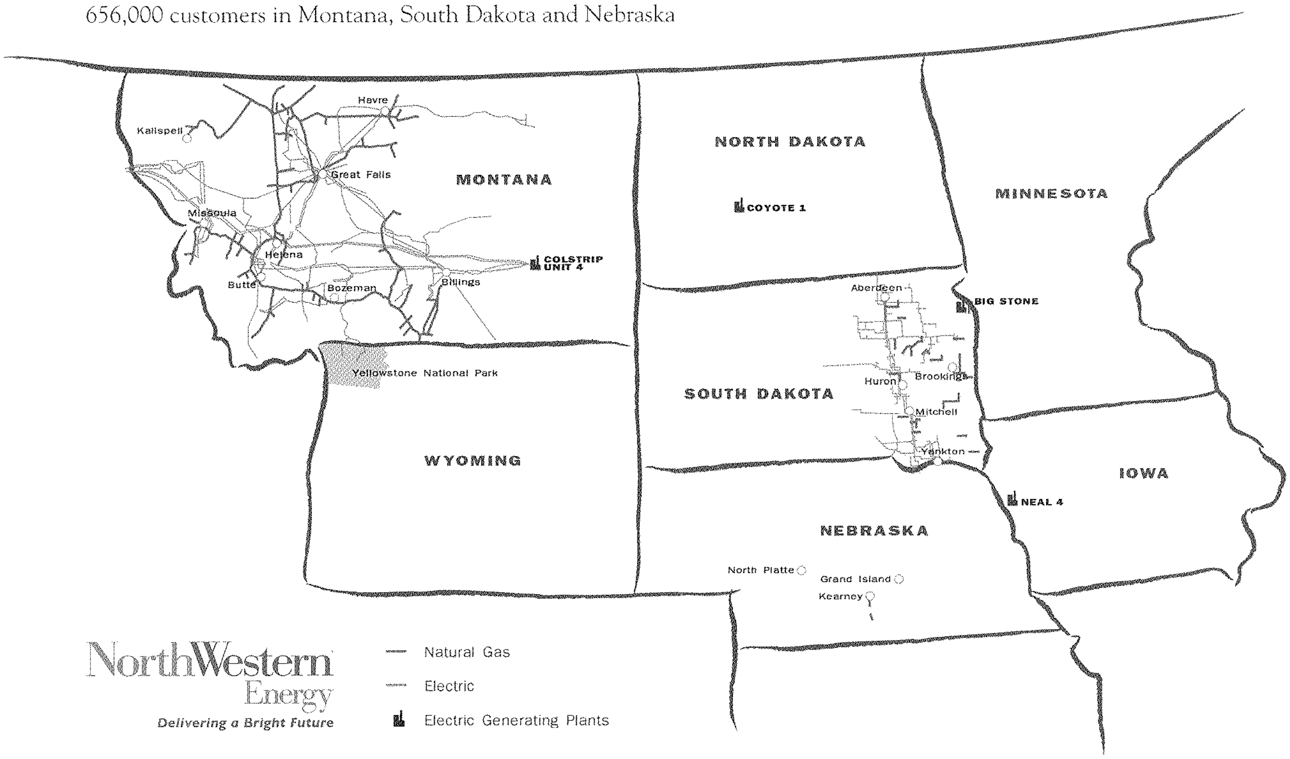
NorthWestern Energy

Delivering a Bright Future

08 ANNUAL REPORT

Cover photo: Sparks rain down on the protective gear of a welder at work in Huron, S.D.
Photographer: *Ron Wipf | Welder-fitter | Huron, S.D.*

NORTHWESTERN ENERGY
We provide electricity and natural gas in the upper Midwest and Northwest, serving approximately 656,000 customers in Montana, South Dakota and Nebraska



NorthWestern Energy
Delivering a Bright Future

NORTHWESTERN ENERGY **AT A GLANCE**

As of January 1, 2009, essentially all of our business consists of state and federally regulated electric and natural gas distribution and transmission operations.

ELECTRIC

MONTANA

332,500 customers in 187 communities
7,000 miles of transmission lines
21,200 miles of distribution lines
Owns 222 net MW of power generation

SOUTH DAKOTA

60,100 customers in 110 communities
3,200 miles of transmission and distribution lines
Owns 312 net MW of power generation

NATURAL GAS

MONTANA

179,200 customers in 105 communities
4,000 miles of underground distribution pipelines
2,000 miles of intrastate transmission pipelines
16.2 Bcf of gas storage

SOUTH DAKOTA

43,000 customers in 60 communities
1,450 miles of distribution gas mains

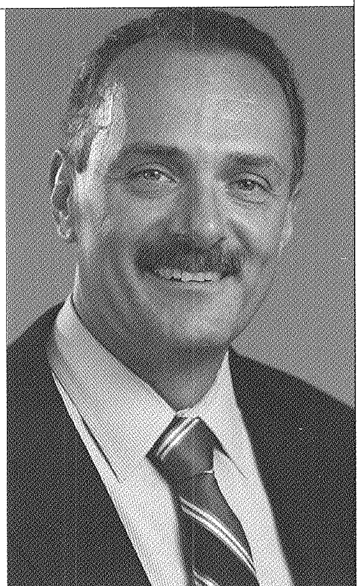
NEBRASKA

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

ABOUT THE PHOTOS IN OUR **ANNUAL REPORT**

The photos depicted in our annual report represent the top entries in a company-sponsored employee photo contest held in late 2008 that offered employees from across our service area the opportunity to showcase their photographic talents.

OUR MESSAGE TO **SHAREHOLDERS**



"Although economic uncertainty will be a continuing global theme in 2009, we at NorthWestern Energy will be working to achieve continued and sustainable financial strength and growth."

BOB ROWE
President and CEO

THE NATIONAL AND GLOBAL ECONOMY WAS ROCKED IN 2008. OUR REGION WAS RELATIVELY STRONGER, BUT NO PART OF THE COUNTRY WAS IMMUNE TO THE EFFECTS OF RECESSION.

The utility sector, including NorthWestern Energy, is being called on to help lead the recovery. We are actively discussing with national and regional leaders how we can do our part, consistent with the long-term interests of our investors and customers.

Thanks to hard work, discipline and a long-term perspective, NorthWestern Energy ended 2008 with an increase in net income of 27 percent over the prior year, a return to being a vertically integrated, regulated utility in all jurisdictions, an increase in our debt ratings, and stock performance that notably exceeded the utility indices. NorthWestern's performance was recognized by the financial community as one of the brightest lights in the utility sector.

We were able to significantly increase our pension funding to partially offset the decline in the stock market and still deliver sound financial results for the year. As we look forward to 2009, we do not have any debt maturing until the fourth quarter and therefore will be able to take advantage of refinancing opportunities that arise.

In addition to the Company's financial performance, I'm very proud of the significant improvement in our safety performance. There is nothing more important than the safety of our employees, our customers and our communities. By working together, our overall safety record has improved in every category. The most significant change was in our Lost Time Incident Rate, which improved by 280 percent as compared with 2007, and we expect to build upon this success in 2009.

Children pose as power poles on a summer day in Bozeman, Mont.
Photographer: *Ande Buffington | Engineer | Bozeman, Mont.*

We continue to provide top-tier reliability and customer service. We received our fifth consecutive Service One award from PA Consulting in 2008, an accomplishment that underscores our commitment to service excellence.

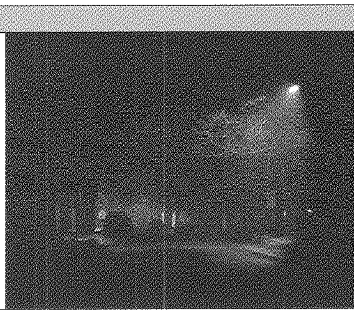
WE ACCOMPLISHED ALL OF THIS WHILE PREPARING THE FRAMEWORK FOR SIGNIFICANT IMPROVEMENTS IN OUR SERVICE AND POTENTIAL FUTURE EARNINGS GROWTH.

In late 2008, we were particularly pleased by the Montana Public Service Commission's decision to place our 222-megawatt interest in Colstrip 4 into rate base, which will benefit both customers and shareholders. Because Colstrip 4 was previously unregulated, it was placed into rate base at a market-determined price. It will provide customers with greater price stability in the future and will provide a base on which we can methodically rebuild a long-term, stable supply portfolio for our Montana electric customers.

The Montana Department of Environmental Quality awarded an air quality permit for the proposed natural gas fired, 150-megawatt Mill Creek Generating Station plant in late 2008. The petition for pre-approval of the regulating reserve plant will be heard by the Montana Public Service Commission in early 2009, with a decision expected in the second quarter. If approved, the plant will be a welcome addition to the economic base in Montana. It will be the first electric generation plant built by NorthWestern Energy in Montana and our second rate-based facility following Colstrip 4.

It is clear that renewable energy development will be a key component of a national economic revitalization plan in the coming months and years. Our region has the potential to take the lead in this environmentally sound development effort, and our transmission projects will be valuable to the region and the nation in achieving this goal.

The Mountain States Transmission Intertie (MSTI) project, a proposed 500-kV transmission line between Townsend, Montana and Midpoint, Idaho, is currently undergoing environmental review. The Montana Department of Environmental Quality has approved the Company's application under the Major Facility Siting Act, which satisfies the state's administrative rules. The draft Environmental Impact Statement is due mid-2009. The project is strongly supported by Montana's political leadership.



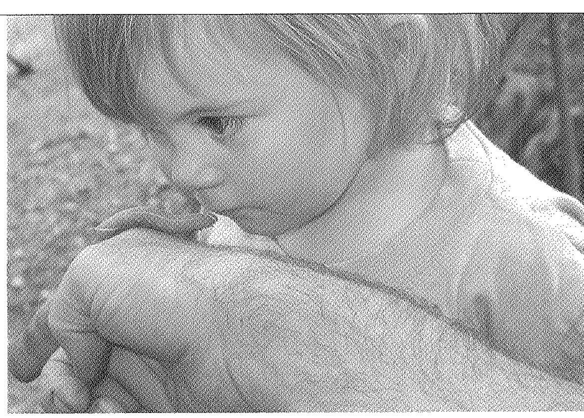
A streetlight casts a warm glow on a foggy winter night in Kalispell, Mont.

Photographer: *Randy Loveless | Administrative Specialist | Kalispell, Mont.*

DELIVERING **A BRIGHT FUTURE**

Transmission structures south of Butte, Mont.

Photographer:
Mark Mallard
Senior Engineer
Butte, Mont.



Aili McClafferty makes friends with a caterpillar while camping with her family on the Big Hole River in southwest Montana.

Photographer:
Kim McClafferty
Engineer
Butte, Mont.

We've also requested the Federal Energy Regulatory Commission to approve an "open season" to determine the level of interest in a collector system that would extend the reach of our existing Montana transmission system into areas currently under consideration by wind energy developers. This collector system consists of up to five new transmission lines in north central, south central, central and eastern Montana. Once interest in the collector system is established, we'll conduct an engineering analysis to determine the appropriate size and rating of each potential new path.

AS WITH ALL OF OUR INVESTMENT INITIATIVES, WE'RE APPLYING A RATIONAL APPROACH THAT BALANCES GROWTH AND OPPORTUNITY WITH FINANCIAL DISCIPLINE.

We won't move forward with any project that doesn't meet our standards for both customer benefit and shareholder value.

One of my goals for NorthWestern Energy is to actively engage all of our stakeholders in shaping our future. This requires a significant amount of outreach and new approaches. I have been pleased to have many opportunities to meet with and hear from our stakeholders. In early January 2009, we hosted an Energy Summit, bringing together industry representatives, regulatory commissioners, legislators, rating agency analysts, stock analysts, representatives from environmental groups, and other stakeholders to discuss issues facing the industry. We will continue to reach out in 2009 to all of our stakeholders.

Another successful program that we will build upon in 2009 is our energy efficiency and conservation initiative. In 2008, we exceeded aggressive targets for energy efficiency and conservation through our Demand Side Management program, thanks to a relentless and aggressive outreach program. We view this effort as a crucial educational partnership with our customers to provide them with the tools and resources they need to make decisions that best fit their lifestyle. We will continue to coordinate with our regulatory bodies to achieve a balanced energy supply mix that encourages energy efficiency and other renewable energy sources without resulting in sharply higher customer rates or negative revenue implications.

ALTHOUGH ECONOMIC UNCERTAINTY WILL BE A CONTINUING GLOBAL THEME IN 2009, WE AT NORTHWESTERN ENERGY WILL BE WORKING TO ACHIEVE CONTINUED AND SUSTAINABLE FINANCIAL STRENGTH AND GROWTH.

This will allow us to meet customers' demands for high-quality service at stable prices; policymakers' expectations for appropriate commitments to technology, energy efficiency and other initiatives; and shareholders' interests in appropriate returns over the long term.

I joined NorthWestern Energy in August; however, I have interacted with the Company for more than 20 years. I am proud of our service, our system and our heritage in serving a remarkable part of the United States. Our employees and their commitment to community involvement not only includes volunteering countless hours of their own time, but employees and the Company together donated more than $1.1 million to local charitable organizations in 2008. Our customers live in dispersed rural and concentrated urban environments, and our infrastructure is subject to extreme weather conditions during every season. Our employees always rise to the challenge to provide our customers with the highest level of service. I am inspired by their performance and proud to be a part of the team. We look forward to meeting the challenges and achieving strong outcomes in 2009.

Sincerely,

Robert C. Rowe
President and CEO

Crews work on a 500 kV transmission tower in a stubble field south of Townsend, Mont.

Photographer: Mark Mallard, Senior Engineer, Butte, Mont.

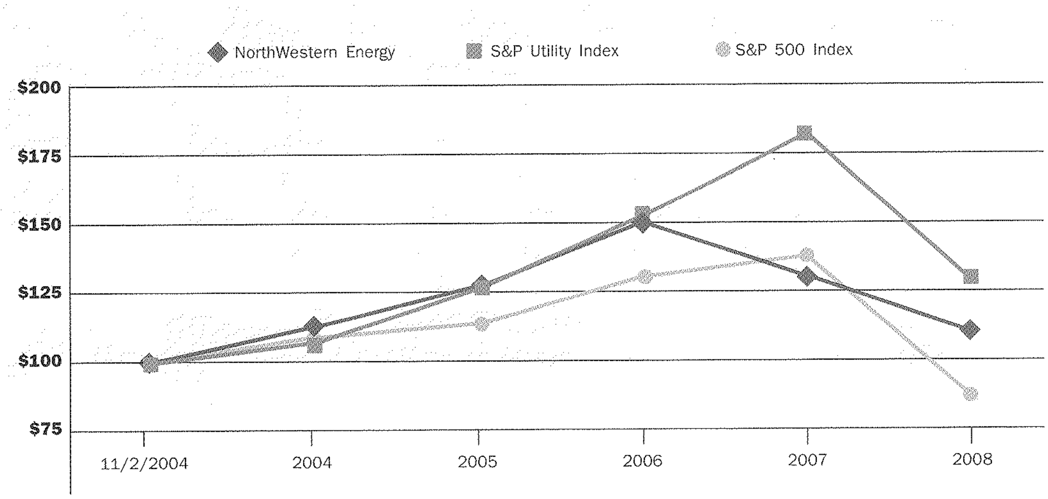
FINANCIAL **HIGHLIGHTS**

(dollars and volumes in thousands)

	2008	2007	% CHANGE
Gross margin	$ 562,053	$ 531,655	6 %
Net income	$ 67,601	$ 53,191	27 %
Earnings per diluted common share	$ 1.77	$ 1.44	23 %
Dividends declared per average common share	$ 1.32	$ 1.28	3 %
Debt outstanding (excluding capital leases)	$ 862,056	$ 805,977	7 %
Total debt to total capitalization ratio	53.0 %	49.5 %	7 %
Capital expenditures	$ 124,563	$ 117,084	6 %
Number of customers	656,000	650,000	1 %
Number of employees	1,385	1,351	3 %
Retail volumes delivered			
Electric (MWH)	10,164	9,953	2 %
Natural gas (dekatherms)	32,263	28,894	12 %

SHAREHOLDER **RETURN**

The graph assumes $100 was invested in our common stock on November 2, 2004 (the first day that our common stock traded publicly following our emergence from bankruptcy) and compares the share price performance with the S&P Utility Index and the S&P 500 Index for the years ending December 31, 2004, 2005, 2006, 2007 and 2008. Total return is computed assuming reinvestment of dividends.



	11/2/04	2004	2005	2006	2007	2008
NorthWestern Energy	$100.00	$112.22	$127.76	$150.84	$131.18	$ 110.18
S&P Utility Index	$100.00	$107.55	$126.51	$153.06	$182.72	$ 129.77
S&P 500 Index	$100.00	$108.27	$112.84	$130.66	$137.84	$ 86.84

CREDIT **RATINGS**

Ratings as of February 1, 2009

	Fitch	Moody's	S&P
Senior secured	BBB+	Baa2	A- (Montana) BBB+ (South Dakota)
Senior unsecured	BBB	Baa3	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, 2008

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

SEC
Mail Processing
Section

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Washington, DC
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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 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 $990,682,000 computed using the last sales price of $25.42 per share of the registrant's common stock on June 30, 2008, the last business day of the registrant's most recently completed second fiscal quarter.

As of February 6, 2009, 35,936,391 shares of the registrant's common stock, par value $0.01 per share, were outstanding.

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ☒ No ☐

Documents Incorporated by Reference
Certain sections of our Proxy Statement for the 2009 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;
- unanticipated 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;
- 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 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. "Predecessor Company" refers to us prior to emergence from bankruptcy (operations prior to October 31, 2004). "Successor Company" refers to us after emergence from bankruptcy (operations after November 1, 2004).

GLOSSARY

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.

Ancillary Services - These services ensure reliability and support the transmission of electricity from generation sites to customer loads. Such services may include: load regulation, spinning reserve, non-spinning reserve, replacement reserve, and voltage support.

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.

Colstrip Lease Holdings, LLC (CLH) - An indirect wholly-owned subsidiary of NorthWestern Corporation.

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.

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 Hinshaw pipeline may receive a certificate authorizing it to transport natural gas out of the state in which it is located, without giving up its status as a Hinshaw pipeline.

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 a 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.

Mid-Columbia Electricity Price Index (Mid-C) - An electric pricing index of volume-weighted averages of specifically defined bilateral, wholesale, physical transactions. Calculations for these indexes average power transactions from Columbia, Midway, Rocky Reach, Wells, and Wanapum/Vantage, delivery points along the Columbia River.

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 form 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 the 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 nine 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 656,000 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 distributed electricity and 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 into this Annual Report on Form 10-K and should not be considered a part of this Annual Report on Form 10-K.

Through December 31, 2008, we operated our business in the following reporting segments:

- Regulated electric operations;
- Regulated natural gas operations;
- Unregulated electric operations;
- All other, which primarily consists of our remaining unregulated natural gas operations and our unallocated corporate costs.

For financial information regarding these segments, see Note 22 to the Consolidated Financial Statements. Effective January 1, 2009, we will no longer present an unregulated electric segment and the results of operations of our interest in Colstrip Unit 4 will be reflected in the regulated electric segment. See the "MPSC Regulation" section for further discussion.

REGULATED ELECTRIC OPERATIONS

MONTANA

Our Montana regulated electric utility business consists of an extensive electric transmission and distribution network. 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 332,500 customers in 187 communities and their surrounding rural areas, 15 rural electric cooperatives and in Wyoming to the Yellowstone National Park. In 2008, by category, residential, commercial and industrial, and other sales accounted for approximately 36%, 52%, and 12% of our Montana regulated electric utility revenue, respectively. 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 1,805 MWs, the average daily load was approximately 1,219 MWs, and more than 10.7 million MWHs were supplied during the year ended December 31, 2008.

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 21,200 miles of overhead and underground distribution lines and 336 transmission and distribution substations.

Electric Supply

Through the end of 2008, we purchased substantially all of our Montana capacity and energy requirements for electric supply from third parties. Our annual electric supply load requirements average approximately 730 MWs. We currently have under contract approximately 82% of the energy requirements necessary to meet our projected load requirements through June 30, 2009, with approximately 83% at fixed prices. For the period July 1, 2009 through June 30, 2010, we have under contract approximately 82% of our projected load requirements, with approximately 96 percent at fixed prices. This includes approximately 111 MWs from Colstrip Unit 4. 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 105 MWs of capacity. We have several other long and medium-term power purchase agreements including contracts for 135 MWs of wind generation and 5 MWs of seasonal base-load hydro supply. In December 2007, we filed a biennial Electric Default Supply Resource Procurement Plan with the MPSC which will guide future resource acquisition activities.

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. Approximately 8% of our electric supply requirements for 2009 are from renewable resources. The amounts in excess of the requirements can be carried forward to future periods. In addition to the general renewable requirements, beginning in 2010, 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 tracking 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 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 FERC. FERC expected the NERC and the North American Energy Standards Board (NAESB) in 2008 to further define and develop business practices and changes to the Open Access Same-time Information System (OASIS), with the intent to allow for further transparency and nondiscriminatory use of the transmission system. Although not completed in 2008, NERC and NAESB continue to work on these initiatives. We will continue to participate in the processes under which these standards and business practices are developed, and will ultimately be subject to them once they are complete.

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. 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.

Per NERC, MRO and WECC guidelines, users, owners and operators of the bulk power system that self-reported non-compliance with any of the NERC standards and that submitted mitigation plans to address the non-compliance would not be subject to penalties if the mitigation plans were submitted on or before June 18, 2007, and approved by the MRO and WECC. We submitted a number of self-reports and mitigation plans, and on June 11, 2008 received a notice of confirmed violation in the MRO relating to sabotage reporting, and on December 31, 2008, we received two preliminary notices of alleged violation in the WECC relating to protection systems / substations maintenance and testing. There were no penalties associated with the MRO violation. At this time we do not know if there will be any penalties associated with the WECC violations. Also, we expect to receive preliminary notices of alleged violation on the other self-reports and mitigations plans we have submitted in the WECC. We are uncertain if the self-reported violations will result in financial penalties; however, we do not believe any penalties would be material based on the results of similar violations reported by other transmission operators. Our compliance with NERC standards will be audited at least every three years, and we expect the first such WECC audit to begin in April 2009.

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. In 2008, ten additional balancing authorities (BAs) had signed the ADI agreement and are expected to be fully implemented into the system during the first quarter of 2009. The BAs are located in the Pacific Northwest and Southwest regions of the WECC Interconnection.

Under FERC approved agreements beginning in January 2008, Powerex and Avista Utilities sold regulating reserve service to us, which in turn we used to provide service under Schedule 3 (Regulation and Frequency Response) to our customers under our OATT. The contracts for this service with Powerex and Avista Utilities terminated as of December 31, 2008. Upon completion of a competitive RFP process, we entered into two-year agreements with Avista Utilities, Grant County Public Utility District and Powerex to replace the 2008 agreements, which allows us to balance loads and resources within our balancing authority area on a moment-to-moment basis and to provide Schedule 3 service under our Montana OATT. These agreements have been approved by the FERC. Our tariffs allow for pass-through of ancillary costs, including the regulating reserve service described above.

Rate Increase - In October 2006, we filed a request with the FERC for an electric transmission revenue increase. In May 2007, we implemented interim rates, which were subject to refund plus interest pending final resolution. We filed settlement documents on February 15, 2008, and on October 16, 2008, FERC approved the settlement. We have been recognizing revenue consistent with the settlement terms since we implemented interim rates in May 2007, which has resulted in an annualized margin increase of approximately $3.0 million. We deferred a portion of the interim rates billed from May 2007 through November 2008 and, in accordance with the settlement agreement, refunded approximately $5.4 million to customers in December 2008.

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.

Colstrip Unit 4 – In January 2008, we announced that we had retained a financial advisor to assist us in the evaluation of our strategic options related to our unregulated joint ownership interest in Colstrip Unit 4. Options reviewed included selling our ownership through a competitive bid process, putting the asset in rate base in Montana, or retaining the asset and contracting future sales of the plant output. On June 10, 2008, we entered into an agreement to sell our interest in Colstrip Unit 4 for $404 million in cash, subject to certain working capital adjustments. The agreement provided a timeline of 120 days for us to explore the viability of placing this asset into our Montana utility rate base.

Consistent with these terms, and in accordance with HB 25, we submitted a filing with the MPSC to review and determine if it would be in the public interest to place our interest in Colstrip Unit 4 into rate base at an equivalent value to the negotiated selling price including certain adjustments. The determination of the selling price was based on a number of factors, including the existing below market commitments of 111 MWs to our Montana regulated electric supply load. The MPSC accepted the application and ordered the asset be placed into utility rate base effective January 1, 2009, at a value of $407 million. 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 or the life of the plant. The difference in the rate base value of $407 million and the negotiated price of $404 million reflects termination fees owed to the potential purchaser upon termination of our June 2008 agreement to sell our interest, offset by avoided sale transaction fees.

This resource will supply approximately 13% of our 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 of Colstrip Unit 4 will be included in our annual electric supply tracking filing for inclusion in customer rates.

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 at an estimated cost of $206 million. The Mill Creek Generating Station would provide supply and regulating resources in Montana to maintain reliability and enable additional wind power to be integrated onto the network to meet future renewable energy portfolio needs. As part of the MPSC filing, we requested a capital structure of 50% equity and 50% debt and an authorized return on equity of 10.75% for this asset. A procedural schedule is currently in process and we anticipate an MPSC decision during the second quarter of 2009.

Montana General Rate Case - On July 1, 2008, the MPSC approved our stipulated agreement with the MCC to settle our general electric and natural gas rate case filed in 2007. The settlement resulted in an annual increase to base electric rates of approximately $10 million, and included certain capital investment commitments. In addition, we will submit a Montana general electric and natural gas rate filing no later than July 31, 2009, based on a 2008 test year.

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 60,100 customers in 110 communities in South Dakota. In 2008, by category, residential, commercial and industrial, wholesale, and other sales accounted for approximately 36%, 52%, 8% and 4% of our South Dakota electric utility revenue, respectively. Currently, we serve these customers principally from generation capacity obtained through our joint ownership interests in three base-load generation plants and other peaking facilities that provide us with 311 MWs of demonstrated capacity. In addition, we have contracted capacity with MidAmerican Energy Company (MidAmerican) for an additional 53 MWs. Peak demand was approximately 284 MWs, the average daily load was approximately 160 MWs, and more than 1.4 million MWHs were supplied during the year ended December 31, 2008. We use market purchases and internal peaking generation to provide peak supply in excess of our base-load capacity.

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 3,200 miles of overhead and underground transmission and distribution lines as well as 120 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 2008, this was approximately 15% of our share of the power generated.

Name and Location of Plant	Fuel Source	Our Ownership Interest	Our Share of 2008 Peak Summer Demonstrated Capacity (MW)	% of Total 2008 Peak Summer Demonstrated Capacity
Big Stone Plant, located near Big Stone City in northeastern South Dakota	Sub-bituminous coal	23.4%	107.24	34.5%
Coyote I Electric Generating Station, located near Beulah, North Dakota	Lignite coal	10.0	42.70	13.8
Neal Electric Generating Unit No. 4, located near Sioux City, Iowa	Sub-bituminous coal	8.7	55.91	18.0
Miscellaneous combustion turbine units and small diesel units (used only during peak periods)	Combination of fuel oil and natural gas	100.0	104.69	33.7
Total Capacity			310.54	100.0%

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. It is anticipated that the wind farm will be in operation by early 2010.

MidAmerican provided 53 MWs of firm capacity during the summer months of 2008 and we have an agreement with them to supply firm capacity of 71 MWs in 2009. During 2008, we extended the current agreement with MidAmerican to provide firm capacity during the summer months of 2010 through 2012 for 74, 77 and 80 MWs, respectively, 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 2013. 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, 2008. 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 I 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	2008	2007	2006	Percent of 2008 MWH Generated
Sub-bituminous-Big Stone	$ 1.77	$ 1.55	$ 1.49	51.2%
Lignite-Coyote	1.18	1.06	0.96	19.7
Sub-bituminous-Neal	1.24	1.15	1.10	28.7
Natural Gas	8.52	7.41	7.17	0.2
Oil	19.34	13.11	15.38	0.2

During the year ended December 31, 2008, the average delivered cost per ton of fuel burned for our base-load plants was $29.15 at Big Stone, $16.21 at Coyote I and $18.69 at Neal #4. The average cost by type of fuel burned and delivered cost per ton of fuel 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. 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 I facility has a contract for the supply of lignite coal that expires in 2016 and provides for an adequate fuel supply for Coyote's estimated economic life.

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 2008, approximately 0.9% 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 I, 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 and Neal #4 to our South Dakota service areas through seven points of interconnection on WAPA's system. 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 2008, our costs for services under this contract totaled approximately $5.1 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 I 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 are not participating in the MISO markets, but continue to utilize WAPA to handle our scheduling and power marketing activities. We have negotiated a settlement as a grandfathered agreement with MISO and the other Big Stone and Coyote I 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. 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 related 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

MONTANA

We distribute natural gas to approximately 179,200 customers in 105 Montana communities. We also serve several smaller distribution companies that provide service to approximately 31,500 customers. Our natural gas distribution system consists of approximately 4,000 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 41 Bcf, and our peak capacity was approximately 335,000 dekatherms per day during the year ended December 31, 2008.

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 16.2 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, 20 of our municipal franchises, which account for approximately 81,000 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 enables 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, 2008, 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 – On July 1, 2008, the MPSC approved our stipulated agreement with the MCC to settle our general electric and natural gas rate case filed in 2007. The settlement resulted in an annual increase to base natural gas rates of approximately $5 million, and included certain capital investment commitments. In addition, we will submit a Montana general electric and natural gas rate filing no later than July 31, 2009, based on a 2008 test year.

SOUTH DAKOTA AND NEBRASKA

We provide natural gas to approximately 84,500 customers in 60 South Dakota communities and four Nebraska communities. We have approximately 2,200 miles of underground distribution pipelines in South Dakota and Nebraska. In South Dakota, we also transport natural gas for five gas-marketing firms and four 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 21.4 Bcf of third-party transportation volume on our South Dakota distribution system and approximately 2.3 Bcf of third-party transportation volume on our Nebraska distribution system during 2008.

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, 43 of our South Dakota and Nebraska municipal franchises, which account for approximately 58,900 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, 2008, were approximately 6.1 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, 2008, were approximately 5.7 Bcf. Our Nebraska natural gas supply, storage and pipeline requirements are fulfilled primarily through a third-party contract with ONEOK Energy Services Co.

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 two propane-air gas peaking units with a peak daily capacity of approximately 6,400 dekatherms. 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.

UNREGULATED ELECTRIC OPERATIONS

We have a 30% joint ownership interest in the Colstrip Unit 4 generation facility, a 740 MW demonstrated-capacity coal-fired power plant located in southeastern Montana. Our interest represents approximately 222 MWs at full load. We sell our output principally to Puget Sound Energy (Puget) and DB Energy Trading, LLC, (DB) under agreements expiring on December 29, 2010. When operating at full contract capacity, we deliver 97 MWs to Puget (plus line losses) and 111 MWs to DB. We have a separate agreement with DB to repurchase 111 MWs through December 2010.

As discussed above in the "MPSC Regulation" section, the MPSC approved placing this asset into our Montana utility rate base. Effective January 1, 2009, we will no longer present an unregulated electric segment and the results of operations of our interest in Colstrip Unit 4 will be reflected in the regulated electric segment as a component of electric supply. We will continue to serve the contract obligations to Puget and DB through their expiration, and the buyback quantity plus any MWs not under contract will be used to serve Montana regulated base-load.

A long-term coal supply contract with Western Energy Company provides the coal necessary to run the Colstrip facility.

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 clean up 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 $22.5 million to $43.8 million. As of December 31, 2008, we have a reserve of approximately $32.1 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 compliance with 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.

Coal-Fired Plants

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.

Global Climate Change - 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. Investor organizations are also applying increased pressure for carbon dioxide emissions reduction. Specifically, coal-fired plants have come under scrutiny due to their emissions of carbon dioxide.

In addition, 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 for installation at the generation facilities we have a joint interest in, or on a cost effective basis. 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.

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. We comply with these 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 with respect to these plants.

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 more stringent cap, which could require us to incur additional costs related to our joint ownership interest in Colstrip Unit 4. We are unable to estimate the ultimate financial impact of this matter in light of the uncertainty surrounding the anticipated federal and state rulemakings; however, the final resolution could have a material impact on capital expenditure estimates. We are continuing to work with the other Colstrip owners to determine the ultimate financial impact of these rules.

For more information on environmental contingencies, see Note 20, Commitments and Contingencies, to the Consolidated Financial Statements.

EMPLOYEES

As of December 31, 2008, we had 1,385 employees. Of these, 1,059 employees were in Montana and 326 were in South Dakota or Nebraska. Of our Montana employees, 415 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 190 employees covered by the System Council U-26 of the International Brotherhood of Electrical Workers. This collective bargaining agreement expires on December 31, 2009. We consider our relations with employees to be in good standing.

Executive Officers

Executive Officer	Current Title and Prior Employment	Age on Feb. 6, 2009
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).	53
Brian B. Bird	Vice President and Chief Financial Officer since December 2003. Director since August 2008. 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.	46
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).	57
Miggie E. Cramblit	Vice President, General Counsel and Corporate Secretary since May 2008. Prior to joining NorthWestern, Ms. Cramblit held positions at DPL Inc. and its primary subsidiary, The Dayton Power and Light Company, including Sr. Vice President, General Counsel and Corporate Secretary (July 2007-October 2007); Vice President, General Counsel and Corporate Secretary (2004-July 2007); and Vice President and General Counsel (2003 to 2004).	53
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.	52
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).	39
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.	44
Bobbi L. Schroeppel	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.	40

Officers are elected annually by, and hold office at the pleasure of the Board, and do not serve a "term of office" as such.

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 shares 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 may result in a decline in energy consumption and an increase in customers' inability to pay their accounts, which may adversely affect our liquidity, results of operations and future growth.

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. Continued instability in the financial markets may increase the cost of capital, limit our ability to draw on our credit facility, negatively impact our ability to refinance debt maturing in 2009 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. Specifically, in our recent 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. 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 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 substantial 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, such as the new mercury emissions rules in Montana, 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.

In addition to the requirements related to the mercury emissions rules noted above, 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. 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.

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.

We have two defined benefit pension plans that cover substantially all of our employees, and a post-retirement medical plan for our Montana employees. The costs of providing these plans are dependent upon a number of factors, including rate of return on plan assets, discount rates, other actuarial assumptions, and government regulation. While we have complied with the minimum funding requirements, our obligations for these plans exceed the value of plan assets. In addition, the Pension Protection Act of 2006 changed the minimum funding requirements for defined benefit pension plans beginning in 2008. Without sustained growth in the plan assets over time and depending upon the other factors noted above, we could be required to fund our plans with significant amounts of cash. Such cash funding obligations may change significantly from projections, and could have a material impact on our liquidity and results of operations.

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, are 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 other proposed projects that may result in direct competition to our proposed transmission expansion. 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. We have capitalized approximately $6.7 million of costs associated with these projects as of December 31, 2008.

Our obligation to supply a minimum annual quantity of power to the Montana electric supply could expose us to material commodity price risk if certain Qualifying Facilities (QF) under contract with us do not perform during a time of high commodity prices, as we are required to supply any quantity deficiency.

We perform management of the QF portfolio of resources under the terms and conditions of the QF Tier II Stipulation with the MPSC. This Stipulation may subject us to commodity price risk if the QF portfolio does not perform in a manner to meet the annual minimum energy requirement.

As part of the Stipulation and Settlement with the MPSC and other parties in the Tier II Docket, we agreed to supply the electric supply with a certain minimum amount of power at an agreed upon price per MW. 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 contracts.

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.

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, 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 condition 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, we would be required under certain credit agreements to provide collateral in the form of letters of credit or cash, which may materially adversely affect our liquidity and/or access to capital.

A downgrade of our credit ratings to less than investment grade could adversely affect our liquidity, as counter parties could require us to post collateral. In addition, our ability to raise capital on favorable terms could be hindered, and our borrowing costs could increase.

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 20, 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, 2008.

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 6, 2009, there were approximately 966 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 2008. Quarterly dividends were declared and paid on our common stock during 2008 as set forth in the table below.

QUARTERLY COMMON STOCK PRICE RANGES AND DIVIDENDS

	Prices		
	High	Low	Cash Dividends Paid
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
2007—			
Fourth Quarter	$ 30.05	$ 26.97	$ 0.33
Third Quarter	32.10	25.30	0.33
Second Quarter	35.47	30.60	0.31
First Quarter	36.51	35.32	0.31

On February 6, 2009, the last reported sale price on the NYSE for our common stock was $24.61.

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, 2008:

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 Notes 2 and 16 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)	—		1,363,998
Total	—		1,363,998

1) Upon emergence from bankruptcy, 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 743,912 shares have been distributed to officers and employees and 158,047 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. Between September 14, 2003 and October 31, 2004, we operated as a debtor-in-possession under the supervision of the Bankruptcy Court. Our financial statements for reporting periods within that timeframe were prepared in accordance with the provisions of Statement of Position 90-7, *Financial Reporting by Entities in Reorganization Under the Bankruptcy Code*. In accordance with SOP 90-7, we applied the principles of fresh-start reporting as of the close of business on October 31, 2004.

FIVE-YEAR FINANCIAL SUMMARY

	Successor Company					Predecessor Company
	Year Ended December 31,				November 1 December 31,	January 1 October 31,
	2008	2007	2006	2005	2004	2004 (1)
Financial Results (in thousands, except per share data)						
Operating revenues	$ 1,260,793	$ 1,200,060	$ 1,132,653	$ 1,165,750	$ 205,952	$ 833,037
Income (loss) from continuing operations (1)	67,601	53,191	37,482	61,547	(6,520)	548,889
Basic earnings (loss) per share from continuing operations (2)	1.78	1.45	1.06	1.73	(0.18)	
Diluted earnings (loss) per share from continuing operations (2)	1.77	1.44	1.00	1.71	(0.18)	
Dividends declared & paid per common share	1.32	1.28	1.24	1.00	—	
Financial Position						
Total assets	$ 2,762,037	$ 2,547,380	$ 2,395,937	$ 2,400,403	$ 2,448,869	$ 2,554,154
Long-term debt and capital leases, including current portion	900,047	846,368	747,117	742,970	836,946	910,154
Ratio of earnings to fixed charges (3)	2.7	2.4	2.0	2.4	—	7.5

1) Income (loss) from continuing operations includes reorganization items. The financial position information is that of the Successor Company as of October 31, 2004.
2) Per share results have not been presented for the Predecessor Company as all shares were cancelled upon emergence.
3) The fixed charges exceeded earnings, as defined by this ratio, by $11.5 million for the two-months ended December 31, 2004.

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 22 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 656,000 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 2008, 2007 and 2006. Following is a brief overview of highlights for 2008, and a discussion of our strategy.

HIGHLIGHTS

Highlights for the year ended December 31, 2008 include:

- Improvement in net income of $14.4 million as compared with 2007;
- Completing our review of strategic options related to our 30% joint ownership interest in Colstrip Unit 4, resulting in placing the asset in regulated electric rate base beginning January 1, 2009;
- Settling our Montana electric and natural gas rate filing, resulting in a $15 million annual increase to base rates;
- Filing a request with the MPSC for advanced approval to construct a 150 MW Mill Creek Generating Station at an estimated cost of $206 million;
- Completing a share buyback program for approximately 3.1 million shares;
- Achieving and maintaining investment grade credit ratings on both a secured and unsecured basis from the three major ratings agencies; and
- Filed the Major Facilities Siting Agreement with the Montana Department of Environmental Quality related to the proposed Mountain States Transmission Intertie (MSTI) project.

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. See the "Capital Requirements" discussion for further detail on planned maintenance capital expenditures.

In addition to the organic load growth in our service territories we also have a number of growth opportunities due to the increased focus on domestic energy resources and renewable energy initiatives. In Montana, the passage of HB-25 in the 2007 legislative session provides us an opportunity to consider 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, we have opportunities to pursue transmission grid expansion due to our geographic location, which places us between many of the parties developing new renewable generation resources and the customers they hope to serve.

Generation Investment

Colstrip Unit 4 – In 2008 we completed our review of strategic options for our unregulated joint ownership interest in Colstrip Unit 4, and took a significant first step toward vertical integration in Montana as allowed by HB 25 by obtaining MPSC approval for the asset to be placed into utility rate base effective January 1, 2009, at a value of $407 million. This resource 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).

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 at an estimated cost of $206 million. The Mill Creek Generating Station would provide regulating resources to balance our transmission system in Montana to maintain reliability and enable additional wind power to be integrated onto the network to meet future renewable energy portfolio needs. As part of the MPSC filing, we requested a capital structure of 50% equity and 50% debt and an authorized return on equity of 10.75%. A procedural schedule is currently in process and we anticipate an MPSC decision during the second quarter of 2009. In addition, the Montana Department of Environmental Quality has issued an Air Quality Permit for this project.

Transmission Investment Opportunities

Due to the abundance of natural resources in Montana, significant electric generation projects 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:

- a new 500 kV transmission line from southwestern Montana to southeastern Idaho with a potential capacity of 1,500 MWs:
- 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.

Siting and permitting work is in process on the new 500 kV transmission line and expansion of the existing Colstrip 500 kV system. 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 are in the process of selecting a preferred, as well as two alternative routes. In addition, we are in the process of conducting a second Open Season Process to identify potential interest for new transmission capacity on this path due to the changing nature of generation projects. We currently have 539 MWs of transmission service requests from open season participants for capacity on the proposed new transmission line. We are conducting a similar open season on the proposed 230 kV collector project to determine interest in the project. 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 MSTI line and collector system will be in service by 2014.

All of the current joint owners of the existing Colstrip 500 kV transmission line, as well as the Bonneville Power Authority, have signed a joint study and development agreement which will complete system studies and draft commercial agreements. We anticipate the study will be completed in the 2nd quarter of 2009. If constructed, we expect the upgrade to be complete by 2011.

Construction on these projects cannot commence until all local, state and federal permits/regulatory requirements are met. 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. We have capitalized approximately \$6.7 million of preliminary survey and investigative costs associated with proposed growth projects, which includes approximately \$5.0 million for the MSTI transmission project and approximately \$1.5 million for the Mill Creek generation project.

Economic Conditions

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.

Liquidity – We believe we have sufficient liquidity despite the disruption of 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 have maintained access to this credit facility during 2008. 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). If economic conditions worsen, we may defer planned capital expenditures to maintain sufficient liquidity. We plan to refinance our revolving credit facility and the debt of our subsidiary, CLH, that matures in December 2009. To fund our strategic growth opportunities we will 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 will continue to target 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 – We sponsor two defined benefit pension plans. Our oversight of the investments held in these plans is rigorous and we believe our investment strategies are prudent. Due to the unprecedented decline in equity markets, we experienced plan asset market losses during 2008 in excess of 30%. Our benefit obligations are remeasured annually using a December 31 measurement date, which resulted in an increase to the pension plans' unfunded status of approximately \$100 million, of which approximately \$86 million is related to our Montana plan. As a result of this increase in unfunded status, we have increased our 2009 cash funding projections for the Montana pension plan to approximately \$47 million, as compared with our previous cash funding estimate of \$17 million. For 2008, we contributed approximately \$22 million.

Pension costs in Montana are included in expense on a pay as you go (cash funding) basis. In 2005, the MPSC authorized recognition of pension costs based on an average of the annual cash funding for 2005 through 2009. Under the 2005 accounting order, Montana pension expense included in our 2008 financial statements would have been approximately \$37.5 million due to the significant increase in 2009 plan contribution requirements. To decrease volatility to both earnings and customer rates, we requested and received approval from the MPSC for a revised accounting order to recognize pension expense for calendar years 2008 through 2012 based on an average of the funding for 2005 through 2012, which is approximately $30.6 million annually, based on current cash funding projections. Pension costs in South Dakota are recovered on an accrual basis. For further discussion of our sensitivity to plan asset returns, see the "Critical Accounting Policies" section. In addition, effective January 1, 2009, the pension plans were closed to new employees. Employees hired after this date are eligible to participate in our defined contribution plan.

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 Continuing 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, 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 include 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 include 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 as discussed above in the MD&A "Overview" section. 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. Based on current funding projections, we expect 2009 pension expense to be comparable with 2008. For further discussion of our sensitivity to plan asset returns, see the "Critical Accounting Policies" section;
- 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. See "Liquidity and Capital Resources" for additional information regarding our refinancing activities.

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. 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 2012, based on our anticipated use of consolidated net operating loss carryforwards (CNOLs).

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. We expect our net income to increase by approximately $9 million in 2009 as a result of the inclusion of our joint ownership interest in Colstrip Unit 4 in regulated electric rate base.

Year Ended December 31, 2007 Compared with Year Ended December 31, 2006

	Year Ended December 31,			
	2007	2006	Change	% Change
		(in millions)		
Operating Revenues				
Regulated Electric	$ 736.7	$ 661.7	$ 75.0	11.3%
Regulated Natural Gas	363.6	359.7	3.9	1.1
Unregulated Electric	74.2	83.0	(8.8)	(10.6)
Other	56.7	77.0	(20.3)	(26.4)
Eliminations	(31.1)	(48.7)	17.6	36.1
	$ 1,200.1	$ 1,132.7	$ 67.4	6.0%

	Year Ended December 31,			
	2007	2006	Change	% Change
		(in millions)		
Cost of Sales				
Regulated Electric	$ 389.7	$ 332.8	$ 56.9	17.1%
Regulated Natural Gas	236.0	240.8	(4.8)	(2.0)
Unregulated Electric	18.0	16.6	1.4	8.4
Other	54.2	70.5	(16.3)	(23.1)
Eliminations	(29.5)	(47.1)	17.6	37.4
	$ 668.4	$ 613.6	$ 54.8	8.9%

	Year Ended December 31,			
	2007	2006	Change	% Change
		(in millions)		
Gross Margin				
Regulated Electric	$ 347.0	$ 328.9	$ 18.1	5.5%
Regulated Natural Gas	127.6	118.9	8.7	7.3
Unregulated Electric	56.2	66.4	(10.2)	(15.4)
Other	2.5	6.5	(4.0)	(61.5)
Eliminations	(1.6)	(1.6)	—	—
	$ 531.7	$ 519.1	$ 12.6	2.4%

Consolidated gross margin in 2007 was $531.7 million, an increase of $12.6 million, or 2.4%, from gross margin in 2006. Primary components of this change included the following:

	Gross Margin 2007 vs. 2006
	(in millions)
Property tax tracker	$ 11.5
Regulated electric and gas customer growth and favorable weather	9.3
Transmission volumes and rate increase	3.2
Unregulated electric volumes	7.5
Unregulated electric pricing and fuel supply costs	(17.7)
Other	(1.2)
Improvement in Gross Margin	**$ 12.6**

A substantial portion of the increase in 2007 regulated margins relates to a change in presentation of property taxes collected through our Montana property tax tracker. In 2007, margins in our regulated electric and natural gas segments increased by $11.5 million related to collections through our Montana property tax tracker. In 2006, we netted comparative property tax tracker collections of $7.8 million against property and other taxes. Additional increases in our regulated margin primarily related to customer growth and favorable weather. In addition, we had higher transmission revenues due to our interim rate increase and increased transmission of energy acquired by others across our system. Offsetting these increases were decreases in unregulated electric margin due to lower average contracted prices and higher fuel supply costs, partially offset by an increase in volumes resulting from higher demand and plant availability.

	Year Ended December 31,			
	2007	2006	Change	% Change
	(in millions)			
Operating Expenses (excluding cost of sales)				
Operating, general and administrative	$ 221.6	$ 240.2	$ (18.6)	(7.7)%
Property and other taxes	87.6	74.2	13.4	18.1
Depreciation	82.4	75.3	7.1	9.4
Ammondson verdict	—	19.0	(19.0)	(100.0)
	$ 391.6	$ 408.7	$ (17.1)	(4.2)%

Consolidated operating, general and administrative expenses were $221.6 million in 2007 as compared to $240.2 million in 2006. Primary components of this change included the following:

	Operating, General, & Administrative Expenses 2007 vs. 2006
	(in millions)
Environmental clean-up cost recovery	$ (12.6)
BBI transaction costs	(12.3)
Operating lease expense	(11.1)
Legal and professional fees	(4.8)
Postretirement medical benefits	(1.5)
Bad debt expense	(1.2)
2006 insurance settlement	9.3
Stock-based compensation and short-term incentive	5.7
Insurance reserves	5.5
Labor	5.3
Other	(0.9)
Reduction in Operating, General & Administrative Expenses	**$ (18.6)**

The reduction in operating, general and administrative expenses reflected above of $18.6 million was primarily due to the following:

- Various MGP environmental issues settled in our South Dakota natural gas rate case resulting in recovery of clean-up costs (see "Critical Accounting Policies and Estimates - Regulatory Assets and Liabilities");
- Lower transaction related costs due to the termination of the proposed merger agreement with BBI during 2007;
- Decreased operating lease expense due to the purchase of our previously leased interest in Colstrip Unit 4 during 2007;
- Decreased legal and professional fees primarily related to outstanding litigation;
- Lower claims for postretirement medical benefits; and
- Improvement in collections of customer balances.

Offsets to these reductions included the following:

- The inclusion in 2006 results of a reduction in expenses due to an insurance settlement received;
- Increases in stock-based compensation due to equity awards granted during 2006, and higher short-term incentive primarily due to better company financial performance in 2007;

- Increases in insurance reserves related to workers compensation claims; and
- Increased labor costs due to a combination of compensation increases and less time spent by employees on capital projects. During 2007, employees spent a greater portion of their time on maintenance projects (which are expensed) and we utilized more contract labor for capital projects.

Property and other taxes were $87.6 million in 2007 as compared to $74.2 million in 2006. Property and other taxes in 2006 were net of $7.8 million that we collected through our Montana property tax tracker, as discussed in the gross margin analysis above. In addition, property and other taxes increased by approximately $5.6 million during 2007.

Depreciation expense was $82.4 million in 2007 as compared with $75.3 million in 2006. This $7.1 million increase was primarily due to increased property in service and a $2.0 million increase due to our purchase of our previously leased interest in Colstrip Unit 4.

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 in a case called Ammondson, et al. v. NorthWestern Corporation, et al. 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.

Consolidated operating income in 2007 was $140.1 million, as compared with $110.4 million in 2006. This $29.7 million increase was primarily due to the $12.6 million increase in gross margin and lower operating expenses as discussed above.

Consolidated interest expense in 2007 was $56.9 million, an increase of $0.9 million, or 1.6%, from 2006. See "Liquidity and Capital Resources" for additional information regarding our refinancing activities.

Consolidated other income in 2007 was $2.4 million, a decrease of $6.7 million from 2006. This decrease was primarily due to the inclusion in 2006 results of gains of $3.9 million related to an interest rate swap and $2.3 million on the sale of a partnership interest in oil and gas properties.

Consolidated income tax expense in 2007 was $32.4 million as compared with $25.9 million in 2006. Our effective tax rate for 2007 was 37.8% as compared to 40.9% for 2006. Portions of our BBI transaction related costs were considered non-deductible for taxes in 2006; however, with the termination of the agreement these costs became deductible, resulting in a reduction to our tax expense of approximately $1.2 million in 2007.

Consolidated net income in 2007 was $53.2 million compared with $37.9 million for the same period in 2006. This increase was primarily due to higher operating income as discussed above, partially offset by lower other income and increased income tax expense.

REGULATED ELECTRIC MARGIN

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)		
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%**
% GM/Rev	**47.0%**	**47.1%**		

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 this summer 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, as discussed above in the property and other tax analysis.

The following summarizes regulated electric volumes, customer counts and cooling degree-days for the years ended December 31, 2008 and 2007:

	Volumes MWH			
	2008	2007	Change	% Change
		(in thousands)		
Retail Electric				
Montana	2,285	2,235	50	2.2%
South Dakota	513	505	8	1.6
Residential	**2,798**	**2,740**	**58**	**2.1**
Montana	3,190	3,213	(23)	(0.7)
South Dakota	872	827	45	5.4
Commercial	**4,062**	**4,040**	**22**	**0.5**
Industrial	3,122	2,992	130	4.3
Other	182	181	1	0.6
Total Retail Electric	**10,164**	**9,953**	**211**	**2.1%**
Wholesale Electric	**265**	**155**	**110**	**71.0%**

Average Customer Counts	2008	2007	Change	% Change
Retail Electric				
Montana	266,100	262,481	3,619	1.4%
South Dakota	47,967	47,713	254	0.5
Residential	**314,067**	**310,194**	**3,873**	**1.2**
Montana	59,595	58,319	1,276	2.2
South Dakota	11,492	11,336	156	1.4
Commercial	**71,087**	**69,655**	**1,432**	**2.1**
Industrial	71	71	—	—
Other	5,823	5,802	21	0.4
Total Retail Electric	**391,048**	**385,722**	**5,326**	**1.4 %**

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

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.

We estimate our regulated wholesale volumes will decrease by approximately 100 MWHs and margin will decrease by approximately $2.4 million in 2009 due to planned maintenance.

Year Ended December 31, 2007 Compared with Year Ended December 31, 2006

The following summarizes the regulated electric revenue, cost of sales, and gross margin for the years ended December 31, 2007 and 2006:

	Results							
	2007		2006		Change		% Change
			(in millions)				
Total Revenues	$	**736.7**	$	**661.7**	$	**75.0**	**11.3%**
Total Cost of Sales		**389.7**		**332.8**		**56.9**	**17.1%**
Gross Margin	$	**347.0**	$	**328.9**	$	**18.1**	**5.5%**
% GM/Rev		**47.1%**		**49.7%**			

The following summarizes the components of the changes in regulated electric margin for the years ended December 31, 2007 and 2006:

	Gross Margin 2007 vs. 2006	
	(in millions)	
Property tax tracker	$	8.4
Customer growth and warmer weather		6.6
2006 MCC stipulation		4.1
Transmission volumes		1.6
FERC jurisdiction transmission interim rate increase		1.6
Lower QF gain		(2.3)
Wholesale and other		(1.9)
Improvement in Gross Margin	$	18.1

Regulated electric margin increased $18.1 million, or 5.5%, due primarily to amounts collected through our Montana property tax tracker and increased volumes from 1.7% customer growth and warmer summer weather in Montana. In addition, we had higher transmission margin in 2007 primarily from transmitting additional energy acquired by others across our transmission system and an interim increase in our transmission rates. These increases were partially offset by lower QF related gains and a 37.5% decrease in wholesale volumes sold in the secondary markets. We recorded gains (reduced cost of sales) related to our QF liability of $0.9 million in 2007 and $3.2 million in 2006 as actual QF output and variable pricing terms were lower than our estimate. Wholesale margin was lower in 2007 primarily due to decreased plant availability resulting from planned and unplanned maintenance. Our 2006 margin was also $4.1 million lower due to a loss recorded as a result of a stipulation with the MCC.

The following summarizes regulated electric volumes, customer counts and cooling degree-days for the years ended December 31, 2007 and 2006:

	Volumes MWH			
	2007	2006	Change	% Change
	(in thousands)			
Retail Electric				
Montana	2,235	2,184	51	2.3%
South Dakota	505	474	**31**	6.5
Residential	**2,740**	**2,658**	**82**	**3.1**
Montana	3,213	3,125	**88**	2.8
South Dakota	827	776	**51**	6.6
Commercial	**4,040**	**3,901**	**139**	**3.6**
Industrial	2,992	2,998	(6)	(0.2)
Other	181	185	(4)	(2.2)
Total Retail Electric	**9,953**	**9,742**	**211**	**2.2%**
Wholesale Electric	**155**	**248**	**(93)**	**(37.5)%**

Average Customer Counts	2007	2006	Change	% Change
Montana	326,248	320,401	5,847	1.8%
South Dakota	59,474	58,968	506	0.9%
Total	**385,722**	**379,369**	**6,353**	**1.7%**

	2007 as compared with:	
Cooling Degree-Days	2006	Historic Average
Montana	25% warmer	82% warmer
South Dakota	Remained Flat	23% warmer

Total retail electric volumes increased 211 MWHs, or 2.2%, due primarily to customer growth and warmer summer weather in Montana. Wholesale electric volumes decreased 93 MWHs, or 37.5%, primarily due to decreased plant availability resulting from planned and unplanned maintenance.

REGULATED NATURAL GAS MARGIN

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)		
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%**
% GM/Rev	**34.8%**	**35.1%**		

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.

The following summarizes regulated natural gas volumes, customer counts and heating degree-days for the years ended December 31, 2008 and 2007:

	Volumes Dekatherms			
	2008	2007	Change	% Change
		(in thousands)		
Retail Gas				
Montana	13,426	12,101	1,325	10.9%
South Dakota	2,975	2,771	204	7.4
Nebraska	2,717	2,519	198	7.9
Residential	**19,118**	**17,391**	**1,727**	**9.9**
Montana	6,754	6,091	663	10.9
South Dakota	3,104	2,444	660	27.0
Nebraska	2,962	2,655	307	11.6
Commercial	**12,820**	**11,190**	**1,630**	**14.6**
Industrial	207	169	38	22.5
Other	118	144	(26)	(18.1)
Total Retail Gas	**32,263**	**28,894**	**3,369**	**11.7%**

Average Customer Counts	2008	2007	Change	% Change
Retail Gas				
Montana	155,409	152,939	2,470	1.6%
South Dakota	36,620	36,662	(42)	(0.1)
Nebraska	36,466	36,343	123	0.3
Residential	**228,495**	**225,944**	**2,551**	**1.1**
Montana	21,703	21,261	442	2.1
South Dakota	5,780	5,765	15	0.3
Nebraska	4,532	4,523	9	0.2
Commercial	**32,015**	**31,549**	**466**	**1.5**
Industrial	303	311	(8)	(2.6)
Other	140	140	—	—
Total Retail Gas	**260,953**	**257,944**	**3,009**	**1.2%**

	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

Total retail natural gas volumes increased primarily due to colder winter weather and 1.2% customer growth. 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.

Year Ended December 31, 2007 Compared with Year Ended December 31, 2006

The following summarizes the regulated natural gas revenue, cost of sales, and gross margin for the years ended December 31, 2007 and 2006:

	Results			
	2007	2006	Change	% Change
		(in millions)		
Total Revenues	**$ 363.6**	**$ 359.7**	**$ 3.9**	**1.1%**
Total Cost of Sales	**236.0**	**240.8**	**(4.8)**	**(2.0)%**
Gross Margin	**$ 127.6**	**$ 118.9**	**$ 8.7**	**7.3%**
% GM/Rev	**35.1%**	**33.1%**		

The following summarizes the components of the changes in regulated natural gas margin for the years ended December 31, 2007 and 2006:

	Gross Margin 2007 vs. 2006
	(in millions)
Property tax tracker	$ 3.1
Customer growth and colder weather	2.7
Transfer of previously unregulated customers	1.7
Storage	0.9
Other	0.3
Improvement in Gross Margin	**$ 8.7**

Regulated natural gas margin increased $8.7 million, or 7.3%, primarily due to amounts collected through our Montana property tax tracker and increased volumes due to 1.8% customer growth and colder winter weather in South Dakota and Nebraska. In addition, regulated natural gas margin increased $1.7 million due to the transfer of certain previously unregulated customers and pipelines into the regulated business, and $0.9 million from higher storage utilization.

The following summarizes regulated natural gas volumes, customer counts and heating degree-days for the years ended December 31, 2007 and 2006:

	Volumes Dekatherms			
	2007	2006	Change	% Change
	(in thousands)			
Retail Gas				
Montana	12,101	12,036	65	0.5%
South Dakota	2,771	2,596	175	6.7
Nebraska	2,519	2,371	148	6.2
Residential	**17,391**	**17,003**	**388**	**2.3**
Montana	6,091	6,025	66	1.1
South Dakota	2,444	2,189	255	11.6
Nebraska	2,655	2,546	109	4.3
Commercial	**11,190**	**10,760**	**430**	**4.0**
Industrial	169	177	(8)	(4.5)
Other	144	153	(9)	(5.9)
Total Retail Gas	**28,894**	**28,093**	**801**	**2.9%**

Average Customer Counts	2007	2006	Change	% Change
Montana	174,651	170,873	3,778	2.2%
South Dakota	42,427	41,842	585	1.4
Nebraska	40,866	40,781	85	0.2
Total	**257,944**	**253,496**	**4,448**	**1.8%**

	2007 as compared with:	
Heating Degree-Days	2006	Historic Average
Montana	1% warmer	8% warmer
South Dakota	8% colder	6% warmer
Nebraska	7% colder	8% warmer

Total retail natural gas volumes increased 801 dekatherms, or 2.9%, primarily due to customer growth and colder winter weather in South Dakota and Nebraska.

UNREGULATED ELECTRIC MARGIN

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

Our unregulated electric segment primarily consists of our 30% joint ownership interest in the Colstrip Unit 4 generation facility, which represents approximately 222 MWs at full load. We sell our Colstrip Unit 4 output principally to two unrelated third parties under agreements through December 2010. Under a separate agreement, we repurchase 111 MWs through December 2010. These 111 MWs were available for market sales to other third parties through June 2007. Beginning July 1, 2007, 90 MWs of base-load energy from Colstrip Unit 4 was being supplied to the Montana electric supply load (included in our regulated electric segment) for a term of 11.5 years at an average nominal price of $35.80 per MWH. In addition, 21 MWs of base-load energy from Colstrip Unit 4 was being provided to the Montana electric supply load for a term of 76 months beginning in March 2008 at $19 per MWH below the Mid-C Index price with a floor of zero.

As discussed above in the "Overview" to the MD&A, in November 2008, the MPSC approved placing this asset into our Montana utility rate base. Effective January 1, 2009, we will no longer present an unregulated electric segment and the results of operations of our interest in Colstrip Unit 4 will be reflected in the regulated electric segment as a component of electric supply. We will continue to serve the third party contract obligations through their expiration, and the buyback quantity plus any MWs not under contract will be used to serve Montana regulated base-load. The generation related costs and return on rate base of Colstrip Unit 4 will be included in our annual electric supply tracking filing for inclusion in customer rates.

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 the 90 and 21 MW contracts described above 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.

Year Ended December 31, 2007 Compared with Year Ended December 31, 2006

The following summarizes the components of the changes in unregulated electric revenue, cost of sales, and gross margin for the years ended December 31, 2007 and 2006:

	Results			
	2007	2006	Change	% Change
		(in millions)		
Total Revenues	**$ 74.2**	**$ 83.0**	**$ (8.8)**	**(10.6)%**
Total Cost of Sales	**18.0**	**16.6**	**1.4**	**8.4%**
Gross Margin	**$ 56.2**	**$ 66.4**	**$ (10.2)**	**(15.4)%**
% GM/Rev	**75.7%**	**80.0%**		

The following summarizes the components of the changes in unregulated electric margin for the years ended December 31, 2007 and 2006:

	Gross Margin 2007 vs. 2006
	(in millions)
Volumes	$ 7.5
Average prices	(15.1)
Fuel supply costs	(2.6)
Decline in Gross Margin	**$ (10.2)**

Unregulated electric margin decreased $10.2 million, or 15.4%, due primarily to lower average contracted prices associated with the 90 MW contract discussed above and higher fuel supply costs, partially offset by an increase in volumes resulting from higher demand and plant availability.

The following summarizes unregulated electric volumes for the years ended December 31, 2007 and 2006:

	Volumes MWH			
	2007	2006	Change	% Change
		(in thousands)		
Wholesale Electric	**1,638**	**1,504**	**134**	**8.9%**

Unregulated electric volumes increased 134 MWHs, or 8.9%. During the second quarter of 2006 strong hydro generation in the Pacific Northwest provided increased supply in the wholesale electricity market, resulting in reduced demand for our Colstrip power. In addition, we had less energy available to sell in 2006 due to decreased plant availability resulting from planned and unplanned outages for plant maintenance.

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.

As a result of the recent volatile conditions in the credit and capital markets, general liquidity in short-term capital markets has been constrained. We have maintained access to short-term liquidity through our $200 million unsecured revolving credit facility. As of December 31, 2008, our total net liquidity was approximately $86.2 million, including $11.3 million of cash and $74.9 million of revolving credit facility availability. A total of nine banks participate in our revolving credit facility, with no one bank providing more than 13% of the total availability. As of December 31, 2008, 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%. The revolving credit facility also contains default and related acceleration provisions related to default on other debt. At December 31, 2008, we were in compliance with the ratio. As of February 6, 2009, our availability under our revolving credit facility was approximately $109 million.

We have taken steps to maintain sufficient liquidity for the near term, and are focused on maintaining liquidity in 2009 and beyond should the current period of economic uncertainty become extended. During the first quarter of 2009, we currently anticipate making contributions in excess of $40 million to our qualified pension plans. We have re-prioritized capital projects as described below, and have deferred some of these projects beyond 2009.

Current debt financing plans for 2009 include issuing up to $350 million of long-term senior debt securities to refinance our CLH loan maturing in December 2009, finance a portion of the proposed Mill Creek Generation project, fund utility capital expenditures and to provide funds for general corporate purposes. We have a filed a request with the MPSC to approve the issuance of such long-term debt securities. In addition, we plan to enter into a new revolving credit facility with availability between $200 and $250 million to replace our existing revolving credit facility maturing in November 2009.

Credit Ratings

Fitch Investors Service (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, 2009, our ratings with these agencies are as follows:

	Senior Secured Rating	Senior Unsecured Rating	Outlook
Fitch (1)	BBB+	BBB	Stable
Moody's (2)	Baa2	Baa3	Positive
S&P (3)	A- (MT) BBB+ (SD)	BBB	Stable

(1) Fitch upgraded our senior secured and senior unsecured credit ratings on January 9, 2009 from BBB and BBB-, respectively, as reflected above.
(2) Moody's upgraded our senior secured and senior unsecured credit ratings on July 9, 2008 from Baa3 and Ba2, respectively, as reflected above.
(3) S&P upgraded our senior secured and senior unsecured credit ratings in March 2008 from BBB and BB-, respectively. In addition, as a result of a change in S&P's utility ratings structure, our senior unsecured credit rating was further upgraded from BBB- to BBB on November 5, 2008.

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 cost of capital expenditures (excluding strategic growth opportunities discussed below) for the next five years is as follows (in thousands):

Year		Amount
2009	$	109,000
2010		119,000
2011		115,000
2012		132,000
2013		131,000

The continual increase in projected capital expenditures reflects our need to address aging infrastructure to maintain reliability, as well as new capacity constraints which are dependent upon load growth projections.

Our strategic growth capital falls within the categories of transmission and generation. 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 $250 million of which we assume a 30% ownership and an estimated completion date in 2012. We estimate capital expenditures related to this project will be approximately $4 million in 2009. The MSTI project has an estimated cost of $1 billion with an anticipated completion date in 2014. We estimate capital expenditures related to this project will be approximately $10 to 15 million in 2009. 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 do not anticipate significant capital expenditures related to this project until the siting and permitting process commences 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.

We have filed a request with the MPSC for advanced approval of a $206 million, 150 MW natural gas fired regulating facility in Montana. If the MPSC approves the project, we estimate capital spending for this project will be between $80 and 100 million in 2009. Based on our ability to extend a capacity agreement and in light of the current economic and credit environment, we have reduced planned strategic growth capital expenditures by approximately $20 million in 2009 by deferring planned peaking generation projects in South Dakota.

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, 2008. See additional discussion in Note 20 to the Consolidated Financial Statements.

	Total	2009	2010	2011	2012	2013	Thereafter
				(in thousands)			
Long-term Debt	$ 862,056	$ 228,045	$ 23,605	$ 6,578	$ 3,792	$ —	$ 600,036
Capital Leases	37,991	1,193	1,253	1,265	1,363	1,468	31,449
Future minimum operating lease payments	4,231	1,551	1,141	723	500	65	251
Estimated Pension and Other Postretirement Obligations (1)	178,450	49,900	41,450	29,600	27,900	29,600	N/A
Qualifying Facilities (2)	1,459,182	61,586	63,589	65,323	67,111	69,816	1,131,757
Supply and Capacity Contracts (3)	1,763,424	498,009	341,495	157,742	146,212	132,519	487,447
Contractual interest payments on debt (4)	317,739	45,801	36,203	34,052	33,639	33,521	134,523
Total Commitments (5)	$4,623,070	$ 886,085	$ 508,736	$ 295,283	$ 280,517	$ 266,989	$ 2,385,463

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. The 2009 funding amount reflects our current estimated funding requirements based on plan asset market losses during 2008, and reflects certain provisions of the Worker, Retiree, and Employer Recovery Act of 2008, which was signed into law in December 2008. This bill granted plan sponsors relief from funding requirements and benefits restrictions by allowing smoothing of asset returns and decreasing funding targets.
2) The QFs require us to purchase minimum amounts of energy at prices ranging from $65 to $138 per MWH through 2032. Our estimated gross contractual obligation related to the QFs is approximately $1.5 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) Contractual interest payments include an assumed average interest rate of 1.15% on an estimated revolving line of credit balance of $108.0 million through maturity in November 2009, and an assumed average interest rate of 3.17% on the $100 million floating rate CLH loan through maturity in December 2009.
5) 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

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 revolving credit facility, 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, which do not impact net income, can have a significant effect on cash flow from operations and make year-to-year comparisons difficult.

As of December 31, 2008, we are under collected on our current Montana natural gas and electric trackers by approximately $10.5 million, as compared with an over collection of $4.0 million as of December 31, 2007, and an undercollection of approximately $16.9 million as of December 31, 2006.

The following table summarizes our consolidated cash flows for 2008, 2007 and 2006.

	Year Ended December 31,		
	2008	**2007**	**2006**
Continuing Operating Activities			
Net income	$ 67.6	$ 53.2	$ 37.9
Non-cash adjustments to net income	132.3	113.1	99.8
Proceeds from hedging activities	—	—	14.5
Changes in working capital	(7.8)	26.9	13.2
Other	6.2	8.8	(0.3)
	198.3	**202.0**	**165.1**
Continuing Investing Activities			
Property, plant and equipment additions	(124.6)	(117.1)	(101.0)
Colstrip Unit 4 acquisition	—	(141.3)	—
Sale of assets	0.2	1.9	24.2
Proceeds from hedging activities	—	—	5.3
	(124.4)	**(256.5)**	**(71.5)**
Continuing Financing Activities			
Net borrowing (repayment) of debt	54.6	46.5	(37.5)
Dividends on common stock	(49.8)	(47.3)	(44.1)
Treasury stock activity	(78.7)	(0.9)	(4.3)
Deferred gas storage	—	—	(11.7)
Proceeds from exercise of warrants	—	68.8	2.9
Other	(1.5)	(1.7)	(7.3)
	(75.4)	**65.4**	**(102.0)**
Discontinued Operations	—	—	**7.6**
Net (Decrease) Increase in Cash and Cash Equivalents	**$ (1.5)**	**$ 10.9**	**$ (0.8)**
Cash and Cash Equivalents, beginning of period	$ 12.8	$ 1.9	$ 2.7
Cash and Cash Equivalents, end of period	**$ 11.3**	**$ 12.8**	**$ 1.9**

Cash Flows Provided By Continuing Operating Activities

As of December 31, 2008, our cash and cash equivalents were $11.3 million as compared with $12.8 at December 31, 2007. 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.

During 2008, the unfunded status of our pension and postretirement benefit plans increased significantly, primarily due to market losses on plan assets. We have increased our funding projections for 2009 and subsequent years, which will impact our cash flow from operations. We anticipate making contributions of approximately $49.9 million to our pension and postretirement benefit plans in 2009.

Our cash flows provided by operating activities increased by approximately $36.9 million in 2007 as compared with 2006, which was primarily due to an overcollection in our electric tracker, which is discussed above in the "Factors Impacting our Liquidity" section, decreased purchases of storage gas, and higher net income. These increases were partially offset by the timing of the semi-annual Colstrip Unit 4 lease payment, and proceeds received from hedging activities during 2006.

Cash Flows Used In Continuing Investing Activities

Cash used in investing activities totaled $124.4 million during the year ended December 31, 2008, as compared with $256.5 million during the year ended December 31, 2007, and $71.5 million in 2006. During 2008, we invested $124.6 million in property, plant and equipment additions. 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.

During 2006, we received approximately $24.2 million from the sale of assets and $5.3 million from the settlement of hedging activities, offset by cash used of approximately $101.0 million for property, plant and equipment additions.

Cash Flows (Used In) Provided By Continuing Financing Activities

Cash used in financing activities totaled $75.4 million during 2008, as compared with cash provided by financing activities of $65.4 million during 2007, and cash used of $102.0 million in 2006. 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, our subsidiary, Colstrip Lease Holdings LLC, closed on a $100 million loan to finance the purchase of an interest in Colstrip Unit 4. In addition, we received proceeds during 2007 of $68.8 million from the exercise of warrants. We also made debt repayments of $53.5 million and paid dividends on common stock of $47.3 million.

In 2006, cash used by financing activities was approximately $102.0 million, which included debt repayments of $37.5 million, dividends on common stock of $44.1 million, and $11.7 million of payments for deferred storage transactions. Cash used to repurchase shares during 2006 was approximately $4.3 million. In addition, in association with our debt refinancings during 2006, we incurred financing costs of $7.2 million.

Discontinued Operations Cash Flows

The decrease in restricted cash held by discontinued operations during 2006 was primarily due to Netexit's $7.7 million distribution to us, along with payment of other allowed claims pursuant to its liquidating plan of reorganization in 2005.

Financing Transactions

During the second quarter of 2008, we issued $55.0 million of South Dakota mortgage bonds at a fixed interest rate of 6.05%, and used the proceeds to redeem our 7.0%, $55 million South Dakota mortgage bonds due in 2023. Consistent with our historical regulatory treatment, the remaining deferred financing costs of approximately $1.1 million were recorded as a regulatory asset and will be amortized over the life of the debt. The new mortgage bonds will mature May 1, 2018, and are secured by our South Dakota electric and natural gas assets. This transaction will reduce our annual interest expense by approximately $0.5 million.

Restrictive Debt Covenants

Our debt and credit agreements contain various financial and other covenants. Covenants associated with our CLH loan, along with an existing temporary waiver with respect to such loan, require that we seek FERC approval to legally move the assets of the owner participant trust from NorthWestern Corporation to Colstrip Lease Holdings, LLC, by January 30, 2009. In addition, other covenants with respect to our CLH loan limit our unfunded benefit obligation to $100 million for our Montana pension plan and to $15 million for our South Dakota pension plan. Our unfunded obligation as of December 31, 2008, for each of these plans exceeded these limits, which triggered a technical default of the loan. In January 2009, we requested and received a waiver of both of these requirements. As of December 31, 2008, we were in compliance with all other financial debt covenants.

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 accounting principles generally accepted in the United States of America. 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 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 on our balance sheet and our operating results. Management's assumptions about future sales 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.

Statement of Financial Accounting Standards (SFAS) No. 142, *Goodwill and Other Intangible Assets*, was issued during 2001 and is effective for all fiscal years beginning after December 15, 2001. According to the guidance set forth in SFAS No. 142, we are required to evaluate our goodwill for impairment at least annually (October 1) and more frequently when indications of impairment exist. 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 whenever indicators of impairment exist. SFAS No. 144, *Accounting for the Impairment or the Disposal of Long-Lived Assets*, requires that 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.

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 $138 per MWH through 2029. As of December 31, 2008, our estimated gross contractual obligation related to the QFs is approximately $1.5 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. If the order is upheld in its current form, we could reduce our QF liability by a range of $25 million to $50 million based on our current estimated changes to the assumptions. 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.

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.

Regulatory Assets and Liabilities

Our regulated operations are subject to the provisions of SFAS No. 71, *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. If any part of our operations become no longer subject to the provisions of SFAS No. 71, then we would need to evaluate the probable future recovery of or reduction in revenue with respect to the related regulatory assets and liabilities. 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. For example, we had recorded liabilities in previous years for remediation obligations related to several formerly operated manufactured gas plants (MGP) in South Dakota. In December 2007, the SDPUC approved our settlement with SDPUC Staff related to our natural gas rate case, which included a provision allowing us to include approximately $1.4 million annually in rates to recover MGP environmental clean-up costs. This was partially offset by a requirement to return approximately $2.3 million ($0.8 million annually) of previous insurance recoveries to customers. The SDPUC's approval of our settlement provides reasonable assurance that we will recover future South Dakota related MGP costs, therefore we recorded net regulatory assets (with a corresponding reduction to operating, general and administrative expenses) of $12.6 million in December 2007 to offset the previously recorded South Dakota MGP related liabilities.

Pension and Postretirement Benefit Plans

We sponsor defined benefit pension plans, which cover substantially all employees, and provide postretirement health care and life insurance benefits for certain of our employees. Our reported costs of providing pension and other postretirement benefits, as described in Note 15 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 2008 we maintained our discount rate at 6.25% for our pension plans.

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 December 31, 2008 accumulated postretirement benefit obligation was a 10% increase in health care costs in 2008, which will 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.

The expected long-term rate of return assumption on plan assets was determined based on the historical returns and the future expectations for returns for each asset class, as well as the target asset allocation of the pension and postretirement portfolios. We target an asset allocation of roughly 70% equity securities, and 30% fixed-income securities. Considering this information and future expectations for asset returns, we maintained our expected long-term rate of return on assets assumption at 8.00%. 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% - 3.60% for nonunion employees in 2008.

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%	$ (1,188)	$ (12,426)
	(0.25)	890	11,364
Rate of return on plan assets	0.25	(850)	N/A
	(0.25)	850	N/A

Accounting Treatment

In accordance with SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*, and SFAS No. 87, *Employers' Accounting for Pensions*, we utilize a number of accounting mechanisms that are intended to 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. SFAS No. 158 also requires that a plan's funded status be recognized as an asset or liability.

As our regulated operations are subject to the provisions of SFAS No. 71, 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

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, 2008, we have approximately $350 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.

We adopted Financial Accounting Standards Board (FASB) Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48) on January 1, 2007. FIN 48 is an interpretation of FASB Statement No. 109, *Accounting for Income Taxes*, and it seeks to reduce the diversity in practice associated with certain aspects of measurement and recognition in accounting for income taxes by prescribing a recognition threshold and measurement process for recording in the financial statements uncertain tax positions taken or expected to be taken in a tax return. Additionally, FIN 48 provides guidance on derecognition, classification, accounting in interim periods and expanded disclosure with respect to the uncertainty in income taxes. FIN 48 provides that a tax position that meets the more-likely-than-not threshold shall initially and subsequently be measured 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 $115.1 million as of December 31, 2008. 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 and the CLH $100 million loan. 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, which was 1.21%, or 0.75% over LIBOR as of December 31, 2008. The CLH loan bears interest at approximately 3.17%, which is 1.25% over LIBOR as of December 31, 2008. Based upon amounts outstanding as of December 31, 2008, a 1% increase in the LIBOR would increase our annual interest expense by approximately $2.1 million.

Commodity Price Risk

Commodity price risk is one of our most significant risks 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 supply portfolio 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.

In our "other" segment, we currently have a capacity contract through 2013 with a pipeline that gives us basis risk depending on gas prices at two different delivery points. We have a sales contract with a customer that provides for a selling price based on the index price of gas coming from a delivery point in Ventura, Iowa. The pipeline capacity contract allows us to take delivery of gas from Canada, which has historically been cheaper than gas coming from Ventura, even when including transportation costs. If the Canadian gas plus transportation cost exceeds the index price at Ventura, then we will lose money on these gas sales. The annual capacity payments are approximately $1.8 million, which represents our maximum annual exposure related to this basis risk.

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-42 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, 2008, 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, 2008 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, 2008. 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, 2008, 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 2009 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 2009 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 2009 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 2009 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 2009 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:

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(a)	Amended and Restated By-Laws of NorthWestern Corporation, dated November 1, 2004 (incorporated by reference to Exhibit 3.2 of NorthWestern Corporation's Current Report on Form 8-K, dated October 20, 2004, Commission File No. 1-10499).
3.2(b)	Amended and Restated By-Laws of NorthWestern Corporation, dated May 3, 2006 (incorporated by reference to Exhibit 3.1 of NorthWestern Corporation's Current Report on Form 8-K, dated March 17, 2006, Commission File No. 1-10499).
3.2(c)	Amended and Restated By-Laws of NorthWestern Corporation, dated May 3, 2006 (incorporated by reference to Exhibit 3.1 of NorthWestern Corporation's Current Report on Form 8-K, dated May 3, 2006, Commission File No. 1-10499).
3.2(d)	Amended and Restated By-Laws of NorthWestern Corporation, dated May 3, 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)	Registration Rights Agreement, dated as of November 1, 2004, between NorthWestern Corporation, as issuer, and Credit Suisse First Boston LLC and Lehman Brothers Inc., as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.3 of NorthWestern Corporation's Current Report on Form 8-K, dated November 1, 2004, Commission File No. 1-10499).

Exhibit Number	Description of Document
4.3(a)	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).
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).
4.5(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

Exhibit Number	Description of Document
	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).
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 Incentive Compensation and Severance Plan, effective through November 1, 2004 (incorporated by reference to Exhibit 10.1(d) to NorthWestern Corporation's Annual Report on Form 10-K for the year ended December 31, 2004, Commission File No. 1-10499).
10.1(c) †	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(d) †	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(e) †	Consulting agreement with Michael J. Hanson, executed August 21, 2008 (incorporated by reference to Exhibit 10.2 to NorthWestern Corporation's Current Report on Form 8-K, dated August 21, 2008, Commission File No. 1-10499).
10.1(f) †	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(g) †	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(h) †	Consulting agreement with Thomas J. Knapp, executed September 5, 2008 (incorporated by reference to Exhibit 10.2 of NorthWestern Corporation's Quarterly Report on Form 10-Q, dated October 30, 2008, Commission File No. 1-10499).
10.1(i) †	Consulting agreement with Gregory G.A. Trandem, executed January 29, 2009 (incorporated by reference to Exhibit 10.2 of NorthWestern Corporation's Current Report on Form 8-K, dated January 29, 2009, Commission File No. 1-10499).
10.1(j) †*	NorthWestern Energy 2008 Employee Incentive Plan.
10.1(k) †*	Offer letter by and between NorthWestern Corporation and Miggie E. Cramblit, executed May _, 2008.
10.2(a)	Credit Agreement, dated as of June 30, 2005, among NorthWestern Corporation, as borrower, the several lenders from time to time parties thereto, Deutsche Bank Securities Inc. and Lehman Brothers Inc., as joint lead arrangers, Lehman Commercial Paper Inc., as syndication agent, Union Bank of California, N.A. and KeyBank National Association, as co-documentation agents, and Deutsche Bank AG New York Branch, as administrative agent and collateral agent (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated June 28, 2005, Commission file No. 1-10499).
10.2(b)	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(c)	Registration Rights Agreement, dated September 13, 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(d)	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(e)	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(f)	Credit Agreement, dated December 28, 2007, among Colstrip Lease Holdings, LLC, as borrower, and West LB AG, New York Branch, as lender (incorporated by reference to Exhibit 10.2 (g) of

Exhibit Number	Description of Document
	NorthWestern Corporation's Annual Report on Form 10-K, for the year ended December 31, 2007, Commission File No. 1-10499).
10.2(g)	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).
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 13, 2009

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, Miggie E. Cramblit, 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 13, 2009
/s/ ROBERT C. ROWE Robert C. Rowe	President, Chief Executive Officer and Director (Principal Executive Officer)	February 13, 2009
/s/ BRIAN B. BIRD Brian B. Bird	Vice President, Chief Financial Officer (Principal Financial Officer)	February 13, 2009
/s/ KENDALL G. KLIEWER Kendall G. Kliewer	Vice President and Controller (Principal Accounting Officer)	February 13, 2009
/s/ STEPHEN P. ADIK Stephen P. Adik	Director	February 13, 2009
Dana J. Dykhouse	Director	
/s/ JON S. FOSSEL Jon S. Fossel	Director	February 13, 2009
/s/ JULIA L. JOHNSON Julia L. Johnson	Director	February 13, 2009
/s/ / PHILIP L. MASLOWE Philip L. Maslowe	Director	February 13, 2009
/s/ D. LOUIS PEOPLES D. Louis Peoples	Director	February 13, 2009

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, 2008 and 2007, and the related consolidated statements of income, common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2008. 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, 2008 and 2007, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, 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.

As discussed in Note 12 to the consolidated financial statements, the Company adopted a new accounting standard in 2007.

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, 2008, 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, 2009, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 12, 2009

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, 2008, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for 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 Controls 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 accounting principles generally accepted in the United States of America ("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, 2008, 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, 2008, of the Company, and our report dated February 12, 2009, expressed an unqualified opinion on those consolidated financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 12, 2009

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

(in thousands, except per share amounts)

	Year Ended December 31,		
	2008	2007	2006
OPERATING REVENUES	$ 1,260,793	$ 1,200,060	$ 1,132,653
OPERATING EXPENSES			
Cost of sales	698,740	668,405	613,582
Operating, general and administrative	226,164	221,566	240,215
Property and other taxes	80,602	87,581	74,187
Depreciation	85,071	82,415	75,305
Ammondson verdict	—	—	19,000
TOTAL OPERATING EXPENSES	1,090,577	1,059,967	1,022,289
OPERATING INCOME	170,216	140,093	110,364
Interest Expense	(63,952)	(56,942)	(56,016)
Other Income	1,558	2,428	9,065
Income From Continuing Operations Before Income Taxes	107,822	85,579	63,413
Income Tax Expense	(40,221)	(32,388)	(25,931)
Income From Continuing Operations	67,601	53,191	37,482
Discontinued Operations, Net of Taxes	—	—	418
Net Income	$ 67,601	$ 53,191	$ 37,900
Average Common Shares Outstanding	37,976	36,623	35,554
Basic Income per Average Common Share			
Continuing Operations	$ 1.78	$ 1.45	$ 1.06
Discontinued Operations	—	—	0.01
Basic	$ 1.78	$ 1.45	$ 1.07
Diluted Income per Average Common Share			
Continuing Operations	$ 1.77	$ 1.44	$ 1.00
Discontinued Operations	—	—	0.01
Diluted	$ 1.77	$ 1.44	$ 1.01
Dividends Declared per Average Common Share	$ 1.32	$ 1.28	$ 1.24

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2008	2007	2006
OPERATING ACTIVITIES:			
Net Income	$ 67,601	$ 53,191	$ 37,900
Items not affecting cash:			
Depreciation	85,071	82,415	75,305
Amortization of debt issue costs, discount and deferred hedge gain	2,444	1,617	2,239
Amortization of restricted stock	3,088	7,116	3,473
Equity portion of allowance for funds used during construction	(641)	(508)	(624)
Income on discontinued operations, net of taxes	—	—	(418)
Gain on rate case settlement	—	(12,636)	—
(Gain) Loss on sale of assets	(214)	85	(2,630)
Gain on derivative instruments	—	—	(4,304)
Deferred income taxes	42,587	34,994	26,711
Proceeds from hedging activities	—	—	14,547
Changes in current assets and liabilities:			
Restricted cash	(245)	1,354	(598)
Accounts receivable	(12,150)	6,311	10,196
Inventories	(7,155)	(3,096)	(19,618)
Prepaid energy supply costs	432	(772)	(640)
Other current assets	(1,768)	1,693	(2,343)
Accounts payable	3,218	12,123	(20,485)
Accrued expenses	(9,883)	(13,918)	32,577
Regulatory assets	9,248	1,221	11,847
Regulatory liabilities	10,522	21,929	2,223
Other noncurrent assets	28,348	23,662	16,800
Other noncurrent liabilities	(22,177)	(14,817)	(17,080)
Cash provided by continuing operating activities	198,326	201,964	165,078
INVESTING ACTIVITIES:			
Property, plant, and equipment additions	(124,563)	(117,084)	(101,046)
Colstrip Unit 4 acquisition	—	(141,257)	—
Proceeds from sale of assets	200	1,842	24,169
Proceeds from hedging activities	—	—	5,355
Cash used in continuing investing activities	(124,363)	(256,499)	(71,522)
FINANCING ACTIVITIES:			
Deferred gas storage	—	—	(11,718)
Proceeds from exercise of warrants	—	68,834	2,896
Dividends on common stock	(49,833)	(47,286)	(44,091)
Issuance of long term debt	55,000	100,000	320,205
Repayment of long-term debt	(96,355)	(15,540)	(326,754)
Line of credit borrowings	254,000	623,001	221,000
Line of credit repayments	(158,000)	(661,001)	(252,000)
Treasury stock activity	(78,706)	(896)	(4,312)
Financing costs	(1,550)	(1,734)	(7,238)
Cash (used in) provided by continuing financing activities	(75,444)	65,378	(102,012)
DISCONTINUED OPERATIONS:			
Operating cash flows of discontinued operations, net	—	—	(3,432)
Investing cash flows of discontinued operations, net	—	—	2,872
Financing cash flows of discontinued operations, net	—	—	—
Decrease in restricted cash held by discontinued operations	—	—	8,255
(Decrease) Increase in Cash and Cash Equivalents	(1,481)	10,843	(761)
Cash and Cash Equivalents, beginning of period	12,773	1,930	2,691
Cash and Cash Equivalents, end of period	$ 11,292	$ 12,773	$ 1,930

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED BALANCE SHEETS

(in thousands, except per share amounts)

	Year Ended December 31, 2008	2007
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 11,292	$ 12,773
Restricted cash	14,727	14,482
Accounts receivable, net	155,672	143,482
Inventories	70,741	63,586
Regulatory assets	46,905	27,049
Prepaid energy supply	2,734	3,166
Deferred income taxes	685	2,987
Other	10,661	10,829
Total current assets	**313,417**	**278,354**
Property, Plant, and Equipment, Net	1,839,699	1,770,880
Goodwill	355,128	355,128
Regulatory assets	233,102	123,041
Other noncurrent assets	20,691	19,977
Total assets	**$ 2,762,037**	**$ 2,547,380**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current maturities of capital leases	$ 1,193	$ 2,389
Current maturities of long-term debt	228,045	18,617
Accounts payable	94,685	91,588
Accrued expenses	215,431	168,610
Regulatory liabilities	49,223	40,635
Total current liabilities	**588,577**	**321,839**
Long-term capital leases	36,798	38,002
Long-term debt	634,011	787,360
Deferred income taxes	114,707	74,046
Noncurrent regulatory liabilities	222,969	194,959
Other noncurrent liabilities	401,442	308,150
Total liabilities	**1,998,504**	**1,724,356**
Commitments and Contingencies (Note 20)		
Shareholders' Equity:		
Common stock, par value $0.01; authorized 200,000,000 shares; issued and outstanding 39,461,441 and 35,928,118, respectively; Preferred stock, par value $0.01; authorized 50,000,000 shares; none issued	395	393
Treasury stock at cost	(89,487)	(10,781)
Paid-in capital	805,900	803,061
Retained earnings	34,371	16,603
Accumulated other comprehensive income	12,354	13,748
Total shareholders' equity	**763,533**	**823,024**
Total liabilities and shareholders' equity	**$ 2,762,037**	**$ 2,547,380**

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, 2005	35,794	192	$ 358	$ 720,857	$ (5,573)	$ 16,889	$ 4,964	$ 737,495
Net income			$ —	$ —	$ —	$ 37,900	$ —	$ 37,900
Other comprehensive income:								
Reclassification of net gains on derivative instruments from OCI to net income	—	—	—	—	—	—	(3,443)	(3,443)
Unrealized gain on derivative instruments	—	—	—	—	—	—	12,588	12,588
Total comprehensive income								47,045
Adjustment to initially apply SFAS No. 158, net of taxes of $101	—	—	—	—	—	—	162	162
Treasury stock activity	—	138	—	—	(4,312)	—	—	(4,312)
Issuance of restricted stock	40	—	—	1,350	—	—	—	1,350
Amortization of unearned restricted stock compensation	18	—	—	2,225	—	—	—	2,225
Warrants exercise	116	—	2	2,895	—	—	—	2,897
Dividends on common stock	—	—	—	—	—	(44,091)	—	(44,091)
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)
SFAS No. 158 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)
SFAS No. 158 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

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 656,000 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 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.

(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.

Fresh-Start Reporting

In accordance with Statement of Position 90-7, *Financial Reporting by Entities in Reorganization under the Bankruptcy Code*, or SOP 90-7, certain companies qualify for fresh start reporting in connection with their emergence from bankruptcy. Fresh-start reporting is required if (1) the reorganization value of the emerging entity's assets immediately before the date of confirmation is less than the total of all postpetition liabilities and allowed claims, and (2) holders of existing voting shares immediately before confirmation receive less than 50% of the voting shares of the emerging entity. Upon applying fresh-start reporting, a new reporting entity is deemed to be created and the recorded amounts of assets and liabilities are adjusted to reflect their estimated fair values, which impact the comparability of financial statements. We met these requirements and adopted fresh-start reporting upon our emergence from bankruptcy on November 1, 2004.

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 $3.0 million and $3.2 million at December 31, 2008 and December 31, 2007, respectively. Receivables include unbilled revenues of $79.1 million and $76.0 million at December 31, 2008.and December 31, 2007, respectively.

Inventories

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

	December 31,	
	2008	2007
Materials and supplies	$ 18,907	$ 17,670
Storage gas	51,834	45,916
	$ 70,741	$ 63,586

Regulation of Utility Operations

Our regulated operations are subject to the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulations* (SFAS No. 71). Accounting under SFAS No. 71 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 on the balance sheet 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 all or a separable portion of our operations becomes no longer subject to the provisions of SFAS No. 71, an evaluation of future recovery of the related regulatory assets and liabilities would be necessary. In addition, we would determine any impairment to the carrying costs of deregulated plant and inventory assets.

Derivative Financial Instruments

We are exposed to market risk, including changes in interest rates and the impact of market fluctuations in the price of electricity and natural gas commodities as discussed further in Note 7. To manage these risks, we may use both derivative and non-derivative contracts that may provide for settlement in cash or by delivery of a commodity, including:

- Forward contracts, which commit us to purchase or sell energy commodities in the future,
- Option contracts, which convey the right to buy or sell a commodity at a predetermined price, and
- Swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined contractual (notional) quantity.

SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133), as amended, requires that all derivatives be recognized in the balance sheet, either as assets or liabilities, at fair value, unless they meet the normal purchase and normal sales criteria. 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.

For contracts in which we are hedging 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 applied the normal purchases and normal sales scope exception, as provided by SFAS No. 133 and interpreted by Derivatives Implementation Guidance Issue C15, to certain contracts involving the purchase and sale of gas and electricity at fixed prices in future periods. 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. For certain regulated electric and gas contracts that do not physically deliver, in accordance with EITF 03-11, Reporting Gains and Losses on Derivative Instruments that are Subject to SFAS No. 133 and not "Held for Trading Purposes" as defined in Issue no. 02-3, revenue is reported net versus gross.

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 8.9%, 8.7%, and 8.8%, for Montana for 2008, 2007, and 2006 respectively, and 8.8%, 8.7%, and 8.9% for South Dakota for 2008, 2007, and 2006 respectively. Interest capitalized totaled $0.9 million for the year ended December 31, 2008, $0.8 million for the year ended December 31, 2007 and $1.0 million for the year ended December 31, 2006 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 $6.7 million and $1.8 million as of December 31, 2008 and 2007, 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 $6.9 million for the year ended December 31, 2008 and $14.6 million for the year ended December 31, 2007.

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 3.3%, 3.5%, and 3.4% for 2008, 2007, and 2006, 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,	
	2008	2007
Pension and other employee benefits	$ 139,306	$ 56,521
Future QF obligation, net	162,841	158,132
Environmental	32,051	32,728
Customer advances	49,998	45,194
Other	17,246	15,575
	$ 401,442	$ 308,150

Stock-based Compensation

Under our equity-based incentive plans, we have granted restricted stock awards to all eligible employees and members of the Board. We discuss these awards in further detail in Note 16. We account for these awards using SFAS No. 123R, *Share-Based Payment* (SFAS No. 123R), which requires companies to recognize compensation expense for all equity-based compensation awards issued to employees that are expected to vest. Under SFAS No. 123R, we recognize the fair value of compensation cost ratably or in tranches (depending if the award has cliff or graded vesting) over the period during which an employee is required to provide service in exchange for the award. As forfeitures of restricted stock grants occur, the associated compensation cost recognized to date is reversed.

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 $5.4 million and $5.6 million as of December 31, 2008 and 2007, 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 statement of operations 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 financial statements and the market for these years is presently illiquid. These emission allowances are not subject to regulatory jurisdiction. When excess SO_2 emission allowances are sold, we reflect the gain in other income and cash received is reflected as an investing activity.

Accounting Standards Issued

In December 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS No. 141R), which replaces SFAS No. 141. SFAS 141R establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements, which will enable users to evaluate the nature and financial effects of the business combination. SFAS No. 141R applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008, and interim periods within those fiscal years. SFAS No. 141R will become effective for our fiscal year beginning January 1, 2009; accordingly, any business combinations we engage in after this date will be recorded and disclosed in accordance with this statement. Based on our evaluation of SFAS No. 141R, if any of our unrecognized tax benefits reverse after adoption, they will affect the income tax provision in the period of reversal rather than goodwill. See Note 12, Income Taxes, for further information.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133* (SFAS No. 161). SFAS No. 161 changes the disclosure requirements for derivative instruments and hedging activities, requiring enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133), and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. This statement will become effective for our fiscal year beginning January 1, 2009. We are still evaluating the impact of SFAS No. 161, if any, but do not expect the statement to have a material impact on our consolidated financial statements.

Accounting Standards Adopted

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* (SFAS No. 162). SFAS No. 162 supersedes the existing hierarchy contained in the U.S. auditing standards. The existing hierarchy was carried over to SFAS No. 162 essentially unchanged. The Statement became effective

60 days following the SEC's approval of the Public Company Accounting Oversight Board amendments to the auditing literature. The new hierarchy did not change current accounting practice in any area.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities-including an amendment of FASB Statement No. 115*, which permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value, with unrealized gains and losses related to these financial instruments reported in earnings at each subsequent reporting date. This option would be applied on an instrument by instrument basis. If elected, unrealized gains and losses on the affected financial instruments would be recognized in earnings at each subsequent reporting date. This statement was effective beginning January 1, 2008. We have assessed the provisions of the statement and elected not to apply fair value accounting to our eligible financial instruments. As a result, adoption of this statement had no impact on our financial results.

Supplemental Cash Flow Information

	Year Ended December 31,		
	2008	2007	2006
Cash paid for			
Income taxes	$ 111	$ 3,921	$ 252
Interest	47,992	43,076	39,267
Significant non-cash transactions:			
Assumption of debt related to Colstrip Unit 4 Acquisitions	—	53,685	—
Additions to property, plant and equipment and capital lease obligations	—	2,400	40,210

(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,	
		2008	2007
	(years)	(in thousands)	
Land and improvements	49 - 105	$ 44,813	$ 41,286
Building and improvements	26 - 71	95,658	94,386
Storage, distribution, and transmission	10 - 79	1,974,505	1,908,688
Generation	30 - 46	439,420	430,216
Construction work in process	—	12,599	19,524
Other equipment	2 - 31	241,485	203,534
		2,808,480	2,697,634
Less accumulated depreciation		(968,781)	(926,754)
		$ 1,839,699	$ 1,770,880

Plant and equipment under capital lease were $36.2 million and $42.3 million as of December 31, 2008 and December 31, 2007, respectively, which included $35.2 million and $37.2 million as of December 31, 2008 and 2007, 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.

(4) Variable Interest Entities

FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*, or FIN 46R, requires the consolidation of entities which are determined to be variable interest entities (VIEs) when we are the primary beneficiary of a VIE, which means we have a controlling financial interest. Certain long-term purchase power and tolling contracts may be considered variable interests under FIN 46R. We have various long-term purchase power contracts with other utilities and certain qualifying facility plants. After evaluation of these contracts, we believe one qualifying facility contract may constitute a variable interest entity under the provisions of

FIN 46R. We are currently engaged in adversary proceedings with this qualifying facility and, while we have made exhaustive efforts, we have been unable to obtain the information necessary to further analyze this contract under the requirements of FIN 46R. We continue to account for this qualifying facility contract as an executory contract as we have been unable to obtain the necessary information from this qualifying facility to determine if it is a VIE and if so, whether we are the primary beneficiary. Based on the current contract terms with this qualifying facility, our estimated gross contractual payments aggregate approximately $494.2 million through 2025, and are included in Contractual Obligations and Other Commitments of Management's Discussion and Analysis. During the years ended December 31, 2008, 2007 and 2006 purchases from this QF were approximately $20.5 million, $21.1 million, and $23.5 million, respectively.

(5) Asset Retirement Obligations

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 pursuant to SFAS No. 71. These amounts do not represent SFAS No. 143, *Accounting for Asset Retirement Obligations*, legal retirement obligations. As of December 31, 2008 and December 31, 2007, we have recognized accrued removal costs of $194.3 million and $165.4 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 $14.3 million and $13.8 million as of December 31, 2008 and December 31, 2007, respectively.

In connection with the adoption of FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47), we have recorded a conditional asset retirement obligation of $6.3 million and $3.9 million, as of December 31, 2008 and December 31, 2007, 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. The initial recording of the obligation had no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset pursuant to SFAS No. 71. 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 conditional ARO during the year ended December 31, 2008, is as follows (in thousands):

Liability at January 1, 2008	$	4,453
Accretion expense		345
Liabilities incurred		227
Liabilities settled		(55)
Revisions to cash flows		2,190
Liability at December 31, 2008	$	7,160

(6) Goodwill

Our goodwill balance is related to our adoption of fresh-start reporting upon emergence from Chapter 11 bankruptcy on November 1, 2004. Since we are a regulated utility, our regulated property, plant and equipment is kept at values included in allowable costs recoverable through utility rates, and the excess of reorganization value over the fair value of assets and liabilities on the date of our emergence of $435.1 million was recorded as goodwill.

As a result of the implementation of FIN 48, we increased our deferred tax assets by $77.5 million and decreased other noncurrent liabilities by $2.4 million, with a corresponding decrease to goodwill. The decrease to goodwill is consistent with the guidance in SFAS No. 109 and the requirements of fresh-start reporting, as our uncertain tax positions relate to periods prior to our emergence from bankruptcy.

Goodwill by segment is as follows (in thousands):

	December 31,	
	2008	2007
Regulated electric	$ 241,100	$ 241,100
Regulated natural gas	114,028	114,028
Unregulated electric	—	—
	$ 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 2008 and 2007 and determined that it was not impaired.

(7) Risk Management and Hedging Activities

We have applied the normal purchases and normal sales scope exception, as discussed above in Note 2, to certain contracts involving the purchase and sale of gas and electricity at fixed prices in future periods. 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.

While we enter into most of our derivative transactions for the purpose of managing commodity price risk, we only apply hedge accounting where specific criteria are met and it is practicable to do so. To apply hedge accounting, the transaction must be designated as a hedge and it must be highly effective in offsetting the hedged risk. Additionally, for hedges of commodity price risk, physical delivery for forecasted commodity transactions must be probable. We use the mark-to-market method of accounting for derivative contracts for which we do not elect or do not qualify for hedge accounting. Under the mark-to-market method of accounting, we record the fair value of these derivatives as assets and liabilities, with changes reflected in our consolidated statements of income. The market prices and quantities used to determine fair value reflect management's best estimate considering various factors; however, future market prices and actual quantities will vary from those used in recording the derivative asset or liability, and it is possible that such variations could be material.

Commodity Prices

Regulated Utilities - Certain contracts for the physical purchase of natural gas associated with our regulated gas utilities do not qualify for normal purchases under SFAS No. 133. Since these contracts are for the purchase of natural gas sold to regulated gas customers, the accounting for these contracts is subject to SFAS No. 71. We use derivative financial instruments to reduce the commodity price risk associated with the purchase price of a portion of our future natural gas requirements and minimize fluctuations in gas supply prices to our regulated customers. We record assets or liabilities based on the fair value of these derivatives, with offsetting positions recorded as regulatory liabilities or regulatory assets on the consolidated balance sheets. Upon settlement of these contracts, associated proceeds or costs are refunded to or collected from our customers consistent with regulatory requirements. At December 31, 2008, we had a derivative liability, included in other current liabilities in the consolidated balance sheet, and an offsetting current regulatory asset of $29.2 million.

Interest Rates

During 2006, we issued $170.2 million of Montana Pollution Control Obligations and $150 million of Montana First Mortgage Bonds. In association with these refinancing transactions, we implemented a risk management strategy of utilizing interest rate swaps to manage our interest rate exposures associated with anticipated refinancing transactions. These swaps were designated as cash-flow hedges under SFAS No. 133 with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in accumulated other comprehensive income (AOCI) in our consolidated balance sheets. We settled $320.2 million of forward starting interest rate swap agreements, and received aggregate settlement payments of approximately $14.6 million in 2006. We reclassify these gains from AOCI into interest expense in our consolidated statements of income during the periods in which the hedged interest payments occur. AOCI includes unrealized pre-tax gains related to these transactions of $11.7 million and $12.8 million at December 31, 2008 and 2007, respectively. 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. We have no further interest rate swaps outstanding.

(8) Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* (SFAS No. 157), which defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. SFAS No. 157 became effective for most fair value measurements, other than leases and certain nonfinancial assets and liabilities, beginning January 1, 2008.

The statement establishes a three-level fair value hierarchy and requires fair value disclosures based upon this hierarchy. The statement also requires that fair value measurements reflect a credit-spread adjustment based on an entity's own credit standing. Consideration of our own credit risk did not have a material impact on our fair value measurements.

The following table sets forth by level within the fair value hierarchy our assets and liabilities that were measured at fair value on a recurring basis as of December 31, 2008 (in thousands):

	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 (1)
Regulated gas derivative liability (2)	$ —	$ (29,156)	$ —	$ —	$ (29,156)
Net derivative liability	**$ —**	**$ (29,156)**	**$ —**	**$ —**	**$ (29,156)**

(1) Fair value was determined using internal models based on quoted external commodity prices.
(2) 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 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. Normal purchases and sales transactions, as defined by SFAS No. 133, and certain other long-term power purchase contracts are not included in the fair values by source table as they are not recorded at fair value. See Note 7 for further discussion.

(9) Discontinued Operations

During the second quarter of 2003, we committed to a plan to sell or liquidate our interest in Netexit. In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we classified the results of operations of Netexit as discontinued operations.

Netexit and its subsidiaries filed for bankruptcy protection in 2004, and Netexit's amended and restated liquidating plan of reorganization was confirmed by the Bankruptcy Court in 2005. The liquidation of Netexit was completed during the second quarter of 2006, and total distributions to NorthWestern were $7.7 million in 2006.

(10) Long-Term Debt and Capital Leases

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

	Due	December 31, 2008	December 31, 2007
Unsecured Debt:			
Unsecured Revolving Line of Credit	2009	$ 108,000	$ 12,000
Secured Debt:			
Mortgage bonds—			
South Dakota—6.05%	2018	55,000	—
South Dakota—7.00%	2023	—	55,000
Montana—6.04%	2016	150,000	150,000
South Dakota & Montana—5.875%	2014	225,000	225,000
Pollution control obligations—			
South Dakota—5.85%	2023	—	7,550
South Dakota—5.90%	2023	—	13,800
Montana—4.65%	2023	170,205	170,205
Montana Natural Gas Transition Bonds— 6.20%	2012	22,355	27,746
Other Long Term Debt:			
Colstrip Unit 4 debt—13.25%	2010	31,666	44,891
Colstrip Lease Holdings, LLC—floating rate	2009	100,000	100,000
Discount on Notes and Bonds	—	(170)	(215)
		862,056	805,977
Less current maturities		(228,045)	(18,617)
		$ 634,011	$ 787,360
Capital Leases:			
Total Capital Leases	Various	$ 37,991	$ 40,391
Less current maturities		(1,193)	(2,389)
		$ 36,798	$ 38,002

Unsecured Revolving Line of Credit

Our $200 million unsecured revolving line of credit will mature on November 1, 2009 and does not amortize. The facility bears interest at a variable rate based upon a grid, which is tied to our credit rating from Fitch, Moody's, and S&P. The 'spread' or 'margin' ranges from 0.625% to 1.75% over the London Interbank Offered Rate (LIBOR). The facility bears interest at a rate of approximately 1.21%, which is 0.75% over LIBOR, as of December 31, 2008, and we had $17.1 million in letters of credit and $108 million of borrowings outstanding. The weighted average interest rate on the outstanding revolving credit facility borrowings was 2.1% as of December 31, 2008.

Commitment fees for the unsecured revolving line of credit were $0.3 million for each of the years ended December 31, 2008 and 2007.

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 two series of general obligation bonds we 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. During 2008, we repaid our South Dakota Pollution Control Obligations that were also secured by our South Dakota indenture.

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.

Refinancing Transaction

During the second quarter of 2008, we issued $55.0 million of South Dakota mortgage bonds at a fixed interest rate of 6.05%, and used the proceeds to redeem our 7.0%, $55 million South Dakota mortgage bonds due in 2023. Consistent with our historical regulatory treatment, the remaining deferred financing costs of approximately $1.1 million were recorded as a regulatory asset and will be amortized over the life of the debt. The new mortgage bonds will mature May 1, 2018, and are secured by our South Dakota electric and natural gas assets. This transaction will reduce our annual interest expense by approximately $0.5 million.

Other Long-Term Debt

In association with the Colstrip Unit 4 transaction our subsidiary, CLH, closed on a $100 million loan on December 28, 2007, which is secured by its interest in Colstrip Unit 4 and is nonrecourse to NorthWestern Corporation. The loan bears interest at a floating rate of 3.17% as of December 31, 2008, which is 1.25% over LIBOR, and matures in December 2009. Covenants associated with this debt limit CLH's ability to, among other things, incur additional indebtedness, create liens, engage in any consolidation or merger or otherwise liquidate or dissolve itself, issue equity interest, dispose of property, make investments, enter into transactions with affiliates, enter into negative pledge clauses, enter into contracts, and exceed certain limits related to pension plan liabilities and environmental.

Covenants associated with our CLH loan, along with an existing temporary waiver with respect to such loan, require that we seek FERC approval to legally move the assets of the owner participant trust from NorthWestern Corporation to Colstrip Lease Holdings, LLC, by January 30, 2009. In addition, other covenants with respect to our CLH loan limit our unfunded benefit obligation to $100 million for our Montana pension plan and to $15 million for our South Dakota pension plan. Our unfunded obligation as of December 31, 2008, for each of these plans exceeded these limits, which triggered a technical default of the loan. In January 2009, we requested and received a waiver of both of these requirements.

As a result of placing our interest in Colstrip Unit 4 into utility rate base (see Note 18), the lender in connection with our CLH loan asked us to directly assume, subject to applicable regulatory approvals, the repayment obligations with respect to such loan in the event that the CLH loan is not repaid in full by April 30, 2009. We agreed to the lender's request and will be seeking the applicable regulatory approvals for us to assume such obligations. We anticipate that we will be able to secure such approvals by April 30, 2009.

In addition, in 2007 we also consolidated existing debt related to our purchase of the owner participant interest in Colstrip Unit 4. This debt amortizes through December 31, 2010 and is at a fixed interest rate of 13.25%.

As of December 31, 2008, we are in compliance with all of our other financial debt covenants.

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt and capital leases, during the next five years are $229.2 million in 2009, $24.9 million in 2010, $7.8 million in 2011, $5.2 million in 2012 and $1.5 million in 2013.

(11) Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of SFAS No. 107, *Disclosures About Fair Value of Financial Instruments*. 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, which is based on market prices.

The fair value estimates presented herein are based on pertinent information available to us as of December 31, 2008 and 2007.

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

	December 31, 2008		December 31, 2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Assets:				
Cash and cash equivalents	$ 11,292	$ 11,292	$ 12,773	$ 12,773
Restricted cash	14,727	14,727	14,482	14,482
Liabilities:				
Long-term debt and capital leases (including current portion)	900,047	818,014	846,368	849,770

(12) Income Taxes

Income tax expense applicable to continuing operations is comprised of the following (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Federal			
Current	$ 863	$ 1,449	$ 11
Deferred	37,916	28,586	24,062
Investment tax credits	(580)	(531)	(536)
State	2,022	2,884	2,394
	$ 40,221	$ 32,388	$ 25,931

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

	Year Ended December 31,		
	2008	2007	2006
Federal statutory rate	35.0%	35.0%	35.0%
State income, net of federal provisions	1.9	3.4	3.8
Amortization of investment tax credit	(0.5)	(0.7)	(0.7)
Depreciation of flow through items	(0.6)	(0.7)	—
Nondeductible professional fees	(0.4)	1.5	1.7
Prior year permanent return to accrual adjustments	0.2	(1.1)	(0.5)
Other, net	1.7	0.4	1.6
	37.3%	37.8%	40.9%

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 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,	
	2008	2007
Excess tax depreciation	$ (139,024)	$ (104,113)
Regulatory assets	(14,144)	(12,179)
Regulatory liabilities	707	(2,288)
Unbilled revenue	2,158	3,819
Unamortized investment tax credit	1,571	1,883
Compensation accruals	5,258	5,034
Reserves and accruals	24,138	23,577
Goodwill amortization	(59,674)	(50,914)
Net operating loss (NOL) carryforward	65,432	65,394
AMT credit carryforward	5,863	5,483
Capital loss carryforward	—	6,376
Valuation allowance	(6,382)	(12,758)
Other, net	75	(373)
	$ (114,022)	$ (71,059)

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 their deferred tax assets. We have a valuation allowance of $6.4 million as of December 31, 2008, against certain state NOL carryforwards as we do not believe these assets will be realized.

At December 31, 2008 we estimate our total federal NOL carryforward to be approximately $350.2 million. If unused, $158.1 million will expire in the year 2023, and $192.1 million will expire in the year 2025. We estimate our state NOL carryforward as of December 31, 2008 is approximately $495.2 million. If unused, $308.5 million will expire in 2010, $33.8 million will expire in 2011, and $152.9 million will expire in 2012. 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.

FIN 48

We adopted the provisions of FIN 48 on January 1, 2007. FIN 48 provides that a tax position that meets the more-likely-than-not threshold shall initially and subsequently be measured 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. As a result of the implementation of FIN 48, we increased our deferred tax assets by $77.5 million and decreased other noncurrent liabilities by $2.4 million, with a corresponding decrease to goodwill. The decrease to goodwill is consistent with the guidance in SFAS No. 109 and the requirements of fresh-start reporting, as our uncertain tax positions relate to periods prior to our emergence from bankruptcy. The change in unrecognized tax benefits is as follows (in thousands):

	2008	2007
Unrecognized Tax Benefits at January 1	$ 111,124	$ 100,264
Gross increases - tax positions in prior period	6,468	13,228
Gross decreases - tax positions in prior period	(2,487)	(2,368)
Unrecognized Tax Benefits at December 31	$ 115,105	$ 111,124

Our unrecognized tax benefits include approximately $78.3 million related to tax positions as of December 31, 2008 and 2007, 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 year ended December 31, 2008, we have not recognized expense for interest or penalties, and do not have any amounts accrued at December 31, 2008 and 2007, respectively, for the payment of interest and penalties.

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

(13) Jointly Owned Plants

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 (South Dakota)	Neal #4 (Iowa)	Coyote (North Dakota)	Colstrip Unit 4 (Montana)
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
December 31, 2007				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 55,691	$ 29,686	$ 42,655	$ 257,129
Accumulated depreciation	34,933	19,816	25,567	14,139

(14) Operating Leases

We lease vehicles, office equipment and facilities under various long-term operating leases. At December 31, 2008 future minimum lease payments for the next five years under non-cancelable lease agreements are as follows (in thousands):

2009	$ 1,551
2010	1,141
2011	723
2012	500
2013	65

Lease and rental expense incurred was $2.1 million, $19.0 million and $30.9 million for the years ended December 31, 2008, 2007 and 2006, respectively.

(15) 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 employees, which includes two cash balance pension plans. The plan for our South Dakota and Nebraska employees is referred to as the NorthWestern Corporation pension plan, and the plan for our Montana employees is referred to as the NorthWestern Energy pension plan.

In accordance with SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*, and SFAS No. 87, *Employers' Accounting for Pensions*, 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. SFAS No. 158 also requires that a plan's funded status be recognized as an asset or liability. See Note 17 for further discussion on how these costs are recovered through rates charged to our customers.

Plan Amendment

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 will be 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,	
	2008	2007	2008	2007
Reconciliation of Benefit Obligation				
Obligation at beginning of period	$ 376,872	$ 387,562	$ 46,494	$ 53,063
Service cost	8,405	8,947	563	581
Interest cost	22,875	21,799	2,367	2,442
Plan Amendments	49	—	—	—
Actuarial loss (gain)	405	(21,106)	(1,275)	(6,219)
Gross benefits paid	(19,947)	(20,330)	(3,826)	(3,373)
Benefit obligation at end of period	$ 388,659	$ 376,872	$ 44,323	$ 46,494

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2008	2007	2008	2007
Reconciliation of Fair Value of Plan Assets..				
Fair value of plan assets at beginning of period	$ 330,446	$ 301,100	$ 16,455	$ 13,358
Return on plan assets	(101,005)	27,038	(5,063)	892
Employer contributions	32,734	22,638	4,855	5,578
Gross benefits paid	(19,947)	(20,330)	(3,826)	(3,373)
Fair value of plan assets at end of period	$ 242,228	$ 330,446	$ 12,421	$ 16,455
Funded Status	$ (146,431)	$ (46,426)	$ (31,902)	$ (30,039)
Unrecognized net actuarial (gain) loss	—	—	—	—
Unrecognized prior service cost	—	—	—	—
Accrued benefit cost	$ (146,431)	$ (46,426)	$ (31,902)	$ (30,039)

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 $388.7 million and $242.2 million, respectively, as of December 31, 2008. The total accumulated benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets were $386.5 million and $242.2 million, respectively, as of December 31, 2008.

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 $376.9 million and $330.4 million, respectively, as of December 31, 2007. The total accumulated benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets were $374.9 million and $330.4 million, respectively, as of December 31, 2007.

Our oversight of the investments held in these plans is rigorous and we believe our investment strategies are prudent. Due to the unprecedented decline in equity markets, we experienced plan asset market losses during 2008 in excess of 30%. Our benefit obligations are remeasured annually using a December 31 measurement date, which resulted in an increase to the pension plans' unfunded status of approximately $100 million, of which approximately $86 million is related to our Montana plan. As a result of this increase in unfunded status, we have increased our 2009 funding projections for the Montana pension plan to be approximately $47 million, as compared with our previous funding estimate of $17 million.

Balance Sheet Recognition

The accrued pension and other postretirement benefit obligations recognized in the accompanying Consolidated Balance Sheets are computed as follows (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2008	2007	2008	2007
Accrued benefit cost	(62,390)	(91,629)	(34,046)	(37,885)
Amounts not yet reflected in net periodic benefit cost				
Prior service cost	(1,980)	(2,177)	—	—
Accumulated gain (loss)	(82,061)	47,380	2,144	7,846
Net amount recognized	$ (146,431)	$ (46,426)	$ (31,902)	$ (30,039)

Plan Assets

Our investment strategy provides for the following asset allocation, within an allowable range of plus or minus 5%:

	Pension Benefits	Other Benefits
Debt securities	30.0%	30.0%
Domestic equity securities	60.0	60.0
International equity securities	10.0	10.0

The percentage of fair value of plan assets held in the following investment types by plan are as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2008	2007	2008	2007	2008	2007
Cash and cash equivalents	0.1%	0.2%	—%	0.2%	—%	0.1%
Debt securities	31.2	29.8	0.7	2.4	31.2	30.3
Domestic equity securities	58.6	58.8	56.6	59.2	58.8	58.6
International equity securities	10.1	11.2	9.1	11.4	10.0	11.0
Participating group annuity contracts	—	—	33.6	26.8	—	—
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

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 (ERISA). Each plan is diversified across asset classes to achieve optimal balance between risk and return and between income and growth through capital appreciation. We review the asset mix on a quarterly basis. Generally, the asset mix will be rebalanced to the target mix as individual portfolios approach their minimum or maximum levels.

We calculate the market related value of plan assets based on the fair market value of plan assets. Debt and equity securities are recorded at their fair market value each year-end as determined by quoted closing market prices on national securities exchanges or other markets as applicable. The participating group annuity contracts are valued based on discounted cash flows of current yields of similar contracts with comparable duration.

Our investment policy allows for all or a portion of each benefit plan to be invested in commingled funds, including mutual funds, collective investment funds, bank commingled funds and insurance company separate accounts. 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. The direct holding of company stock is not permitted; however, any holding in a diversified mutual fund or collective investment fund is permitted. The policy prohibits any transactions that would threaten the tax exempt status of the fund and actions that would create a conflict of interest or transactions between fiduciaries and parties in interest as defined under ERISA.

Our investment policy for fixed income investments 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 including Moodys and S&P. 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.

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.

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2008 and 2007. 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 2008 and 2007, 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.

The expected long-term rate of return assumption on plan assets for both the pension and postretirement plans was determined based on the historical returns and the future expectations for returns for each asset class, as well as the target asset allocation of the portfolios.

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,		
	2008	2007	2006	2008	2007	2006
Discount rate	6.25%	6.25%	5.75%	6.00-6.25%	5.75-6.00%	5.50%
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	3.61	3.55	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 2008 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.

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,		
	2008	2007	2006	2008	2007	2006
Components of Net Periodic Benefit Cost						
Service cost	$ 8,405	$ 8,947	$ 9,049	$ 563	$ 580	$ 741
Interest cost	22,875	21,800	20,791	2,367	2,442	2,775
Expected return on plan assets	(27,212)	(24,422)	(21,458)	(1,316)	(1,068)	(829)
Amortization of transitional obligation	—	—	—	—	—	—
Amortization of prior service cost	246	242	242	—	—	—
Recognized actuarial (gain) loss	(818)	—	—	(599)	(259)	117
Net Periodic Benefit Cost	$ 3,496	$ 6,567	$ 8,624	$ 1,015	$ 1,695	$ 2,804

We estimate amortizations from regulatory assets into net periodic benefit cost during 2008 will be as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
Prior service cost	$ 246	$ —
Accumulated gain	3,880	(42)

Assumed health care cost trend rates have a significant effect on the amounts reported for the costs each year as well as on 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	$ 173
on postretirement benefit obligation	1,646
Effect of a one percentage point decrease in assumed health care cost trend	
on total service and interest cost components	$ (152)
on postretirement benefit obligation	(1,468)

Cash Flows

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law, with changes that impact the funding calculation for benefit plans. PPA encouraged plan sponsors to fully fund their defined benefit pension plans by 2011, and meet incremental plan funding thresholds applicable for each year prior to 2011. PPA imposed certain consequences on plans beginning in 2008 if these thresholds were not met. The determination of our pension funding amounts are based on annual actuarial studies prepared for each plan in accordance with contribution guidelines established by PPA as discussed above, ERISA and the Internal Revenue Code.

Due to the volatility of equity markets in 2008, we and other plan sponsors experienced significant plan asset market losses, requiring significant increases in funding levels to meet the requirements of PPA. In December 2008, Congress passed the Worker, Retiree, and Employer Recovery Act of 2008, which providing for relief under PPA by allowing smoothing of assets, and decreasing the funding targets for each year through 2011. Asset smoothing allows the use of asset averaging, including expected returns, for a 24-month period in the determination of funding requirements. We anticipate making contributions of approximately $49.9 million to our pension and other postretirement benefit plans in 2009. For our postretirement welfare 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 401(h) and VEBA 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
2009	$ 20,856	$ 3,743
2010	21,642	3,881
2011	22,551	3,815
2012	23,410	3,816
2013	24,936	3,959
2014-2018	146,139	21,359

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, 2008, 2007 and 2006 were $5.3 million, $4.7 million and $4.3 million, respectively.

(16) Stock-Based Compensation

Restricted Stock Awards

Under our long-term incentive plans administered by the Human Resources Committee of our Board, we have granted service-based restricted stock to all eligible employees and members of our Board. Under these plans, a total of 1,300,000 shares have been set aside for restricted stock. We may issue new shares or reuse forfeited shares to deliver shares to employees for equity grants. As of December 31, 2008, there were 626,361 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 requirements are met. Nonvested shares do not receive dividend distributions. The long-term incentive plans provide for accelerated vesting in the event of a change in control.

In accordance with SFAS No. 123R, we account for our service-based restricted stock awards using the fixed accounting method, whereby we amortize the value of the market price of the underlying stock on the date of grant (grant-date fair value) to compensation expense over the service period either ratably or in tranches. We reverse any expense associated with restricted stock that is canceled or forfeited during the performance or service period.

Compensation expense recognized for restricted stock awards was $3.2 million, $7.0 million, and $3.6 million for the years ended December 31, 2008, 2007, and 2006, respectively. For the years ended December 31, 2008, 2007 and 2006, an income tax benefit was recognized of $0.2 million, $4.4 million and $1.5 million, respectively.

Summarized share information for our restricted stock awards is as follows:

	Year Ended December 31, 2008	Weighted-Average Grant-Date Fair Value	Year Ended December 31, 2007	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	$ 361,313	$ 34.45	$ 476,105	$ 29.54
Granted	3,500	25.84	4,208	31.72
Vested	(135,818)	34.28	(107,973)	31.94
Forfeited	(34,923)	34.59	(11,027)	34.37
Remaining nonvested grants	$ 194,072	$ 34.39	$ 361,313	$ 34.45

As of December 31, 2008, we had $2.2 million of unrecognized compensation cost related to the nonvested portion of outstanding restricted stock awards, which is reflected as unearned restricted 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 1.5 years. The total fair value of shares vested was $4.7 million, $3.4 million, and $1.7 million for the years ended December 31, 2008, 2007 and 2006.

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 directors 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 years (not to exceed 10 years). During the years ended December 31, 2008, 2007 and 2006, DSUs issued to members of our Board totaled 33,750, 30,563 and 22,805, respectively. Total compensation expense attributable to the DSUs during the years ended December 31, 2008, 2007 and 2006 was approximately $0.2 million, $0.7 million and $0.9 million, respectively.

(17) Regulatory Assets and Liabilities

We prepare our financial statements in accordance with the provisions of SFAS No. 71, 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, 2008	2007
Pension	15	Undetermined	$ 148,534	$ 47,091
Postretirement benefits	15	Undetermined	25,010	21,099
Competitive transition charges		4 Years	18,273	23,227
Environmental clean-up		Various	15,904	14,765
Supply costs		1 Year	3,239	14,195
Energy supply derivatives		1 Year	29,156	—
Income taxes	12	Plant Lives	16,466	11,279
Deferred financing costs		Various	5,061	4,318
Other		Various	18,364	14,116
Total regulatory assets			**$ 280,007**	**$ 150,090**
Removal cost	5	Various	$ 208,201	$ 178,968
Gas storage sales		31 Years	12,933	13,354
Supply costs		1 Year	31,669	32,443
Energy supply derivatives		1 Year	3,785	5,720
Environmental clean-up		2 Years	1,411	2,208
State & local taxes & fees		1 Year	9,701	1,462
Other		Various	4,492	1,439
Total regulatory liabilities			**$ 272,192**	**$ 235,594**

Pension and Postretirement Benefits

We adopted the recognition and disclosure provisions of SFAS No. 158 effective December 31, 2006, which required that the unfunded portion of plan benefit obligations be recorded in the balance sheet and remeasured at each year end, with a corresponding adjustment in accumulated other comprehensive income recorded to retained earnings. As the costs associated with these plans are recovered in rates, these adjustments were classified as regulatory assets / liabilities in accordance with regulatory treatment. In 2008, we experienced significant plan asset market losses due to market volatility, which resulted in increases in the unfunded portion of the plan benefit obligation as of the December 31, 2008, measurement date, which is reflected in the increase in regulatory assets above.

Historically, the MPSC rates have allowed recovery of pension costs on a cash basis. The MPSC approved a revised accounting order in 2008 to provide for the recognition of the average of the cash funding for the 8-year period including calendar years 2005 – 2012 due to the significant increase in cash funding projections (see Note 18 for further discussion). The portion of the regulatory asset related to our Montana pension plan will amortize as cash funding amounts exceed accrual expense as determined by SFAS No. 158. The SDPUC allows recovery of pension costs on an accrual basis. The MPSC allows recovery of SFAS No. 106 costs on an accrual basis.

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; 10.61% and 7.96%, respectively, in South Dakota; and 8.55% 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 20. In December 2007, the SDPUC approved our settlement with SDPUC Staff related to our natural gas rate case, which included a provision allowing us to include approximately $1.4 million annually in rates to recover MGP environmental clean-up costs. This was partially offset by a requirement to return approximately $2.3 million ($0.8 million annually) of previous insurance recoveries to customers. The SDPUC's approval of our settlement provides reasonable assurance that we will recover future South Dakota related MGP costs. Therefore, we recorded net regulatory assets (with a corresponding reduction to operating, general and administrative expenses) of $12.6 million in December 2007 to offset the previously recorded South Dakota MGP related liabilities.

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.

State & Local Taxes & Fees

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. In 2006, the MPSC 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 in 1999. In 2007, we filed a general rate case in Montana, which reestablishes the amount of state and local taxes and fees collected in base rates.

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, SFAS No. 143 precludes this treatment. Our depreciation method, including cost of removal, is established by the respective regulatory commissions. Therefore, in accordance with SFAS No. 71, we continue to accrue removal costs for our regulated assets by increasing our regulatory liability. See Note 5, 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.

(18) Regulatory Matters

Colstrip Unit 4

In January 2008, we announced that we had retained a financial advisor to assist us in the evaluation of our strategic options related to our joint ownership interest in this facility. Options reviewed included selling our ownership through a competitive bid process, putting the asset in rate base in Montana, or retaining the asset and contracting future sales of the plant output. On June 10, 2008, we entered into an agreement to sell our interest in Colstrip Unit 4 for $404 million in cash, subject to certain working capital adjustments. The agreement provided a timeline of 120 days for us to explore the viability of placing this asset into our Montana utility rate base.

The 2007 Montana House Bill 25 (HB 25), labeled *The Generation Reintegration Act*, 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 electricity supply resource projects and requires carbon offsets to reduce carbon dioxide emissions.

Consistent with this bill and in accordance with the agreement with the purchaser, on June 30, 2008, we submitted a filing with the MPSC to initiate a review process to determine if it would be in the public interest to place our interest in Colstrip Unit 4 into rate base at an equivalent value to the negotiated selling price including certain adjustments. The determination of the selling price was based on a number of factors, including the existing below market commitments of 111 MWs to our Montana regulated electric supply load. The MPSC accepted the application and ordered the asset be placed into utility rate base effective January 1, 2009, at a value of $407 million. 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 or the life of the plant. The difference in rate base value of $407 million and the negotiated price of $404 million reflects termination fees of approximately $6.3 million offset by avoided sale transaction fees of approximately $3.3 million.

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 at an estimated cost of $206 million. The Mill Creek Generating Station would provide regulating resources to balance our transmission system in Montana to maintain reliability and enable additional wind power to be integrated onto the network to meet future renewable energy portfolio needs. As part of the MPSC filing, we requested a capital structure of 50% equity and 50% debt and an authorized return on equity of 10.75%. A procedural schedule is currently in process and we anticipate an MPSC decision during the second quarter of 2009.

Pension Accounting Order

Due to the significant decline in equity markets resulting in plan asset market losses, we have significantly increased our 2009 funding projections for the Montana pension plan. Pension costs in Montana are included in expense on a pay as you go (cash funding) basis. In 2005, the MPSC authorized recognition of pension costs based on an average of the annual funding for 2005 through 2009. To decrease volatility to both earnings and customer rates, we requested and received approval from the MPSC for a revised accounting order to recognize pension expense for calendar years 2008 through 2012 based on an average of the funding for 2005 through 2012.

Property Tax Settlement

We resolved our dispute with the Montana Department of Revenue over property tax assessments related to the years 2005 through 2008. We had previously paid the taxes for those years but protested portions of those property taxes, as permitted by state law. As a result of this settlement, we agreed to withdraw the protest and receive a refund of approximately $4.7 million of the previously paid property taxes. We have a property tax tracker in Montana, which allows us to track the annual increases in property taxes from amounts in rates. Therefore, in December 2008, we filed a tax tracker adjustment to reduce our electric and natural gas transmission and distribution rates beginning January 1, 2009, to reflect lower 2008 Montana property taxes and the portion of the refund to be returned to customers, which was approximately $2.6 million.

Montana Electric and Natural Gas Rate Case

In July 2007, we filed a request with the MPSC for an electric transmission and distribution revenue increase of $31.4 million, and a natural gas transmission, storage and distribution revenue increase of $10.5 million. In December 2007, we and the MCC filed a joint stipulation with the MPSC to settle our electric and natural gas rate cases. Specific terms of the stipulation included:

- An annual increase in base electric rates of $10 million and base natural gas rates of $5 million;
- Interim rates effective January 1, 2008;
- Capital investment in our electric and natural gas system totaling $38.8 million to be completed in 2008 and 2009 on which we will not earn a return on, but will recover depreciation expense;
- A commitment of 21 MWs of unit contingent power from Colstrip Unit 4 at Mid-Columbia (Mid-C) Index prices minus $19 per MWH, but not less than zero, to electric supply for a period of 76 months beginning March 1, 2008; and
- We will submit a general electric and natural gas rate filing no later than July 31, 2009, based on a 2008 test year.

On July 1, 2008, the MPSC approved the stipulated agreement, finalizing the Montana electric and natural gas rate case. The approval of the inclusion of our interest in Colstrip Unit 4 in rate base negated the commitment of 21 MWs of unit contingent power.

FERC Transmission Rate Case

In October 2006, we filed a request with the FERC for an electric transmission revenue increase. In May 2007, we implemented interim rates, which were subject to refund plus interest pending final resolution. We filed settlement documents on February 15, 2008, and on October 16, 2008, FERC approved the settlement. We have been recognizing revenue consistent with the settlement terms since we implemented interim rates in May 2007, which has resulted in an annualized margin increase of approximately $3.0 million. We deferred a portion of the interim rates billed from May 2007 through November 2008 and, in accordance with the settlement agreement, refunded approximately $5.4 million to customers in December 2008.

(19) Earnings Per Share

Basic earnings per share is computed by dividing earnings applicable to common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per share reflects 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 shares and DSUs. Average shares used in computing the basic and diluted earnings per share are as follows:

	December 31,	
	2008	2007
Basic computation	37,975,554	36,622,547
Dilutive effect of		
Restricted shares and DSUs	302,124	435,615
Diluted computation	38,277,678	37,058,162

(20) 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 $138 per MWH through 2029. Our estimated gross contractual obligation related to the QFs is approximately $1.5 billion through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $1.2 billion through 2029. Upon adoption of fresh-start reporting, we computed the fair value of the remaining liability of approximately $367.9 million to be approximately $143.8 million based on the net present value (using a 7.75% discount factor) of the difference between our obligations under the QFs and the related amount recoverable.

The following table summarizes the change in the QF liability (in thousands):

	December 31,	
	2008	2007
Beginning QF liability	$ 158,132	$ 147,893
Unrecovered amount	(7,246)	(1,223)
Interest expense	11,955	11,462
Ending QF liability	$ 162,841	$ 158,132

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

	Gross Obligation	Recoverable Amounts	Net
2009	$ 61,586	$ 53,322	$ 8,264
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
Thereafter	1,131,757	853,215	278,542
Total	$ 1,459,182	$ 1,125,095	$ 334,087

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 23 years. Costs incurred under these contracts were approximately $564.0 million, $445.0 million and $447.1 million for the years ended December 31, 2008, 2007, and 2006, respectively. As of December 31, 2008 our commitments under these contracts are $498 million in 2009, $341 million in 2010, $158 million in 2011, $146 million in 2012, $133 million in 2013, and $487 million thereafter. These commitments are not reflected in our Consolidated Financial Statements.

Environmental Liabilities

Our liability for environmental remediation obligations is estimated to range between $22.5 million to $43.8 million. As of December 31, 2008, we have a reserve of approximately $32.1 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.

Manufactured Gas Plants - Approximately $26.9 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 $13.4 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 initiated during the first quarter of 2008 and are expected to be complete 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.

Coal-Fired Plants - 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.

Global Climate Change - 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 US 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. Increased pressure for carbon dioxide emissions reduction also is coming from investor organizations. Specifically, coal-fired plants have come under scrutiny due to their emissions of carbon dioxide.

In addition, 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 for installation at the generation facilities we have a joint interest in, or on a cost effective basis. 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.

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. We comply with these 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 with respect to these plants.

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 Litigation – 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 would require every coal-fired generating plant in the state to achieve reduction levels by 2010. The joint owners currently plan to install chemical injection technologies to meet these requirements. We estimate our share of the capital cost would be approximately $1 million, with ongoing annual operating costs of approximately $3 million. If the Montana rules are maintained in their current form and enhanced chemical injection technologies are not sufficiently developed to meet the Montana levels of reduction by 2010, then adsorption/absorption technology with fabric filters at the Colstrip Unit 4 generation facility would be required, which could represent a material cost. Recent tests have shown that it may be possible to meet the Montana rules with more refined chemical injection technology combined with adjustments to boiler/fireball dynamics at a minimal cost. We are continuing to work with the other Colstrip owners to determine the ultimate financial impact of these rules.

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

Magten/Law Debenture/QUIPS Litigation

Magten Settlement - In July 2008, the US Bankruptcy Court approved a global settlement agreement between NorthWestern, Magten Asset Management (Magten), Law Debenture Trust Company of New York (Law Debenture) and the Plan Committee that resolves the litigation related to claims of holders of quarterly income preferred securities (QUIPS) in our Chapter 11 bankruptcy case. On July 23, 2008 the Ad Hoc Committee filed an appeal to the global settlement agreement, however, we and the other parties involved waived a closing condition and closed on the settlement on July 24, 2008. Under the approved global settlement agreement Magten, Law Debenture, their lawyers and the holders of the QUIPS, collectively received a cash payment of $23 million to be allocated amongst them in accordance with the terms of the global settlement agreement. The cash payment was funded by our repurchase of 782,059 shares held in the disputed claims reserve established under our confirmed Plan of Reorganization, as discussed below. This settlement resolves the last significant claim from the bankruptcy case, and also provided for reimbursement of previously incurred legal fees and expenses of $4 million, which are reflected as a reduction of operating, general and administrative expenses. The Ad Hoc Committee's appeal remains pending before The United States District Court of Delaware.

Disputed Claims Reserve - In July 2008, we obtained bankruptcy court approval for the purchase of the remaining shares in the disputed claims reserve. 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, which we expect to be heard during the first quarter of 2009. Upon resolution of this motion, we expect to distribute the remaining cash and shares in the disputed claims reserve to eligible claimants.

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. 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 L.L.C. (now CFB), which plaintiffs claim is a successor to the Montana Power Company.

We are 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. This lawsuit seeks, among other things, the avoidance of the transfer of assets from CFB to us, declaration that the assets were fraudulently transferred and were not property of our bankruptcy estate, the imposition of constructive trusts over the transferred assets, and the return of such assets to CFB. 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, wherein the McGreevey plaintiffs executed a covenant not to execute against us, and we quit claimed any interest we had in any claims we may or may not have under any applicable directors and officers liability insurance policy, against any insurers for contractual or extracontractual damages, and against certain defendants in the McGreevey lawsuits. In November 2006, this agreement was approved by the Delaware Bankruptcy Court and the claims were discharged. We filed a joint motion with the plaintiffs' attorneys in U.S. District Court in Montana to dismiss the claims against us in the McGreevey lawsuits. On March 16, 2007, the U.S. District Court in Montana denied the motion to dismiss us from the McGreevey lawsuits, questioning the benefits of the settlement to be received by the class members in the settlement and the authority of the plaintiffs' counsel to have negotiated the settlement without a class having been certified by the court. On January 11, 2008, the U.S. District Court in Montana suggested that the settlement agreement was invalid because the plaintiffs' attorneys had not secured the court's permission to engage in settlement discussions. The District Court enjoined the plaintiffs from taking any further action in any of these matters. The plaintiffs appealed the District Court's January 11th injunction to the Ninth Circuit U.S. Court of Appeals, where on July 10, 2008, the Ninth Circuit U.S. Court of Appeals heard oral arguments; a determination is pending. We do not anticipate a resolution of this litigation before class representatives and class counsel are approved by the U.S. District Court in Montana. However, we believe that given the scope of the Order confirming the Plan and the injunctions issued by the Delaware Bankruptcy Court which channeled the claims to the D&O Trust, we have limited exposure to the plaintiffs for damages arising from the McGreevey claims. In January 2009, the U.S. District Court in Montana held a status conference and issued a bench ruling asking all parties to submit memorandum discussing the party's willingness to enter into a global settlement of the matter. We responded noting our position that all matters are resolved against NorthWestern as discussed above and noted that we are willing to work with the other parties and the Court. We will continue to vigorously defend against these claims and explore ways to remove ourselves from the lawsuits.

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., Case No. DV-05-97. 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 in a case called Ammondson, et al. v. NorthWestern Corporation, et al. 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 have appealed the judgment to the Montana Supreme Court and posted a $25.8 million bond. We intend to vigorously pursue the appeal; however, there can be no assurance that we will prevail in our efforts. Interest accrues on the verdict amount during the appeal process.

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) against us and two other co-owners (the Defendants) of Big Stone Generating Station (Big Stone). The complaint alleges 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 alleges 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 alleges 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 seeks 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 seeks unspecified civil penalties, including a beneficial mitigation project. We believe that these claims are without merit and that Big Stone has been 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. These matters are still pending. The ultimate outcome of these matters cannot be determined at this time.

Other Litigation and Contingencies

FERC Investigation

During the second quarter of 2007, we voluntarily informed the FERC of several potential regulatory compliance issues related to our natural gas business. We entered into a stipulation and agreement with FERC Enforcement Staff to resolve these matters, which was approved by FERC in November 2008 and resulted in us paying a civil penalty of $450,000.

Colstrip Energy Limited Partnership

In December 2006, the MPSC issued an order finalizing certain qualifying facility rates for the periods July 1, 2003 through June 30, 2006. Colstrip Energy Limited Partnership (CELP) is a qualifying facility with which we have a power purchase agreement through 2025. 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. CELP filed a complaint against NorthWestern and the MPSC in Montana district court on July 6, 2007 which contests the MPSC's order. CELP is disputing inputs in to the rate-setting formula, used by us and approved by the MPSC on an annual basis, to calculate energy and capacity payments for the contract years 2004, 2005 and 2006. CELP is claiming that NorthWestern breached the power purchase agreement causing damages, which CELP asserts are not presently known but believed to be approximately \$22 million for contract years 2004, 2005 and 2006. If the MPSC's order is upheld in its current form, we anticipate reducing our QF liability by approximately \$25 to \$50 million as our estimate of energy and capacity rates for the remainder of the contract period would be reduced. A temporary restraining order was agreed to by the parties and has been issued restraining us from implementing the rates finalized by the MPSC order pending an ultimate decision on CELP's complaint. On June 30, 2008, the state district court judge granted our motions to enforce the contractual arbitration provision and to stay all discovery and proceedings against us, pending the decision of the required contract arbitration. The state district court, on June 30, 2008, also granted a motion by the MPSC to bifurcate, having the effect of separating the issues between contract/tort claims and the administrative appeal of the MPSC's orders; which we supported. The order also stayed the appellate decision pending a decision in our arbitration proceedings. An arbitration is scheduled for June 2009. We believe that we will prevail in the arbitration and intend to vigorously defend our positions.

Colstrip Unit 4 Coal Royalties

Relative to our joint ownership in Colstrip Unit 4, the Mineral Management Service of the United States Department of Interior (MMS) issued two orders to Western Energy Company (WECO) in 2002 and 2003 to pay additional royalties concerning coal sold to Colstrip Units 3 and 4 owners. The orders assert that additional royalties are owed as a result of WECO not paying royalties in connection with revenue received by WECO from the Colstrip Units 3 and 4 owners under a coal transportation agreement during the period October 1, 1991 through December 31, 2001. On April 28, 2005, the appeals division of the MMS issued an order that reduced the amount claimed based upon the applicable statute of limitations. The State of Montana issued a demand to WECO in May 2005 consistent with the MMS position outlined above on these transportation revenues. Further, on September 28, 2006, the MMS issued an order to pay additional royalties on the basis of an audit of WECO's royalty payments during the three years 2002 to 2004. WECO appealed these orders to the Interior Board of Land Appeals of the United States Department of Interior (IBLA) who affirmed the orders on September 12, 2007. WECO filed a complaint and request for declaratory ruling in the US District Court for the District of Columbia in January 2008 seeking relief from the orders issued by the MMS and affirmed by the IBLA, and we continue to monitor the appeals process. The Colstrip Units 3 and 4 owners and WECO currently dispute the responsibility of the expenses if the MMS position prevails. We believe that the Colstrip Units 3 and 4 owners have reasonable defenses in this matter. However, if the MMS position prevails and WECO succeeds in passing the expense responsibility to the owners, our share of the alleged additional royalties would be 15 percent, or approximately \$6.0 million, and we would have ongoing royalty expenses related to coal transportation. The parties have an agreement in principle to resolve this dispute. If the matter is resolved as contemplated, it would not have a material impact on our financial position, results of operations or cash flows. We expect the parties to finalize the agreement during the first half of 2009.

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. Proof of claims from creditors are due to be filed by

March 12, 2009. We do not anticipate Blue Dot's ultimate liquidation will have a material adverse effect, if any, on our financial condition, results of operations or cash flows.

MPSC Investigation

During the first quarter of 2008, the MPSC opened a proceeding to investigate our compliance with a 2004 MPSC order limiting our ability to provide loans, guarantees, advances, equity investments or working capital to subsidiaries or affiliates. This proceeding is in response to an MCC complaint that we violated the MPSC's order when we purchased our previously leased interests in Colstrip Unit 4. We have provided documentation to the MPSC that we did not violate their order. A hearing was conducted in September 2008 and the MPSC issued an order in December 2008 finding that we violated the 2004 MPSC order and recommended a $765,000 penalty. MPSC also asked the Staff to open a new docket to review the Bankruptcy Stipulation. This docket has not yet been opened. We have accrued $765,000 in other current liabilities in the Consolidated Balance Sheets. We filed a motion for reconsideration with the MPSC, as did the MCC; and both motions were denied in January 2009. To enforce the penalty, MPSC must file a petition in District Court. We are currently evaluating our options related to this matter.

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.

(21) 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 16.

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 41,289 and 33,196 during the years ended December 31, 2008 and 2007, respectively, and are reflected in treasury stock. These shares were credited to treasury stock based on their fair market value on the vesting date.

(22) Segment and Related Information

We operate the following business units: (i) regulated electric, (ii) regulated natural gas, (iii) unregulated electric, and (iv) all other, which primarily consists of our remaining unregulated natural gas operations and our unallocated corporate costs.

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		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)
Income from operations	$ 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

	Regulated		Unregulated			
December 31, 2007	**Electric**	**Gas**	**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)
Income (loss) from operations	$ 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

December 31, 2006	Regulated Electric	Regulated Gas	Unregulated Electric	Other	Eliminations	Total
Operating revenues	$ 661,710	$ 359,701	$ 83,007	$ 76,959	$ (48,724)	$ 1,132,653
Cost of sales	332,786	240,788	16,639	70,480	(47,111)	613,582
Gross margin	328,924	118,913	66,368	6,479	(1,613)	519,071
Operating, general and administrative	125,359	58,560	40,219	17,690	(1,613)	240,215
Property and other taxes	51,416	19,722	2,942	107	—	74,187
Depreciation	58,033	14,614	1,597	1,061	—	75,305
Ammondson verdict	—	—	—	19,000	—	19,000
Operating income (loss)	94,116	26,017	21,610	(31,379)	—	110,364
Interest expense	(41,770)	(12,503)	—	(1,743)	—	(56,016)
Other income	3,244	2,062	147	3,612	—	9,065
Income tax (expense) benefit	(21,556)	(5,489)	(8,776)	9,890	—	(25,931)
Income (loss) from operations	$ 34,034	$ 10,087	$ 12,981	$ (19,620)	$ —	$ 37,482
Total assets	$ 1,547,302	$ 762,847	$ 54,800	$ 30,988	$ —	$ 2,395,937
Capital expenditures	$ 71,039	$ 24,419	$ 5,122	$ 466	$ —	$ 101,046

(23) 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:

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

2007	First	Second	Third	Fourth
Operating revenues	$ 366,565	$ 259,608	$ 265,863	$ 308,024
Operating income	44,353	18,223	33,238	44,279
Net income	$ 19,142	$ 2,434	$ 13,177	$ 18,438
Average common shares outstanding	35,720	35,988	36,471	38,284
Income per average common share (basic):				
Net income	$ 0.54	$ 0.07	$ 0.36	$ 0.48
Income per average common share (diluted):				
Net income	$ 0.51	$ 0.06	$ 0.35	$ 0.52
Dividends per share	$ 0.31	$ 0.31	$ 0.33	$ 0.33
Stock price:				
High	$ 36.51	$ 35.47	$ 32.10	$ 30.05
Low	35.32	30.60	25.30	26.97
Quarter-end close	35.43	31.81	27.17	29.50

SCHEDULE II. VALUATION AND QUALIFYING ACCOUNTS
NORTHWESTERN CORPORATION AND SUBSIDIARIES

Column A	Column B	Column C	Column D	Column E
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Balance End of Period
		(in thousands)		
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
FOR THE YEAR ENDED DECEMBER 31, 2006				
RESERVES DEDUCTED FROM APPLICABLE ASSETS				
Uncollectible accounts	2,164	3,892	(2,816)	3,240

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 function):
    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 13, 2009
/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 function):

    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 13, 2009
/s/ BRIAN B. BIRD
Brian B. Bird
Vice President and Chief Financial Officer

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, 2008, 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 13, 2009

/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, 2008, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Brian B. Bird, Vice President and Chief Financial 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 13, 2009

/s/ BRIAN B. BIRD
Brian B. Bird
Vice President and Chief Financial Officer

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: $23.47
Shares Outstanding: 35.9 million
Market Capitalization: $842 million
Dividend Yield: 5.6%

Common Stock Dividends
We currently pay a dividend of 33.5 cents per share. Anticipated record and payment dates for 2009 are as follows:

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

2009 Annual Meeting
April 22, 2009
2:00 p.m. Mountain time
Montana Tech Student Union Building
1300 West Park Street
Butte, MT

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, 2008, the certifications of our Chief Executive Officer and Chief Financial Officer required by Section 302 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, 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.

NorthWestern Energy
Delivering a Bright Future

BOARD OF **DIRECTORS**

E. LINN DRAPER, JR. (67)
Chairman of the Board
Austin, Tex.
Retired Chairman, President and Chief Executive Officer of American Electric Power Co., Inc.
Director since 2004

STEPHEN P. ADIK (65)
Valparaiso, Ind.
Retired Vice Chairman of NiSource, Inc.
Director since 2004
Committees: *Audit, Human Resources*

DANA J. DYKHOUSE (51)
Sioux Falls, S.D.
President and Chief Executive Officer of First PREMIER Bank
Director since January 2009
Committees: *Audit, Nominating and Corporate Governance*

JULIA L. JOHNSON (46)
Windermere, Fla.
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 (62)
Palm Beach Gardens, Fla.
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*

D. LOUIS PEOPLES (67)
Incline Village, Nev.
Retired Chief Executive Officer and Vice Chairman of the Board of Orange and Rockland Utilities, Inc.
Director since 2006
Committees: *Audit, Nominating and Corporate Governance*

ROBERT C. ROWE (53)
Sioux Falls, S.D.
President and Chief Executive Officer of NorthWestern Corporation
Director since August 2008

500 kV transmission towers south of Townsend, Mont.

Photographer: Mark Mallard
Senior Engineer
Butte, Mont.

OFFICERS

ROBERT C. ROWE (53)
President and Chief Executive Officer

BRIAN B. BIRD (46)
Vice President and Chief Financial Officer

PATRICK R. CORCORAN (57)
Vice President – Government and Regulatory Affairs

MIGGIE E. CRAMBLIT (53)
Vice President, General Counsel and Corporate Secretary

DAVID G. GATES (52)
Vice President – Wholesale Operations

KENDALL G. KLIEWER (39)
Vice President and Controller

CURTIS T. POHL (44)
Vice President – Retail Operations

BOBBI L. SCHROEPPEL (40)
Vice President – Customer Care and Communications

This annual report is prepared primarily for the information of our shareholders and is not given in connection with the sale of any security or offer to sell or buy any security.

Printed on recycled paper.

NorthWestern™
Energy
Delivering a Bright Future

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