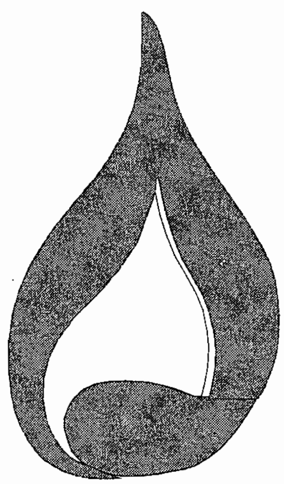
YEAR ENDING 2007

ANNUAL REPORT
OF

NorthWestern Energy

GAS UTILITY



TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 202601
HELENA, MT 59620-2601

Gas Annual Report

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Description	Schedule

Sch. 1	IDENTIFICATION

Legal Name of Respondent:	NorthWestern Corporation
Name Under Which Respondent Does Business:	NorthWestern Energy
Date Utility Service First Offered in Montana:	Electricity - Dec 12, 1912 Natural Gas - Jan 01, 1933 Propane - Oct 13, 1995
Person Responsible for Report:	Kendall G. Kliewer
Telephone Number for Report Inquiries:	(406) 497-2759
Address for Correspondence Concerning Report:	40 East Broadway Street Butte, MT 59701

If direct control over respondent is held by another entity, provide below the name, address, means by which control is held and percent ownership of controlling entity:

N/A

Sch. 2	BOARD OF DIRECTORS	
	Director's Name & Address (City, State)	Remuneration
1		
2	See Northwestern Corporation's Annual Report on Form 10-K	
3	to the SEC for the Corporate Board of Directors.	
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Sch. 3	OFFICERS		
	Title	Department Supervised	Name
	President & Chief Executive Officer	Executive Safety/Health/Environmental Services	Michael Hanson
	Vice President, Chief Financial Officer	Tax, Internal Audit & Controls Financial Planning & Analysis Controller & Treasury Functions Information Technology Investor Relations & Business Development	Brian Bird
	Vice President, General Counsel & Corporate Secretary	Legal	Thomas Knapp
	Vice President, Retail Operations	Asset Management Business Development & Community Relations Safety & Quality Control General Construction General MT/SD/NE Operations Large Project Development Organizational Development & Labor Relations	Curt Pohl
	Vice President, Wholesale Operations	Energy Supply Operations Transmission Operations Unregulated Power Supply	David Gates
	Vice President, Governmental & Regulatory Affairs	Government & Regulatory Affairs State, Local & Community Relations	Patrick Corcoran
	Vice President, Administrative Services	Support Services Human Resources Compensation & Benefits Records Management Pilots	Greg Trandem
	Vice President, Customer Care & Communications	Revenue Collections Customer Interaction Customer Care Systems & Support Key Accounts/Customer Education Communications	Bobbi Schroeppel
	Internal Audit & Controls Officer	Internal Audit Enterprise Risk Financial System Applications	Michael Nieman
	Vice President, Controller	Financial Reporting Accounting Accounts Payable & Payroll	Kendall Kliewer
	Treasurer	Treasury Functions Risk Management Energy Risk Management Credit Cash Management	Paul Evans

Reflects active officers as of March 31, 2008.

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		**$ 42,418**	**79.75%**
NorthWestern Corporation:			
Montana Utility Operations	Electric Utility Natural Gas Utility Natural Gas Pipeline Propane Utility Natural Gas Funding Trust - (Bond Transition Financing) 1/		
South Dakota Utility Operations	Electric Utility Natural Gas Utility		
Nebraska Utility Operations	Natural Gas Utility		
Unregulated Operations		**$ 10,773**	**20.25%**
Colstrip Unit 4	Wholesale Electric		
Direct Subsidiaries:			
NorthWestern Services, LLC	Nonregulated natural gas marketing, property management, owner participant interest		
Clarkfoot and Blackfoot, LLC	Milltown hydroelectric facility		
NorthWestern Investments, LLC	Holds non-utility assets		
Risk Partners Assurance, Ltd.	Captive insurance company		
Colstrip Unit 4 79 MW Trust	Owner participant interest		
Indirect Subsidiaries:			
Montana Generation, LLC	Non-regulated energy marketing		
Colstrip Lease Holdings LLC	Owner participant interest		
Total Corporation		**$ 53,191**	**100.00%**

1/ While the Natural Gas Funding Trust (the Trust) is regulated by the MPSC and information pertaining to the Trust is reported to the MPSC on a semi-annual basis, it is reflected on the equity basis in this presentation.

Sch. 5

CORPORATE ALLOCATIONS

Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
Utility Administration Executive Department	Includes the following departments: CEO; COO	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and revenue.	$1,669,961	67.66%	$798,205
Legal Department	Includes the following departments: Chief Legal	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and revenue.	12,567,808	84.35%	2,332,475
Administration & Human Resources	Includes the following departments: Human Resources, Benefits Admin, Compensation & Benefits, VP Admin, Printing, Rec Mgmt & Aircraft	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and revenue.	27,877,278	84.83%	4,984,872
Finance / Accounting, Information Technology	Includes the following departments: CFO, Treasury, FP&A, Controller, Fixed Assets, Accounting, Tax & Financial Reporting, Investor Relations, IT Sr, IT Applications Infrastructure, Licensing & Leasing	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and revenue.	13,957,060	68.07%	6,547,305
Regulatory and Gov't Affairs	Includes the following departments: Regulatory Affairs, Load Research, Government Affairs, Reg Support Services, Community Relations	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and revenue.	3,443,692	82.77%	716,852
Customer Care	Includes the following departments: Customer Care Common, Customer Care Combined, CC MT Only and Corp Communications	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and revenue.	15,689,348	71.08%	6,384,249
Audit & Controls	Includes the following departments: Audit and Controls, Enterprise Risk Management	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and revenue.	804,209	67.66%	384,394
TOTAL			$76,009,356	77.44%	$22,148,352

Sch. 6	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Utility	% of Total Affil. Exp.	Charges to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4	Colstrip Unit 4	Purchased Power	Market Rates	$21,977,426	29.60%	$21,977,426
5	Montana Generation, LLC 1/	Purchased Power	Negotiated Rates	$13,341,388	100.00%	$13,341,388
6						
7						
8						
9	**Total Nonutility Subsidiaries**			$35,318,814		$35,318,814
10	**Total Nonutility Subsidiaries Revenues**			$87,477,814		
11						
12						
13	**Utility Subsidiaries**					
14	Canadian-Montana Pipeline Corporation	Transportation	Tariff Rates	$55,360	1.89%	$55,360
15	**Total Utility Subsidiaries**			$55,360		$55,360
16	**Total Utility Subsidiaries Revenues**			$2,935,448		
17	**TOTAL AFFILIATE TRANSACTIONS**			$35,374,174		$35,374,174

1/ During 2007, a contract was executed whereby Montana Generation, LLC agreed to sell NorthWestern Default Supply 90 megawatts of unit contingent power for a term running from July 1, 2007 through December 31, 2018. The price, quantity, and term was the result of a negotiated settlement between NorthWestern and the Montana Consumer Counsel and was approved by the Montana Public Service Commission.

Sch. 7	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Affiliate	% of Total Affil. Exp.	Revenues to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4	Colstrip Unit 4	Wheeling	Tariff Rates	$396,899	0.53%	$396,899
5						
6						
7						
8						
9	**Total Nonutility Subsidiaries**			$396,899		$396,899
10	**Total Nonutility Subsidiaries Expenses**			$74,574,922		
11						
12						
13	**Utility Subsidiaries**					
14					0.00%	$0
15	**Total Utility Subsidiaries**			$0		$0
16	**Total Utility Subsidiaries Expenses**			$1,085,459		
17	**TOTAL AFFILIATE TRANSACTIONS**			$396,899		$396,899

Sch. 8	MONTANA UTILITY INCOME STATEMENT - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	400 Operating Revenues	$ 356,733,907	$ 115,909,279	$ 240,824,628	$ 243,184,588	-0.97%
3						
4	**Total Operating Revenues**	356,733,907	115,909,279	240,824,628	243,184,588	-0.97%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expense	277,834,787	104,297,455	173,537,332	177,541,331	-2.26%
9	402 Maintenance Expense	8,318,730	1,171,058	7,147,672	4,171,295	71.35%
10	403 Depreciation Expense	16,449,898	4,955,999	11,493,899	10,781,253	6.61%
11	404-405 Amort. & Depletion of Gas Plant	2,382,708	740,345	1,642,363	1,502,450	9.31%
12	406 Amort. of Plant Acquisition Adj.	(2,288,552)	(2,288,552)	-	-	-
13	407.3 Regulatory Amortizations - Debit	9,998,611	2,464,200	7,534,411	7,641,238	-1.40%
14	407.4 Regulatory Amortizations - Credit	(16,442,084)	(14,307,305)	(2,134,779)	(3,991,498)	46.52%
15	408.1 Taxes Other Than Income Taxes	25,048,996	2,100,459	22,948,537	21,455,887	6.96%
16	409.1 Income Taxes-Federal	2,036,090	(2,279,000)	4,315,090	13,623,094	-68.33%
17	-Other	290,100	(254,532)	544,632	1,712,464	-68.20%
18	410.1 Deferred Income Taxes-Dr.	6,359,634	7,007,193	(647,559)	-	-100.00%
19	411.1 Deferred Income Taxes-Cr.	-	-	-	(8,442,046)	100.00%
20	411.4 Investment Tax Credit Adj.	(40,117)	(40,117)	-	-	-
21						
22	**Total Operating Expenses**	329,948,801	103,567,203	226,381,598	225,995,468	0.17%
23	**NET OPERATING INCOME**	$ 26,785,106	$ 12,342,076	$ 14,443,030	$ 17,189,120	-15.98%

This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, in accordance with FERC requirements, subsidiaries are presented using the equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana Pipeline Corporation.

Sch. 9	MONTANA REVENUES - NATURAL GAS (INCLUDES CMP)				
Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
Core Distribution Business Units (DBUs)					
440 Residential	$ 191,852,233	$ 63,401,173	$ 128,451,060	$ 137,445,515	-6.54%
442.1 Commercial	112,368,764	47,801,834	64,566,930	69,076,373	-6.53%
442.2 Industrial Firm	1,749,403	-	1,749,403	1,986,587	-11.94%
445 Public Authorities	529,675	-	529,675	534,923	-0.98%
448 Interdepartmental Sales	461,134	-	461,134	551,903	-16.45%
491.2 CNG Station	-	-	-	-	-
Total Sales to Core DBUs	306,961,209	111,203,007	195,758,202	209,595,301	-6.60%
447 Sales for Resale	22,946,833	-	22,946,833	12,297,483	86.60%
Total Sales of Natural Gas	22,946,833	-	22,946,833	12,297,483	86.60%
Transportation					
489 Transportation (inc. CMP)	22,433,604	3,887,612	18,545,992	17,364,900	6.80%
495 Off System Storage	54,385	-	54,385	-	100.00%
Total Revenues From Transportation	22,487,989	3,887,612	18,600,377	17,364,900	7.11%
Other Operating Revenue					
Miscellaneous Revenues	4,337,876	818,660	3,519,216	3,926,904	-10.38%
Total Other Operating Revenue	4,337,876	818,660	3,519,216	3,926,904	-10.38%
TOTAL OPERATING REVENUE	$ 356,733,907	$ 115,909,279	$ 240,824,628	$ 243,184,588	-0.97%

Sales for Resale reported on line 13 represents on and off-system sales from excess supply. Revenues generated from these sales flow back to customers as a credit to gas cost expense. This line consists of sales for resale and sales to other utilities, as compared to Schedule 35, which only reflects sales to other utilities.

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Gas Raw Materials**					
2	**Gas Raw Materials-Operation**					
3	728 Liquefied Petroleum Gas	$ -	$ -	$ -	$ -	-
4	735 Miscellaneous Production Expenses	32,626	32,626	-	-	-
5	**Total Operation-Gas Raw Materials**	32,626	32,626	-	-	-
6						
7	**Gas Raw Materials-Maintenance**					
8	741 Structures & Improvements	43,728	43,728	-	-	-
9	**Total Maintenance-Gas Raw Materials**	43,728	43,728	-	-	-
10	**Total Gas Raw Materials**	76,354	76,354	-	-	-
11	**Production Expenses**					
12						
13	**Production & Gathering-Operation**					
14	750 Supervision & Engineering	-	-	-	-	-
15	751 Maps & Records	-	-	-	-	-
16	752 Gas Wells Expenses	-	-	-	-	-
17	753 Field Lines Expenses	-	-	-	-	-
18	754 Field Compressor Station Expense	-	-	-	-	-
19	755 Field Comp. Station Fuel & Power	-	-	-	-	-
20	756 Field Meas. & Reg. Station Expense	-	-	-	-	-
21	757 Dehydration Expense	-	-	-	-	-
22	758 Gas Well Royalties	-	-	-	-	-
23	759 Other Expenses	-	-	-	-	-
24	760 Rents	-	-	-	-	-
25	**Total Oper.-Production & Gathering**	-	-	-	-	-
26						
27	**Other Gas Supply Expense-Operation**					
28	800 NG Wellhead Purchases	139,478,941	-	139,478,941	161,470,994	-13.62%
29	803 NG Transmission Line Purchases	422,935	-	422,935	102,447	>300.00%
30	805 Other Gas Purchases	91,208,549	92,300,348	(1,091,799)	7,228,938	-115.10%
31	805 Purchased Gas Cost Adjustments	-	-	-	-	-
32	805 Incremental Gas Cost Adjustments	-	-	-	-	-
33	805 Deferred Gas Cost Adjustments	-	-	-	-	-
34	806 Exchange Gas	-	-	-	-	-
35	807 Well Expenses-Purchased Gas	1,083,780	16,385	1,067,395	1,278,529	-16.51%
36	807 Purch. Gas Meas. Stations-Oper.	-	-	-	-	-
37	807 Purch. Gas Meas. Stations-Maint.	-	-	-	-	-
38	807 Purch. Gas Calculations Expenses	-	-	-	-	-
39	808 Other Purchased Gas Expenses	-	-	-	-	-
40	808 Gas Withdrawn from Storage -Dr.	(2,643,210)	-	(2,643,210)	(26,587,260)	90.06%
41	809 Gas Delivered to Storage -Cr.	-	-	-	-	-
42	810 Gas Used-Comp. Station Fuel-Cr.	-	-	-	-	-
43	811 Gas Used-Products Extraction-Cr.	-	-	-	-	-
44	812 Gas Used-Other Utility Oper.-Cr.	-	-	-	-	-
45	813 Other Gas Supply Expenses	-	-	-	-	-
46	**Total Other Gas Supply Expenses**	229,550,995	92,316,733	137,234,262	143,493,648	-4.36%
47	**Total Production Expenses**	229,550,995	92,316,733	137,234,262	143,493,648	-4.36%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Storage Expenses**					
2						
3	**Underground Storage-Operation**					
4	814 Supervision & Engineering	10,201	-	10,201	6,898	47.88%
5	815 Maps & Records	3,783	-	3,783	181	>300.00%
6	816 Wells	193,131	-	193,131	161,389	19.67%
7	817 Lines	33,546	-	33,546	9,252	262.58%
8	818 Compressor Station	379,789	-	379,789	319,624	18.82%
9	819 Compressor Station Fuel & Power	-	-	-	-	-
10	820 Measuring & Regulating Station	37,919	-	37,919	18,138	109.06%
11	821 Purification	71,823	-	71,823	67,965	5.68%
12	824 Other Expenses	91,074	-	91,074	134,607	-32.34%
13	825 Storage Well Royalties	146,609	-	146,609	143,998	1.81%
14	826 Rents	-	-	-	-	-
15	**Total Operation-Underground Storage**	967,875	-	967,875	862,052	12.28%
16						
17	**Underground Storage-Maintenance**					
18	830 Supervision & Engineering	-	-	-	-	-
19	831 Structures & Improvements	16,517	-	16,517	10,973	50.53%
20	832 Reservoirs & Wells	7,184	-	7,184	7,004	2.57%
21	833 Lines	10,598	-	10,598	10,545	0.50%
22	834 Compressor Station Equipment	198,081	-	198,081	177,976	11.30%
23	835 Meas. & Reg. Station Equipment	17,606	-	17,606	13,469	30.72%
24	836 Purification Equipment	14,817	-	14,817	12,656	17.08%
25	837 Other Equipment	4,283	-	4,283	1,684	154.24%
26	**Total Maintenance-Underground Storage**	269,086	-	269,086	234,307	14.84%
27	**Total Underground Storage Expenses**	1,236,961	-	1,236,961	1,096,359	12.82%
28	**Transmission Expenses**					
29	**Transmission-Operation**					
30	850 Supervision & Engineering	1,080,556	-	1,080,556	1,765,963	-38.81%
31	851 System Control & Load Dispatching	816,122	-	816,122	705,579	15.67%
32	853 Compressor Station Labor & Expense	596,597	-	596,597	577,577	3.29%
33	855 Other Fuel & Power for Comp. Stat.	-	-	-	-	-
34	856 Mains	879,350	-	879,350	985,282	-10.75%
35	857 Measuring & Regulating Station	711,104	-	711,104	704,554	0.93%
36	858 Transmission & Comp.-By Others	-	-	-	-	-
37	859 Other Expenses	1,153,909	-	1,153,909	1,075,018	7.34%
38	860 Rents	-	-	-	-	-
39	**Total Operation-Transmission**	5,237,638	-	5,237,638	5,813,973	-9.91%
40	**Transmission-Maintenance**					
41	861 Supervision & Engineering	1,025,095	-	1,025,095	169,825	>300.00%
42	862 Structures & Improvements	68,316	-	68,316	81,957	-16.64%
43	863 Mains	1,811,000	-	1,811,000	342,846	>300.00%
44	864 Compressor Station Equipment	553,384	-	553,384	489,239	13.11%
45	865 Meas. & Reg. Station Equipment	253,236	-	253,236	297,313	-14.83%
46	867 Other Equipment	14,730	-	14,730	15,463	-4.74%
47	**Total Maintenance-Transmission**	3,725,761	-	3,725,761	1,396,643	166.77%
48	**Total Transmission Expenses**	8,963,399	-	8,963,399	7,210,616	24.31%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Distribution Expenses**					
2	**Distribution-Operation**					
3	870 Supervision & Engineering	2,300,417	1,116,897	1,183,520	1,265,730	-6.50%
4	871 Load Dispatching	93,648	93,648	-	-	-
5	872 Compressor Station Labor & Expense	-	-	-	-	-
6	873 Compressor Station Fuel and Power	-	-	-	-	-
7	874 Mains and Services	3,571,228	1,459,535	2,111,693	1,803,181	17.11%
8	875 Meas. & Reg. Station-General	304,163	140,700	163,463	125,796	29.94%
9	876 Meas. & Reg. Station-Industrial	-	-	-	-	-
10	877 Meas. & Reg. Station-City Gate	54,128	53,325	803	203	295.72%
11	878 Meter & House Regulator	2,074,588	693,026	1,381,562	1,128,390	22.44%
12	879 Customer Installations	2,657,927	170,747	2,487,180	2,526,758	-1.57%
13	880 Other Expenses	1,258,462	353,586	904,876	702,755	28.76%
14	881 Rents	3,641	-	3,641	1,946	87.11%
15	**Total Operation-Distribution**	12,318,202	4,081,464	8,236,738	7,554,759	9.03%
16	**Distribution-Maintenance**					
17	885 Supervision & Engineering	388,692	155,410	233,282	228,420	2.13%
18	886 Structures & Improvements	8,674	8,674	-	-	-
19	887 Mains	918,808	288,501	630,307	464,792	35.61%
20	889 Meas. & Reg. Station Exp.-General	107,290	65,919	41,371	45,700	-9.47%
21	890 Meas. & Reg. Station Exp.-Industrial	-	-	-	-	-
22	891 Meas. & Reg. Station Exp.-City Gate	47,823	47,823	-	-	-
23	892 Services	699,148	189,521	509,627	297,544	71.28%
24	893 Meters & House Regulators	834,616	237,070	597,546	494,510	20.84%
25	894 Other Equipment	-	-	-	-	-
26	**Total Maintenance-Distribution**	3,005,051	992,918	2,012,133	1,530,966	31.43%
27	**Total Distribution Expenses**	15,323,253	5,074,382	10,248,871	9,085,725	12.80%
28	**Customer Accounts Expenses**					
29	**Customer Accounts-Operation**					
30	901 Supervision	-	-	-	-	-
31	902 Meter Reading	1,152,867	724,148	428,719	435,551	-1.57%
32	903 Customer Records & Collection	3,065,662	590,623	2,475,039	2,331,792	6.14%
33	904 Uncollectible Accounts	1,402,620	455,314	947,306	1,407,013	-32.67%
34	905 Miscellaneous Customer Accounts	52,691	52,708	(17)	118	-114.75%
35	**Total Customer Accounts Expenses**	5,673,840	1,822,793	3,851,047	4,174,474	-7.75%
36						
37	**Customer Service & Information Expenses**					
38	**Customer Service-Operation**					
39	907 Supervision	-	-	-	-	-
40	908 Customer Assistance	2,094,201	978,188	1,116,013	1,006,306	10.90%
41	909 Inform. & Instructional Advertising	359,628	87,157	272,471	221,643	22.93%
42	910 Misc. Customer Service & Inform.	-	-	-	-	-
43	**Total Customer Service & Information Exp.**	2,453,829	1,065,345	1,388,484	1,227,949	13.07%
44						
45	**Sales Expenses**					
46	**Sales-Operation**					
47	911 Supervision	-	-	-	-	-
48	912 Demonstrating & Selling	-	-	-	-	-
49	913 Advertising	390,384	109,370	281,014	326,186	-13.85%
50	916 Miscellaneous Sales	-	-	-	-	-
51	**Total Sales Expenses**	390,384	109,370	281,014	326,186	-13.85%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Administrative & General Expenses**					
2	**Admin. & General - Operation**					
3	920 Administrative & General Salaries	12,440,051	3,441,205	8,998,846	7,127,534	26.25%
4	921 Office Supplies & Expenses	2,870,075	933,149	1,936,926	1,739,271	11.36%
5	922 Administrative Exp. Transferred-Cr.	(2,893,517)	(747,012)	(2,146,505)	(1,867,952)	-14.91%
6	923 Outside Services Employed	2,085,928	425,905	1,660,023	1,691,523	-1.86%
7	924 Property Insurance	301,389	88,518	212,871	235,077	-9.45%
8	925 Legal & Claim Department	3,692,778	1,202,566	2,490,212	1,195,016	108.38%
9	926 Employee Pensions & Benefits	(1,123,975)	(900,577)	(223,398)	550,031	-140.62%
10	928 Regulatory Commission Expenses	155,513	238	155,275	105,826	46.73%
11	930 Miscellaneous General Expenses	2,756,935	167,947	2,588,988	2,854,839	-9.31%
12	931 Rents	924,221	257,185	667,036	457,125	45.92%
13	**Total Operation-Admin. & General**	21,209,398	4,869,124	16,340,274	14,088,290	15.98%
14	**Admin. & General - Maintenance**					
15	935 General Plant	1,275,104	134,412	1,140,692	1,009,379	13.01%
16	**Total Admin. & General Expenses**	22,484,502	5,003,536	17,480,966	15,097,668	15.79%
17	**TOTAL OPER. & MAINT. EXPENSES**	$ 286,153,517	$ 105,468,513	$ 180,685,004	$ 181,712,626	-0.57%
18						
19						
20						
21						
22						

Sch. 11	MONTANA TAXES OTHER THAN INCOME - NATURAL GAS (INCLUDES CMP)			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	$1,447,586	$1,285,405	12.62%
3	Property Taxes	20,099,799	18,694,300	7.52%
4	Crow Tribe RR and Utility Tax	55,887	53,097	5.25%
5	Blackfoot Possessoray Tax	291,271	288,455	0.98%
6	City Tax	3,436	2,600	32.15%
7	Consumer Counsel	173,901	176,297	-1.36%
8	Public Service Commission	566,017	618,935	-8.55%
9	Heavy Highway Use	8,477	5,019	68.90%
10	Vehicle Use Taxes	67,583	61,221	10.39%
11	Oil & Gas Royalty Taxes	180,658	217,973	-17.12%
12	Delaware Franchise Tax	36,149	35,728	1.18%
13				
14				
15				
16	**Canadian Taxes**			
17	Ad Valorem	17,773	16,857	5.43%
18				
19				
20				
21				
22	**TOTAL TAXES OTHER THAN INCOME**	$22,948,537	$21,455,887	6.96%

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	Alco Oil & Gas Production	Engineering & Fabrication Services	$ 124,552
2	Alliance Data Systems	IT Support Services	2,895,074
3	American Gas Association	Membership Dues	77,658
4	Areva T&D Inc.	Software Support Services	219,705
5	Asplundh Tree Expert Co.	Tree Trimming	3,784,900
6	Associated Arborists	Vegetation Management	259,392
7	Automotive Rentals Inc.	Fleet Management	6,264,065
8	Baker Hughes-Pipeline Management	Pipeline Cleaning & Inspection	77,454
9	Balhoff & Rowe LLC	Legal Services	105,000
10	Bill Field Trucking Inc.	Equipment Transportation	375,809
11	Black & Veatch Corporation	Rate Case Consultants	162,158
12	Browning, Kaleczyc, Berry & Hoven	Legal Services	501,089
13	CA Inc.	IT Network Support	76,188
14	Capstone Advisory Group LLC	Legal Services	383,668
15	Central Air Service Inc.	Aerial Patrol Services	207,500
16	Curtis, Mallet-Prevost, Colt & Mosle LLP	Legal Services	4,757,116
17	Davenport, Evans, Hurwitz & Smith, LLC	Legal Services	1,573,942
18	Deloitte & Touche LLP	Audit Services	1,921,793
19	Deloitte Tax LLP	Tax Consulting Services	205,539
20	Dept. of Health and Human Services	Weatherization Program Services	1,549,713
21	Devlin Enterprises	Lobbying & Special Projects	77,085
22	Diamond Construction Inc	Construction	92,388
23	Dickstein Shapiro LLP	Legal Services	3,045,284
24	Distribution Construction Co.	Gas Pipeline Construction	1,995,343
25	Edison Electric Institute	Membership Dues	249,455
26	EDM International Inc.	Anchor Rod Inspection Services	112,689
27	EideBailly	Audit Services	83,592
28	EIM Energy Insurance Mutual	Insurance Premiums	480,264
29	Elliott Avation Inc	Aircraft Maintenance	78,725
30	ELM Locating & Utility Service	Locating Services & Excavation Notifications	2,164,177
31	Energy Share of Montana	USBC Services	527,083
32	Entrix Inc	Consulting & Engineering Services	990,402
33	Factory Mutual Insurance Company	Insurance Premiums	880,525
34	Faegre & Benson LLP	Legal Services	163,956
35	Falls Construction Company	Construction	150,000
36	Filenet Corporation	Software Maintenance	85,091
37	Flow-Cal	Software & Support Services	408,200
38	Flying Horse Communication Inc.	Advertising & Public Relations	1,389,879
39	GE Support Services	Redesign/Remanufacture of Auto Transformer	354,989
40	Greenberg - Traurig	Legal Services	268,732
41	Gregory & Cook Inc.	Construction	5,904,360
42	Haverfield International Inc.	Aerial Inspection Services	204,028
43	Heath Consultants Inc	Gas Leak Surveys	98,010
44	High Mountain Inspection Services	Gas Pipeline Inspection Services	167,104
45	Hughes, Kellner, Sullivan & Alke	Legal Services	188,544
46	Independent Inspection Company	Electric Line Inspection	648,157
47	Independent Power Systems Inc.	Installation of Renewal Energy Systems	145,603
48	Integrity Interactive	Employee Online Training	103,000
49	Intergraph Corporation	Software Consultants	570,215
50	Itron Inc.	Hardware & Software Maintenance	715,171
51	Jon S. Fossel	Board of Directors' Fees	173,027
52	Jordon Contracting Inc.	Construction & Hauling Services	360,152
53	Kema Services Inc.	USB & DSM Programs & Services	3,314,074
54	Lands Energy Consulting	Energy Consultants	145,767
55	Larson Digging Inc	Construction	116,342
56	Law Debenture Trust Company of New York	Legal Services	112,089
57	LC Staffing Service	Temporary Employment Services	273,918
58	Leonard, Street & Deinard	Legal Services	2,178,859
59	Manatt, Phelps & Phillips LLP	Legal Services	193,475
60	MAPPCOR	Electric Reliability Services	176,879
61	Marsh USA Inc	Insurance Premiums & Consulting	3,405,684
62	Mattingly Testing Services Inc	Radiographic Inspection Services	82,307
63	Mercer Human Resource Consultants	Actuarial & Consulting Services	110,432
64	Moran Iron Works Inc	Electric Generation Contractor	91,100

Sch. 12A	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
65	National Tank & Tower	Construction	100,600
66	Nat'l Center for Appropriate Technology	Lab Testing	458,651
67	Natural Gas Services Inc.	Gas Serviceman	147,430
68	Nexant Inc.	USB & DSM Program Consultants	536,030
69	Northwest Energy Efficiency	Energy Services	255,133
70	Par Electric Contractors Inc.	Electric Construction & Maintenance	6,736,228
71	Paul Hastings, Janofsky & Walker	Legal Services	1,138,844
72	Paul, Weiss, Rifkind, Wharton	Legal Services	331,438
73	Paulsen Marketing	Advertising	344,127
74	Pole Maintenance Company LLC	GIS Pole Inventory Services	206,016
75	Pondera Engineers	Engineering Services	109,562
76	Poteet Construction	Traffic Control Services	82,774
77	Power Engineers Inc.	Engineering Services	745,944
78	Pro Pipe Services Inc.	Pipeline Fabrication Services	3,404,478
79	Regenco LLC	Electric Generation Contractor	573,999
80	Rembolt Ludtke LLP	Rate Case Consultant	85,479
81	RML Inc.	Boring Services	101,391
82	Rocky Mountain Contractors Inc.	Electric Construction & Maintenance	14,094,820
83	Rod Tabbert Construction Inc.	Construction	524,171
84	Rounds Brothers Trenching	Boring Services	109,758
85	SAP America Inc.	Software Maintenance	800,290
86	Schrock Construction Inc	Construction	98,647
87	Scott Magie	Electric Generation Consultant	109,625
88	Solar Plexus	USB & DSM Program Consultants	85,169
89	Spherion Corporation	Temporary Employment Services	106,813
90	State Line Contractors Inc.	Electric Construction & Maintenance	436,644
91	Stencil Corporation	Construction	93,971
92	Steptoe & Johnson LLP	Legal Services	362,741
93	Stone & Webster Consultants	Power Generation Development	256,691
94	Sundance Solar Systems	Installation of Renewal Energy Systems	280,649
95	TC Power LLC	Engine Repair Services	121,545
96	Terra Contracting LLC	Remediation Work	1,234,184
97	Terracon	Engineering Services	141,124
98	The Bayard Firm	Legal Services	101,076
99	The Brattle Group	Cost of Capital Consultants	322,311
100	The Electric Company	Construction & Maintenance	261,902
101	The Energy Authority Inc.	Scheduling & Dispatching	431,700
102	The L E Meyers Co	Storm Damage Restoration	492,076
103	Tony Laslovich Construction	Construction	199,398
104	TP Construction Inc.	Construction	109,489
105	Trademark Electric Inc.	Electrical Contractors	228,337
106	Upper Cut Tree Service	Tree Trimming	117,464
107	Utilities Underground Location	Locating Services & Excavating Notifications	131,782
108	Varsity Contractors Inc.	Janitorial Services	210,958
109	Walker Truesdell & Associates	Legal Services	268,050
110	Washington Forestry Consultants	Forestry Consultants	251,872
111	Waterman Energy Inc	Pipeline Inspection Services	84,062
112	Wayne M Hitt CPA	Tax Consulting Services	292,983
113	Williamson Fencing & Spr.,Inc.	Construction	99,502
114	Wilmer Cutler Pickering Hale	Legal Services	276,929
115	Wood Group Pratt & Whitney LLC	Electric Construction & Maintenance	122,983
116	Wright and Sudlow, Inc.	Concrete Contractor	88,979
117	Wright Tree Service Inc	Tree Trimming	262,035
118	Zacha Underground Construction Co.	Construction	124,308
	Total of Payments Set Forth Above		**$ 97,291,633**

1/ This schedule includes payments for professional services over $75,000 by NorthWestern Corporation, doing business as NorthWestern Energy.

Sch. 13	POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS			
	Description	Total Company	Montana	% Montana
1				
2	NorthWestern Energy does not make any			
3	contributions to Political Action Committees			
4	(PACs) or candidates. The company may			
5	contribute to ballot issue campaigns in			
6	accordance with various state laws.			
7				
8				
9	There are two employee PACs, one called			
10	Citizens for Responsible Government /			
11	Employees of NorthWestern Energy, and one			
12	called NorthWestern Public Service			
13	Employee's Political Action Committee. These			
14	are organizations of employees and			
15	shareholders of NorthWestern Energy. All of			
16	the money contributed by members goes to			
17	support political candidates. No company			
18	funds may be spent in support of a political			
19	candidate. Nominal administrative costs for			
20	such things as duplicating, postage and			
21	meeting expenses are paid by the company.			
22	These costs are charged to shareholder			
23	expense.			
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46				
47	**TOTAL Contributions**			

Sch. 14	**Pension Costs** 1/			
1	Plan Name: NorthWestern Energy Pension Plan			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Projected Unit Credit	IRS Code: ______		
4	Annual Contribution by Employer: Variable	Is the Plan Over Funded? No		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year	$ 334,814,884	$ 333,296,099	0.46%
8	Service cost	7,985,513	8,075,745	-1.12%
9	Interest cost	18,926,540	17,957,484	5.40%
10	Plan participants' contributions	-	-	-
11	Amendments	-	-	-
12	Actuarial (gain) loss	(17,719,569)	(9,175,027)	-93.13%
13	Acquisition	-	-	-
14	Benefits paid	(16,863,774)	(15,339,417)	-9.94%
15	Benefit obligation at end of year	$ 327,143,594	$ 334,814,884	-2.29%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 258,200,790	$ 230,694,073	11.92%
18	Actual return on plan assets	23,905,777	27,096,134	-11.77%
19	Acquisition	-	-	-
20	Employer contribution	21,966,321	15,750,000	39.47%
21	Plan participants' contributions	-	-	-
22	Benefits paid	(16,863,774)	(15,339,417)	-9.94%
23	Fair value of plan assets at end of year	$ 287,209,114	$ 258,200,790	11.23%
24	**Funded Status**	$ (39,934,480)	$ (76,614,094)	47.88%
26	Unrecognized net actuarial gain (loss)	-	-	-
27	Unrecognized prior service cost	-	-	-
29	Prepaid (accrued) benefit cost	$ (39,934,480)	$ (76,614,094)	47.88%
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	6.25%	5.75%	8.70%
32	Expected return on plan assets	8.00%	8.00%	
33	Rate of compensation increase	3.50% Union & 3.55% Non-Union	3.50% Union & 3.57% Non-Union	
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	$ 7,985,513	$ 8,075,745	-1.12%
36	Interest cost	18,926,540	17,957,484	5.40%
37	Expected return on plan assets	(21,160,455)	(18,357,293)	-15.27%
38	Amortization of prior service cost	241,913	241,913	-
39	Recognized net actuarial loss			
40	Net periodic benefit cost (SEC Basis)	$ 5,993,511	$ 7,917,849	-24.30%
41	**Montana Intrastate Costs: (MPSC Regulatory Basis)**	-	-	
42	Pension Costs	$ 21,950,000	$ 21,950,000	-
43	Pension Costs Capitalized	$ 4,045,338	$ 4,389,649	-7.84%
44	Accumulated Pension Asset (Liability) at Year End	$ (39,934,480)	$ (76,614,094)	47.88%
45	**Number of Company Employees:**		-	
46	Covered by the Plan	3,190	3,186	0.13%
47	Not Covered by the Plan			
48	Active	1,060	1,062	-0.19%
49	Retired	1,244	1,222	1.80%
50	Deferred Vested Terminated	886	902	-1.77%

1/ NorthWestern Corporation has a separate pension plan covering South Dakota and Nebraska employees that is not reflected above.

Sch. 14a	**Pension Costs**			
1	Plan Name: NorthWestern Energy 401k Retirement Savings Plan			
2	Defined Benefit Plan? No	Defined Contribution Plan? Yes		
3	Actuarial Cost Method? N/A	IRS Code: 401(k)		
4	Annual Contribution by Employer: Variable	Is the Plan Over Funded? N/A		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year			
8	Service cost			
9	Interest cost			
10	Plan participants' contributions	Not Applicable		
11	Amendments			
12	Actuarial loss			
13	Acquisition			
14	Benefits paid			
15	Benefit obligation at end of year	$ -	$ -	
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year			
18	Actual return on plan assets			
19	Acquisition			
20	Employer contribution 2/	$ 4,723,552	$ 4,292,508	10.04%
21	Plan participants' contributions			
22	Benefits paid			
23	Fair value of plan assets at end of year 2/	$ 207,762,674	$ 199,305,859	4.24%
24	**Funded Status**	Not Applicable		
25	Unrecognized net actuarial loss			
26	Unrecognized prior service cost			
27	Prepaid (accrued) benefit cost	$ -	$ -	
28				
29	**Weighted-average Assumptions as of Year End**	Not Applicable		
30	Discount rate			
31	Expected return on plan assets			
32	Rate of compensation increase			
33				
34	**Components of Net Periodic Benefit Costs**	Not Applicable		
35	Service cost			
36	Interest cost			
37	Expected return on plan assets			
38	Amortization of prior service cost			
39	Recognized net actuarial loss			
40	Net periodic benefit cost (SEC Basis)	$ -	$ -	
41				
42	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
43	Pension Costs	$ 3,100,121	$ 2,881,684	7.58%
44	Pension Costs Capitalized	571,346	$ 576,291	-0.86%
45	Accumulated Pension Asset (Liability) at Year End	Not Applicable		
46	**Number of Company Employees:**	3/	3/	
47	Covered by the Plan - Eligible	1,340	1,340	
48	Not Covered by the Plan			
49	Active - Participating	1,273	1,265	0.63%
50	Retired			
51	Vested Former Employees, Retirees and Active-	267	275	-2.91%
52	Noncontributing			

2/ This plan covers all NorthWestern Corporation employees.

3/ Represents total company 401(k) plan participants.

Sch. 15	**Other Post Employment Benefits (OPEBS)**			
	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number: 93.6.24			
4	Order number: 5709d			
5	Amount recovered through rates	$3,238,965	$4,691,046	-30.95%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	6.00%	5.75%	4.35%
8	Expected return on plan assets	8.00%	8.00%	
9	Medical Cost Inflation Rate 3/	10.0%,5.0%:13	8.0%,5.0%:10	
10	Actuarial Cost Method	Projected Unit Credit Actuarial, Cost Method Allocated from the Date of Hire to Full Eligibility Date		
11	Rate of compensation increase	3.50% Union & 3.55% Non-Union	3.50% Union & 3.57% Non-Union	
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	**Union Employees - VEBA - Yes, tax advantaged**			
14	**Non-Union Employees - 401(h) - Yes, tax advantaged**			
15	**Describe any Changes to the Benefit Plan:**			
16				

1/ Obtained from NorthWestern Energy-Montana's 2007 FASB 106 Valuation. Assumptions and data are as of December 31, 2007.

2/ Obtained from NorthWestern Energy-Montana's 2006 FASB 106 Valuation. Assumptions and data are as of December 31, 2006.

3/ First Year, Ultimate, Years to Reach Ultimate.

Sch. 15a	Other Post Employment Benefits (OPEBS) (continued)			
	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan			
3	Not Covered by the Plan			
4	Active			
5	Retired			
6	Spouses/Dependants covered by the Plan			
7	**Montana 4/**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year	$43,025,921	$45,277,018	-4.97%
10	Service cost	580,372	$740,490	-21.62%
11	Interest Cost	2,034,633	$2,340,596	-13.07%
12	Plan participants' contributions	-		-
13	Amendments	-		-
14	Actuarial loss/(gain)	(5,972,918)	($2,768,590)	-115.74%
15	Acquisition	-		-
16	Benefits paid	(2,348,542)	($2,563,593)	8.39%
17	Benefit obligation at end of year	$37,319,466	$43,025,921	-13.26%
18	**Change in Plan Assets**	-	-	
19	Fair value of plan assets at beginning of year	$13,357,707	$10,362,537	28.90%
20	Actual return on plan assets	890,955	$1,040,979	-14.41%
21	Acquisition	-		-
22	Employer contribution	4,554,140	$4,517,784	0.80%
23	Plan participants' contributions	-		-
24	Benefits paid	(2,348,542)	($2,563,593)	8.39%
25	Fair value of plan assets at end of year	$16,454,260	$13,357,707	23.18%
26	**Funded Status**	($20,865,206)	($29,668,214)	29.67%
27	Unrecognized net transition (asset)/obligation	-	-	-
28	Unrecognized net actuarial loss/(gain)	-	-	-
29	Unrecognized prior service cost	-	-	-
30	Prepaid (accrued) benefit cost	($20,865,206)	($29,668,214)	29.67%
31	**Components of Net Periodic Benefit Costs**	-	-	
32	Service cost	$580,372	$740,490	-21.62%
33	Interest cost	2,034,633	$2,340,596	-13.07%
34	Expected return on plan assets	(1,068,617)	($829,003)	-28.90%
35	Amortization of transitional (asset)/obligation	-	$788,960	-100.00%
36	Amortization of prior service cost	-	$28,211	-100.00%
37	Recognized net actuarial loss/(gain)	(358,849)	$1,621,792	-122.13%
38	Net periodic benefit cost	$1,187,539	$4,691,046	-74.68%
39	**Accumulated Post Retirement Benefit Obligation**	-	-	
40	Amount Funded through VEBA	$ -	$729,200	-100.00%
41	Amount Funded through 401(h)	1,028,663	$1,476,398	-30.33%
42	Amount Funded through other - Company funds	2,210,302	$2,485,448	-11.07%
43	TOTAL	$3,238,965	$4,691,046	-30.95%
44	Amount that was tax deductible - VEBA		$729,200	-100.00%
45	Amount that was tax deductible - 401(h)	1,028,663	$1,476,398	-30.33%
46	Amount that was tax deductible - Other	2,210,302	$2,485,448	-11.07%
47	TOTAL	$3,238,965	$4,691,046	-30.95%
48	**Montana Intrastate Costs:**	-	-	
49	Pension Costs	$3,238,965	$4,691,046	-30.95%
50	Pension Costs Capitalized	596,934	938,134	-36.37%
51	Accumulated Pension Asset (Liability) at Year End	($20,865,206)	($29,668,214)	29.67%
52	**Number of Montana Employees:**		-	
53	Covered by the Plan	2,164	2,173	-0.41%
54	Not Covered by the Plan	157	168	-6.55%
55	Active	1,080	1,086	-0.55%
56	Retired	974	976	-0.20%
57	Spouses/Dependants covered by the Plan	110	111	-0.90%

4/ There is approximately an additional $9,174,106 and $10,037,080 in other company OPEBS liabilities outstanding at December 31, 2007 and 2006, respectively for other supplemental retirement agreements in addition to what is reflected for Montana above.

SCHEDULE 16

Note: This schedule includes the ten most highly compensated employees assigned or allocated to Montana that are not already included on Sch 17.

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary (Wages)	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	David G. Gates Vice President, Wholesale Operations	197,428	51,895 A	21,808 C 9,000 D 525 E 81,961 F 10,478 G 10,550 H 148 I	383,792	318,071	21%
2	Bart A. Thielbar Director, Special Projects	194,906	43,907 A	32,330 C 9,000 D 649 E 82,759 F 0 G 70 H	363,621	287,207	27%
3	Kendall Kliewer Vice President, Controller	189,519	46,095 A	29,729 C 9,000 D 71,667 F 1,202 G	347,213	287,200	21%
4	Paul James Evans Treasurer	186,745	44,774 A	28,995 C 9,000 D 62,821 F 3,533 G	335,868	275,679	22%
5	Bobbi L. Schroeppel Vice President, Customer Care & Communications	174,519	43,239 A	30,816 C 9,000 D 630 E 57,792 F 0 G	315,997	256,768	23%
6	Patrick R. Corcoran Vice President, Government & Regulatory Affairs	166,538	38,368 A	13,004 C 9,000 D 57,252 F 17,328 G	301,491	254,035	19%
7	Michael L. Nieman Officer, Internal Audit & Control	157,115	31,653 A	28,825 C 420 E 41,876 F 0 G	259,889	210,833	23%
8	Christian P. Fonss Director, Tax	159,863	22,181 A	3,997 B 23,081 C 35,529 F 6,695 G	251,346	221,907	13%
9	John S Fitzpatrick Director, Exec State/Local Comm Rel	151,233	18,007 A	17,347 C 6,300 D 30,242 F 16,865 G 222 I	240,216	N/A	
10	W Wayne Harper Senior Attorney	156,537	16,322 A	20,634 C 3,413 D 210 E 31,451 F 7,613 G	236,180	N/A	

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation

1/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the 2007 Employee Incentive Compensation Plan. Amounts were earned in 2007 but paid in the first quarter of 2008. Based on company performance against plan, the incentive plan was funded at 75% of target. Individual awards varied from the funded level based on individual performance.

2/ All Other Compensation for named employees consists of the following:

B> Merit cash.

C> Employer contributions to benefits - medical, dental, vision, employee assistance program, group term life, 401(k) match, and non-elective 401(k) contribution.

D> Vehicle allowance.

E> Imputed income - personal use of Hebgen Lake property.

F>These values reflect the compensation expense recognized for restricted stock awards and are calculated using the provisions of SFAS No. 123R, *Share-Based Payments*.

G>Change in pension value over previous year. The present value of accumulated benefits was calculated assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2007. Changes in actuarial assumptions for discount rate from 5.75% to 6.25% and interest crediting rate from 6.0% to 5.5% resulted in lower changes in pension value than was reported for 2006. Where the change in value is shown as zero (0), the actuarial change in value is as follows:

Mr. Thielbar	(5,932)
Ms. Schroeppel	(1,282)
Mr. Nieman	(7,275)

H> Vacation sold back during the year.

I> Taxable gift certificate with gross up.

SCHEDULE 17

Note: This schedule contains the five most highly compensated corporate officers who are assigned or allocated to Montana.

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary (Wages)	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	Michael J. Hanson President & Chief Executive Officer	521,635	0 A	35,928 B 14,400 C 2,847 D 431,975 F 14 G	1,006,799	896,743	12%
2	Brian B. Bird Vice President, Chief Financial Officer	301,846	109,411 A	32,638 B 12,000 C 208,235 F 4,731 G	668,862	496,910	35%
3	Thomas J. Knapp Vice President, General Counsel & Corporate Secretary	265,420	77,842 A	36,138 B 10,200 C 139,482 F 7,950 G	537,033	395,517	36%
4	Gregory G. Trandem Vice President, Administrative Services	206,731	60,912 A	38,079 B 1,428 D 500 E 108,534 F 6,447 G	422,631	312,233	35%
5	Curtis T. Pohl Vice President, Retail Operations	190,000	51,846 A	32,426 B 9,000 D 93,973 F 0 G	377,245	269,619	40%

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation

1/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the 2007 Employee Incentive Compensation Plan. Amounts were earned in 2007 but paid in the first quarter of 2008. Based on company performance against plan, the incentive plan was funded at 75.% of target. Officer awards varied from the funded level based on individual performance.

2/ All Other Compensation for named employees consists of the following:

B> Employer contributions to benefits - medical, dental, vision, employee assistance program, group term life, 401(k) match, and non-elective 401(k) contribution.

C> Imputed income - personal use of company provided vehicle.

D> Imputed income - spouse travel

E> Imputed income - personal use of Hebgen Lake property.

F>These values reflect the compensation expense recognized for restricted stock awards and are calculated using the provisions of SFAS No. 123R, *Share-Based Payments*.

G>Change in pension value over previous year. The present value of accumulated benefits was calculated assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2007. Changes in actuarial assumptions for discount rate from 5.75% to 6.25% and interest crediting rate from 6.0% to 5.5% resulted in lower changes in pension value than was reported for 2006. In Mr. Pohl's case, the change in value was calculated at ($14,129).

Sch. 18	BALANCE SHEET 1/			
	Account Title	This Year	Last Year	% Change
1	**Assets and Other Debits**			
2	**Utility Plant**			
3	101 Plant in Service	$2,554,329,610	$2,454,337,364	4.07%
4	101.1 Property Under Capital Leases	40,209,537	40,209,537	0.00%
5	105 Plant Held for Future Use	4,900	4,900	0.00%
6	107 Construction Work in Progress	23,014,098	3,240,549	>300.00%
7	108 Accumulated Depreciation Reserve	(1,235,398,220)	(1,183,035,857)	4.43%
8	108.1 Accumulated Depreciation - Capital Leases	(3,015,704)	(1,005,236)	200.00%
9	111 Accumulated Amortization & Depletion Reserves	(44,057,594)	(34,727,173)	26.87%
10	114 Electric Plant Acquisition Adjustments	3,106,285	3,106,285	0.00%
11	115 Accumulated Amortization-Electric Plant Acq. Adj.	(2,916,457)	(2,821,543)	3.36%
12	116 Utility Plant Adjustment - Goodwill	355,128,500	435,075,587	-18.38%
13	117 Gas Stored Underground-Noncurrent	32,114,042	32,141,968	-0.09%
14	**Total Utility Plant**	1,722,518,996	1,746,526,381	-1.37%
15	**Other Property and Investments**			
16	121 Nonutility Property	7,570,168	5,357,845	41.29%
17	122 Accumulated Depr. & Amort.-Nonutililty Property	(132,378)	(1,473,243)	-91.01%
18	123.1 Investments in Assoc Companies and Subsidiaries	135,378,281	122,047,039	10.92%
19	124 Other Investments	989,732	1,541,359	-35.79%
20	128 Miscellaneous Special Funds	-	-	-
21	LT Portion of Derivative Assets - Hedges	-	-	-
22	**Total Other Property & Investments**	143,805,804	127,473,000	12.81%
23	**Current and Accrued Assets**			
24	131 Cash	12,663,974	1,823,151	>300.00%
25	134 Other Special Deposits	3,309,573	2,965,707	11.59%
26	135 Working Funds	42,285	42,010	0.65%
27	136 Temporary Cash Investments	-	-	-
28	141 Notes Receivable	9,613	49,909	-80.74%
29	142 Customer Accounts Receivable	62,246,102	65,175,722	-4.49%
30	143 Other Accounts Receivable	11,819,105	18,820,350	-37.20%
31	144 Accumulated Provision for Uncollectible Accounts	(3,166,261)	(3,239,842)	-2.27%
32	145 Notes Receivable-Associated Companies	-	-	-
33	146 Accounts Receivable-Associated Companies	30,101,180	15,337,813	96.25%
34	151 Fuel Stock	4,725,662	3,313,948	42.60%
35	154 Plant Materials and Operating Supplies	17,951,184	17,902,740	0.27%
36	164 Gas Stored - Current	40,851,403	39,240,016	4.11%
37	165 Prepayments	10,114,245	9,964,222	1.51%
38	171 Interest and Dividends Receivable	-	-	-
40	172 Rents Receivable	33,816	61,624	-45.13%
41	173 Accrued Utility Revenues	75,953,898	68,858,563	10.30%
42	174 Miscellaneous Current & Accrued Assets	988,362	1,161,255	-14.89%
43	175 Derivative Instrument Assets (175)	5,719,757	-	100.00%
44	(Less) Long-Term Portion of Derivative Instrument Assets	-	-	-
45	176 LT Portion of Derivative Assets - Hedges	-	-	-
46	(less) LT Portion of Derivative Assets - Hedges	-	-	-
47	**Total Current & Accrued Assets**	273,363,897	241,477,188	13.20%
48	**Deferred Debits**			
49	181 Unamortized Debt Expense	14,858,756	17,255,590	-13.89%
50	182 Regulatory Assets	108,179,282	148,502,899	-27.15%
51	183 Preliminary Survey and Investigation Charges	1,752,718	-	100.00%
52	184 Clearing Accounts	9,306	43,321	-78.52%
53	185 Temporary Facilities	78	78	0.00%
54	186 Miscellaneous Deferred Debits	704,587	21,292,515	-96.69%
55	189 Unamortized Loss on Reacquired Debt	4,318,150	4,637,192	-6.88%
56	190 Accumulated Deferred Income Taxes	84,729,364	45,646,258	85.62%
57	191 Unrecovered Purchased Gas Costs	(12,436,320)	5,612,870	>-300.00%
58	**Total Deferred Debits**	202,115,920	242,990,723	-16.82%
59	**TOTAL ASSETS and OTHER DEBITS**	$ 2,341,804,617	$ 2,358,467,292	-0.71%

Sch. 18	cont. BALANCE SHEET 1/			
	Account Title	This Year	Last Year	% Change
1	**Liabilities and Other Credits**			
2	**Proprietary Capital**			
3	201 Common Stock Issued	$ 393,339	$ 359,624	9.38%
4	204 Preferred Stock Issued	-	-	-
5	207 Premium on Capital Stock	-	-	-
6	211 Miscellaneous Paid-In Capital	803,061,335	727,327,890	10.41%
7	213 Discount on Capital Stock	-	-	-
8	214 Capital Stock Expense	-	-	-
9	215 Appropriated Retained Earnings	-	-	-
10	216 Unappropriated Retained Earnings	16,602,789	10,697,804	55.20%
12	217 Reacquired Capital Stock	(10,780,785)	(9,885,098)	9.06%
13	219 Accumulated Other Comprehensive Income	13,747,958	14,271,357	-3.67%
14	**Total Proprietary Capital**	823,024,636	742,771,577	10.80%
15	**Long Term Debt**			
16	221 Bonds	621,555,000	621,920,000	-0.06%
17	223 Advances in Associated Companies	-	-	-
18	224 Other Long Term Debt	12,000,000	50,000,000	-76.00%
19	226 Unamortized Discount on Long Term Debt-Debit	63,700	71,051	-10.35%
20	**Total Long Term Debt**	633,491,300	671,848,949	-5.71%
21	**Other Noncurrent Liabilities**			
22	227 Obligations Under Capital Leases-Noncurrent	38,001,667	39,323,563	-3.36%
23	228.1 Accumulated Provision for Property Insurance	-	(70,841)	-100.00%
24	228.2 Accumulated Provision for Injuries and Damages	11,128,272	8,617,963	29.13%
25	228.3 Accumulated Provision for Pensions and Benefits	44,970,186	52,570,168	-14.46%
26	228.4 Accumulated Miscellaneous Operating Provisions	189,459,290	180,640,922	4.88%
27	229 Accumulated Provision for Rate Refunds	2,243,806	-	100.00%
28	230 Asset Retirement Obligations	4,453,043	3,801,012	17.15%
29	**Total Other Noncurrent Liabilities**	290,256,263	284,882,787	1.89%
30	**Current and Accrued Liabilities**			
31	231 Notes Payable	-	-	-
32	232 Accounts Payable	99,473,440	88,243,949	12.73%
33	233 Notes Payable to Associated Companies	-	-	-
34	234 Accounts Payable to Associated Companies	6,294,395	42,752,662	-85.28%
35	235 Customer Deposits	8,113,459	7,641,259	6.18%
36	236 Taxes Accrued	132,621,196	129,908,326	2.09%
37	237 Interest Accrued	11,882,783	11,091,501	7.13%
39	238 Dividends Declared	-	-	-
40	241 Tax Collections Payable	1,386,961	1,429,703	-2.99%
41	242 Miscellaneous Current and Accrued Liabilities	54,859,330	60,141,393	-8.78%
42	243 Obligations Under Capital Leases-Current	2,388,703	1,414,661	68.85%
43	244 Derivative Instrument Liabilities	51,483	4,331,833	-98.81%
44	245 Derivative Instrument Liabilities - Hedges	-	-	-
45	**Total Current and Accrued Liabilities**	317,071,751	346,955,287	-8.61%
46	**Deferred Credits**			
47	252 Customer Advances for Construction	45,193,740	33,501,677	34.90%
48	253 Other Deferred Credits	45,237,585	87,874,078	-48.52%
49	254 Regulatory Liabilities	32,137,737	26,296,808	22.21%
50	255 Accumulated Deferred Investment Tax Credits	3,497,059	4,028,288	-13.19%
51	257 Unamortized Gain on Reacquired Debt	-	-	-
52	281-283 Accumulated Deferred Income Taxes	151,894,547	160,307,841	-5.25%
53	**Total Deferred Credits**	277,960,667	312,008,692	-10.91%
54	**TOTAL LIABILITIES and OTHER CREDITS**	$ 2,341,804,617	$ 2,358,467,292	-0.71%
55				
56	1/ This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory			
57	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the			
58	equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian			
59	Montana Pipeline Corp.			
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NOTES TO FINANCIAL STATEMENTS

(1) Nature of Operations

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas to approximately 650,000 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 financial statements for the periods included herein have been prepared by NorthWestern Corporation (NorthWestern, we or us), pursuant to the rules and regulations of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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.

(2) Termination of Merger Agreement with Babcock & Brown Infrastructure Limited

On April 25, 2006, we entered into an Agreement and Plan of Merger (Merger Agreement) with BBI, an infrastructure investment company listed on the Australian Stock Exchange, under which BBI would acquire NorthWestern Corporation in an all-cash transaction at $37 per share. We had received all approvals necessary for the transaction, except from the Montana Public Service Commission (MPSC). On May 22, 2007, the MPSC unanimously directed its staff to draft an order denying the transaction. On June 25, 2007, we and BBI filed a formal joint request asking the MPSC to consider a revised proposal. In connection with our joint request to the MPSC, we and BBI agreed that if the MPSC denied the revised application, then either party in their sole discretion could terminate the Merger Agreement. On July 24, 2007, the MPSC denied the joint request and BBI terminated the Merger Agreement. The MPSC issued a final written order on July 31, 2007.

We incurred and expensed transaction related costs of approximately $1.5 million, and $13.9 million during the years ended December 31, 2007, and December 31, 2006, respectively.

(3) Significant Accounting Policies

Financial Statement Presentation and Basis of Accounting

The financial statements are presented on the basis of the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts. This report differs from GAAP due to FERC requiring the presentation of subsidiaries on the equity method of accounting, which differs from Statement of Financial Accounting Standards No. 94 "Consolidation of All Majority-Owned Subsidiaries" (SFAS No. 94). SFAS No. 94 requires that all majority-owned subsidiaries be consolidated (See Note 5). The other significant differences consist of the following:

- Comparative statements of net income per share are not presented;
- Removal costs of transmission and distribution assets are reflected in the balance sheets as a component of accumulated depreciation of $165.4 million and $153.4 million as of December 31, 2007 and 2006, respectively, in accordance with regulatory treatment as compared to regulatory liabilities for GAAP purposes (see Note 7);
- Goodwill is reflected in the balance sheets as a utility plant adjustment of $355.1 million and $435.1 million as of December 31, 2007 and 2006, respectively, in accordance with regulatory treatment, as compared to goodwill for GAAP purposes (see Note 8);

- The write-down of plant values associated with the 2002 acquisition of the Montana operations is reflected in the balance sheets as a component of accumulated depreciation of $192.8 million for both December 31, 2007 and 2006, in accordance with regulatory treatment as compared to plant for GAAP purposes;

- The current portion of gas stored underground is reflected in the balance sheets as current and accrued assets, as compared to materials and supplies for GAAP purposes;

- Current and long-term debt is classified in the balance sheets as all long-term debt in accordance with regulatory treatment, while GAAP presentation reflects current and long-term debt on separate lines; and

- Accumulated deferred tax assets and liabilities are classified in the balance sheets as gross deferred debits and credits, respectively, while GAAP presentation reflects either a net deferred tax asset or liability.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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 impacts 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 respective 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 Montana 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.

Inventories

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

	December 31,	
	2007	2006
Fuel Stock	$ 4,726	$ 3,314
Materials and supplies	17,951	17,903
Gas stored underground (including the non-current portion reflected in utility plant)	72,965	71,382
	$ 95,642	$ 92,599

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 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 9. In order to manage these risks, we 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.

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 8.7% and 8.8% for Montana for 2007 and 2006, respectively, and 8.7% and 8.9% for South Dakota for 2007 and 2006, respectively. Interest capitalized totaled $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 may require contributions in aid of construction from customers when we extend service. Amounts used from these contributions to fund capital additions were $14.6 million for the year ended December 31, 2007 and $8.7 million for the year ended December 31, 2006.

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 3.5% for 2007 and 3.4% for 2006.

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.

Stock-based Compensation

Under our equity-based incentive plans, we have granted restricted stock awards to all employees and members of the Board of Directors (Board). We discuss these awards in further detail in Note 17. 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.

Income Taxes

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

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

Emission Allowances

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

Accounting Standards Issued

In December 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS No. 141R), which replaces FASB Statement 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 preliminary 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 utility plant adjustments. See Note 13, Income Taxes, for further information.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statement—amendments of ARB No. 51* (SFAS No. 160). SFAS No. 160 states that accounting and reporting for minority interests will be recharacterized as noncontrolling interests and eliminates diversity in practice by requiring these interests to be classified as a component of equity. The Statement also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS No. 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding noncontrolling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement will become effective for our fiscal year beginning January 1, 2009, and early adoption is prohibited. We do not expect SFAS No. 160 to have any effect on our financial statements.

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 (*SFAS No. 159), 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 is effective as of the beginning of our 2008 fiscal year. We do not expect to apply this fair value option to our current financial instruments, and as such do not expect SFAS No. 159 to have a material impact on our financial statements.

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. The provisions of SFAS No. 157 are effective as of the beginning of our 2008 fiscal year. We do not expect SFAS No. 157 to have a material impact on our financial statements.

Accounting Standards Adopted

In July 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). FIN 48 is an interpretation of FASB Statement No. 109, *Accounting for Income Taxes* (SFAS No. 109), 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 the derecognition, classification, accounting in interim periods and expanded disclosure with respect to the uncertainty in income taxes. We adopted FIN 48 as of January 1, 2007. See Note 13, Income Taxes for further discussion of the impact to our financial statements.

(4) Colstrip Unit 4 Acquisition

On March 13, 2007, we completed the purchase from Mellon Leasing Corporation (Mellon) of Mellon's Owner Participant interest in the 740 megawatt (MW) demonstrated capacity coal-fired steam electric generation unit known as Colstrip Unit 4 for an aggregate purchase price of approximately $40.2 million, which includes applicable closing costs. The transaction involved a transfer by Mellon to us of its Owner Participant interest in the Owner Trust that holds title to Mellon's beneficial interest. The Owner Participant interest acquired represents approximately 79 MWs of our 222 MW interest. We remain the lessee of that interest under the lease from the Owner Trustee. The transaction does not result in any change in control over, or operation of, Colstrip Unit 4. In accordance with FERC guidance, this purchase is accounted for as an equity investment and is reflected in the Investments in Associated Companies on the Balance Sheet.

(5) Equity Investments

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

	December 31, 2007	December 31, 2006
Clark Foot & Blackfoot, LLC	$ (7,287)	$ (6,274)
Colstrip Unit 4 79 MW Trust	51,811	-
Natural Gas Funding Trust	1,482	1,379
NorthWestern Services, LLC	(9,543)	21,365
NorthWestern Investments, LLC	96,505	103,273
Risk Partners Assurance, Ltd.	2,410	2,304
Total Investments in Subsidiary Companies	$ 135,378	$ 122,047

(6) Property, Plant and Equipment

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

	December 31, 2007	December 31, 2006
Land and improvements	$ 42,374	$ 40,881
Building and improvements	139,482	137,971
Storage, distribution, and transmission	2,025,242	1,963,790
Generation	175,218	143,138
Construction work in process	23,014	3,241
Other equipment	215,334	211,878
	2,620,664	2,500,899
Less accumulated depreciation	(1,285,388)	(1,221,590)
	$ 1,335,276	$ 1,279,309

Plant and equipment under capital lease were $42.3 million and $44.8 million as of December 31, 2007 and December 31, 2006, respectively, which included $37.2 million and $39.8 million as of December 31, 2007 and 2006, 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.

(7) 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, 2007 and 2006, we have recognized accrued removal costs of $165.4 million and $153.4 million, respectively, which are classified as accumulated depreciation. In addition, for our generation properties, we have accrued decommissioning costs since the generating units were first put into service in the amount of $13.8 million and $13.3 million as of December 31, 2007 and 2006, respectively, which are classified as accumulated depreciation.

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 $3.9 million and $3.5 million, as of December 31, 2007 and 2006, respectively, which increases our property, plant and equipment and other regulatory assets. 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, 2007, is as follows (in thousands):

Liability at January 1, 2007	$	3,801
Accretion expense		294
Liabilities incurred		61
Liabilities settled		(43)
Revisions to cash flows		340
Liability at December 31, 2007	$	4,453

(8) Utility Plant Adjustments

Our utility plant adjustments balance is related to our adoption of fresh-start reporting upon emergence from Chapter 11 bankruptcy on October 31, 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 a utility plant adjustment.

As a result of the implementation of FIN 48, we increased our accumulated deferred income taxes by $77.5 million and decreased other deferred credits by $2.4 million, with a corresponding decrease to utility plant adjustments. The decrease to utility plant adjustments 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 utility plant adjustments balance is not amortized; rather, it is evaluated for impairment at least annually. We evaluated our utility plant adjustment balance during the fourth quarters of 2007 and 2006 and determined that it was not impaired.

(9) Risk Management and Hedging Activities

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. We employ established policies and procedures to manage our risk associated with these market fluctuations using various commodity and financial derivative and non-derivative instruments, including forward contracts, swaps and options.

Interest Rates

During 2005, we implemented a risk management strategy of utilizing interest rate swaps to manage our interest rate exposures associated with anticipated refinancing transactions of approximately $380 million. 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 the Balance Sheets.

During the first quarter of 2006, based on a review of our capital structure and cash flow, and approval by our Board of Directors, we decided not to refinance $60 million included in the interest rate swap that was being carried on our revolver. As the refinancing transaction and associated interest payments will not occur, the market value included in AOCI of $3.8 million was recognized in Miscellaneous Nonoperating Income. This forward starting interest rate swap was settled during the second quarter of 2006, and we received an aggregate payment of approximately $3.9 million, which is reflected in investing activities on the statement of cash flows.

During the second and third quarters of 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 settled $170.2 million and $150 million of forward starting interest rate swap agreements, and received aggregate settlement payments of approximately $6.3 million and $8.3 million, respectively. AOCI includes unrealized pre-tax gains related to these transactions of $12.8 million and $14.0 million at December 31, 2007 and December 31, 2006, respectively. We reclassify gains and losses on the hedges from AOCI into interest on long-term debt in our Statements of Income during the periods in which the interest payments being hedged occur. We expect to reclassify approximately $1.2 million of pre-tax gains on these cash-flow hedges from AOCI into interest on long-term debt during the next twelve months. The cash proceeds related to these hedges are reflected in operating activities on the statement of cash flows. We have no further interest rate swaps outstanding.

(10) Related Party Transactions

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

	December 31, 2007	December 31, 2006
Accounts Receivable from Associated Companies:		
Clark Fork & Blackfoot, LLC	$ 6,437	$ 5,588
NorthWestern Energy Marketing, LLC	-	2,433
NorthWestern Services, LLC	23,646	7,299
Risk Partners Assurance, Ltd.	18	18
	$ 30,101	$ 15,338
Accounts Payable to Associated Companies:		
Colstrip 4 Mellon	$ 4,419	$ -
Natural Gas Funding Trust	59	217
NorthWestern Investments, LLC	-	6,770
NorthWestern Services, LLC	1,816	35,766
	$ 6,294	$ 42,753

(11) Long-Term Debt

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

	Due	December 31, 2007	December 31, 2006
Unsecured Debt:			
Unsecured Revolving Line of Credit	2009	$ 12,000	$ 50,000
Secured Debt:			
Mortgage bonds—			
South Dakota—7.00%	2023	55,000	55,000
Montana—6.04%	2016	150,000	150,000
Montana—8.25%	2007	—	365
South Dakota & Montana—5.875%	2014	225,000	225,000
Pollution control obligations—			
South Dakota—5.85%	2023	7,550	7,550
South Dakota—5.90%	2023	13,800	13,800
Montana—4.65%	2023	170,205	170,205
Discount on Notes and Bonds	—	(64)	(71)
		$ 633,491	$ 671,849

Unsecured Revolving Line of Credit

The 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 currently bears interest at a rate of approximately 6.2%, which is 1.125% over LIBOR. As of December 31, 2007, we had $29.3 million in letters of credit and $12 million of borrowings outstanding under the unsecured revolving line of credit. The weighted average interest rate on the outstanding revolver borrowings was 4.5% as of December 31, 2007.

Commitment fees for the unsecured revolving line of credit were $0.3 million and $0.3 million for the years ended December 31, 2007 and 2006, respectively.

The credit facility includes covenants, which require us to meet certain financial tests, including a minimum interest coverage ratio and a minimum debt to capitalization ratio. The amended and restated line of credit also contains covenants which, among other things, limit our ability to incur additional indebtedness, create liens, engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, make restricted payments, make loans or advances, and enter into transactions with affiliates. Many of these restrictive covenants will fall away upon the line of credit being rated "investment grade" by two of the three major credit rating agencies consisting of Fitch, Moody's and S&P. 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, and the South Dakota Pollution Control Obligations are three obligations under our South Dakota indenture. All of such bonds are secured by substantially all of our South Dakota and Nebraska electric and natural gas assets.

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

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt during the next five years are zero in 2008, 2010, 2011, and 2012, and $12 million in 2009.

(12) 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.

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

- The carrying amounts of cash and working funds, special deposits and investments approximate fair value due to the short maturity of the instruments.

- Fair values for debt were determined 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, 2007 and 2006.

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

	December 31, 2007		December 31, 2006	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Assets:				
Cash and working funds	$ 12,706	$ 12,706	$ 1,865	$ 1,865
Special deposits	3,310	3,310	2,966	2,966
Investments	990	990	1,541	1,541
Liabilities:				
Long-term debt (including current portion)	633,491	635,714	671,849	674,131

(13) Income Taxes

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

	December 31, 2007	December 31, 2006
Excess tax depreciation	$ (107,384)	$ (96,967)
Regulatory assets	(11,179)	(20,392)
Regulatory liabilities	(2,289)	1,264
Unbilled revenue	3,624	2,980
Unamortized investment tax credit	1,883	2,169
Compensation accruals	5,034	3,680
Reserves and accruals	27,537	21,540
Goodwill amortization	(50,914)	(42,155)
Net operating loss carryforward (NOL)	62,258	13,338
AMT credit carryforward	5,483	3,186
Capital loss carryforward	6,376	6,376
Valuation allowance	(9,858)	(10,256)
Other, net	2,264	575
	$ (67,165)	$ (114,662)

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 $12.8 million as of December 31, 2007 against capital loss carryforwards and certain state NOL carryforwards as we do not believe these assets will be realized.

At December 31, 2007 we estimate our total federal NOL carryforward to be approximately $346.0 million. If unused, $172.4 million will expire in the year 2023, and $173.6 million will expire in the year 2025. We estimate our state NOL carryforward as of December 31, 2007 is approximately $491.9 million. If unused, $320.0 million will expire in 2010, $33.8 million will expire in 2011, and $138.1 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 deferred credits by $2.4 million, with a corresponding decrease to utility plant adjustments. The decrease to utility plant adjustments 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 since adoption of FIN 48 is as follows:

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

If any of our unrecognized tax benefits were recognized, they would have no impact on our effective tax rate. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statute 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, 2007, we have not recognized expense for interest or penalties, and do not have any amounts accrued at December 31, 2007 and 2006, respectively, for the payment of interest and penalties.

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

(14) 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 Balance Sheets on a pro rata basis and our share of operating expenses is reflected in the Statements of Income. The participants each finance their own investment.

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

	Big Stone (S.D.)	Neal #4 (Iowa)	Coyote (N.D.)
December 31, 2007			
Ownership percentages	23.4%	8.7%	10.0%
Plant in service	$ 55,691	$ 29,686	$ 42,655
Accumulated depreciation	34,933	19,816	25,567
December 31, 2006			
Ownership percentages	23.4%	8.7%	10.0%
Plant in service	$ 52,948	$ 29,930	$ 42,797
Accumulated depreciation	34,588	19,309	24,393

(15) Operating Leases

We lease vehicles, office equipment and facilities under various long-term operating leases. At December 31, 2007 future minimum lease payments for the next five years under non-cancelable lease agreements are as follows (in thousands):

2008	$ 1,828
2009	1,081
2010	684
2011	501
2012	429

Lease and rental expense incurred was $30.3 and $30.9 million for the years ended December 31, 2007 and 2006, respectively.

(16) 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. Through fresh-start reporting in 2004 we had previously recorded the funded status of our plans on the balance sheet, and adjusted our qualified pension and other postretirement benefit plans to their projected benefit obligation by recognition of all previously unamortized actuarial gains and losses. Therefore, we recognized all prior service costs, and net actuarial gains and losses from 2005 and 2006 as of December 31, 2006. See Note 18 for further discussion on how these costs are recovered through rates charged to our customers.

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, 2007	December 31, 2006	December 31, 2007	December 31, 2006
Reconciliation of Benefit Obligation				
Obligation at beginning of period	$ 387,562	$ 386,915	$ 53,063	$ 55,620
Service cost	8,947	9,049	581	741
Interest cost	21,799	20,791	2,442	2,775
Actuarial gain	(21,106)	(10,265)	(6,219)	(2,705)
Gross benefits paid	(20,330)	(18,928)	(3,373)	(3,368)
Benefit obligation at end of period	$ 376,872	$ 387,562	$ 46,494	$ 53,063

	Pension Benefits		Other Postretirement Benefits	
	December 31, 2007	December 31, 2006	December 31, 2007	December 31, 2006
Reconciliation of Fair Value of Plan Assets				
Fair value of plan assets at beginning of period	$ 301,100	$ 271,103	$ 13,358	$ 10,363
Return on plan assets	27,038	30,918	892	1,041
Employer contributions	22,638	18,007	5,578	5,322
Gross benefits paid	(20,330)	(18,928)	(3,373)	(3,368)
Fair value of plan assets at end of period	$ 330,446	$ 301,100	$ 16,455	$ 13,358
Funded Status	$ (46,426)	$ (86,463)	$ (30,039)	$ (39,705)
Unrecognized net actuarial (gain) loss	—	—	—	—
Unrecognized prior service cost	—	—	—	—
Accrued benefit cost	$ (46,426)	$ (86,463)	$ (30,039)	$ (39,705)

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.

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 $387.6 million and $301.1 million, respectively, as of December 31, 2006. 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 $385.4 million and $301.1 million, respectively, as of December 31, 2006.

Balance Sheet Recognition

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

	Pension Benefits		Other Postretirement Benefits	
	December 31, 2007	December 31, 2006	December 31, 2007	December 31, 2006
Accrued benefit cost	$ (91,629)	$ (107,700)	$ (37,885)	$ (41,768)
Amounts not yet reflected in net periodic benefit cost:				
Prior service cost	(2,177)	(2,419)	—	—
Accumulated gain	47,380	23,656	7,846	2,063
Net amount recognized	$ (46,426)	$ (86,463)	$ (30,039)	$ (39,705)

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 the NorthWestern Energy pension plan, NorthWestern Corporation pension plan and NorthWestern Energy Health and Welfare Plan as of December 31, 2007 and December 31, 2006, are as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31, 2007	December 31, 2006	December 31, 2007	December 31, 2006	December 31, 2007	December 31, 2006
Cash and cash equivalents	0.2%	1.9%	0.2%	0.7%	0.1%	—%
Debt securities	29.8	30.5	2.4	—	30.3	28.3
Domestic equity securities	58.8	56.1	59.2	57.0	58.6	71.3
International equity securities	11.2	11.5	11.4	11.6	11.0	0.4
Participating group annuity contracts	—	—	26.8	30.7	—	—
	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, 2007 and 2006. 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 2007 and 2006, 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 700 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:

	December 31, 2007	December 31, 2006	December 31, 2007	December 31, 2006
Discount rate	6.25%	5.75%	5.75-6.00%	5.50 - 5.75%
Expected rate of return on assets	8.00%	8.00%	8.00%	8.00%
Long-term rate of increase in compensation levels (nonunion)	3.58%	3.61%	3.55%	3.57%
Long-term rate of increase in compensation levels (union)	3.50%	3.50%	3.50%	3.50%

The postretirement benefit obligation is calculated assuming that health care costs increased by 10% in 2007 and the rate of increase in the per capita cost of covered health care benefits thereafter was assumed to decrease gradually to 5% by the year 2013.

Net Periodic Cost

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

	December 31, 2007	December 31, 2006	December 31, 2007	December 31, 2006
Components of Net Periodic Benefit Cost				
Service cost	$ 8,947	$ 9,049	$ 580	$ 741
Interest cost	21,800	20,791	2,442	2,775
Expected return on plan assets	(24,422)	(21,458)	(1,068)	(829)
Amortization of transitional obligation	—	—	—	—
Amortization of prior service cost	242	242	—	—
Recognized actuarial (gain) loss	—	—	(259)	117
Net Periodic Benefit Cost	$ 6,567	$ 8,624	$ 1,695	$ 2,804

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

	Pension Benefits	Other Postretirement Benefits
Prior service cost	$ 242	$ —
Accumulated gain	(854)	(292)

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	$ 150
on postretirement benefit obligation	1,639
Effect of a one percentage point decrease in assumed health care cost trend	
on total service and interest cost components	$ (129)
on postretirement benefit obligation	(1,450)

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. Pension funding is based on annual actuarial studies prepared for each plan in accordance with contribution guidelines established by PPA, ERISA and the Internal Revenue Code. We anticipate making contributions of approximately $26.1 million to our pension and other postretirement benefit plans in 2008. 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
2008	$ 20,415	$ 3,900
2009	20,776	3,986
2010	21,544	4,129
2011	22,443	4,072
2012	23,312	4,038
2013-2017	137,730	21,542

Defined Contribution Plans

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 were $4.7 million and $4.3 million for 2007 and 2006, respectively.

(17) 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 grants, in addition to 228,315 shares of restricted stock granted upon our emergence from bankruptcy. We may issue new shares or reuse forfeited shares in order to deliver shares to employees for equity grants. As of December 31, 2007 there were 625,107 shares of common stock remaining available for grants. The stock vests to participants at various times ranging from one to five 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 $7.0 million and $3.6 million the years ended December 31, 2007and 2006, respectively. The total income tax benefit recognized in the income statement for these restricted stock awards was $4.4 million and $1.5 million for the years ended December 31, 2007 and 2006, respectively.

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

	Year Ended December 31, 2007	Weighted-Average Grant-Date Fair Value	Year Ended December 31, 2006	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	476,105	$ 29.54	35,164	$ 20.00
Granted	4,208	31.72	503,337	34.42
Vested	107,973	31.94	57,393	29.94
Forfeited	11,027	34.37	5,003	34.39
Remaining nonvested grants	361,313	34.45	476,105	29.54

As of December 31, 2007 we had $6.6 million of unrecognized compensation cost related to nonvested portion of outstanding restricted stock awards, which is reflected as in other paid-in capital in our Balance Sheet. The cost is expected to be recognized over a weighted-average period of 1.9 years. The total fair value of shares vested was $3.4 million and $1.7 million for the years ended December 31, 2007 and 2006, respectively.

Director's Deferred Compensation

Nonemployee directors may elect to defer up to 100% of any qualified compensation that would be otherwise payable to him or her, subject to compliance with our 2005 Deferred Compensation Plan for Nonemployee Directors and Section 409A of the Internal Revenue Code. The deferred compensation may be invested in NorthWestern stock or in designated investment funds. Compensation deferred in a particular month is recorded as a deferred stock unit (DSU) on the first of the following month based on the closing price of NorthWestern stock or the designated investment fund. A DSU entitles the grantee to receive one share of common stock for each DSU at the end of the deferral period. The value of these 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, 2007 and 2006, DSUs issued to members of our Board totaled 30,563 and 22,805, respectively. Total compensation expense attributable to the DSUs during the years ended December 31, 2007 and 2006 was approximately $0.7 million and $0.9 million, respectively.

(18) Regulatory Assets and Liabilities

We prepare our financial statements in accordance with the provisions of SFAS No. 71, as discussed in Note 3 to the Financial Statements. 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, 2007	2006
Pension	16	Undetermined	$ 47,091	$ 87,397
Postretirement benefits	16	Undetermined	21,099	28,725
Environmental clean-up		Various	14,765	—
Income taxes	13	Plant Lives	11,278	9,453
State & local taxes & fees		1 Year	—	5,105
Other		Various	13,946	17,823
Total regulatory assets			**$ 108,179**	**$ 148,503**
Gas storage sales		32 Years	$ 13,354	$ 13,774
Supply costs		1 Year	13,211	9,061
Environmental clean-up		3 Years	2,208	—
Other		Various	3,365	3,462
Total regulatory liabilities			**$ 32,138**	**$ 26,297**

Pension and Postretirement Benefits

A regulatory asset has been recognized for costs in excess of amounts recovered in rates. Historically, the MPSC rates have allowed recovery of pension costs on a cash basis. In 2005, the MPSC authorized the recognition of pension costs based on an average of the funding to be made over a 5-year period for the calendar years 2005 through 2009. The South Dakota Public Utilities Commission (SDPUC) allows recovery of pension costs on an accrual basis. The MPSC allows recovery of SFAS No. 106 costs on an accrual basis. This amount also includes adjustments recognized due to the adoption of fresh-start reporting in 2004 and SFAS No. 158 in 2006 (see Note 16).

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 offset to regulatory credits) 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.

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.

Gas Storage Sales

A gas storage sales 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.

(19) Regulatory Matters

South Dakota Natural Gas Rate Case - In June 2007, we filed a request with the SDPUC for a natural gas distribution revenue increase of $3.7 million. We reached a settlement with the SDPUC, and in December 2007 an order was issued authorizing a base rate increase of $3.1 million annually. This settlement includes a rate moratorium for a period of three years.

Nebraska Natural Gas Rate Case - In June 2007, we filed a request with the Nebraska Public Service Commission (NPSC) for a natural gas distribution revenue increase of $2.8 million. We reached a settlement with the NPSC, and in December 2007 an order was issued authorizing a base rate increase of $1.5 million annually.

FERC Transmission Rate Case - In October 2006, we filed a request with the FERC for an electric transmission revenue increase. Our requested increase pertains only to FERC jurisdictional wholesale transmission and retail choice customers representing approximately $8.6 million in revenue. In May 2007, we implemented interim rates, which are subject to refund plus interest pending final resolution. We filed settlement documents on February 15, 2008 and are awaiting FERC approval, which is expected during the first half of 2008. This proposed settlement would result in an annualized margin increase of approximately $3.0 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 Montana Consumer Counsel filed a joint stipulation with the MPSC to settle our electric and natural gas rate cases. Specific terms of the Stipulation include:

- An 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-C minus $19 per MWH 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.

The MPSC has approved interim rates, subject to refund, beginning January 1, 2008, and we anticipate finalizing the rate case during the second quarter of 2008.

(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 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, 2007	December 31, 2006
Beginning QF liability	$ 147,893	$ 140,467
Unrecovered amount	(1,223)	(3,460)
Interest expense	11,462	10,886
Ending QF liability	$ 158,132	$ 147,893

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

	Gross Obligation	Recoverable Amounts	Net
2008	$ 60,574	$ (53,060)	$ 7,514
2009	62,598	(53,583)	9,015
2010	64,580	(54,086)	10,494
2011	66,067	(54,628)	11,439
2012	68,156	(55,180)	12,976
Thereafter	1,196,704	(907,370)	289,334
Total	$ 1,518,679	$ (1,177,907)	$ 340,772

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 $445.0 million, $447.1 million, and $433.9 million for the years ended December 31, 2007, 2006 and 2005, respectively. As of December 31, 2007 our commitments under these contracts are $518 million in 2008, $328 million in 2009, $305 million in 2010, $149 million in 2011, $127 million in 2012, and $452 million thereafter. These commitments are not reflected in our Financial Statements.

Environmental Liabilities

Environmental laws and regulations are continually evolving, and, therefore, the character, scope, cost and availability of the measures we may be required to take to ensure compliance with evolving laws or regulations cannot be accurately predicted. The range of exposure for environmental remediation obligations at present is estimated to range between $19.8 million to $57.0 million. As of December 31, 2007, we have a reserve of approximately $32.7 million. We anticipate that as environmental costs become fixed and reliably determinable, we will seek insurance reimbursement and/or authorization to recover these in rates; therefore, we do not expect these costs to have a material adverse effect on our financial position, ongoing operations, or cash flows.

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.

Coal-Fired Plants

We are joint owners in Colstrip Unit 4, a coal-fired power plant located in southeastern Montana, and three coal-fired plants used to serve our South Dakota customer supply demands. Citing its authority under the Clean Air Act, the EPA had finalized Clean Air Mercury Regulations (CAMR) that affected coal-fired plants. These regulations established a cap-and-trade program that would have taken effect in two phases beginning January 2010 and January 2018. Under CAMR, each state was allocated a mercury emissions cap and was required to develop regulations to implement the requirements, which could follow the federal requirements or be more restrictive. In February 2008 the EPA's CAMR were turned down by the U.S. Court of Appeals for the District of Columbia Circuit; however, under this opinion, the EPA must either properly remove mercury from regulation under the hazardous air pollutant provisions of the Clean Air Act or develop standards requiring maximum achievable control technology for mercury emissions.

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.

Manufactured Gas Plants

Approximately $26.1 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 $12.4 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 initiated additional site investigation and assessment work at these locations. 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 exceedences of 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 problems 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 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.

Based upon our investigations to date, our current environmental liability reserves, applicable insurance coverage, and the potential to recover some portion of prudently incurred remediation costs in rates, we do not expect remediation costs at these locations to be materially different from the established reserve.

Milltown Mining Waste

Our subsidiary, Clark Fork and Blackfoot, LLC (CFB), owns the Milltown Dam, which 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 within a year. We have a remaining financial obligation of $1.4 million to the State of Montana, which will be covered solely through a combination of a premium refund upon cancellation of an environmental insurance policy, and the sale or transfer of land and water rights associated with the Milltown Dam operations.

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 and Law Debenture v. NorthWestern Corporation - On April 16, 2004, Magten Asset Management Corporation (Magten) and Law Debenture Trust Company (Law Debenture) initiated an adversary proceeding, which we refer to as the QUIPS Litigation, against NorthWestern seeking among other things, to void the transfer of certain assets and liabilities of CFB to us. In essence, Magten and Law Debenture are asserting that the transfer of the transmission and distribution assets acquired from the Montana Power Company was a fraudulent conveyance because it allegedly left CFB insolvent and unable to pay certain claims. The plaintiffs also assert that they are creditors of CFB as a result of Magten owning a portion of the Series A 8.45% Quarterly Income Preferred Securities (QUIPS) for which Law Debenture serves as the Indenture Trustee. Plaintiffs seek, among other things, the avoidance of the transfer of assets, declaration that the assets were fraudulently transferred and are not NorthWestern's property, the imposition of constructive trusts over the transferred assets and the return of such assets to CFB. On July 18, 2007, the Delaware District Court extended the discovery schedule and scheduled the trial for March 2008; however, the trial date has been adjourned pending the Delaware Bankruptcy Court's consideration of a comprehensive settlement, discussed below. The parties have entered into a comprehensive settlement and release agreement, dated March 17, 2008 (the Magten Settlement), which would resolve the

QUIPS Litigation and other disputes. A motion to approve the Magten Settlement is scheduled to be heard by the Delaware Bankruptcy Court on May 7, 2008. We have and will continue to vigorously defend against the QUIPS litigation in the event the Magten Settlement does not become effective.

Magten v. Certain Current and Former Officers of CFB - On April 19, 2004, Magten filed a complaint against certain former and current officers of CFB in U.S. District Court in Montana, seeking compensatory and punitive damages for alleged breaches of fiduciary duties by such officers in connection with the same transaction described above which is at issue in the QUIPS Litigation, namely the transfer of the transmission and distribution assets acquired from the Montana Power Company to NorthWestern. Those officers have requested CFB to indemnify them for their legal fees and costs in defending against the lawsuit and any settlement and/or judgment in such lawsuit. That lawsuit was transferred to the Federal District Court in Delaware in July 2005 and is consolidated with the QUIPS Litigation for purposes of discovery and pre-trial matters. On July 18, 2007, the Delaware District Court extended the discovery schedule and scheduled the trial for March 2008; however, the trial date has been adjourned pending the Delaware Bankruptcy Court's consideration of the Magten Settlement.

Magten v. Bank of New York - In July 2006, Magten served a complaint against The Bank of New York ("BNY") in an action filed in New York State court, seeking damages for alleged breach of contract, breach of fiduciary duty and negligence in connection with the same transaction described above which is at issue in the QUIPS Litigation. Specifically, Magten alleges that BNY, as the Indenture Trustee at the time of the 2002 transfer of assets from Montana Power Company to NorthWestern, should have taken steps to protect the QUIPS holders' interests by seeking to set aside the transfer and imposing a constructive trust on the assets. The New York State court dismissed Magten's complaint in May 2007 and Magten has filed a notice of appeal. BNY has asserted a right to indemnification by NorthWestern for legal fees and costs incurred in defending against Magten's claims pursuant to the terms of the Indenture governing the QUIPS under which BNY served as Trustee. NorthWestern's position is that any such recovery should be payable from the Class 9 Disputed Claim Reserve set aside under NorthWestern's Chapter 11 Plan of Reorganization (the "Plan"). The Plan Committee, acting on behalf of certain creditors of NorthWestern's bankruptcy estate, has objected to NorthWestern's position in this regard; however, NorthWestern and the Plan Committee have resolved this dispute pursuant to a settlement agreement between them, dated November 27, 2007 (the "Plan Committee Settlement"). The joint motion of NorthWestern and the Plan Committee to approve the Plan Committee Settlement is currently scheduled to be heard by the Delaware Bankruptcy Court on May 7, 2008. The Magten Settlement would settle the underlying claims that Magten has asserted against BNY.

Magten and Law Debenture v. NorthWestern Corporation and Certain Individuals - On April 15, 2005, Magten and Law Debenture filed an adversary complaint in the Bankruptcy Court against NorthWestern and certain former and current officers and directors seeking to revoke the Confirmation Order of our NorthWestern's Plan on the grounds that it was procured by fraud as a result of the alleged failure to adequately fund the Class 9 Disputed Claims Reserve with enough shares of new common stock to satisfy a potential full recovery on all disputed claims against NorthWestern's bankruptcy estate which were outstanding at the time the Plan became effective on November 1, 2004. The plaintiffs also alleged breach of fiduciary duty on the part of certain former and current officers in connection with the alleged under-funding of the Disputed Claims Reserve. NorthWestern filed a motion to dismiss or stay the litigation and on July 26, 2005, the Bankruptcy Court ordered a stay of the litigation pending resolution of Magten's appeal of the Order confirming the Plan. The Magten Settlement would resolve this litigation; however, NorthWestern intends to seek dismissal of this action and to the extent such action is not dismissed, NorthWestern intends to vigorously defend this action in the event the Magten Settlement does not become effective.

As indicated above, the Magten Settlement would effectuate a "global" resolution of all the currently pending claims and litigation arising out of our bankruptcy proceeding involving Magten, NorthWestern, CFB, the Plan Committee, BNY and other interested persons. On April 1, 2008, the Ad Hoc Committee filed an objection to the Magten Settlement. The Ad Hoc Committee is comprised of: Basso Capital Management; Bond Street Capital, LLC; Willow Fund, LLC; Franklin Mutual Advisers, LLC; FrontPoint Partners; and Stonehill Capital Management LLC. Such objection also purports to be a late-filed objection to the Plan Committee Settlement which provides for reimbursement of certain of NorthWestern's defense costs related to the Magten litigation as well as certain Plan Committee and BNY defense costs related to the Magten litigation. A hearing on the two settlement agreements is currently scheduled for May 7, 2008. The Magten Settlement, if it is approved and becomes effective, would be funded from the Class 9 Disputed Claims Reserve and payments from NorthWestern's former attorneys and insurance proceeds. We cannot currently predict if the Magten Settlement will be approved and become effective; however, our view is that the plaintiffs' claims with respect to the QUIPs Litigation should be treated as general unsecured, or Class 9, claims which would, in either case, be satisfied, in the event they are allowed, out of the Disputed Claims Reserve established under the Plan.

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, like the *Magten* litigation described above, seeks, among other things, the avoidance of the transfer of assets from CFB to us, declaration that the assets were fraudulently transferred and are not property of our bankruptcy estate, the imposition of constructive trusts over the transferred assets, and the return of such assets to CFB.

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 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. We will continue to vigorously defend against these claims and explore ways to remove ourselves from the lawsuits.

City of Livonia

In November 2005, we and our directors were named as defendants in a shareholder class action and derivative action entitled *City of Livonia Employee Retirement System v. Draper, et al.*, pending in the U.S. District Court for the District of South Dakota. The plaintiff claimed, among other things, that the directors breached their fiduciary duties by not sufficiently negotiating with Montana Public Power Inc. and Black Hills Corporation, two entities that had made public, unsolicited offers to purchase NorthWestern. On April 26, 2006, Livonia amended its complaint to add allegations that our directors had erred in choosing the BBI offer because it was not the most attractive offer they had received for the company. In December 2006, the plaintiffs agreed to dismiss the lawsuit with prejudice on the condition that the federal court would retain jurisdiction over any award of attorneys' fees. Plaintiffs filed a motion for attorneys' fees and costs seeking $9.9 million on the grounds that the Board's acceptance of the BBI offer was attributable to their efforts. On December 13, 2007, the federal court ordered additional simultaneous briefing on the issue of whether, in light of the BBI termination, the Livonia litigation had benefited our shareholders. In March 2008 the district court ruled that the plaintiffs lawyers should receive approximately $1.8 million in fees and costs. We have filed an appeal of the court's order in the U.S. Court of Appeals for the Eighth Circuit. We have also filed a lawsuit in South Dakota state court against the insurance carrier as the carrier would not provide a definitive decision that any award of attorneys' fees would be reimbursed by insurance proceeds. We recorded a $1.8 million liability during the first quarter of 2008, pending the outcome of the appeal and lawsuit against the insurance carrier.

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, 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 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 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, and we expect to incur additional legal and court costs related to these proceedings.

Other Litigation and Contingencies

During the second quarter of 2007, we voluntarily informed the FERC of several potential regulatory compliance issues related to our natural gas business. The FERC has initiated a nonpublic, informal investigation. We cannot currently predict the outcome of the FERC's investigation.

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 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 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 a decision on CELP's request for a preliminary injunction. We believe CELP has no basis for their complaint and intend to vigorously defend this action. On January 24, 2008, we commenced an adversary proceeding against CELP in the Delaware Bankruptcy Court seeking a declaration that no prior order of the Delaware Bankruptcy Court either limited or curtailed the rate setting authority of the MPSC. On February 25, 2008, CELP filed a motion to dismiss the adversary proceeding and on April 7, 2008, NorthWestern timely filed its objection to that motion. A hearing on the motion to dismiss our adversary proceeding at CELP has not yet been scheduled.

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. While the percentage of our share of the alleged additional royalties is not expected to change, the estimated amount may increase as the MMS updates its assessment to reflect ongoing royalty and interest expenses.

We are also subject to various other legal proceedings and claims that arise in the ordinary course of business. In the opinion of management, the amount of ultimate liability with respect to these 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. In addition, 2,265,957 shares of common stock are reserved for the incentive plan awards. For further detail of grants under this plan see Note 17.

Repurchase of Common Stock

On November 8, 2005, our Board of Directors authorized a common stock repurchase program that allowed us to repurchase up to $75 million of common stock under a specific trading plan. This plan was cancelled in May 2006. From the program's inception through December 31, 2005 we repurchased in open market transactions 96,442 shares of common stock for approximately $2.8 million. During 2006, we repurchased in open market transactions 121,306 shares of common stock for approximately $3.7 million.

Shares tendered by employees to us to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock awards totaled 33,196 and 16,664 during the years ended December 31, 2007 and 2006, respectively, and are reflected in treasury stock. These shares were credited to treasury stock based on their fair market value on the vesting date.

Sch. 19	MONTANA PLANT IN SERVICE - NATURAL GAS (INCLUDES CMP)			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1	**Intangible Plant**			
2	2301 Organization	$12,873	$12,873	0.00%
3	2302 Franchises and Consents	114,169	114,169	0.00%
4	2303 Miscellaneous Intangible Plant	593,468	565,524	4.94%
5	**Total Intangible Plant**	720,510	692,566	4.03%
6				
7	**Underground Storage Plant**			
8	2350 Land and Land Rights	4,403,501	4,287,510	2.71%
9	2351 Structures and Improvements	3,012,261	2,998,683	0.45%
10	2352 Wells	7,807,401	7,807,401	0.00%
11	2353 Lines	7,942,838	7,942,838	0.00%
12	2354 Compressor Station Equipment	7,358,334	7,306,416	0.71%
13	2355 Measuring & Regulating Equip.	2,162,564	2,279,744	-5.14%
14	2356 Purification Equipment	225,030	225,030	0.00%
15	2357 Other Equipment	834,494	834,494	0.00%
16	**Total Underground Storage Plant**	33,746,423	33,682,116	0.19%
17				
18	**Transmission Plant**			
19	2365 Rights of Way	6,968,929	6,228,965	11.88%
20	2366 Structures and Improvements	9,651,947	9,228,299	4.59%
21	2367 Mains	165,898,693	152,274,051	8.95%
22	2368 Compressor Station Equipment	17,851,270	17,796,172	0.31%
23	2369 Meas. & Reg. Station Equipment	13,029,675	11,944,511	9.09%
24	2370 Communication Equipment	-	-	-
24	2371 Other Equipment	268,974	961,166	-72.02%
25	**Total Transmission Plant**	213,669,488	198,433,164	7.68%
26				
27	**Distribution Plant**			
28	2374 Land and Land Rights	902,556	874,556	3.20%
29	2375 Structures and Improvements	71,404	71,404	0.00%
30	2376 Mains	94,313,819	88,256,250	6.86%
31	2377 Compressor Station Equipment	-	-	-
32	2378 M&R Station Equip.-General	2,290,621	2,232,222	2.62%
33	2379 M&R Station Equip.-City Gate	-	-	-
34	2380 Services	56,876,005	55,959,916	1.64%
35	2381 Customers Meters and Regulators	47,111,688	44,884,472	4.96%
36	2382 Meter Installations	-	-	-
37	2383 House Regulators	-	-	-
38	2384 House Regulator Installations	-	-	-
39	2385 M&R Station Equip.-Industrial	56,334	56,334	0.00%
40	2386 Other Prop. on Customers' Premises	-	-	-
41	2387 Other Equipment	26,216	26,216	0.00%
42	**Total Distribution Plant**	201,648,643	192,361,370	4.83%

Sch. 19	cont. MONTANA PLANT IN SERVICE - NATURAL GAS (INCLUDES CMP)			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1				
2	**General Plant**			
3	2389 Land and Land Rights	101,675	101,675	0.00%
4	2390 Structures and Improvements	696,605	692,561	0.58%
5	2391 Office Furniture and Equipment	170,937	184,631	-7.42%
6	2392 Transportation Equipment	6,046,711	5,426,346	11.43%
7	2393 Stores Equipment	8,413	9,319	-9.72%
8	2394 Tools, Shop & Garage Equipment	3,216,396	2,102,190	53.00%
9	2395 Laboratory Equipment	742,637	753,642	-1.46%
10	2396 Power Operated Equipment	1,936,873	1,868,774	3.64%
11	2397 Communication Equipment	1,722,116	1,672,298	2.98%
12	2398 Miscellaneous Equipment	83,542	86,886	-3.85%
13	2399 Other Tangible Property	-	-	-
14	**Total General Plant**	14,725,905	12,898,322	14.17%
15	**Total Gas Plant in Service**	464,510,969	438,067,538	6.04%
16				
17	4101 Gas Plant Allocated from Common	29,223,045	29,507,288	-0.96%
18	2105 Gas Plant Held for Future Use	4,900	4,900	0.00%
19	2107 Gas Construction Work in Progress	2,684,290	1,493,123	79.78%
20	2117 Gas in Underground Storage	70,172,936	67,529,726	3.91%
21				
22				
23	TOTAL GAS PLANT	$566,596,140	$536,602,575	5.59%
24				
25				

26	**CONSOLIDATED**	December 31,	
27	**PLANT IN SERVICE**	2007	2006
28			
29	Montana Electric	$ 1,343,863,437	$ 1,297,290,677
30	Yellowstone National Park	11,658,388	11,643,416
31	Colstrip Unit 4	83,990,140	79,416,087
32	Montana Natural Gas (Includes CMP)	464,510,969	438,067,538
33	Common	88,234,399	88,828,986
34	Townsend Propane	1,453,165	1,437,828
35	South Dakota Electric	391,601,736	381,737,459
36	South Dakota Natural Gas	122,382,899	106,888,501
37	South Dakota Common	42,726,864	45,479,695
38	Asset Retirement Obligation	3,907,613	3,547,177
39	TOTAL PLANT	$ 2,554,329,610	$ 2,454,337,364

Sch. 20	MONTANA DEPRECIATION SUMMARY - NATURAL GAS (INCLUDES CMP)				
	Functional Plant Class	Montana Plant Cost	This Year Montana	Last Year Montana	Current Avg. Rate
1	**Accumulated Depreciation**				
2					
3	Production and Gathering	$ -	$ -	$ -	-
4					
5	Underground Storage	33,682,116	18,854,382	17,967,495	2.69%
6					
7	Other Storage	-	-	-	-
8					
9	Transmission	198,225,977	75,701,757	72,257,994	1.77%
10					
11	Distribution	192,361,370	84,981,212	79,620,174	2.89%
12					
13	General and Intangible	13,386,633	9,143,844	8,634,359	6.50%
14					
15	Common	28,522,263	12,919,534	11,869,593	7.37%
16					
17					
18	**Total Accum Depreciation**	$466,178,359	$201,600,729	$190,349,615	2.48%
19					
20					
21					

	Consolidated Accumulated Depreciation	December 31, 2007	December 31, 2006
22	**Consolidated**	December 31,	
23	**Accumulated Depreciation**	2007	2006
24			
25	Montana Electric	$610,454,677	$567,499,232
26	Yellowstone National Park	7,462,625	7,088,124
27	Colstrip Unit 4	37,664,198	35,695,257
28	Montana Natural Gas (Includes CMP)	188,681,195	178,480,022
29	Common	39,653,707	36,603,175
30	Townsend Propane	480,339	443,648
31	South Dakota Electric	207,981,811	200,651,799
32	South Dakota Natural Gas	48,947,473	44,276,873
33	South Dakota Common	15,157,562	16,336,309
34	Acquisition Writedown	123,364,837	130,830,517
35	Basin Creek Capital Lease	3,015,704	1,005,236
36	FIN 47	255,716	120,638
37	CWIP-Capital Retirement Clearing	-648,326	-262,564
38	**Total Consolidated Accum Depreciation**	$1,282,471,518	$1,218,768,266

Sch. 21	MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED) - NATURAL GAS			
	Account Number & Title	This Year Montana	Last Year Montana	%Change
1				
2	154 Plant Materials & Operating Supplies			
3	Assigned and Allocated to:			
4	Operation & Maintenance	-	-	-
5	Construction	-	-	-
6	Storage Plant	$ 243,832	$ 237,395	2.71%
7	Transmission Plant	1,543,846	1,398,576	10.39%
8	Distribution Plant	1,752,679	1,636,180	7.12%
9				
10	**Total MT Materials and Supplies**	$3,540,357	$3,272,151	8.20%
11				
12				
13	**Consolidated**	December 31,		
14	**Materials and Supplies**	2007	2006	
15				
16	Montana Natural Gas	$3,540,357	$3,272,151	
17	Montana Electric	8,276,602	8,843,078	
18	Colstrip Unit 4	1,559,279	1,473,527	
19	South Dakota	4,574,946	4,313,984	
20				
21	**Total Consolidated Materials and Supplies**	$17,951,184	$17,902,740	

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - NATURAL GAS			
	Commission Accepted - Most Recent 1/	% Capital Structure	% Cost Rate	Weighted Cost
	Docket Number: 2000.8.113			
	Order Number : 6271c			
	Common Equity	45.00%	10.75%	4.84%
	Preferred Stock	6.97%	6.40%	0.45%
	QUIPS Preferred	7.86%	8.54%	0.67%
	Long Term Debt	40.17%	7.13%	2.86%
	Other			
	TOTAL	100.00%		8.82%
	NorthWestern Corporation Consolidated	% Capital Structure	% Cost Rate 2/	Weighted Cost
	Common Equity	51.10%	10.75%	5.49%
	Preferred Stock	0.00%	0.00%	0.00%
	QUIPS Preferred	0.00%	0.00%	0.00%
	Long Term Debt	48.90%	5.77%	2.82%
	Other			
	TOTAL	100.00%		8.31%

1/ Docket 2000.8.113, Order 6271c specifies the authorized capital structure and associated costs for the regulated gas utility effective May 8, 2001.

2/ The cost of debt represents Montana jurisdiction only, as reflected on Schedule 24.

Sch. 23	STATEMENT OF CASH FLOWS			
	Description	This year	Last year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2	**Cash Flows from Operating Activities:**			
3	Net Income	$ 53,191,154	$ 37,900,165	40.35%
4	Noncash Charges (Credits) to Income:			
5	Depreciation	81,031,947	75,150,690	7.83%
6	Amortization, Net	(556,565)	(909,060)	38.78%
7	Other Noncash Charges to Net Income, Net	(2,465,509)	(191,334)	>-300.00%
8	Deferred Income Taxes, Net	29,773,876	1,594,907	>300.00%
9	Investment Tax Credit Adjustments, Net	(531,229)	(536,281)	0.94%
10	Change in Operating Receivables, Net	26,635,221	761,456	>300.00%
11	Change in Materials, Supplies & Inventories, Net	(3,124,179)	(19,820,325)	84.24%
12	Change in Operating Payables & Accrued Liabilities, Net	(977,858)	33,517,935	-102.92%
13	Allowance for Funds Used During Construction (AFUDC)	(507,828)	(623,697)	18.58%
14	Change in Other Assets & Liabilities, Net	(2,935,660)	192,405	>-300.00%
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	(3,572,780)	(2,428,010)	-47.15%
17	Change in Regulatory Assets	22,912,870	20,676,673	10.82%
18	Change in Regulatory Liabilities	(2,158,411)	1,759,892	-222.64%
19	Proceeds from hedging activities	-	14,546,654	-100.00%
20	**Net Cash Provided by/(Used in) Operating Activities**	196,715,050	161,592,070	21.74%
21	**Cash Inflows/Outflows From Investment Activities:**			
22	Construction/Acquisition of Property, Plant and Equipment	(117,084,191)	(100,580,122)	-16.41%
23	(Net of AFUDC)			
24	Proceeds from Sale of Assets	1,841,686	24,168,975	-92.38%
25	Proceeds from Hedging Activities	-	5,356,360	-100.00%
26	Other Investing Activities:			
27	Investments in and Advances to Assoc. and Subsidiary Companies	(141,256,832)	-	-100.00%
28	Distribution from Subsidiaries	-	7,694,557	-100.00%
29	**Net Cash Provided by/(Used in) Investing Activities**	(256,499,337)	(63,360,230)	>-300.00%
30	**Cash Flows from Financing Activities:**			
31	Proceeds from Issuance of:			
32	Long-Term Debt	-	320,205,000	-100.00%
33	Long-Term Debt of Subsidiary Companies	100,000,000	-	100.00%
34	Payment for Retirement of:			
35	Credit Facilities Borrowings/Repayments, Net	(38,000,000)	(31,000,000)	-22.58%
36	Long-Term Debt	(365,000)	(320,278,500)	99.89%
37	Long-Term Debt of Subsidiary Companies	(8,793,384)	-	-100.00%
38	Capital Lease Obligations, Net	(1,133,573)	(1,163,520)	2.57%
39	Dividends on Common Stock	(47,286,168)	(44,091,245)	-7.25%
40	Other Financing Activities:			
41	Exercise of Warrants	68,833,514	2,895,841	>300.00%
42	Deferred Gas Storage Financing	-	(11,718,029)	100.00%
43	Debt Financing Costs	(1,734,317)	(7,238,014)	76.04%
44	Treasury Stock Purchases	(895,688)	(4,312,494)	79.23%
45	**Net Cash Provided by (Used in) Financing Activities**	70,625,385	(96,700,961)	173.03%
46	**Net Increase/(Decrease) in Cash and Cash Equivalents**	10,841,098	1,530,879	>300.00%
47	**Cash and Cash Equivalents at Beginning of Year**	1,865,161	334,282	>300.00%
48	**Cash and Cash Equivalents at End of Year**	$ 12,706,259	$ 1,865,161	>300.00%
49				
50	This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory			
51	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity			
52	method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana			
53	Pipeline Corp.			
54				

Sch. 24

MONTANA LONG TERM DEBT 1/

Description	Issue Date	Maturity Date	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem./Disc	Total Cost %
First Mortgage Bonds								
6.04% Series, Due 2016	09/13/06	09/01/16	$150,000,000	$148,319,155	$149,936,300	6.040%	$9,229,390	6.16%
5.875% Series, Due 2014	11/01/04	11/01/14	161,000,000	161,000,000	161,000,000	5.875%	9,934,663	6.17%
Total First Mortgage Bonds			$311,000,000	$309,319,155	$310,936,300		$19,164,053	6.16%
Pollution Control Bonds								
4.65% Series, Due 2023	04/27/06	08/01/23	$170,250,000	$164,451,956	$170,205,000	4.650%	$8,248,090	4.85%
Total Pollution Control Bonds			$170,250,000	$164,451,956	$170,205,000		$8,248,090	4.85%
Other Long Term Debt								
Cost Associated with Prior Debt Retirements	N/A	N/A					$296,467	N/A
Other Capital Leases - Fleet Lease	09/24/02	08/27/09	$6,179,475	$6,179,475	$193,085		$48,436	6.48%
Total Other Long Term Debt			$6,179,475	$6,179,475	$193,085		$344,903	
TOTAL LONG TERM DEBT			$487,429,475	$479,950,586	$481,334,385		$27,757,046	5.77%

Total Long Term Debt does not include amounts due within 1 year of $310,323. It also does not include amounts associated with the Basin Creek contract, which totals $38,819,599.

Sch. 25	PREFERRED STOCK									
	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1										
2	NOT APPLICABLE									
3										
4										
5										
6										
7										
8										
9										
10										
11										
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26										
27										
28										
29										
30										
31										
32	TOTAL									

Sch. 26	COMMON STOCK							
	Avg. Number of Shares Outstanding 1/	Book Value Per Share	Earnings Per Share	Dividends Per Share (Declared)	Retention Ratio	Market Price		Price/ Earnings Ratio
						High	Low	
January	35,671,111	$21.06				$36.00	$35.30	
February	35,748,930	21.25				36.66	35.54	
March	35,849,980	21.14	$0.54	$0.31		36.51	35.32	
April	35,913,840	21.21				35.57	34.92	
May	36,081,115	21.26				35.40	32.10	
June	36,081,433	20.97	0.07	0.31		33.11	30.25	
July	36,108,425	21.13				32.61	26.66	
August	36,747,581	21.23				27.94	24.45	
September	36,827,691	20.99	0.36	0.33		27.60	26.50	
October	38,824,685	20.05				27.70	26.88	
November	38,970,551	21.32				28.10	26.95	
December	38,970,551	21.12	0.48	0.33		30.20	27.64	
TOTAL Year End	36,622,547	$21.12	$1.45	$1.28	11.72%	$29.50		20.3

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for the twelve months ended December 31, 2007.

Sch. 27	MONTANA EARNED RATE OF RETURN - GAS			
	Description	This Year	Last Year	% Change
1	**Rate Base**			
2	101 Plant in Service	$478,235,813	$453,077,943	5.55%
3	108 Accumulated Depreciation	(196,936,048)	(184,501,233)	-6.74%
5	**Net Plant in Service**	$281,299,765	$268,576,710	4.74%
6	Additions:			
7	154, 156 Materials & Supplies	$4,196,508	$3,590,040	16.89%
8	165 Prepayments			
9	Other Additions 1/	36,913,955	36,118,730	2.20%
11	**Total Additions**	$41,110,463	$39,708,770	3.53%
12	Deductions:			
13	190 Accumulated Deferred Income Taxes 2/	$26,021,964	$24,696,843	5.37%
14	252 Customer Advances for Construction	7,978,281	5,585,960	42.83%
15	255 Accumulated Def. Investment Tax Credits			
16	Other Deductions	38,196,997	35,416,042	7.85%
18	**Total Deductions**	$72,197,242	$65,698,845	9.89%
19	**Total Rate Base**	$250,212,986	$242,586,635	3.14%
20	**Net Earnings**	$14,443,030	$17,189,120	-15.98%
21	**Rate of Return on Average Rate Base**	5.772%	7.086%	-18.54%
22	**Rate of Return on Average Equity 3/**	4.741%	7.664%	-38.14%
24	**Major Normalizing and**			
25	**Commission Ratemaking Adjustments**			
26	Rate Schedule Revenues	$3,289,684	$2,508,238	31.16%
27	Funding Trust Regulatory Liability	102,684	380,299	-73.00%
29	Non-Allowables:			
30	Advertising	281,201	330,289	-14.86%
31	Dues, Contributions, Other	53,845	13,472	299.67%
33	Associated Income Taxes 4/	(899,995)	(223,089)	>-300.00%
35	**Total Adjustments**	$2,827,419	$3,009,209	-6.04%
36	**Revised Net Earnings**	$17,270,449	$20,198,329	-14.50%
37	**Adjusted Rate of Return on Average Rate Base**	6.902%	8.326%	-17.10%
38	**Adjusted Rate of Return on Average Equity 3/**	6.478%	9.218%	-29.72%

1/ Other additions includes a FAS 109 Regulatory Asset that provides an offset to the accumulated deferred taxes.

2/ The Annual Report for 2006 contained an error in the FAS 109 Regulatory Asset and deferred tax Balance. This balance has been corrected and reclassified to conform to the 2007 presentation. Since the FAS 109 Regulatory Asset and accumulated deferred taxes offset each other in the rate base calculation, there was no change in the rate of return percentages.

3/ Return on Equity calculated using the capital structure approved in Docket D2000.8.113.

4/ Associated Income taxes include an interest synchronization adjustment based upon the approved capital structure in Docket D2000.8.113.

Sch. 27	cont. MONTANA EARNED RATE OF RETURN - GAS			
	Description	This Year	Last Year	% Change
1				
2	**Detail - Other Additions**			
3	FAS 109 Regulatory Asset 2/	$2,696,974	$2,514,586	7.25%
4	Gas Stored Underground	32,096,313	31,829,436	0.84%
5	Cost of Refinancing Debt	1,403,709	852,903	64.58%
6	SAP Development Costs	716,959	921,805	-22.22%
7				
8	**Total Other Additions**	$36,913,955	$36,118,730	2.20%
9				
10	**Detail - Other Deductions**			
11	Personal Injury and Property Damage	$37,624	($2,179,206)	101.73%
12	Storage Gas Sales 2000 & 2001	13,563,946	13,984,462	-3.01%
13	Gross Cash Requirements	6,608,131	5,923,944	11.55%
14	Bond Refinancing CTC - GP	4,298,064	4,298,064	0.00%
15	Bond Refinancing CTC - RA	13,689,232	13,689,232	0.00%
16	USBC Gas	0	(300,454)	100.00%
17				
18	**Total Other Deductions**	$38,196,997	$35,416,042	7.85%
19				
20				
21				
22				
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Sch. 28	MONTANA COMPOSITE STATISTICS - NATURAL GAS (INCLUDES CMP)			
		Description		Amount
1				
2		**Plant (Intrastate Only)**		
3				
4	101	Plant in Service (Includes Allocation from Common)	$	493,734,014
5	105	Plant Held for Future Use		4,900
6	107	Construction Work in Progress		2,684,290
7	117	Gas in Underground Storage		70,172,936
8	151-163	Materials & Supplies		3,540,356
9		(Less):		
10	108, 111	Depreciation & Amortization Reserves		201,600,729
11	252	Contributions in Aid of Construction		9,364,039
12	**NET BOOK COSTS**		$	359,171,728
13				
14		**Revenues & Expenses**		
15				
16	400	Operating Revenues	$	240,824,628
17				
18	**Total Operating Revenues**		$	240,824,628
19				
20	401-402	Other Operating Expenses (including regulatory amortizations)	$	186,084,636
21	403-407	Depreciation & Amortization Expenses		13,136,262
22	408.1	Taxes Other than Income Taxes		22,948,537
23	409-411	Federal & State Income Taxes		4,212,163
24				
25	**Total Operating Expenses**		$	226,381,598
26	**Net Operating Income**		$	14,443,030
27				
28	415-421.1	Other Income		445,181
29	421.2-426.5	Other Deductions		226,894
30	**NET INCOME BEFORE INTEREST EXPENSE**			$14,661,317
31				
32		**Average Customers (Intrastate Only)**		
33		Residential		152,941
34		Commercial		21,266
35		Industrial		312
36		Other (including interdepartmental)		144
37	**TOTAL AVERAGE NUMBER OF CUSTOMERS**			174,663
38				
39		**Other Statistics (Intrastate Only)**		
40		Average Annual Residential Use (Dkt)		79.1
41		Average Annual Residential Cost per (Dkt)		$10.62
42		Average Residential Monthly Bill		$69.99
43				
44		Plant in Service (Gross) per Customer		$2,827

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,234	467	79	2	548
2	Amsterdam		55	9		64
3	Anaconda	9,417	3,357	321	5	3,683
4	Augusta	284	195	43	1	239
5	Belfry	219	5	-	-	5
6	Belgrade	5,728	5,025	663	1	5,689
7	Big Mountain		174	33		207
8	Big Sandy	703	296	67	-	363
9	Big Timber	1,650	932	174	9	1,115
10	Bigfork	1,421	1,224	190	-	1,414
11	Billings	89,847	16	3	2	21
12	Bonner	1,693	72	5	-	77
13	Boulder	1,300	475	81	2	558
14	Bozeman	27,509	18,217	2,856	10	21,083
15	Browning	3,877	1,074	166	2	1,242
16	Buffalo		5	-	-	5
17	Butte	33,892	12,378	1,358	42	13,778
18	Cardwell	40	17	5	-	22
19	Carter	62	29	10	-	39
20	Chester	871	363	119	3	485
21	Chinook	1,386	700	130	6	836
22	Choteau	1,802	848	171	3	1,022
23	Churchill		439	50	-	489
24	Clancy	1,406	682	32	1	715
25	Clinton		367	17	1	385
26	Columbia Falls	3,645	3,241	337	4	3,582
27	Columbus	1,748	1,022	155	5	1,182
28	Conrad	2,753	1,124	199	15	1,338
29	Coram	337	113	21	-	134
30	Corvallis	443	1,102	92	-	1,194
31	Cut Bank	3,105	43	11	1	55
32	Deer Lodge	3,421	1,601	203	7	1,811
33	Dillon	3,752	2,019	333	5	2,357
34	Drummond	318	210	55	2	267
35	East Glacier Park	396	125	43	1	169
36	East Helena	1,642	1,949	115	1	2,065
37	Elliston	225	97	13	-	110
38	Essex		73	14	1	88
39	Fairfield	659	399	88	4	491
40	Florence	901	1,160	71	1	1,232
41	Floweree		42	7	-	49
42	Fort Belnap	1,262	346	55	-	401
43	Fort Benton	1,594	632	157	1	790
44	Fort Harrison			5	58	63
45	Fort Shaw	274	106	13	-	119
46	Galata		3	-	-	3
47	Gallatin Gateway		162	38	-	200
48	Garneill		9	1	-	10
49	Garrison	112	23	5	-	28
50	Gildford	185	79	28	-	107
51	Gransdale		22	2	-	24
52	Great Falls	56,690	945	46	4	995

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Greycliff	56	46	4	-	50
2	Hall		63	13	-	76
3	Hamilton	3,705	3,813	666	7	4,486
4	Harlem	848	326	71	2	399
5	Harlowton	1,062	526	103	2	631
6	Havre	9,621	4,483	629	9	5,121
7	Helena	45,819	16,556	2,281	38	18,875
8	Hingham	157	83	29	-	112
9	Hungry Horse	934	255	36	-	291
10	Iverness	103	35	12	-	47
11	Jefferson City	295	142	13	2	157
12	Joplin	210	94	28	-	122
13	Judith Gap	164	67	15	-	82
14	Kalispell	14,223	11,333	1,940	17	13,290
15	Kremlin	126	47	14	-	61
16	Laurel	6,255	11	1	-	12
17	Ledger		6	-	-	6
18	Lewistown	6,178	2,901	469	14	3,384
19	Livingston	7,348	3,953	535	17	4,505
20	Logan		48	4	-	52
21	Lohman		2	1	-	3
22	Lolo	3,388	1,443	92	-	1,535
23	Loma	92	42	19	-	61
24	Manhattan	1,396	714	101	1	816
25	Martin City	331	117	15	-	132
26	Milltown		73	9	-	82
27	Missoula	57,053	28,630	3,653	52	32,335
28	Montana City		689	59	-	748
29	Moore	186	3	-	-	3
30	Philipsburg	914	420	79	-	499
31	Ramsay		38	7	-	45
32	Red Lodge	2,177	1,723	266	7	1,996
33	Reedpoint	185	108	16	1	125
34	Roberts		164	20	-	184
35	Rocker		25	8	-	33
36	Rudyard	275	130	29	-	159
37	Ryegate		4	1	-	5
38	Shawmut		22	4	-	26
39	Shelby	3,216	9	2	-	11
40	Sheridan	659	401	71	-	472
41	Silver Star		20	4	-	24
42	Silverbow		4	-	2	6
43	Simms	373	156	17	-	173
44	Somers	556	347	19	-	366
45	Springdale		1	-	-	1
46	Stevensville	1,553	1,527	243	5	1,775
47	Sun River	131	109	17	-	126
48	Three Forks	1,728	808	126	1	935
49	Turah		112	1	-	113
50	Twin Bridges	400	210	52	-	262

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Valier	498	305	67	4	376
2	Vaughn	701	322	22	1	345
3	Victor	859	474	75	1	550
4	Walkerville		242	10	-	252
5	Warm Springs		-	1	-	1
6	West Glacier		106	38	3	147
7	Whitefish	5,032	3,761	479	4	4,244
8	Whitehall	1,044	680	109	3	792
9	Whitlash		2	-	-	2
10	Williamsburg		1	-	-	1
11	Willow Creek	209	97	13	-	110
12	Wolf Creek		53	28	1	82
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48	**Total**	447,863	152,941	21,325	394	174,660

1/ Customer populations represent an average of the 12 month period from 01/01/07 through 12/31/07.

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
3	Executive	6	7	7
4	Safety, Health & Environmental	12	13	13
5	Financial, Risk Mgmt. & Information Services	108	117	113
6	Human Resources & Administration	27	25	26
7	Utility Services & Division Administration	652	642	647
8	Regulatory Affairs	21	21	21
9	Transmission	168	177	173
10	Legal	6	6	6
11				
12				
13				
14				
15				
16				
17	**TOTAL EMPLOYEES**	1,000	1,008	1,004

1/ Consistent with prior years, part time employees have been converted to full-time equivalents.

Sch. 31	MONTANA CONSTRUCTION BUDGET 2008 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3			
4	GTF Southeast (New) 40 MVA	$2,390,638	$2,390,638
5	GTF Riverview 20 MVA	1,591,136	1,591,136
6	ET-SUBS Billings Steamplant 100 kv ring bus Year 2 of 3	1,444,286	1,444,286
7	Mill Creek PST	1,300,000	1,300,000
8	HEL Townsend 20MVA + Regs	1,102,174	1,102,174
9	MT Growth Transformer purchases	5,320,099	5,320,099
10	All Other Projects < $1 Million Each MT	38,609,641	38,609,641
11	All Other Projects SD	16,763,862	
12	**Total Electric Utility Construction Budget**	68,521,836	51,757,974
13			
14	**Natural Gas Operations**		
15	Gas Transmission - Gold Creek Loop	7,714,961	7,714,961
16	Gas Transmission - Pipeline Integrity Management Projects	2,573,732	2,573,732
17	Gas Transmission Mainline #3 Solar Addition	2,357,593	2,357,593
18			
19			
20	All Other Projects < $1 Million Each MT	8,443,504	8,443,504
21	All Other Projects SD/NE	2,706,500	
22	**Total Natural Gas Utility Construction Budget**	23,796,290	21,089,790
23			
24	**Common**		
25	07 MT Fleet replacements	3,469,000	3,469,000
26	IT CIS Implementation year 2 of 2	1,230,028	1,230,028
27	All Other Projects < $1 Million Each MT	4,410,366	4,410,366
28	(Includes IS, Communications, Facillities, Cust Serv)		
29	All Other Projects SD/NE	2,459,338	
30			
31	**Total Common Utility Construction Budget**	11,568,732	9,109,394
32			
33	CU4 capital additions - PPL invoice	3,113,142	3,113,142
34			
35	All Other Projects < $1 Million Each	-	-
36			
37			
38			
39	**Total Colstrip Unit 4 Construction Budget**	3,113,142	3,113,142
40	**TOTAL CONSTRUCTION BUDGET**	$107,000,000	$85,070,300

Sch. 32	MONTANA TRANSMISSION, DISTRIBUTION and STORAGE SYSTEMS -NATURAL GAS						
	Transmission System-Sales and Transportation						
		Peak Day of Month		Peak Day Volume (MMBTU's)		Monthly Volumes (MMBTU's)	
	Month	Total Company	Montana	Total Company	Montana	Total Company	Montana
1	January					6,206,706	6,048,549
2	February					5,172,939	5,598,390
3	March					4,274,672	4,817,332
4	April		NOT AVAILABLE 1/			3,012,866	3,163,579
5	May					1,994,440	2,306,732
6	June					1,462,908	1,671,157
7	July					1,419,942	1,480,188
8	August					1,490,868	1,433,145
9	September					1,736,709	1,505,771
10	October					2,793,858	2,280,700
11	November					4,125,056	3,246,931
12	December					5,606,082	5,282,424
13	TOTAL					39,297,046	38,834,898
14							
15							

16	Distribution System-Sales and Transportation						
17		Sales Volumes		Transportation Volumes		Monthly Volumes (MMBTU's)	
18	Month	Total Company	Montana	Total Company	Montana	Total Company	Montana
19	January	3,217,544		274,986		3,492,530	3,217,544
20	February	2,995,088		244,322		3,239,410	2,995,088
21	March	2,382,008		225,892		2,607,900	2,382,008
22	April	1,635,513		152,285		1,787,798	1,635,513
23	May	1,168,738		48,447		1,217,185	1,168,738
24	June	759,832		18,544		778,376	759,832
25	July	450,852		144,697		595,549	450,852
26	August	379,683		160,523		540,206	379,683
27	September	443,571		115,642		559,213	443,571
28	October	880,010		100,593		980,603	880,010
29	November	1,432,011		142,885		1,574,896	1,432,011
30	December	2,747,915		163,851		2,911,766	2,747,915
31	TOTAL	18,492,765		1,792,667		20,285,432	18,492,765
32							
33							

34	Storage System-Sales and Transportation						
35		Peak Day & Peak Day Vol.		Total Monthly Volumes (MMBTU's)			
36		Total Company	Montana	Total Company		Montana	
37	Month	1/	1/	Injection	Withdrawal	Injection	Withdrawal
38	January			2,854	3,307,925		2,203,914
39	February			1,922	2,643,218		1,881,245
40	March			157,326	1,436,171		1,099,728
41	April			1,074,407	300,997	584,315	
42	May			2,660,524	59,356	1,711,284	
43	June			2,505,918	59,730	1,950,263	
44	July			3,100,586	38,251	2,375,526	
45	August			1,851,217	44,814	920,510	
46	September			1,274,118	63,359	469,628	
47	October			871,102	230,009		42,933
48	November			364,637	1,011,492		829,714
49	December			3,182	2,786,305		1,807,242
50	TOTAL			13,867,793	11,981,627	8,011,526	7,864,776
51							
52	1/ Data is not accumulated on a daily basis, therefore the peak day and peak day volumes are not available.						
53							
54							
55							

Sch. 33	SOURCES OF MONTANA CORE NATURAL GAS SUPPLY				
	Supply Location	Last Year Volumes MMBTU	This Year Volumes MMBTU	Last Year Avg. Commodity Cost	This Year Avg. Commodity Cost
1					
2	Canadian Pipeline	423,778		$10.3450	
3	Havre Pipeline	7,008,399		5.8220	
4	Encana Pipeline	8,214,296		5.8970	
5	Intra Montana Purchase	3,234,094		6.2717	
6	**TOTAL CORE SUPPLY LAST YEAR**	18,880,567		$6.0332	
7					
8	Canadian Pipeline		3,201,827		$6.1400
9	Havre Pipeline		6,194,693		5.9100
10	Encana Pipeline		6,970,187		5.9560
11	Intra Montana Purchase		3,412,060		5.9500
12	**TOTAL CORE SUPPLY THIS YEAR**		19,778,767		$5.9920
13					
14					
15					
16					

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Sch. 34	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (Mcf or Dkt)	Achieved Savings (Mcf or Dkt)	Difference
1							
2	2007 Residential Gas DSM Program	$606,691	$958,630	-36.71%	114,526	70,059	44,467
3	10-year life						
4							
5							
6							
7							
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11							
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18							
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20							
21	A program participant is a Montana residential gas customer who installs eligible						
22	energy conservation measures and receives financial incentives/rebates and/or						
23	weatherization measures.						
24							
25							
26							
27							
28							
29							
30							
31							
32	**TOTAL**	$606,691	$958,630	-36.71%	114,526	70,059	(44,467)

Sch. 35

MONTANA CONSUMPTION AND REVENUES - NATURAL GAS

Description	Operating Revenues 1/		Dkt Sold 1/		Average Customers	
	Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
Sales of Natural Gas						
Residential	$ 128,451,060	$ 137,445,515	12,100,691	12,035,670	152,941	149,695
Commercial	64,566,930	69,076,373	6,090,733	6,025,265	21,266	20,724
Industrial Firm	1,749,403	1,986,587	169,279	177,104	312	323
Public Authorities	529,675	534,923	51,610	45,648	82	80
Interdepartmental	461,134	551,903	45,756	48,554	59	60
Sales to Other Utilities 2/	1,499,959	1,764,228	198,114	193,866	3	3
TOTAL SALES	197,258,161	211,359,529	18,656,183	18,526,107	174,663	170,885
	Operating Revenues		Dkt Transported		Average Customers	
	Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
Transportation of Gas						
On System Transportation	$ 17,647,421	$ 16,909,580	17,386,087	19,048,395	241	241
Off System Transportation & Storage	908,620	416,176	3,077,953	2,067,823	4	4
Canadian Montana Pipeline	44,336	39,144				
TOTAL TRANSPORTATION	18,600,377	17,364,900	20,464,040	21,116,218	245	245

1/ Revenue and Dkts include unbilled and Canadian Montana Pipeline.

2/ Includes Sales to Other Utilities only, as compared to Schedule 9 which includes all Sales for Resale.

Sch. 36a	Natural Gas Universal System Benefits Programs					
	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (Dkt)	Most recent program evaluation
1	Local Conservation					
2	E+ Residential Audit	307,000	-	307,000	35336	2007
3	NWE Promotion	-	-	-		
4	NWE Labor	19,278	-	19,278		
5	NWE Admin. Non-labor	3	-	3		
6	USB Interest & Svc Chg	(577)	-	(577)		
7	Market Transformation					
8	Research & Development					
9	Low Income					
10	Bill Assistance	1,391,803	-	1,391,803		
11	Free Weatherization	585,000	-	585,000	22908	2007
12	Energy Share	-	-	-		
13	2007 Gas USB Revenue Shortfall	(157,414)	-	(157,414)		
14	NWE Promotion	-	-	-		
15	NWE Labor	17,159	-	17,159		
16	NWE Admin. Non-labor	18	-	18		
17	USB Interest & Svc Chg	(3,247)	-	(3,247)		
18	Total	$ 2,159,023	$ -	$ 2,159,023		
19	Number of customers that received low income rate discounts				7721	
20	Average monthly bill discount amount ($/mo)				$ 30.04	*(a)*
21	Average LIEAP-eligible household income				n/a	
22	Number of customers that received weatherization assistance				524	*(b)*
23	Expected average annual bill savings from weatherization				44	Dkt
24	Number of residential audits performed				4473	*(c)*
25	*(a)* Average monthly bill discount is for the 6 month time period that the gas discount is in effect.					
26	*(b)* Total of all homes weatherized in 2007 including electric and gas USB funds.					
27	*(c)* Total of all residential audits in 2007 including electric and gas USB funds.					

Sch. 36b	Montana Conservation & Demand Side Management Programs					
	Program Description (These are Gas USB Programs	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (dKt)	Most recent program evaluation
1	Local Conservation					
2	E+ Energy Audit for the Home (Natural Gas)	$ 307,000	$ -	$ 307,000	13,063	2007
3						
4						
5						
6						
7						
8	Demand Response					
9						
10						
11						
12						
13						
14						
15	Market Transformation					
16						
17						
18						
19						
20						
21						
22	Research & Development					
23						
24						
25						
26						
27						
28						
29	Low Income					
30	Free Weatherization (Natural Gas)	$ 585,000	$ -	$ 585,000	22,908	2007
31						
32						
33						
34						
35	Other					
36						
37						
38						
39						
40						
41						
46						
47						
48	Total	$ 892,000	$ -	$ 892,000	35,971	