705	22,875	3,149	2,367
Plan amendments	—	49	(25,427)	—
Actuarial loss (gain)	13,962	405	14,191	(1,275)
Gross benefits paid	(19,318)	(19,947)	(4,882)	(3,826)
Benefit obligation at end of period	$ 415,278	$ 388,659	$ 32,347	$ 44,323
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of	$ 242,228	$ 330,446	$ 12,421	$ 16,455
Return on plan assets	75,619	(101,005)	2,877	(5,063)
Employer contributions	92,900	32,734	4,882	4,855
Gross benefits paid	(19,318)	(19,947)	(4,882)	(3,826)
Fair value of plan assets at end of period	$ 391,429	$ 242,228	$ 15,298	$ 12,421
Funded Status	$ (23,849)	$ (146,431)	$ (17,049)	$ (31,902)
Unrecognized net actuarial (gain) loss	—	—	—	—
Unrecognized prior service cost	—	—	—	—
Accrued benefit cost	$ (23,849)	$ (146,431)	$ (17,049)	$ (31,902)
Amounts recognized in the balance sheet				
Current liability	—	—	(1,028)	(883)
Noncurrent liability	(23,849)	(146,431)	(16,021)	(31,019)
Net amount recognized	$ (23,849)	$ (146,431)	$ (17,049)	$ (31,902)
Amounts recognized in regulatory assets				
Transition obligation	—	—	—	—
Prior service (cost) credit	(1,734)	(1,980)	27,332	
Net actuarial (loss) gain	(38,711)	(82,061)	(9,908)	1,203
Amounts recognized in AOCI consist of:				
Transition obligation	—	—	—	—
Prior service cost	—	—	(1,905)	—
Net actuarial gain	—	—	21	941
Total	$ (40,445)	$ (84,041)	$ 15,540	$ 2,144

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,	
	2009	2008
Projected benefit obligation	$ 415.3	$ 388.7
Accumulated benefit obligation	413.2	386.5
Fair value of plan assets	391.4	242.2

Net Periodic Cost

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

	Pension Benefits			Other Postretirement Benefits		
	December 31,			December 31,		
	2009	2008	2007	2009	2008	2007
Components of Net Periodic Benefit Cost						
Service cost	$ 8,270	$ 8,405	$ 8,947	$ 993	$ 563	$ 580
Interest cost	23,705	22,875	21,800	3,149	2,367	2,442
Expected return on plan assets	(22,383)	(27,212)	(24,422)	(994)	(1,316)	(1,068)
Amortization of transitional obligation	—	—	—	—	—	—
Amortization of prior service cost	246	246	242	—	—	—
Recognized actuarial loss (gain)	4,058	(818)	—	277	(599)	(259)
Net Periodic Benefit Cost	$ 13,896	$ 3,496	$ 6,567	$ 3,425	$ 1,015	$ 1,695

We estimate amortizations from regulatory assets into net periodic benefit cost during 2010 will be as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
Prior service cost	$ 246	$ (1,952)
Accumulated gain	—	586

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2009 and 2008. 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 2009 and 2008, 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 the fourth quarter of 2009, we revised our target asset allocation from 70% equity securities, and 30% fixed-income securities to 60% equity securities, and 40% 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 8.00% to 7.75% for 2010.

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,		
	2009	2008	2007	2009	2008	2007
Discount rate	5.75-6.00%	6.25%	6.25%	4.75-6.00%	6.00-6.25%	5.75-6.00%
Expected rate of return on assets	8.00	8.00	8.00	8.00	8.00	8.00
Long-term rate of increase in compensation levels (nonunion)	3.58	3.58	3.58	3.58	3.55	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 9.5% in 2009 and the rate of increase in the per capita cost of covered health care benefits thereafter was assumed to decrease gradually to 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. The following table sets forth the sensitivity of retiree welfare results (in thousands):

Effect of a one percentage point increase in assumed health care cost trend	
on total service and interest cost components	$ —
on postretirement benefit obligation	—
Effect of a one percentage point decrease in assumed health care cost trend	
on total service and interest cost components	$ (1)
on postretirement benefit obligation	(14)

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,	
	2009	2008	2009	2008
Debt securities	40.0%	30.0%	40.0%	30.0%
Domestic equity securities	50.0	60.0	50.0	60.0
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,	
	2009	2008	2009	2008	2009	2008
Cash and cash equivalents	—%	0.1%	—%	—%	—%	—%
Debt securities	38.9	31.2	39.1	34.3	36.9	31.2
Domestic equity securities	51.2	58.6	51.0	56.6	52.5	58.8
International equity securities	9.9	10.1	9.9	9.1	10.6	10.0
	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 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, 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	—
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	—
	$ 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 U.S. issuers from diverse industries, debt securities issued by 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 7.

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. On March 31, 2009, the U.S. Department of the Treasury (Treasury) provided guidance on the selection of the corporate bond yield curve for determining plan liabilities and allowed companies to choose from the range of months in selecting a rate, rather than requiring the use of prescribed rates. The Treasury's announcement specifically referenced 2009, but also indicated that technical guidance will be forthcoming to address future years. In addition, the IRS and Treasury issued final regulations effective October 15, 2009 applying to plan years beginning on or after January 1, 2010 which provided guidance on pension plan 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 minimum required contributions in the future will be approximately $9 million. We may elect to make contributions earlier than the required dates. 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:

	2009	2008	2007
NorthWestern Energy Pension Plan (MT).........	$ 80,600	$ 31,140	$ 21,966
NorthWestern Pension Plan (SD)......................	12,300	1,594	672
	$ 92,900	$ 32,734	$ 22,638

The 2009 contributions exceeded our minimum funding requirements by approximately $75.0 million. For our postretirement medical benefits, our policy is to contribute an amount equal to the annual actuarially determined cost that is also recoverable in rates. We generally fund our postretirement medical trusts monthly, subject to our liquidity needs and the maximum deductible amounts allowed for income tax purposes.

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

	Pension Benefits	Other Postretirement Benefits
2010	$ 22,047	$ 3,818
2011	23,327	3,558
2012	23,900	3,331
2013	25,714	3,331
2014	26,740	3,295
2015-2019	155,834	14,801

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, 2009, 2008 and 2007 were $5.8 million, $5.3 million and $4.7 million, respectively.

(13) 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, 2009, there were 521,828 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 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 earnings per share (EPS) and return on equity growth; and (ii) total shareholder return (TSR) relative to a peer group. The fair value of the EPS 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 significant assumptions used to calculate fair value of the TSR component also included a three-year risk-free rate of 1.37%, volatility of 25.1% to 46.5% for the peer group, and maintenance of our $1.34 annual dividend over the performance period. 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.

A summary of nonvested shares as of December 31, 2009, and changes during the year ended December 31, 2009 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	—	$ —	194,072	$ 34.39
Granted	80,515	21.53	8,000	22.85
Vested	—	—	(117,905)	33.75
Forfeited	(2,169)	21.53	(14,213)	34.60
Remaining nonvested grants	78,346	$ 21.53	69,954	$ 34.37

We recognized compensation expense of $1.8 million, $3.2 million, and $7.0 million for the years ended December 31, 2009, 2008, and 2007, respectively, and a related income tax (expense) benefit of $(0.6) million, $0.2 million and $4.4 million, for the years ended December 31, 2009, 2008, and 2007, respectively. As of December 31, 2009, we had $1.7 million of unrecognized compensation cost related to the nonvested portion of outstanding awards, which is reflected as nonvested stock as a portion of additional paid in capital in our Statement of Common Shareholders' Equity and Comprehensive Income. The cost is expected to be recognized over a weighted-average period of 1.1 years. The total fair value of shares vested was $4.0 million, $4.7 million, and $3.4 million for the years ended December 31, 2009, 2008 and 2007, 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, 2009, 2008 and 2007, DSUs issued to members of our Board totaled 42,870, 33,750 and 30,563, respectively. Total compensation expense attributable to the DSUs during the years ended December 31, 2009, 2008 and 2007 was approximately $1.1 million, $0.2 million and $0.7 million, respectively.

(14) 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. Of these regulatory assets and liabilities, energy supply costs are the only items earning a rate of return. The remaining 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, 2009	December 31, 2008
Pension	12	Undetermined	$ 87,934	$ 148,534
Postretirement benefits	12	Undetermined	6,191	25,010
Competitive transition charges		3 Years	12,962	18,273
Environmental clean-up		Various	14,631	15,904
Supply costs		1 Year	699	3,239
Energy supply derivatives	6	1 Year	23,812	29,156
Income taxes	9	Plant Lives	47,241	16,466
Deferred financing costs		Various	8,623	5,061
Other		Various	20,798	18,364
Total regulatory assets			**$ 222,891**	**$ 280,007**
Removal cost	4	Various	$ 224,632	$ 208,201
Gas storage sales		30 Years	12,513	12,933
Supply costs		1 Year	18,563	31,669
Energy supply derivatives		1 Year	2,044	3,785
Environmental clean-up		1 Year	1,041	1,411
State & local taxes & fees		1 Year	6,012	9,701
Other		Various	3,149	4,492
Total regulatory liabilities			**$ 267,954**	**$ 272,192**

Pension and Postretirement Benefits

We recognize the unfunded portion of plan benefit obligations in the Consolidated 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 SDPUC allows recovery of pension costs on an accrual basis. The MPSC allows recovery of postretirement benefit costs on an accrual basis. The volatility in plan asset market returns and significant increases in funding is discussed in Note 12, and is reflected in regulatory assets above.

Natural Gas Competitive Transition Charges

Natural gas transition bonds were issued in 1998 to recover stranded costs of production assets and related regulatory assets and provide a lower cost to utility customers, as the cost of debt was less than the cost of capital. The MPSC authorized the securitization of these assets and approved the recovery of the competitive transition charges in rates over a 15-year period. The regulatory asset relating to competitive transition charges amortizes proportionately with the principal payments on the natural gas transition bonds.

Supply Costs

The MPSC, SDPUC and NPSC have authorized the use of electric and natural gas supply cost trackers, as applicable, which enable us to track actual supply costs and either recover the under collection or refund the over collection to our customers. Accordingly, we have recorded a regulatory asset and liability to reflect the future recovery of under collections and refunding of over collections through the ratemaking process. We earn interest on the electric and natural gas supply costs of 8.46% and 8.82%, respectively, in Montana; 10.60% and 7.96%, respectively, in South Dakota; and 8.49% for natural gas in Nebraska. These same rates are paid to our customers in the event of a refund.

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 17. Our 2007 natural gas rate case settlement with the SDPUC allows recovery of manufactured gas plant (MGP) environmental clean-up costs, which is reflected as a regulatory asset above.

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.

Deferred Financing Costs

Consistent with our historical regulatory treatment, a regulatory asset has been established to reflect the remaining deferred financing costs on long-term debt that has been replaced through the issuance of new debt. These amounts are amortized over the life of the new debt.

State and Local Taxes and 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.

Removal Cost

Historically, the anticipated costs of removing assets upon retirement were provided for over the life of those assets as a component of depreciation expense; however, the applicable GAAP guidance precludes this treatment. Our depreciation method, including cost of removal, is established by the respective regulatory commissions, therefore, consistent with this regulated treatment, we continue to accrue removal costs for our regulated assets by increasing our regulatory liability. See Note 4, Asset Retirement Obligations, for further information regarding this item.

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.

(15) 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 request was based on a return on a 2008 test period, a return on equity of 10.9%, an equity ratio of 49.45% and rate base of $632.2 million and $256.6 million for electric and natural gas, respectively.

In November 2009, the MPSC issued a determination that the rate case filing did not meet the MPSC's applicable minimum filing requirements, related to allocated cost of service and rate design. We submitted a supplemental filing on January 15, 2010 to meet the MPSC's minimum filing requirements, which was accepted as compliant on February 2, 2010. We have agreed to extend the timeframe by which the MPSC must issue a final order concerning the general rate filing by 90 days to October 11, 2010. We requested interim rate adjustments, which may be authorized during the processing of the filing if the MPSC finds it meets the established criteria. Final rate adjustments would become effective upon the issuance of a final order on this matter.

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. 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.

On May 30, 2008, we filed an annual electric supply cost tracker request with the MPSC for any unrecovered actual electric supply costs for the 12-month period ended June 30, 2008 and for the projected electric supply costs for the 12-month period ended June 30, 2009. On June 27, 2008, the MPSC issued an interim order approving recovery of our projected electric supply costs. On May 29, 2009, we filed an annual electric supply cost tracker request with the MPSC for any unrecovered actual electric supply costs for the 12-month period ended June 30, 2009 and for the projected electric supply costs for the 12-month period ended June 30, 2010. On June 26, 2009, the MPSC issued an interim order approving recovery of our projected electric supply costs. Our annual electric supply cost tracker requests for the 12-month periods ended June 30, 2008 and June 30, 2009 were combined and are still pending final approval of the MPSC. The MCC disputed (1) our ability to use financial swaps in purchasing electricity supply, (2) the recovery of certain labor costs associated with real-time schedulers and (3) our estimated revenues associated with demand side management for our Colstrip Unit 4 generation asset. During the fourth quarter of 2009, we entered into a settlement with the MCC agreeing to (a) withdraw our request to use financial swaps, (b) remove approximately $100,000 in labor costs and (c) remove approximately $83,000 of calculated lost revenues from the tracker. On February 3, 2010, the MPSC conducted a hearing to review the filings and resulting settlement and scheduled additional briefing for March 2010.

On June 2, 2009, we filed an annual gas cost tracker request with the MPSC for any unrecovered actual gas costs for the 12-month period ended June 30, 2009, and for the projected gas costs for the 12-month period ending June 30, 2010. On June 24, 2009, the MPSC issued an interim order, approving recovery of our projected gas costs pending its review. No procedural schedule has been established for this request.

Montana Property Tax Tracker

In December 2009, 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 2009 actual property taxes and estimated property taxes for 2010. This filing also included an adjustment for property taxes related to Colstrip Unit 4. In our 2008 filing requesting to include our interest in Colstrip Unit 4 in utility rate base, we estimated base property taxes would be approximately $5.5 million, by multiplying the rate base value by the latest known mill levy. This filing was approved by the MPSC. Actual 2009 Colstrip Unit 4 related property taxes were approximately $2.1 million and we proposed refunding 60% of the change to customers, consistent with previous MPSC orders. In January 2010, the MPSC issued an order requiring us to reset the base rates for Colstrip, effectively requiring us to refund 100% of the change in property taxes from our original 2008 filing. While we have accounted for our property tax tracker consistent with the MPSC's January 2010 order, we are disputing various aspects of the order and have filed a Motion for Reconsideration with the MPSC.

Mill Creek Generating Station

In August 2008, we filed a request with the MPSC for advanced approval to construct a 150 megawatt natural gas fired facility. The Mill Creek Generating Station, estimated to cost approximately $202 million, will provide regulating resources to balance our transmission system in Montana to maintain reliability and enable wind power to be integrated onto the network to meet renewable energy portfolio needs. 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 is scheduled to be operational by December 31, 2010. As of December 31, 2009, we have capitalized approximately $84.7 million in construction work in progress related to this project.

Western Electricity Coordination Council Compliance Audit

We completed our compliance audit for our Montana operations under the compliance monitoring and enforcement program of the WECC, a regional electric reliability organization, during 2009. WECC has responsibility for monitoring and enforcing compliance with the FERC approved mandatory reliability standards within the western interconnection of the Unites States. In connection with the compliance audit, WECC found no violations of the applicable standards. Since June 2007, we have identified and self-reported violations of 32 requirements to WECC. All but nine of these violations were dismissed or were subject to expedited dispositions with no penalties. During the fourth quarter of 2009, we reached a settlement agreement with WECC addressing six of the remaining nine violations for a total penalty of $80,000, which has been accrued. The settlement is pending formal NERC and FERC approval. The remaining three violations all relate to one standard and this standard is pending a NERC interpretation. We also filed mitigation plans for two potential violations with the MRO for our South Dakota operations. We have completed the mitigation measures in compliance with the plans and expect to hear from the MRO during the first half of 2010 of any further action. We expect our compliance with NERC standards will be audited at least every three years.

Mountain States Transmission Intertie (MSTI) and Other Transmission FERC Developments

In January 2009, we filed a request with the FERC seeking negotiated rates for the proposed 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 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.

We have capitalized approximately $11.4 million of preliminary survey and investigative costs associated with proposed transmission projects.

Colstrip Unit 4

In January 2009, as a result of approval by the MPSC, we placed our joint ownership interest in Colstrip Unit 4, which had previously been an unregulated asset, into utility rate base at a value of $407 million. The assets are reflected in the Consolidated Balance Sheets at historical cost. The order included a capital structure of 50% equity and 50% debt, an authorized return on equity of 10% and cost of debt of 6.5%, which are set for 34 years, based on the estimated useful life of the plant. Our interest in Colstrip Unit 4 is expected to supply approximately 13% of our Montana base-load requirements through 2010 and approximately 25% thereafter (upon expiration of an existing power sale agreement). The generation related costs and return on rate base related to Colstrip Unit 4, including the cost of any replacement power purchased during outages, will be included in our annual electric supply tracker filing for inclusion in customer rates.

(16) Earnings Per Share

Basic earnings per share are computed by dividing earnings applicable to common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per share reflect the potential dilution of common stock equivalent shares that could occur if all unvested restricted shares were to vest. Common stock equivalent shares are calculated using the treasury stock method, as applicable. The dilutive effect is computed by dividing earnings applicable to common stock by the weighted average number of common shares outstanding plus the effect of the outstanding unvested restricted stock and performance share awards. Average shares used in computing the basic and diluted earnings per share are as follows:

	December 31,	
	2009	**2008**
Basic computation	36,091,362	37,975,554
Dilutive effect of		
Restricted stock and performance share awards (1)	212,980	302,124
Diluted computation	36,304,342	38,277,678

(1) Performance share awards are included in diluted weighted average number of shares outstanding based upon what would be issued if the end of the most recent reporting period was the end of the term of the award.

(17) 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 $1.4 billion through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $1.1 billion through 2029. The fair value of the remaining QF liability is recorded in our Consolidated Balance Sheets. The following summarizes the change in the QF liability (in thousands):

	December 31,	
	2009	2008
Beginning QF liability	$ 162,841	$ 158,132
Unrecovered amount	(9,366)	(7,246)
Interest expense	12,364	11,955
Ending QF liability	$ 165,839	$ 162,841

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

	Gross Obligation	Recoverable Amounts	Net
2010	$ 63,589	$ 53,835	$ 9,754
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
Thereafter	1,059,402	797,190	262,212
Total	$ 1,397,595	$ 1,071,773	$ 325,822

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 $434.5 million, $564.0 million and $445.0 million for the years ended December 31, 2009, 2008, and 2007, respectively. As of December 31, 2009 our commitments under these contracts are $363.0 million in 2010, $192.0 million in 2011, $174.5 million in 2012, $162.0 million in 2013, $120.3 million in 2014, and $659.4 million thereafter. These commitments are not reflected in our Consolidated Financial Statements.

Other Purchase Obligations

We have entered into purchase obligations related to the construction of the Mill Creek Generating Station, which primarily include engineering, procurement and construction (EPC) and gas turbine generators. Total payments under these contracts were $67.9 million during 2009. Our estimated future obligation under these contracts is $70.8 million for 2010.

Environmental Liabilities

Our liability for environmental remediation obligations is estimated to range between $22.4 million to $44.1 million. As of December 31, 2009, we have a reserve of approximately $31.9 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 consolidated financial position or ongoing operations.

Manufactured Gas Plants - Approximately $26.6 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 (CERCLIS) 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. In 2007, we completed remediation of sediment in a short segment of Moccasin Creek that had been impacted by the former manufactured gas plant operations. Our current reserve for remediation costs at this site is approximately $13.0 million, and we estimate that approximately $10 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 Montana Department of Environmental Quality (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.

Milltown Dam Removal - Our subsidiary, Clark Fork and Blackfoot, LLC (CFB), owns the former Milltown Dam site, and previously operated a three MW hydroelectric generation facility located at the confluence of the Clark Fork and Blackfoot Rivers. Dam removal activities were completed in 2009. Our remaining obligation to the State of Montana related to this site is approximately $0.6 million, which will be solely funded through the transfer of land and water rights associated with the former Milltown Dam operations to the State of Montana.

Global Climate Change **-** We have a joint 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. In addition, a significant portion of the electric supply we procure in the market is generated by coal-fired plants.

There is a growing concern nationally and internationally about global climate change and the contribution of emissions of greenhouse gases 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 greenhouse emissions. Specifically, coal-fired plants have come under scrutiny due to their emissions of carbon dioxide.

Clean Air Act - The Clean Air Act Amendments of 1990 and subsequent amendments stipulate limitations on sulfur dioxide and nitrogen oxide emissions from coal-fired power plants and motor vehicles. We comply with existing emission requirements through purchase of sub-bituminous coal, and we believe that we are in compliance with all presently applicable environmental protection requirements and regulations.

In June 2008, the Sierra Club filed a lawsuit in U.S. District Court in South Dakota against NorthWestern and the other joint owners of the Big Stone plant alleging certain violations of the Clean Air Act. For further discussion see the Legal Proceedings – Sierra Club section below.

Clean Air Mercury Rule – In March 2005, the EPA issued the Clean Air Mercury Regulations (CAMR) to reduce the emissions of mercury from coal-fired facilities through a market-based cap-and-trade program. Although the U.S. Court of Appeals for the District of Columbia Circuit struck down CAMR, the state of Montana has finalized its own rules more stringent than CAMR's 2018 cap that require every coal-fired generating plant in the state to achieve reduction levels by 2010. Chemical injection technologies were installed at Colstrip Unit 4 during the fourth quarter of 2009 to meet these requirements, and our share of the capital cost was approximately $1.0 million, with ongoing annual operating costs estimated to be approximately $1.5 million. If the enhanced chemical injection technologies are not sufficient to meet the required levels of reduction, then adsorption/absorption technology with fabric filters would be required, which could represent a material cost. We are continuing to work with the other Colstrip owners to assess compliance with these reduction levels.

There is a gap between proposed emissions reduction levels and the current capabilities of technology, as there is no currently available commercial scale technology that would achieve the proposed reduction levels. Such technology may not be available within a timeframe consistent with the implementation of climate change legislation or at all. To the extent that such technology does become available, 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 is not presently available on a commercial scale.

The proposed regulations and/or current litigation related to global climate change could have a material impact on our future capital expenditures and results of operations, but the costs are not determinable at this time. Our current capital expenditures projections do not include significant amounts related to environmental projects. 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 customer rates.

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 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. The final arbitration panel award is still pending confirmation by the Montana district court. Once confirmed, the arbitration award will require us to refile with the MPSC for a new determination of rates subsequent to June 30, 2006 using data inputs required by the purchase power agreement. Based on the initial MPSC order and subsequent arbitration award, we had estimated that if upheld, the reduction to our QF liability would be approximately \$20 to \$30 million due to the estimated reduction of energy and capacity rates for the remainder of the contract period. CELP continues to dispute the results of the arbitration award, and due to the uncertainty around the resolution we are currently unable to predict the outcome of this matter.

Gonzales

We are a defendant – along with our predecessor entities 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 plaintiff’s 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 have filed an appeal to the Supreme Court of the State of Montana with respect to these issues and intend to continue to defend the lawsuit vigorously. We also believe the sixth amended complaint violates the Bankruptcy Settlement Stipulation and have filed a motion with the Bankruptcy Court seeking enforcement of the Bankruptcy Settlement Stipulation. The motion before the Bankruptcy Court is pending. In addition, settlement discussions concerning these claims are ongoing.

Maryland Street

On March 16, 2009, Monsignor John F. McCarthy, as the duly appointed personal representative for the estate of Father James C. McCarthy, filed a complaint in the Montana Second Judicial District Court, Butte-Silver Bow County against us, one of our employees and other unknown individuals and entities. The complaint arises out of an April 2007 natural gas explosion and alleges negligence and strict liability with respect to the maintenance and operation of the natural gas distribution system that served Fr. McCarthy’s residence. The explosion destroyed a four-plex residence and nearby properties sustained damages. Fr. McCarthy died in November 2007. The plaintiff seeks unspecified compensatory and punitive damages and other equitable relief, costs and attorney’s fees. The investigation of this incident is ongoing, and while we cannot predict an outcome, we intend to vigorously defend against this complaint. We filed a notice of removal to remove the case from Montana state court to the Butte Division of the U.S. District Court for the District of Montana (Montana Federal District Court), but the Montana

Federal District Court remanded the case to the Montana state court. Subsequently, we filed a motion in the Montana state court seeking to dismiss the amended complaint as to our employee. On November 9, 2009, the Montana Second Judicial District Court, Silver Bow County, filed its order denying our employee's motion to dismiss.

Bozeman Explosion

On March 5, 2009, a natural gas explosion occurred in downtown Bozeman, Montana. The explosion resulted in one fatality, the destruction of or damage to several buildings and the businesses in them, as well as damage to other nearby properties and businesses. 11 lawsuits against NorthWestern have been filed to date in Montana state court and a number of claims have been made with respect to this incident. Our total available insurance coverage is approximately $150 million for known and potential claims. We have paid our deductible under these policies and our insurance carrier has assumed the defense and handling of the existing and anticipated future lawsuits and claims.

Ammondson

In April 2005, a group of former employees of the Montana Power Company filed a lawsuit in the state court of Montana against us and certain officers styled Ammondson, et al. v. NorthWestern Corporation, et al. The former employees have alleged that by moving to terminate their supplemental retirement contracts in our bankruptcy proceeding without having listed them as claimants or giving them notice of the disclosure statement and plan of reorganization, that we breached those contracts, and breached a covenant of good faith and fair dealing under Montana law and by virtue of filing a complaint in our bankruptcy case against those employees from seeking to prosecute their state court action against NorthWestern, we had engaged in malicious prosecution and should be subject to punitive damages. In May 2005, the Bankruptcy Court found that it did not have jurisdiction over these contracts, dismissed our action against these former employees, and transferred our motion to terminate the contracts to Montana state court, thereby removing any claim from consideration in the resolution of our bankruptcy case. In February 2007, a jury verdict was rendered against us in Montana state court, which ordered us to pay $17.4 million in compensatory and $4.0 million in punitive damages. Due to the verdict, we recognized a loss of $19.0 million in our 2006 results of operations to increase our recorded liability related to this claim. The Montana state court reviewed the amount of the punitive damages under state law and did not alter the amount. We appealed the March 5, 2007, judgment to the Montana Supreme Court. On October 13, 2009 the Montana Supreme Court issued a decision affirming the jury verdict and the various rulings of the Montana state court before, during and after trial, and remanded the judgment to the Montana state court so that it could be reduced to reflect the payments made to the plaintiffs since the judgment was entered. During December 2009, the parties settled this litigation and we paid $26.7 million (including accrued interest) to the plaintiffs.

McGreevey Litigation

We are one of several defendants in a class action lawsuit entitled McGreevey, et al. v. The Montana Power Company, et al., now pending in U.S. District Court in Montana. The lawsuit, which was filed by former shareholders of The Montana Power Company (most of whom became shareholders of Touch America Holdings, Inc. (Touch America) as a result of a corporate reorganization of The Montana Power Company), contends that the disposition of various generating and energy-related assets by The Montana Power Company are void because of the failure to obtain shareholder approval for the transactions. Plaintiffs thus seek to reverse those transactions, or receive fair value for their stock as of late 2001, when plaintiffs claim shareholder approval should have been sought. NorthWestern is named as a defendant due to the fact that we purchased The Montana Power Company L.L.C. (now CFB), which plaintiffs claim is a successor to the Montana Power Company.

We were one of the defendants in a second class action lawsuit brought by the McGreevey plaintiffs, also entitled McGreevey, et al. v. The Montana Power Company, et al., pending in U.S. District Court in Montana. We were dismissed from this lawsuit by the U.S. District Court in Montana in February 2009.

In June 2006, we and the McGreevey plaintiffs entered into an agreement to settle all claims brought by the McGreevey plaintiffs in all of the actions described above. This agreement was approved by the Bankruptcy Court in November 2006; however on January 11, 2008, the U.S. District Court in Montana suggested that the settlement agreement was invalid and enjoined the plaintiffs from taking any further action in any of these matters. The plaintiffs appealed the District Court's injunction to the Ninth Circuit U.S. Court of Appeals, where a determination is pending. In January 2009, the U.S. District Court in Montana asked all parties to submit memorandum discussing the party's willingness to enter into a global settlement of the matter.

In October 2009, the parties to the various lawsuits reached a global settlement involving various agreements, which must be approved by the U.S. District Court in Montana and the Delaware Bankruptcy Court. In November 2009, the parties submitted documentation concerning the settlement to the U.S. District Court in Montana for its approval. Approval of the settlement by the U.S. District Court in Montana is still pending. A fairness hearing concerning the proposed settlement is scheduled for May 2010. If the court approves the settlement, we will receive approximately $2.0 million from the Touch America bankruptcy estate and have no remaining liability in the litigation.

Sierra Club

On June 10, 2008, 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 (Big Stone). The complaint alleged certain violations of the (i) Prevention of Significant Deterioration and (ii) New Source Performance Standards (NSPS) provisions of the Clean Air Act and certain violations of the South Dakota State Implementation Plan (South Dakota SIP). The action further alleged that the Defendants modified and operated Big Stone without obtaining the appropriate permits, without meeting certain emissions limits and NSPS requirements and without installing appropriate emission control technology, all allegedly in violation of the Clean Air Act and the South Dakota SIP. Sierra Club alleged that Defendants' actions have contributed to air pollution and visibility impairment and have increased the risk of adverse health effects and environmental damage. Sierra Club sought both declaratory and injunctive relief to bring the Defendants into compliance with the Clean Air Act and the South Dakota SIP and to require Defendants to remedy the alleged violations. Sierra Club also sought unspecified civil penalties, including a beneficial mitigation project. We believe these claims are without merit and that Big Stone was and is being operated in compliance with the Clean Air Act and the South Dakota SIP.

The Defendants filed a Motion to Dismiss the Sierra Club complaint on August 12, 2008, based on certain of the claims being barred by statute of limitations and the remaining claims being an impermissible collateral attack on valid Clean Air Permits issued by the state of South Dakota. On September 22, 2008, the Sierra Club filed its response. Additionally on September 22, 2008, the Sierra Club sent a Notice of Intent to Sue for additional violations of the Clean Air Act at Big Stone, which are similar in nature and seek the same remedies as the June 2008 complaint. 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. Sierra Club filed a motion for reconsideration of the dismissal, which was denied in July 2009. On July 30, 2009, Sierra Club appealed the South Dakota Federal District Court's decision to dismiss the complaint. The briefing schedule initially adopted by the Eighth Circuit Court of Appeals called for the appellant to submit its brief by mid-October, for appellees to submit their brief by mid-November and for appellant to submit its reply brief by the end of November. On October 13, 2009, the United States Department of Justice (USDOJ) filed a motion seeking a 30-day extension of the time to file an amicus brief in support of the Sierra Club's position. The Court of Appeals granted this motion, as well as our subsequent joint motion with the Sierra Club, extending the time to file our principal brief and the Sierra Club's reply brief and a later joint motion with the USDOJ further extending the time for it to file an amicus brief. In accordance with the revised briefing schedule, the Sierra Club filed its brief on October 14, 2009, and we filed our brief on December 24, 2009 (the state of South Dakota served an amicus brief in support of our position on December 30, 2009).

REC Silicon

REC Advanced Silicon Materials LLC (REC) is a large transmission customer which manufactures polysilicon and silane gas for the photovoltaic and electronics industries. REC purchases services from us pursuant to our OATT. REC brought an action against us in June 2009, in the Montana Second Judicial District Court, Silver Bow County, which alleges breach of contract and negligence. REC claims we failed to properly maintain a substation, which resulted in an outage for approximately three hours and disrupted REC's production operations for several days. REC has reduced its alleged damage claims to approximately $760,000 from initial allegations of $1.25 million. We do not believe the ultimate outcome of this matter will have a material effect on our financial position, results of operations or cash flows.

Bankruptcy Related Litigation

Disputed Claims Reserve - In July 2008, we obtained Bankruptcy Court approval for the purchase of the remaining shares in the disputed claims reserve established by our plan of reorganization that was confirmed by the Bankruptcy Court in 2004. The motion allowed unsecured creditors and debt holders in Class 7 and Class 9 to elect to receive their surplus distribution in stock or cash. We repurchased 1.1 million shares from the disputed claims reserve for those claimants who elected a cash payment. In October 2008, we filed a motion requesting the Bankruptcy Court to determine the disputed claims reserve is taxable as a grantor trust. The IRS filed an objection to the motion; however we reached an agreement with the IRS and the committee of creditors to settle this matter. In September 2009, the Bankruptcy Court approved the settlement agreement and authorized a final distribution from the disputed claims reserve. This settlement did not have a material impact on our financial position, results of operations or cash flows. On October 30, 2009, we distributed the remaining cash and shares in the disputed claims reserve to eligible claimants.

Blue Dot Bankruptcy - During the second quarter of 2008, our subsidiary Blue Dot Services, LLC (Blue Dot) lost an arbitration matter with an insurance carrier and the insurance carrier was awarded $3.5 million plus interest related to a dispute that originated in 2007. The award was partially satisfied by $2.5 million in letter of credit draws by the insurance carrier and approximately $300,000 in cash. On September 5, 2008, Blue Dot and its subsidiaries filed a petition for protection under Chapter 7 of the Bankruptcy Code in United States Bankruptcy Court for the District of Delaware. We classified Blue Dot as a discontinued operation in 2003. We do not anticipate Blue Dot’s ultimate liquidation will have a material adverse effect on our financial position, results of operations or cash flows.

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.

(18) 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 13.

Repurchase of Common Stock

On May 23, 2008, we announced plans to initiate a share buyback program for approximately 3.1 million shares, which is equal to the number of shares in the disputed claims reserve established under our Plan of Reorganization that was confirmed by the bankruptcy court in 2004. We purchased 1.9 million shares from the disputed claims reserve and the remaining shares were purchased using privately negotiated transactions, at our discretion. The actual number and timing of share purchases were subject to market conditions, restrictions related to price, volume, timing, and applicable SEC rules. The total aggregate purchase price was approximately $77.7 million.

Shares tendered by employees to us to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock awards totaled 30,684 and 41,289 during the years ended December 31, 2009 and 2008, respectively, and are reflected in treasury stock. These shares were credited to treasury stock based on their fair market value on the vesting date.

(19) Segment and Related Information

Our reportable business segments are primarily engaged in the regulated electric and regulated natural gas business. The remainder of our operations is presented as other. While it is not considered a business unit, other primarily consists of our remaining unregulated natural gas capacity contract, the wind down of our captive insurance subsidiary and our unallocated corporate costs. As discussed in Note 15, the operations of our joint ownership interest in Colstrip Unit 4 were unregulated through December 31, 2008, and are included in regulated operations beginning January 1, 2009, due to an MPSC order. We have not revised the 2008 segment presentation due to the nature of the transfer of the asset from unregulated to the regulated business.

We evaluate the performance of these segments based on gross margin. The accounting policies of the operating segments are the same as the parent except that the parent allocates some of its operating expenses to the operating segments according to a methodology designed by management for internal reporting purposes and involves estimates and assumptions. Financial data for the business segments are as follows (in thousands):

	Regulated				
December 31, 2009	**Electric**	**Gas**	**Other**	**Eliminations**	**Total**
Operating revenues	$ 782,318	$ 354,470	$ 6,747	$ (1,625)	$ 1,141,910
Cost of sales	356,722	210,016	6,948	—	573,686
Gross margin	425,596	144,454	(201)	(1,625)	568,224
Operating, general and administrative	170,656	76,730	(143)	(1,625)	245,618
Property and other taxes	58,488	20,953	141	—	79,582
Depreciation	71,968	17,038	33	—	89,039
Operating income (loss)	124,484	29,733	(232)	—	153,985
Interest expense	(51,193)	(12,858)	(3,709)	—	(67,760)
Other income	2,125	261	113	—	2,499
Income tax (expense) benefit	(13,493)	(2,457)	646	—	(15,304)
Net income (loss)	$ 61,923	$ 14,679	$ (3,182)	$ —	$ 73,420
Total assets	$ 1,960,488	$ 819,495	$ 15,149	$ —	$ 2,795,132
Capital expenditures	$ 167,303	$ 22,057	$ —	$ —	$ 189,360

	Regulated		Unregulated			
December 31, 2008	**Electric**	**Gas**	**Electric**	**Other**	**Eliminations**	**Total**
Operating revenues	$ 774,229	$ 416,675	$ 77,680	$ 30,039	$ (37,830)	$ 1,260,793
Cost of sales	410,471	271,690	23,463	29,141	(36,025)	698,740
Gross margin	363,758	144,985	54,217	898	(1,805)	562,053
Operating, general and administrative	149,913	68,912	15,928	(6,784)	(1,805)	226,164
Property and other taxes	56,310	21,381	2,898	13	—	80,602
Depreciation	61,734	15,980	7,324	33	—	85,071
Operating income	95,801	38,712	28,067	7,636	—	170,216
Interest expense	(36,757)	(12,637)	(10,911)	(3,647)	—	(63,952)
Other income	547	1,001	154	(144)	—	1,558
Income tax expense	(20,219)	(10,027)	(6,971)	(3,004)	—	(40,221)
Net income	$ 39,372	$ 17,049	$ 10,339	$ 841	$ —	$ 67,601
Total assets	$ 1,669,350	$ 824,031	$ 256,507	$ 12,149	$ —	$ 2,762,037
Capital expenditures	$ 87,198	$ 34,149	$ 3,216	$ —	$ —	$ 124,563

December 31, 2007	Regulated Electric	Regulated Gas	Unregulated Electric	Other	Eliminations	Total
Operating revenues	$ 736,657	$ 363,584	$ 74,231	$ 56,748	$ (31,160)	$ 1,200,060
Cost of sales	389,681	235,958	18,079	54,222	(29,535)	668,405
Gross margin	346,976	127,626	56,152	2,526	(1,625)	531,655
Operating, general and administrative	133,091	52,008	28,662	9,430	(1,625)	221,566
Property and other taxes	61,281	22,959	3,301	40	—	87,581
Depreciation	61,912	16,592	3,782	129	—	82,415
Operating income (loss)	90,692	36,067	20,407	(7,073)	—	140,093
Interest expense	(39,132)	(13,464)	(2,849)	(1,497)	—	(56,942)
Other income	801	505	57	1,065	—	2,428
Income tax (expense) benefit	(18,631)	(8,509)	(7,341)	2,093	—	(32,388)
Net income (loss)	$ 33,730	$ 14,599	$ 10,274	$ (5,412)	$ —	$ 53,191
Total assets	$ 1,529,048	$ 749,099	$ 251,100	$ 18,133	$ —	$ 2,547,380
Capital expenditures	$ 71,905	$ 40,600	$ 4,579	$ —	$ —	$ 117,084

(20) Quarterly Financial Data (Unaudited)

Our quarterly financial information has not been audited, but, in management's opinion, includes all adjustments necessary for a fair presentation. Our business is seasonal in nature with the peak sales periods generally occurring during the summer and winter months. Accordingly, comparisons among quarters of a year may not represent overall trends and changes in operations. Amounts presented are in thousands, except per share data:

2009	First	Second	Third	Fourth
Operating revenues	$ 370,903	$ 235,713	$ 232,886	$ 302,408
Operating income	50,463	27,469	26,967	49,086
Net income	$ 22,813	$ 6,098	$ 18,900	$ 25,609
Average common shares outstanding	35,934	35,940	35,968	36,142
Income per average common share (basic):				
Net income	$ 0.63	$ 0.17	$ 0.53	$ 0.70
Income per average common share (diluted):				
Net income	$ 0.63	$ 0.17	$ 0.52	$ 0.70
Dividends per share	$ 0.335	$ 0.335	$ 0.335	$ 0.335
Stock price:				
High	$ 25.39	$ 23.49	$ 24.94	$ 26.85
Low	18.48	20.00	22.58	23.61
Quarter-end close	21.48	22.76	24.43	26.02

2008	First	Second	Third	Fourth
Operating revenues	$ 385,975	$ 276,506	$ 272,244	$ 326,068
Operating income	52,090	31,520	35,320	51,286
Net income	$ 23,451	$ 9,503	$ 13,379	$ 21,268
Average common shares outstanding	38,972	38,973	38,057	35,921
Income per average common share (basic):				
Net income	$ 0.60	$ 0.24	$ 0.35	$ 0.59
Income per average common share (diluted):				
Net income	$ 0.59	$ 0.24	$ 0.35	$ 0.59
Dividends per share	$ 0.33	$ 0.33	$ 0.33	$ 0.33
Stock price:				
High	$ 29.32	$ 26.72	$ 26.30	$ 25.49
Low	24.22	23.78	23.74	17.24
Quarter-end close	24.37	25.42	25.13	23.47

SCHEDULE II. VALUATION AND QUALIFYING ACCOUNTS
NORTHWESTERN CORPORATION AND SUBSIDIARIES

Column A	Column B	Column C	Column D	Column E
	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Balance End of Period
Description		(in thousands)		
FOR THE YEAR ENDED DECEMBER 31, 2009				
RESERVES DEDUCTED FROM APPLICABLE ASSETS				
Uncollectible accounts	$ 2,978	$ 2,604	$ (2,781)	$ 2,801
FOR THE YEAR ENDED DECEMBER 31, 2008				
RESERVES DEDUCTED FROM APPLICABLE ASSETS				
Uncollectible accounts	3,166	3,453	(3,641)	2,978
FOR THE YEAR ENDED DECEMBER 31, 2007				
RESERVES DEDUCTED FROM APPLICABLE ASSETS				
Uncollectible accounts	3,240	2,705	(2,779)	3,166

EXHIBIT 31.1

CERTIFICATION PURSUANT TO
RULE 13a-14(a)/15d-14(a)
PROMULGATED UNDER
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert C. Rowe, certify that:

1. I have reviewed this annual report on Form 10-K of NorthWestern Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2010
/s/ ROBERT C. ROWE
Robert C. Rowe
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION PURSUANT TO
RULE 13a-14(a)/15d-14(a)
PROMULGATED UNDER
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Brian B. Bird, certify that:

1. I have reviewed this annual report on Form 10-K of NorthWestern Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2010
/s/ BRIAN B. BIRD
Brian B. Bird
Vice President, Chief Financial Officer and Treasurer

EXHIBIT 32.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of NorthWestern Corporation (the "Company") on Form 10-K for the period ended December 31, 2009, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert C. Rowe, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

1) The Report fully complies with the requirements of Sections 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 12, 2010

/s/ ROBERT C. ROWE
Robert C. Rowe
President and Chief Executive Officer

Exhibit 32.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of NorthWestern Corporation (the "Company") on Form 10-K for the period ended December 31, 2009, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Brian B. Bird, Vice President, Chief Financial Officer and Treasurer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

1) The Report fully complies with the requirements of Sections 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 12, 2010

/s/ BRIAN B. BIRD

Brian B. Bird

Vice President, Chief Financial Officer and Treasurer

investor INFORMATION

Corporate Headquarters

NorthWestern Energy
3010 W. 69th Street
Sioux Falls, SD 57108
Phone: (605) 978-2900
Fax: (605) 978-2910
Web Site: www.northwesternenergy.com

Market Information

New York Stock Exchange
Ticker Symbol: NWE

Year-End Closing Price: $26.02
Shares Outstanding: 36.0 million
Market Capitalization: $937 million
Dividend Yield: 5.2%

Common Stock Dividends

We currently pay a dividend of 34 cents per share. Anticipated record and payment dates for 2010 are as follows:

Record Date	Payment Date
March 15	March 31
June 15	June 30
September 15	September 30
December 15	December 31

2010 Annual Meeting

April 22, 2010
9:00 a.m. Central time
NorthWestern Energy Operations Center
600 Market Street W.
Huron, South Dakota

Independent Registered Accounting Firm

Deloitte & Touche LLP
50 South Sixth Street, Suite 2800
Minneapolis, MN 55402

Certifications

We have filed as exhibits to our Annual Report on Form 10-K for the fiscal year ended December 31, 2009, the certifications of our Chief Executive Officer and Chief Financial Officer required by Sections 302 and 906 of the Sarbanes-Oxley Act.

Registrar, Transfer Agent and Dividend Disbursing Agent

Questions regarding stock transfer, lost certificates and dividend checks should be referred to:

Registrar and Transfer Company
10 Commerce Drive
Cranford, NJ 07016
Telephone: 1+ (800) 368-5948

Investor Relations

Phone: (605) 978-2945
E-mail: investor.relations@northwestern.com

Media Relations

Phone: 1+ (866) 622-8081

Brokerage Accounts

Stock purchased and held for shareholders by brokers is listed in the broker's name, or "street name." Annual and quarterly reports, proxy material and dividend payments are sent to shareholders by their broker. Questions should be directed to the broker.

Financial Publications

The company reports details concerning its operation and other matters periodically to the Securities and Exchange Commission on Form 8-K, Form 10-Q and Form 10-K. These publications are available on our Web site at www.northwesternenergy.com under About Us/Investor Information or by contacting Investor Relations.

Corporate Governance Information

Corporate governance information, including our Corporate Governance Guidelines, Code of Conduct, Code of Ethics for CEO and Senior Financial Officers, and charters for the Committees of our Board of Directors, is available on our Web site at www.northwesternenergy.com under About Us/Corporate Governance.

board of DIRECTORS

NorthWestern Energy
Delivering a Bright Future

E. Linn Draper, Jr.
Chairman of the Board
Lampasas, Texas
Retired Chairman, President and Chief Executive Officer of American Electric Power Co., Inc.
Director Since 2004

Stephen P. Adik
Valparaiso, Indiana
Retired Vice Chairman of NiSource, Inc.
Director Since 2004
Committees: Audit, Human Resources

Dorothy M. Bradley
Clyde Park, Montana
Retired District Court Administrator for the 18th Judicial Court of Montana
Director Since 2009
Committees: Nominating and Corporate Governance

Dana J. Dykhouse
Sioux Falls, South Dakota
President and Chief Executive Officer of First PREMIER Bank
Director Since 2009
Committees: Audit, Nominating and Corporate Governance

Julia L. Johnson
Windermere, Florida
President and Founder of NetCommunications, LLC, a strategy consulting firm specializing in the energy, telecommunications and information technology public policy arenas; former Chairperson of the Florida Public Service Commission
Director Since 2004
Committees: Human Resources, Nominating and Corporate Governance

Philip L. Maslowe
Palm Beach Gardens, Florida
Formerly Executive Vice President and Chief Financial Officer of The Wackenhut Corporation, a security staffing and privatized prisons corporation
Director Since 2004
Committees: Audit, Human Resources

Denton Louis Peoples
Incline Village, Nevada
Retired Chief Executive Officer and Vice Chairman of the Board of Orange and Rockland Utilities, Inc.
Director Since 2006
Committees: Audit, Human Resources

Robert C. Rowe
Helena, Montana
President and Chief Executive Officer of NorthWestern Corporation
Director Since 2008

OFFICERS

Robert C. Rowe
President and Chief Executive Officer

Brian B. Bird
Vice President, Chief Financial Officer and Treasurer

Patrick R. Corcoran
Vice President – Government and Regulatory Affairs

David G. Gates
Vice President – Wholesale Operations

Kendall G. Kliewer
Vice President and Controller

Timothy P. Olson
Interim General Counsel and Corporate Secretary

Curtis T. Pohl
Vice President – Retail Operations

Bobbi Schroeppel
Vice President – Customer Care, Communications and Human Resources

A contract crew and NorthWestern Energy employees use a barge to float a line truck about a half mile out in floodwaters of the James River to repair 115-kV electric transmission structures near Aberdeen, South Dakota.
– photographer: Tom Glanzer

NorthWestern Energy
Delivering a Bright Future

CORPORATE OFFICE
3010 West 69th Street, Sioux Falls, SD 57108
(605) 978-2900
www.northwesternenergy.com