YEAR ENDING 2008

ANNUAL REPORT
OF

NorthWestern Energy
(Townsend Propane)

GAS UTILITY

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

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Gas Annual Report

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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
	See Northwestern Corporation's Annual Report on Form 10-K to the SEC for the Corporate Board of Directors.	

Sch. 3

OFFICERS

Title	Department Supervised	Name
President & Chief Executive Officer	Executive	Robert Rowe
Vice President, Chief Financial Officer	Tax, Internal Audit, Investor Relations Financial Planning & Analysis Controller & Treasury Functions Information Technology Flight Services, Executive Compensation	Brian Bird
Vice President, General Counsel, Corporate Secretary & Chief Compliance Officer	Legal Services Corporate Secretary Records Management	Miggie Cramblit
Vice President, Retail Operations	Retail Operations - MT/SD/NE Construction, Asset Management Organizational Development & Labor Relations Large Project Development Safety/Health/Environmental Services Support Services	Curt Pohl
Vice President, Wholesale Operations	Transmission and Supply Compliance Energy Supply Production and Generation	David Gates
Vice President, Governmental & Regulatory Affairs	Government & Regulatory Affairs	Patrick Corcoran
Vice President, Customer Care, Communications & Human Resources	Business Development and Community Relations Corporate Communications Account and Analysis Systems and Support Revenue Collection, Customer Interaction Key Accounts/Customer Education Human Resources	Bobbi Schroeppel
Internal Audit & Controls Officer	Internal Audit Enterprise Risk	Michael Nieman
Vice President, Controller	Financial and SEC Reporting Accounting Accounts Payable/Payroll Compensation and Benefits	Kendall Kliewer
Treasurer	Treasury Functions, Cash Management Risk Management Energy Risk Management Credit	Paul Evans

Reflects active officers as of April 24, 2009.

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		**$ 57,466**	**85.01%**
NorthWestern Corporation:			
Montana Utility Operations	Electric Utility Natural Gas Utility Natural Gas Pipeline (including CMP) 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		**$ 10,135**	**14.99%**
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		
Colstrip Unit 4 143 MW Trust	Owner participant interest		
Mountain States Transmission Intertie, LLC	Will hold new transmission infrastructure assets		
Indirect Subsidiaries:			
Montana Generation, LLC	Non-regulated energy marketing		
Colstrip Lease Holdings LLC	Owner participant interest		
Total Corporation		**$ 67,601**	**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

Line	Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
3	Utility Administration Executive Department	Includes the following departments: CEO	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	$2,999,787	71.47%	$1,197,323
8	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 margin.	10,162,039	65.81%	5,280,375
13	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 margin.	35,966,145	86.49%	5,615,916
18	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 margin.	15,045,865	73.52%	5,420,180
24	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 margin.	3,268,686	79.29%	854,009
29	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 margin.	16,604,387	72.35%	6,346,999
34	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 margin.	884,722	73.56%	318,000
44	**TOTAL**			$84,931,631	77.24%	$25,032,802

Reflects organizational structure and corporate allocations for 2008. The organizational structure presented on schedule 3 became effective on January 30, 2009.

Sch. 6 **AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY**

	Affiliate Name	Products & Services	Method to Determine Price	Charges to Utility	% of Total Affil. Rev.	Charges to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4	Colstrip Unit 4	Purchased Power	Market Rates	$4,661,784	6.0%	$4,661,784
5	Montana Generation, LLC 1/	Purchased Power	Negotiated Rates	$32,702,875	100.0%	$32,702,875
6						
7						
8						
9	**Total Nonutility Subsidiaries**			$37,364,659		$37,364,659
10	**Total Nonutility Subsidiaries Revenues**			$109,944,776		
11						
12						
13	**Utility Subsidiaries**					
14	Canadian-Montana Pipeline Corporation	Transportation	Tariff Rates	$32,924	49.3%	$32,924
15	**Total Utility Subsidiaries**			$32,924		$32,924
16	**Total Utility Subsidiaries Revenues**			$2,745,418		
17	**TOTAL AFFILIATE TRANSACTIONS**			$37,397,583		$37,397,583

1/ During 2008, Montana Generation, LLC (MG) had two agreements to supply base-load energy to serve the Montana electric supply load. Beginning July 2007, MG supplied 90 megawatts of base-load energy for a term of 11.5 years at an average nominal price of $35.80 per megawatt hour. Beginning March 2008, MG supplied 21 megawatts of base-load energy at $19 per megawatt hour below the Mid-C Index price with a floor of zero for a term of 76 months. The price, quantity, and term of these energy supply agreements were the result of negotiated settlements between NorthWestern and the Montana Consumer Counsel and were approved by the Montana Public Service Commission. Pursuant to MPSC Order Number D2008.6.69, the inclusion of our interest in Colstrip Unit 4 in rate base as of January 1, 2009 negated these agreements.

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	$287,333	0.44%	$287,333
5						
6						
7						
8						
9	**Total Nonutility Subsidiaries**			$287,333		$287,333
10	**Total Nonutility Subsidiaries Expenses**			$103,841,167		
11						
12						
13	**Utility Subsidiaries**					
14						$0
15	**Total Utility Subsidiaries**			$0		$0
16	**Total Utility Subsidiaries Expenses**			$1,095,499		
17	**TOTAL AFFILIATE TRANSACTIONS**			$287,333		$287,333

Sch. 8	MONTANA UTILITY INCOME STATEMENT - PROPANE					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	400 Operating Revenues	$ 446,357	$ -	$ 446,357	$ 398,808	11.92%
3						
4	**Total Operating Revenues**	446,357	-	446,357	398,808	11.92%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expense	959,428	-	959,428	697,859	37.48%
9	402 Maintenance Expense	17,431	-	17,431	21,017	-17.06%
10	403 Depreciation Expense	41,071	-	41,071	48,390	-15.13%
11	407.3 Regulatory Debits	-	-	-	-	-
12	408.1 Taxes Other Than Income Taxes	52,759	-	52,759	57,836	-8.78%
13	409.1 Income Taxes-Federal	(232,832)	-	(232,832)	(152,013)	-53.17%
14	-Other	(29,187)	-	(29,187)	(19,056)	-53.16%
15	410.1 Deferred Income Taxes-Dr.	14,490	-	14,490	2,240	>300.00%
16	411.1 Deferred Income Taxes-Cr.	-	-	-	-	-
17						
18	**Total Operating Expenses**	823,160	-	823,160	656,273	25.43%
19	**NET OPERATING INCOME**	(376,803)	$ -	$ (376,803)	$ (257,465)	-46.35%

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, 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 - PROPANE					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	**Sales to Ultimate Consumers**					
3						
4	440 Residential	$ 321,486	$ -	$ 321,486	$ 289,727	10.96%
5	442 Commercial & Industrial-Small	124,871	-	124,871	109,081	14.48%
6						
7	**Total Sales to Ultimate Consumers**	446,357	-	446,357	398,808	11.92%
8	447 Sales for Resale					
9						
10	**Total Sales of Propane**	446,357	-	446,357	398,808	11.92%
11	449.1 Provision for Rate Refunds					
12						
13	**Total Revenue Net of Rate Refunds**	446,357	-	446,357	398,808	11.92%
14						
15	**Other Operating Revenues**					
16						
17	**Total Other Operating Revenue**	-	-	-	-	-
18	**TOTAL OPERATING REVENUE**	$ 446,357	$ -	$ 446,357	$ 398,808	11.92%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - PROPANE					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Supply Expenses**					
2	**Other Propane Supply Expense-Operation**					
3	804 Purchases	$ -	$ -	$ -	$ -	-
4	805 Other Propane Purchases	227	-	227	-	-
5	807 Purchased Propane Expense	2,246	-	2,246	-	-
6	808 Propane Withdrawn from Storage	866,936	-	866,936	624,566	38.81%
7	809 Propane Delivered to Storage	-	-	-	-	-
8	**Total Supply Expenses**	869,409	-	869,409	624,566	39.20%
9	**Storage Expenses**					
10	**Other Storage-Operation**					
11	840 Operation Supervision & Engineering	-	-	-	-	-
12	841 Operation Labor & Expenses	-	-	-	-	-
13	842 Rents	17,782	-	17,782	13,200	34.72%
14	**Total Operation-Other Storage**	17,782	-	17,782	13,200	34.72%
15						
16	**Other Storage-Maintenance**					
17	847 Maintenance Storage Expenses	-	-	-	-	-
18	**Total Maintenance-Other Storage**	-	-	-	-	-
19	**Total Storage Expenses**	17,782	-	17,782	13,200	34.72%
20	**Distribution Expenses**					
21	**Distribution-Operation**					
22	870 Supervision & Engineering	-	-	-	-	-
23	874 Mains & Service	11,517	-	11,517	4,073	182.73%
24	878 Meter & House Regulators	14,052	-	14,052	13,493	4.14%
25	879 Customer Installation	5,427	-	5,427	7,488	-27.52%
26	880 Other	1,222	-	1,222	1,524	-19.79%
27	**Total Operation-Distribution**	32,218	-	32,218	26,578	21.22%
28	**Distribution-Maintenance**					
29	885 Maintenance Superv. & Eng.	-	-	-	-	-
30	887 Maintenance of Mains	16,836	-	16,836	20,990	-19.79%
31	892 Maint. of Services	494	-	494	(106)	>300.00%
32	893 Maint. of Meters & House Regulators	101	-	101	133	-24.24%
33	894 Maintenance of Other Equipment	-	-	-	-	-
34	**Total Maintenance-Distribution**	17,431	-	17,431	21,017	-17.06%
35	**Total Distribution Expenses**	49,649	-	49,649	47,595	4.32%
36						
37	**Customer Accounts Expenses**					
38	**Customer Accounts-Operation**					
39	901 Supervision	-	-	-	-	-
40	902 Meter Reading	1,304	-	1,304	1,194	9.20%
41	903 Customer Records & Collection Expense	50	-	50	-	-
42	**Total Customer Accounts Expenses**	1,354	-	1,354	1,194	13.37%
43	**Administrative & General Expenses**					
44	**Admin. & General - Operation**					
45	920 Salaries	571	-	571	916	-37.71%
46	921 Office Supplies & Expenses	18	-	18	25	-25.63%
47	923 Outside Services	38,076	-	38,076	31,380	21.34%
48	925 Injuries & Damages	-	-	-	-	-
49	926 Employee Pensions and Benefits	-	-	-	-	-
50	928 Regulatory Commission Expense	-	-	-	-	-
51	**Total Operation-Admin. & General**	38,665	-	38,665	32,321	19.63%
52	**Admin. & General - Maintenance**					
53	935 General Plant	-	-	-	-	-
54	**Total Admin. & General Expenses**	38,665	-	38,665	32,321	19.63%
55						
56	**TOTAL OPER. & MAINT. EXPENSES**	$ 976,859	$ -	$ 976,859	$ 718,876	35.89%

Sch. 11	MONTANA TAXES OTHER THAN INCOME - PROPANE			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	$1,592	$1,962	-18.86%
3	Real Estate & Personal Property	49,908	54,438	-8.32%
4	Consumer Counsel	268	319	-15.99%
5	Public Service Commission	982	1,117	-12.09%
6	Vehicle Use	9	-	-
7				
8	**TOTAL TAXES OTHER THAN INCOME**	$52,759	$57,836	-8.78%

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	Aclara Software Inc.	Computer Consulting	145,605
2	Alco Oil & Gas Production	Engineering and Fabrication Services	215,505
3	Alliance Data Systems	IT Support Services	2,751,429
4	American Arbitration Association	Arbitration Services	131,125
5	American Gas Association	Membership Dues	82,347
6	American Innovations Inc.	Software Licensing Fees	641,401
7	Arcadis	Engineering Services	766,152
8	Areva T&D Inc.	Software Support Services	240,371
9	Asplundh Tree Expert Co.	Tree Trimming	4,360,187
10	Associated Arborists	Vegetation Management	437,054
11	Automotive Rentals Inc.	Fleet Management	7,706,086
12	Balhoff Williams LLC	Professional Services	517,608
13	Bart Engineering Company	Engineering Services	134,950
14	Bill Field Trucking Inc.	Equipment Transportation	284,610
15	Bondholder Communications Group	Legal Services	81,702
16	Brown, Williams, Moorhead and Quinn, Inc	Consulting - Regulating Reserve Analysis	81,597
17	Browning, Kaleczyc, Berry and Hoven	Legal Services	886,618
18	Central Air Service, Inc	Aerial Pilot Services	411,970
19	CINC, LLC	Energy Consulting	355,714
20	Corporate Executive Board	Membership Dues	206,900
21	Curtis, Mallet-Prevost, Colt & Mosle, LLC	Legal Services	3,357,432
22	Davenport, Evans, Hurwitz & Smith, LLC	Legal Services	125,030
23	Davey Tree Surgery Company	Tree Trimming	129,679
24	Davis O'Neill & Ross	Executive Search Fees	100,185
25	Deloitte & Touche LLP	Audit Services	1,697,176
26	Denton Louis Peoples	Board of Directors Fees	86,850
27	Dewild Grant Reckart & Associates	Engineering Services	91,680
28	Dickstein Shapiro, LLP	Legal Services	1,504,459
29	Distribution Construction Co.	Gas Pipeline Construction	1,074,566
30	DJ&A P.C. Consulting Engineers	Engineering Services	197,538
31	Edison Electric Institute	Membership Dues	146,291
32	EDM International, Inc.	Anchor Rod Inspection Services	92,543
33	Eide Bailly	Audit Services	88,020
34	Elliott Aviation Inc.	Aircraft Maintenance	279,020
35	Elm Locating & Utility Service	Locating Services and Excavation Notifications	1,999,452
36	Emmet, Marvin & Martin, LLP	Legal Services	267,052
37	Energy Share of Montana	USBC Services	902,255
38	Entrix, Inc.	Consulting and Engineering Services	296,959
39	Factory Mutual Insurance Company	Insurance Premiums	649,825
40	Faegre & Benson, LLP	Legal Services	173,901
41	Falls Construction Company	Construction	107,369
42	Flying Horse Communication, Inc.	Advertising and Public Relations	941,651
43	Gartner Group, Inc.	IT Consulting Services	97,500
44	Gillespie, Prudhon & Associates	Engineering Services	82,383
45	Glacier Electric Cooperative	Engineering Services	280,263
46	Grant Thornton, LLP	Professional Services	85,723
47	Graphic Technologies, Inc.	Software Licensing Fees	125,000
48	Greenburg - Traurig	Legal Services	145,312
49	Heath Consultants, Inc.	Gas Leak Surveys	296,848
50	Hughes, Kellner, Sullivan & Alke	Legal Services	89,349
51	Independent Inspection Company	Electric Line Inspection	860,724
52	Independent Power Systems, Inc	Installation of Renewal Energy Systems	177,310
53	Intergraph Corporation	Software Consultants	175,487
54	Itron	Hardware and Software Maintenance	1,223,384
55	Jensen's Tree Service, Inc	Tree Trimming	117,902

Sch. 12a	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
56	Jon S. Fossel	Board of Directors Fees	144,950
57	Jones Day	Legal Services	146,351
58	Kema Services, Inc.	USB and DSM Programs and Services	4,121,379
59	Kurtzman Carlson Consultants	Consulting Services - Bankruptcy	315,029
60	Lands Energy Consulting	Energy Consultants	93,340
61	Larson Digging, Inc.	Construction	109,916
62	LC Staffing Service	Temporary Employment Services	323,591
63	Leonard, Street & Deinard	Legal Services	1,545,265
64	Management Applications Consultants	Rate Case Consulting Services	191,699
65	Manatt, Phelps & Phillips, LLP	Legal Services	93,785
66	Mappcor	Electric Reliability Services	178,548
67	Marsh USA, Inc.	Insurance Premiums & Consulting	3,676,324
68	Mercer Human Resource Consulting	Actuarial and Consulting Services	179,448
69	Michael J. Hanson	Consulting Fees	201,339
70	Michels Corporation	Contractor - Construction	5,151,540
71	Microsoft Licensing, GP	Computer Licensing	881,304
72	Moody's KMV	Credit Professional Fees	95,068
73	Moss & Barnett	Legal Services	172,808
74	National Center for Appropriate Technology	Lab Testing	654,219
75	Natural Gas Services, Inc	Gas Servicemen	114,315
76	Northwest Energy Efficiency	Energy Services	453,139
77	Par Electric Contractors, Inc.	Electric Construction and Maintenance	4,566,736
78	Paul, Weiss, Rifkind, Wharton & Garrison, LLP	Legal Services	719,095
79	Paulsen Marketing	Advertising	945,555
80	Philip Maslowe	Board of Directors Fees	94,863
81	Pioneer Technical Service Inc,	Engineering Services	91,050
82	Pole Maintenance Company, LLC.	GIS Pole Inventory Services	88,563
83	Power Engineers Incorporated	Engineering Services	2,337,149
84	Pro Pipe Services, Inc.	Pipeline Fabrication Services	790,589
85	Rembolt Ludtke, LLP	Legal Services	155,248
86	RML Incorporated	Boring Services	150,689
87	Rocky Mountain Contractors, Inc.	Electric Construction and Maintenance	13,363,552
88	Rod Tabbert Construction, Inc.	Construction	403,283
89	Rounds Brothers Trenching	Boring Services	162,961
90	SAP America Inc.	Software Maintenance	1,712,889
91	SK Geotechnical Corporation	Engineering and Drilling Services	156,361
92	Smartpros Ltd.	HR Consulting	79,495
93	Solar Plexus	USB and DSM Programs and Services	94,211
94	Spherion Corporation	Temporary Employment Services	104,060
95	State Line Contractors, Inc.	Electric Construction and Maintenance	473,853
96	Stencil Construction, Inc.	Construction	102,523
97	Steptoe & Johnson LLP	Legal Services	238,033
98	Stone & Webster Consultants	Power Generation Development	1,384,238
99	Sullivan, Tabaracci & Rhoades, PC	Legal Services	93,241
100	Sundance Solar Systems	Installation of Renewal Energy Systems	154,683
101	Terra Contracting, LLC	Remediation Work	319,510
102	Terracon	Engineering Services	125,463
103	The Bayard Firm	Legal Services	137,729
104	The Claro Group, LLC	Environmental Consulting Services	492,806
105	The Electric Company	Construction and Maintenance	431,926
106	The Energy Authority, Inc	Scheduling and Dispatching	419,284
107	The L.E. Myers Co.	Storm Damage Restoration	659,635
108	Tony Laslovich Construction	Construction	172,511
109	Towers Perrin HR Services	HR Consulting	108,247

Sch. 12b	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
110	TP Construction Incorporated	Construction	78,763
111	Trademark Electric, Inc.	Electrical Contractors	394,027
112	Transcon Environmental, Inc.	Environmental Consulting	135,068
113	Utilities Underground Location	Locating Services and Excavation Notifications	126,386
114	Varsity Contractors, Inc.	Janitorial Services	257,528
115	Washington Forestry Consultants	Forestry Consultants	308,475
116	Waterman Energy, Inc.	Pipeline Inspection Services	120,612
117	Williamson Fencing & Sprinklers, Inc.	Construction	83,828
118	Winston & Strawn, LLP	Legal Services	501,292
119	Wright & Sudlow, Inc.	Concrete Contractor	158,261
120	Wright Tree Service	Tree Trimming	729,920
121	Zacha Underground Construction	Construction	84,128
	Total of Payments Set Forth Above		**$ 91,656,721**

1/ This schedule includes payments for services over $75,000.

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.			
24				
25				
26				
27	During 2008, NorthWestern Energy			
28	made contributions in support of:			
29				
30	Six-mill University Levy	$10,000	$10,000	100.00%
31				
32	Lewis and Clark Library Levy	$3,000	$3,000	100.00%
33				
34				
35				
36				
37				
38				
39				
40	**TOTAL Contributions**	$13,000	$13,000	100%

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	$ 327,143,594	$ 334,814,884	-2.29%
8	Service cost	7,517,814	7,985,513	-5.86%
9	Interest cost	19,934,599	18,926,540	5.33%
10	Plan participants' contributions	-	-	-
11	Amendments	48,933	-	-
12	Actuarial (gain) loss	563,657	(17,719,569)	103.18%
13	Acquisition	-	-	-
14	Benefits paid	(15,958,833)	(16,863,774)	5.37%
15	Benefit obligation at end of year	$ 339,249,764	$ 327,143,594	3.70%
16	**Change in Plan Assets**	-	-	
17	Fair value of plan assets at beginning of year	$ 287,209,114	$ 258,200,790	11.23%
18	Actual return on plan assets	(88,636,398)	23,905,777	>-300.00%
19	Acquisition	-	-	-
20	Employer contribution	31,140,000	21,966,321	41.76%
21	Plan participants' contributions	-	-	-
22	Benefits paid	(15,958,833)	(16,863,774)	5.37%
23	Fair value of plan assets at end of year	$ 213,753,883	$ 287,209,114	-25.58%
24	**Funded Status**	$ (125,495,881)	$ (39,934,480)	-214.25%
26	Unrecognized net actuarial gain (loss)	-	-	-
27	Unrecognized prior service cost	-	-	-
29	Prepaid (accrued) benefit cost	$ (125,495,881)	$ (39,934,480)	-214.25%
30	**Weighted-average Assumptions as of Year End**	-	-	
31	Discount rate	6.25%	6.25%	
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 & 3.55% Non-Union	
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	$ 7,517,814	$ 7,985,513	-5.86%
36	Interest cost	19,934,599	18,926,540	5.33%
37	Expected return on plan assets	(23,940,000)	(21,160,455)	-13.14%
38	Amortization of prior service cost	246,361	241,913	1.84%
39	Recognized net actuarial gain	(655,324)	-	-
40	Net periodic benefit cost (SEC Basis)	$ 3,103,450	$ 5,993,511	-48.22%
41	**Montana Intrastate Costs: (MPSC Regulatory Basis)**	-	-	
42	Pension Costs	$ 30,590,000	$ 21,950,000	39.36%
43	Pension Costs Capitalized	5,928,299	4,045,338	46.55%
44	Accumulated Pension Asset (Liability) at Year End	$ (125,495,881)	$ (39,934,480)	-214.25%
45	**Number of Company Employees:**		-	
46	Covered by the Plan	3,205	3,190	0.47%
47	Not Covered by the Plan			
48	Active	1,075	1,060	1.42%
49	Retired	1,254	1,244	0.80%
50	Deferred Vested Terminated	876	886	-1.13%
	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/	$ 5,290,935	$ 4,723,552	12.01%
21	Plan participants' contributions			
22	Benefits paid			
23	Fair value of plan assets at end of year 2/	$ 146,828,131	$ 207,762,674	-29.33%
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	$ 3,334,352	$ 3,100,121	7.56%
44	Pension Costs Capitalized	646,193	571,346	13.10%
45	Accumulated Pension Asset (Liability) at Year End	Not Applicable		
46	**Number of Company Employees:**	3/	3/	
47	Covered by the Plan - Eligible	1,387	1,340	3.51%
48	Not Covered by the Plan			
49	Active - Participating	1,340	1,273	5.26%
50	Retired			
51	Vested Former Employees, Retirees and Active-	285	267	6.74%
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	$2,650,762	$3,238,965	-18.16%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	6.25%	6.00%	4.17%
8	Expected return on plan assets	8.00%	8.00%	
9	Medical Cost Inflation Rate 3/	9.5%,4.5%:20	10.0%,5.0%:13	
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 & 3.55% 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 2008 FASB 106 Valuation. Assumptions and data are as of December 31, 2008.
2/ Obtained from NorthWestern Energy-Montana's 2007 FASB 106 Valuation. Assumptions and data are as of December 31, 2007.
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	$37,319,466	$43,025,921	-13.26%
10	Service cost	563,273	$580,372	-2.95%
11	Interest Cost	1,981,367	$2,034,633	-2.62%
12	Plan participants' contributions	-		-
13	Amendments	-		-
14	Actuarial loss/(gain)	(913,152)	($5,972,918)	84.71%
15	Acquisition	-		-
16	Benefits paid	(2,952,575)	($2,348,542)	-25.72%
17	Benefit obligation at end of year	$35,998,379	$37,319,466	-3.54%
18	**Change in Plan Assets**	-	-	
19	Fair value of plan assets at beginning of year	$16,454,260	$13,357,707	23.18%
20	Actual return on plan assets	(5,061,977)	$890,955	>-300.00%
21	Acquisition	-		-
22	Employer contribution	3,981,238	$4,554,140	-12.58%
23	Plan participants' contributions	-		-
24	Benefits paid	(2,952,575)	($2,348,542)	-25.72%
25	Fair value of plan assets at end of year	$12,420,946	$16,454,260	-24.51%
26	**Funded Status**	($23,577,433)	($20,865,206)	-13.00%
27	Unrecognized net transition (asset)/obligation	-	-	-
28	Unrecognized net actuarial loss/(gain)	-	-	-
29	Unrecognized prior service cost	-	-	-
30	Prepaid (accrued) benefit cost	($23,577,433)	($20,865,206)	-13.00%
31	**Components of Net Periodic Benefit Costs**	-	-	
32	Service cost	$563,273	$580,372	-2.95%
33	Interest cost	1,981,367	$2,034,633	-2.62%
34	Expected return on plan assets	(1,316,341)	($1,068,617)	-23.18%
35	Amortization of transitional (asset)/obligation	-		-
36	Amortization of prior service cost	-		-
37	Recognized net actuarial loss/(gain)	(568,278)	($358,849)	-58.36%
38	Net periodic benefit cost	$660,021	$1,187,539	-44.42%
39	**Accumulated Post Retirement Benefit Obligation**	-	-	
40	Amount Funded through VEBA	$ -	$ -	-
41	Amount Funded through 401(h)	-	1,028,663	-100.00%
42	Amount Funded through other - Company funds	2,952,575	2,210,302	33.58%
43	TOTAL	$2,952,575	$3,238,965	-8.84%
44	Amount that was tax deductible - VEBA	$ -		-
45	Amount that was tax deductible - 401(h)	-	$1,028,663	-100.00%
46	Amount that was tax deductible - Other	2,650,762	$2,210,302	19.93%
47	TOTAL	$2,650,762	$3,238,965	-18.16%
48	**Montana Intrastate Costs:**	-		
49	Pension Costs	$2,650,762	$3,238,965	-18.16%
50	Pension Costs Capitalized	513,714	596,934	-13.94%
51	Accumulated Pension Asset (Liability) at Year End	($23,577,433)	($20,865,206)	-13.00%
52	**Number of Montana Employees:**		-	
53	Covered by the Plan	2,159	2,164	-0.23%
54	Not Covered by the Plan	160	157	1.91%
55	Active	1,080	1,080	
56	Retired	976	974	0.21%
57	Spouses/Dependants covered by the Plan	103	110	-6.36%
	4/ There is approximately an additional $8,324,249 and $9,174,106 in other company OPEBS liabilities outstanding at December 31, 2008 and 2007, respectively for other supplemental retirement agreements in addition to what is reflected for Montana above.			

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	Michael J. Hanson Former President & Chief Executive Officer	355,180	210,825 A	38,667 B 536,900 C (127,678) D 26,115 E 32,591 F	1,072,600	1,006,799	7%
2	Thomas J. Knapp Former Vice President, General Counsel & Corporate Secretary	200,398	68,543 A	41,498 B 284,012 C (119,100) D 11,018 E 23,144 F	509,514	537,033	-5%
3	David G. Gates Vice President, Wholesale Operations	214,478	68,977 A	20,115 B 55,937 D 62,810 E 6,247 F 217 G	428,781	383,792	12%
4	Bart A. Thielbar Director, Special Projects	195,142	53,274 A	35,608 B 55,800 D 10,992 E 9,000 H 4,391 I	364,207	363,621	0%
5	Paul J. Evans Treasurer	205,443	59,009 A	32,706 B 45,042 D 9,016 E 2,500 J	353,716	335,868	5%
6	Kendall G. Kliewer Vice President, Controller	206,386	37,252 A	33,233 B 50,109 D 9,401 E	336,382	347,213	-3%
7	Patrick R. Corcoran Vice President, Government & Regulatory Affairs	181,061	49,815 A	14,668 B 38,181 D 49,821 E	333,546	301,491	11%
8	Bobbi L. Schroeppel Vice President, Customer Care & Communications	193,209	53,428 A	35,509 B 38,688 D 9,280 E 761 G	330,874	315,997	5%
9	Nicole L. Benge Senior Manager, Operations & Substations	117,631	16,386 A	19,339 B 6,091 D 14,093 E 6,300 H 94,575 K	274,415	N/A	
10	Michael L. Nieman Officer, Internal Audit & Control	174,284	25,690 A	33,671 B 30,024 D 9,292 E	272,962	259,889	5%

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 2008 Employee Incentive Compensation Plan. Amounts were earned in 2008 but paid in the first quarter of 2009. Based on company performance against plan, the incentive plan was funded at 91% 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> Employer contributions to benefits - medical, dental, vision, employee assistance program, group term life, 401(k) match, and non-elective 401(k) contribution.

C> Lump sum severance payment paid upon termination of employment.

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

E>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, 2008.

F> Paid time off sold back.

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

H> Vehicle allowance.

I> Merit cash.

J> Merit bonus.

K> Payments related to relocation.

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	Robert C. Rowe President & Chief Executive Officer	169,231	120,960 A	7,253 B 100,000 C 15,050 E	412,493	N/A	
2	Brian B. Bird Vice President, Chief Financial Officer	325,129	149,244 A	35,759 B 132,221 D 11,415 E	653,768	668,862	-2%
3	Gregory G. Trandem Former Vice President, Administrative Services	216,000	78,624 A	41,136 B 74,335 D 13,006 E 543 F	423,645	422,631	0%
4	Curtis T. Pohl Vice President, Retail Operations	207,988	67,012 A	38,616 B 63,840 D 17,813 E 543 F	395,812	377,245	5%
5	Miggie E. Cramblit Vice President, General Counsel & Corporate Secretary	175,385	69,160 A	20,699 B 9,033 D 106,963 G	381,240	N/A	

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 2008 Employee Incentive Compensation Plan. Amounts were earned in 2008 but paid in the first quarter of 2009. Based on company performance against plan, the incentive plan was funded at 91% of target.

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, reimbursement of premiums under COBRA, 401(k) match, and non-elective 401(k) contribution.

C> Imputed income related to the buyout of a contract with Mr. Rowe's former employer.

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

E>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, 2008.

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

G> Payments related to relocation.

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	$2,668,916,341	$2,554,329,610	4.49%
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	13,392,200	23,014,098	-41.81%
7	108 Accumulated Depreciation Reserve	(1,301,034,680)	(1,235,398,220)	5.31%
8	108.1 Accumulated Depreciation - Capital Leases	(5,026,172)	(3,015,704)	66.67%
9	111 Accumulated Amortization & Depletion Reserves	(42,077,470)	(44,057,594)	-4.49%
10	114 Electric Plant Acquisition Adjustments	9,356,285	3,106,285	201.20%
11	115 Accumulated Amortization-Electric Plant Acq. Adj.	(3,011,371)	(2,916,457)	3.25%
12	116 Utility Plant Adjustment - Goodwill	355,128,500	355,128,500	0.00%
13	117 Gas Stored Underground-Noncurrent	32,111,698	32,114,042	-0.01%
14	**Total Utility Plant**	1,767,969,768	1,722,518,996	2.64%
15	**Other Property and Investments**			
16	121 Nonutility Property	7,935,491	7,570,168	4.83%
17	122 Accumulated Depr. & Amort.-Nonutililty Property	(198,054)	(132,378)	49.61%
18	123.1 Investments in Assoc Companies and Subsidiaries	168,434,709	159,750,871	5.44%
19	124 Other Investments	472,249	989,732	-52.29%
20	128 Miscellaneous Special Funds	-	-	-
21	LT Portion of Derivative Assets - Hedges	-	-	-
22	**Total Other Property & Investments**	176,644,394	168,178,393	5.03%
23	**Current and Accrued Assets**			
24	131 Cash	11,208,641	12,663,974	-11.49%
25	134 Other Special Deposits	4,027,516	3,309,573	21.69%
26	135 Working Funds	42,798	42,285	1.21%
27	136 Temporary Cash Investments	-	-	-
28	141 Notes Receivable	-	9,613	-100.00%
29	142 Customer Accounts Receivable	69,840,344	62,246,102	12.20%
30	143 Other Accounts Receivable	13,918,466	11,819,105	17.76%
31	144 Accumulated Provision for Uncollectible Accounts	(2,978,917)	(3,166,261)	-5.92%
32	145 Notes Receivable-Associated Companies	-	-	-
33	146 Accounts Receivable-Associated Companies	7,775,366	6,455,660	20.44%
34	151 Fuel Stock	4,874,590	4,725,662	3.15%
35	154 Plant Materials and Operating Supplies	19,307,628	17,951,184	7.56%
36	164 Gas Stored - Current	46,543,828	40,851,403	13.93%
37	165 Prepayments	9,723,553	10,114,245	-3.86%
38	171 Interest and Dividends Receivable	-	-	-
40	172 Rents Receivable	139,033	33,816	>300.00%
41	173 Accrued Utility Revenues	79,144,114	75,953,898	4.20%
42	174 Miscellaneous Current & Accrued Assets	3,222,422	988,362	226.04%
43	175 Derivative Instrument Assets (175)	3,785,419	5,719,757	-33.82%
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**	270,574,803	249,718,377	8.35%
48	**Deferred Debits**			
49	181 Unamortized Debt Expense	12,469,833	14,858,756	-16.08%
50	182 Regulatory Assets	253,429,595	108,179,282	134.27%
51	183 Preliminary Survey and Investigation Charges	6,660,776	1,752,718	280.03%
52	184 Clearing Accounts	32,373	9,306	247.86%
53	185 Temporary Facilities	78	78	0.00%
54	186 Miscellaneous Deferred Debits	493,054	704,587	-30.02%
55	189 Unamortized Loss on Reacquired Debt	5,061,068	4,318,150	17.20%
56	190 Accumulated Deferred Income Taxes	64,595,190	84,729,364	-23.76%
57	191 Unrecovered Purchased Gas Costs	(22,960,922)	(12,436,320)	84.63%
58	**Total Deferred Debits**	319,781,045	202,115,920	58.22%
59	**TOTAL ASSETS and OTHER DEBITS**	$ 2,534,970,010	$ 2,342,531,686	8.21%

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	$ 394,614	$ 393,339	0.32%
4	204 Preferred Stock Issued	-	-	-
5	207 Premium on Capital Stock	-	-	-
6	211 Miscellaneous Paid-In Capital	805,900,184	803,061,335	0.35%
7	213 Discount on Capital Stock	-	-	-
8	214 Capital Stock Expense	-	-	-
9	215 Appropriated Retained Earnings	-	-	-
10	216 Unappropriated Retained Earnings	34,370,579	16,602,789	107.02%
12	217 Reacquired Capital Stock	(89,487,420)	(10,780,785)	>300.00%
13	219 Accumulated Other Comprehensive Income	12,354,188	13,747,958	-10.14%
14	**Total Proprietary Capital**	763,532,146	823,024,636	-7.23%
15	**Long Term Debt**			
16	221 Bonds	600,205,000	621,555,000	-3.43%
17	223 Advances in Associated Companies	-	-	-
18	224 Other Long Term Debt	108,000,000	12,000,000	>300.00%
19	226 Unamortized Discount on Long Term Debt-Debit	56,350	63,700	-11.54%
20	**Total Long Term Debt**	708,148,650	633,491,300	11.78%
21	**Other Noncurrent Liabilities**			
22	227 Obligations Under Capital Leases-Noncurrent	36,798,159	38,001,667	-3.17%
23	228.1 Accumulated Provision for Property Insurance	-	-	-
24	228.2 Accumulated Provision for Injuries and Damages	10,961,477	11,128,272	-1.50%
25	228.3 Accumulated Provision for Pensions and Benefits	71,251,411	44,970,186	58.44%
26	228.4 Accumulated Miscellaneous Operating Provisions	194,305,799	189,459,290	2.56%
27	229 Accumulated Provision for Rate Refunds	1,318	2,243,806	-99.94%
28	230 Asset Retirement Obligations	7,160,145	4,453,043	60.79%
29	**Total Other Noncurrent Liabilities**	320,478,310	290,256,263	10.41%
30	**Current and Accrued Liabilities**			
31	231 Notes Payable	-	-	-
32	232 Accounts Payable	102,856,895	99,473,440	3.40%
33	233 Notes Payable to Associated Companies	-	-	-
34	234 Accounts Payable to Associated Companies	15,832,169	7,021,464	125.48%
35	235 Customer Deposits	7,215,417	8,113,459	-11.07%
36	236 Taxes Accrued	128,253,825	132,621,196	-3.29%
37	237 Interest Accrued	10,449,036	11,882,783	-12.07%
39	238 Dividends Declared	-	-	-
40	241 Tax Collections Payable	2,567,240	1,386,961	85.10%
41	242 Miscellaneous Current and Accrued Liabilities	56,715,874	54,859,330	3.38%
42	243 Obligations Under Capital Leases-Current	1,192,887	2,388,703	-50.06%
43	244 Derivative Instrument Liabilities	29,155,980	51,483	>300.00%
44	245 Derivative Instrument Liabilities - Hedges	-	-	-
45	**Total Current and Accrued Liabilities**	354,239,325	317,798,820	11.47%
46	**Deferred Credits**			
47	252 Customer Advances for Construction	49,997,718	45,193,740	10.63%
48	253 Other Deferred Credits	124,713,000	45,237,585	175.68%
49	254 Regulatory Liabilities	37,383,507	32,137,737	16.32%
50	255 Accumulated Deferred Investment Tax Credits	2,916,870	3,497,059	-16.59%
51	257 Unamortized Gain on Reacquired Debt	-	-	-
52	281-283 Accumulated Deferred Income Taxes	173,560,485	151,894,547	14.26%
53	**Total Deferred Credits**	388,571,579	277,960,667	39.79%
54	**TOTAL LIABILITIES and OTHER CREDITS**	$ 2,534,970,010	$ 2,342,531,686	8.21%
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.			
60				
61	Certain 2007 amounts have been reclassified to conform to the 2008 presentation.			
62				
63				
64				

NOTES TO FINANCIAL STATEMENTS

(1) Nature of Operations

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas to approximately 656,000 customers in Montana, South Dakota and Nebraska. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have distributed electricity and natural gas in Montana since 2002.

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

(2) Significant Accounting Policies

Financial Statement Presentation

The financial statements are presented on the basis of the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts. This report differs from GAAP due to FERC requiring the presentation of subsidiaries on the equity method of accounting, which differs from Statement of Financial Accounting Standards No. 94 "Consolidation of All Majority-Owned Subsidiaries" (SFAS No. 94). SFAS No. 94 requires that all majority-owned subsidiaries be consolidated (see Note 3). The other significant differences consist of the following:

- Comparative statements of net income per share are not presented;
- Removal costs of transmission and distribution assets are reflected in the Balance Sheets as a component of accumulated depreciation of $194.3 million and $165.4 million as of December 31, 2008 and December 31, 2007, respectively, in accordance with regulatory treatment as compared to regulatory liabilities for GAAP purposes;
- Goodwill is reflected in the balance sheets as a utility plant adjustment of $355.1 million as of December 31, 2008 and 2007, respectively, in accordance with regulatory treatment, as compared to goodwill for GAAP purposes (see Note 6);
- The write-down of plant values associated with the 2002 acquisition of the Montana operations is reflected in the Balance Sheets as a component of accumulated depreciation of $192.8 million for both December 31, 2008 and December 31, 2007, 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 GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Estimates are used for such items as long-lived asset values and impairment charges, long-lived asset useful lives, tax provisions, asset retirement obligations, uncollectible accounts, our QF obligation, environmental costs, unbilled revenues and actuarially determined benefit costs. We revise the recorded estimates when we get better information or when we can determine actual amounts. Those revisions can affect operating results.

Revenue Recognition

For our South Dakota and Nebraska operations, as prescribed by the applicable regulatory authorities, electric and natural gas utility revenues are based on billings rendered to customers. For our Montana operations, as prescribed by the Montana Public Service Commission (MPSC), operating revenues are recorded monthly on the basis of consumption or services rendered. Customers are billed monthly on a cycle basis. To match revenues with associated expenses, we accrue unbilled revenues for electrical and natural gas services delivered to customers, but not yet billed at month-end.

Cash Equivalents

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

Inventories

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

	December 31,	
	2008	2007
Fuel Stock	$ 4,875	$ 4,726
Materials and supplies	19,308	17,951
Gas stored underground (including the non-current portion reflected in utility plant)	78,656	72,965
	$ 102,839	$ 95,642

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 7. To manage these risks, we may use both derivative and non-derivative contracts that may provide for settlement in cash or by delivery of a commodity, including:

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

SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133), as amended, requires that all derivatives be recognized in the Balance Sheet, either as assets or liabilities, at fair value, unless they meet the normal purchase and normal sales criteria. The changes in the fair value of recognized derivatives are recorded each period in current earnings or accumulated other comprehensive income (AOCI), 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 AOCI. 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 utility plant are assets under capital lease, which are stated at the present value of minimum lease payments.

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to net interest charges, while the equity component is included in other income. We determine the rate used to compute AFUDC in accordance with a formula established by the FERC. This rate averaged 8.9% and 8.7% for Montana for 2008 and 2007, respectively, and 8.8% and 8.7% for South Dakota for 2008 and 2007, respectively. Interest capitalized totaled $0.9 million for the year ended December 31, 2008 and $0.8 million for the year ended December 31, 2007 for Montana and South Dakota combined.

We capitalize preliminary survey and investigation charges related to the determination of the feasibility of transmission or generation utility projects in deferred debits. Upon commencement of construction, these costs are transferred to construction work in progress, and upon completion, these costs will be transferred to utility plant. These costs totaled approximately $6.7 million and $1.8 million as of December 31, 2008 and 2007, respectively. Capitalized costs are charged to operating expense if the development of the project is no longer feasible.

We may require contributions in aid of construction from customers when we extend service. Amounts used from these contributions to fund capital additions were $6.9 million for the year ended December 31, 2008 and $14.6 million for the year ended December 31, 2007.

We record provisions for depreciation at amounts substantially equivalent to calculations made on a straight-line method by applying various rates based on useful lives of the various classes of properties (ranging from three to 40 years) determined from engineering studies. As a percentage of the depreciable utility plant at the beginning of the year, our provision for depreciation of utility plant was approximately 3.3% and 3.5% for 2008 and 2007, respectively.

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

Stock-based Compensation

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

Income Taxes

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

Environmental Costs

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

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

Emission Allowances

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

Accounting Standards Issued

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

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

Accounting Standards Adopted

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* (SFAS No. 162). SFAS No. 162 supersedes the existing hierarchy contained in the U.S. auditing standards. The existing hierarchy was carried over to SFAS No. 162 essentially unchanged. The Statement became effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board amendments to the auditing literature. The new hierarchy did not change current accounting practice in any area.

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

(3) Equity Investments

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

	December 31, 2008	December 31, 2007
Clark Fork & Blackfoot, LLC	$ (7,673)	$ (7,287)
Colstrip 4 79 MW Trust	56,355	51,811
Colstrip 4 143 MW Trust	29,320	24,771
Natural Gas Funding Trust	1,627	1,482
NorthWestern Services, LLC	(9,745)	(9,941)
NorthWestern Investments, LLC	96,028	96,505
Risk Partners Assurance, Ltd.	2,523	2,410
Total Investments in Subsidiary Companies	$ 168,435	$ 159,751

(4) Property, Plant and Equipment

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

	December 31, 2008	December 31, 2007
Land and improvements	$ 45,902	$ 42,374
Building and improvements	142,388	139,482
Storage, distribution, and transmission	2,114,815	2,025,242
Generation	182,465	175,218
Construction work in process	13,392	23,014
Other equipment	232,917	215,334
	2,731,879	2,620,664
Less accumulated depreciation	(1,351,149)	(1,285,388)
	$ 1,380,730	$ 1,335,276

Plant and equipment under capital lease were $36.2 million and $42.3 million as of December 31, 2008 and December 31, 2007, respectively, which included $35.2 million and $37.2 million as of December 31, 2008 and 2007, respectively, related to a long-term power supply contract with the owners of a natural gas fired peaking plant.

(5) Asset Retirement Obligations

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

Our regulated utility operations have, however, previously recognized removal costs of transmission and distribution assets as a component of depreciation in accordance with regulatory treatment. Generally, the accrual of future non-ARO removal obligations is not required. However, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. These amounts do not represent SFAS No. 143, *Accounting for Asset Retirement Obligations*, legal retirement obligations. As of December 31, 2008 and 2007, we have recognized accrued removal costs of $194.3 million and $165.4 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

$14.3 million and $13.8 million as of December 31, 2008 and December 31, 2007, 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 $6.3 million and $3.9 million, as of December 31, 2008 and December 31, 2007, respectively, which increases our utility plant and asset retirement obligations. This is primarily related to Department of Transportation requirements to cut, purge and cap retired natural gas pipeline segments. 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 an other regulatory asset until the settlement of the liability.

The change in our conditional ARO during the year ended December 31, 2008, is as follows (in thousands):

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

(6) Utility Plant Adjustments

Our utility plant adjustments balance is related to our adoption of fresh-start reporting upon emergence from Chapter 11 bankruptcy on November 1, 2004. Since we are a regulated utility, our regulated property, plant and equipment is kept at values included in allowable costs recoverable through utility rates, and the excess of reorganization value over the fair value of assets and liabilities on the date of our emergence of $435.1 million was recorded as 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 adjustments balance during the fourth quarters of 2008 and 2007 and determined that it was not impaired.

(7) Risk Management and Hedging Activities

We have applied the normal purchases and normal sales scope exception, as discussed above in Note 2, to certain contracts involving the purchase and sale of gas and electricity at fixed prices in future periods. Revenues and expenses from these contracts are reported on a gross basis in the appropriate revenue and expense categories as the commodities are received or delivered

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

Commodity Prices

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

Interest Rates

During 2006, we issued $170.2 million of Montana Pollution Control Obligations and $150 million of Montana First Mortgage Bonds. In association with these refinancing transactions, we implemented a risk management strategy of utilizing interest rate swaps to manage our interest rate exposures associated with anticipated refinancing transactions. These swaps were designated as cash-flow hedges under SFAS No. 133 with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in AOCI in our Balance Sheets. We settled $320.2 million of forward starting interest rate swap agreements, and received aggregate settlement payments of approximately $14.6 million in 2006. We reclassify these gains from AOCI into interest on long-term debt in our Statements of Income during the periods in which the hedged interest payments occur. AOCI includes unrealized pre-tax gains related to these transactions of $11.7 million and $12.8 million at December 31, 2008 and 2007, respectively. We expect to reclassify approximately $1.2 million of pre-tax gains on these cash-flow hedges from AOCI into interest on long-term debt during the next twelve months. We have no further interest rate swaps outstanding.

(8) Related Party Transactions

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

	December 31,	
	2008	2007
Accounts Receivable from Associated Companies:		
Clark Fork & Blackfoot, LLC	$ 7,007	$ 6,438
NorthWestern Investments, LLC	750	-
Risk Partners Assurance, Ltd.	18	18
	$ 7,775	$ 6,456
Accounts Payable to Associated Companies:		
Colstrip Unit 4 79 MW Trust	$ 9,096	$ 4,419
Colstrip Unit 4 143 MW Trust	6,088	1,816
Natural Gas Funding Trust	54	59
NorthWestern Services, LLC	594	727
	$ 15,832	$ 7,021

(9) Fair Value Measurements

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

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

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

	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Margin Cash Collateral Offset	Total Net Fair Value (1)
Regulated gas derivative liability (2)	$ —	$ (29,156)	$ —	$ —	$ (29,156)
Net derivative liability	**$ —**	**$ (29,156)**	**$ —**	**$ —**	**$ (29,156)**

(1) Fair value was determined using internal models based on quoted external commodity prices.
(2) The changes in the fair value of these derivatives are deferred as a regulatory asset or liability until the contracts are settled. Upon settlement, associated proceeds or costs are passed through the applicable cost tracking mechanism to customers.

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. Normal purchases and sales transactions, as defined by SFAS No. 133, and certain other long-term power purchase contracts are not included in the fair values by source table as they are not recorded at fair value. See Note 7 for further discussion.

(10) Long-Term Debt

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

	Due	December 31, 2008	December 31, 2007
Unsecured Debt:			
Unsecured Revolving Line of Credit	2009	$ 108,000	$ 12,000
Secured Debt:			
Mortgage bonds—			
South Dakota—6.05	2018	55,000	—
South Dakota—7.00%	2023	—	55,000
Montana—6.04%	2016	150,000	150,000
South Dakota & Montana—5.875%	2014	225,000	225,000
Pollution control obligations—			
South Dakota—5.85%	2023	—	7,550
South Dakota—5.90%	2023	—	13,800
Montana—4.65%	2023	170,205	170,205
Discount on Notes and Bonds	—	(56)	(64)
		708,149	633,491

Unsecured Revolving Line of Credit

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

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

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

Secured Debt

First Mortgage Bonds and Pollution Control Obligations

The South Dakota Mortgage Bonds are two series of general obligation bonds we issued under our South Dakota indenture. All of such bonds are secured by substantially all of our South Dakota and Nebraska electric and natural gas assets. During 2008, we repaid our South Dakota Pollution Control Obligations that were also secured by our South Dakota indenture.

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

Refinancing Transaction

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

Subsidiary Long-Term Debt

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

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

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt during the next five years are $108 million in 2009 and zero in 2010 through 2013.

(11) Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of SFAS No. 107, *Disclosures About Fair Value of Financial Instruments*. The estimated fair-value amounts have been determined using available market information and appropriate valuation methodologies. However, considerable judgment is necessarily required in interpreting market data to develop estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we would realize in a current market exchange.

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

- The carrying amounts of cash and working funds, special deposits, and investments approximate fair value due to the short maturity of the instruments.
- We determined fair values for debt based on interest rates that are currently available to us for issuance of debt with similar terms and remaining maturities, except for publicly traded debt, which is based on market prices.

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

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

	December 31, 2008		December 31, 2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Assets:				
Cash and working funds	$ 11,251	$ 11,251	$ 12,706	$ 12,706
Special deposits	4,028	4,028	3,310	3,310
Investments	472	472	990	990
Liabilities:				
Long-term debt (including current portion)	708,149	625,698	633,491	635,714

(12) 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,	
	2008	2007
Excess tax depreciation	$ (133,462)	$ (107,384)
Regulatory assets	(14,144)	(11,179)
Regulatory liabilities	707	(2,289)
Unbilled revenue	2,289	3,624
Unamortized investment tax credit	1,571	1,883
Compensation accruals	5,258	5,034
Reserves and accruals	22,967	27,537
Utility plant adjustments amortization	(59,674)	(50,914)
Net operating loss (NOL) carryforward	62,917	62,258
AMT credit carryforward	5,862	5,483
Capital loss carryforward	—	6,376
Valuation allowance	(3,331)	(9,858)
Other, net	75	2,264
	$ (108,965)	$ (67,165)

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 $3.3 million as of December 31, 2008, against certain state NOL carryforwards as we do not believe these assets will be realized.

At December 31, 2008 we estimate our total federal NOL carryforward to be approximately $350.2 million. If unused, $158.1 million will expire in the year 2023, and $192.1 million will expire in the year 2025. We estimate our state NOL carryforward as of December 31, 2008 is approximately $495.2 million. If unused, $308.5 million will expire in 2010, $33.8 million will expire in 2011, and $152.9 million will expire in 2012. Management believes it is more likely than not that sufficient taxable income will be generated to utilize these NOL carryforwards except as noted above.

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

FIN 48

We adopted the provisions of FIN 48 on January 1, 2007. FIN 48 provides that a tax position that meets the more-likely-than-not threshold shall initially and subsequently be measured as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. As a result of the implementation of FIN 48, we increased our deferred tax assets by $77.5 million and decreased other 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 is as follows (in thousands):

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

Our unrecognized tax benefits include approximately $78.3 million related to tax positions as of December 31, 2008 and 2007, respectively, that if recognized, would impact our annual effective tax rate. We do not anticipate total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitations within the next twelve months.

Our policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. During the year ended December 31, 2008, we have not recognized expense for interest or penalties, and do not have any amounts accrued at December 31, 2008 and 2007, respectively, for the payment of interest and penalties.

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

(13) Jointly Owned Plants

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

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

	Big Stone (SD)	Neal #4 (IA)	Coyote (ND)	Colstrip Unit 4 (MT)
December 31, 2008				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 58,026	$ 29,771	$ 43,406	$ 266,627
Accumulated depreciation	34,636	20,708	26,795	21,462
December 31, 2007				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 55,691	$ 29,686	$ 42,655	$ 257,129
Accumulated depreciation	34,933	19,816	25,567	14,139

(14) Operating Leases

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

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

Lease and rental expense incurred was $2.1 million and $30.3 million for the years ended December 31, 2008 and 2007, respectively.

(15) Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

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

In accordance with SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*, and SFAS No. 87, *Employers' Accounting for Pensions*, we utilize a number of accounting mechanisms that reduce the volatility of reported pension costs. Differences between actuarial assumptions and actual plan results are deferred and are recognized into earnings only when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the market-related value of plan assets. If necessary, the excess is amortized over the average remaining service period of active employees. SFAS No. 158 also requires that a plan's funded status be recognized as an asset or liability. See Note 17 for further discussion on how these costs are recovered through rates charged to our customers.

Plan Amendment

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

Benefit Obligation and Funded Status

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

	Pension Benefits				Other Postretirement Benefits			
	December 31,				December 31,			
	2008		2007		2008		2007	
Reconciliation of Benefit Obligation								
Obligation at beginning of period	$	376,872	$	387,562	$	46,494	$	53,063
Service cost		8,405		8,947		563		581
Interest cost		22,875		21,799		2,367		2,442
Plan Amendments		49		—		—		—
Actuarial loss (gain)		405		(21,106)		(1,275)		(6,219)
Gross benefits paid		(19,947)		(20,330)		(3,826)		(3,373)
Benefit obligation at end of period	$	388,659	$	376,872	$	44,323	$	46,494

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

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

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

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

Balance Sheet Recognition

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

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

Plan Assets

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

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

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

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

Our investment goals with respect to managing the pension and other postretirement assets are to meet current and future benefit payment needs while maximizing total investment returns (income and appreciation) after inflation within the constraints of diversification, prudent risk taking, and the Prudent Man Rule of the Employee Retirement Income Security Act of 1974 (ERISA). Each plan is diversified across asset classes to achieve optimal balance between risk and return and between income and growth through capital appreciation. We review the asset mix on a quarterly basis. Generally, the asset mix will be rebalanced to the target mix as individual portfolios approach their minimum or maximum levels.

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

Our investment policy allows for all or a portion of each benefit plan to be invested in commingled funds, including mutual funds, collective investment funds, bank commingled funds and insurance company separate accounts. These pooled investment funds must have an adequate asset base relative to their asset class and be invested in a diversified manner and have a minimum of three years of verified investment performance experience or verified portfolio manager investment experience in a particular investment strategy and have management and oversight by an Investment Advisor registered with the SEC. The direct holding of company stock is not permitted; however, any holding in a diversified mutual fund or collective investment fund is permitted. The policy prohibits any transactions that would threaten the tax exempt status of the fund and actions that would create a conflict of interest or transactions between fiduciaries and parties in interest as defined under ERISA.

Our investment policy for fixed income investments consist of U.S. as well as international instruments. Core domestic portfolios can be invested in government, corporate, asset-backed and mortgage-backed obligation securities. The portfolio may invest in high yield securities, however, the average quality must be rated at least "investment grade" by rating agencies including Moodys and S&P. In addition, the NorthWestern Corporation pension plan assets also include a participating group annuity contract in the John Hancock General Investment Account, which consists primarily of fixed-income securities.

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

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2008 and 2007. The actuarial assumptions used to compute the net periodic pension cost and postretirement benefit cost are based upon information available as of the beginning of the year, specifically, market interest rates, past experience and management's best estimate of future economic conditions. Changes in these assumptions may impact future benefit costs and obligations. In computing future costs and obligations, we must make assumptions about such things as employee mortality and turnover, expected salary and wage increases, discount rate, expected return on plan assets, and expected future cost increases. Two of these items generally have the most impact on the level of cost: (1) discount rate and (2) expected rate of return on plan assets.

For 2008 and 2007, we set the discount rate using a yield curve analysis, which projects benefit cash flows into the future and then discounts those cash flows to the measurement date using a yield curve. This is done by constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year, projected benefit cash flow from our plans.

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

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

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

	Pension Benefits			Other Postretirement Benefits		
	December 31,			December 31,		
	2008	2007	2006	2008	2007	2006
Discount rate	6.25%	6.25%	5.75%	6.00-6.25%	5.75-6.00%	5.50%
Expected rate of return on assets	8.00	8.00	8.00	8.00	8.00	8.00
Long-term rate of increase in compensation levels (nonunion)	3.58	3.58	3.61	3.55	3.55	3.55
Long-term rate of increase in compensation levels (union)	3.50	3.50	3.50	3.50	3.50	3.50

The postretirement benefit obligation is calculated assuming that health care costs increased by 9.5% in 2008 and the rate of increase in the per capita cost of covered health care benefits thereafter was assumed to decrease gradually to 4.5% by the year 2029.

Net Periodic Cost

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

	Pension Benefits			Other Postretirement Benefits		
	December 31,			December 31,		
	2008	2007	2006	2008	2007	2006
Components of Net Periodic Benefit Cost						
Service cost	$ 8,405	$ 8,947	$ 9,049	$ 563	$ 580	$ 741
Interest cost	22,875	21,800	20,791	2,367	2,442	2,775
Expected return on plan assets	(27,212)	(24,422)	(21,458)	(1,316)	(1,068)	(829)
Amortization of transitional obligation	—	—	—	—	—	—
Amortization of priorservice cost	246	242	242	—	—	—
Recognized actuarial (gain) loss	(818)	—	—	(599)	(259)	117
Net Periodic Benefit Cost	$ 3,496	$ 6,567	$ 8,624	$ 1,015	$ 1,695	$ 2,804

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

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

Assumed health care cost trend rates have a significant effect on the amounts reported for the costs each year as well as on the accumulated postretirement benefit obligation. The following table sets forth the sensitivity of retiree welfare results (in thousands):

Effect of a one percentage point increase in assumed health care cost trend	
on total service and interest cost components	$ 173
on postretirement benefit obligation	1,646
Effect of a one percentage point decrease in assumed health care cost trend	
on total service and interest cost components	$ (152)
on postretirement benefit obligation	(1,468)

Cash Flows

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

Due to the volatility of equity markets in 2008, we and other plan sponsors experienced significant plan asset market losses, requiring significant increases in funding levels to meet the requirements of PPA. In December 2008, Congress passed the Worker, Retiree, and Employer Recovery Act of 2008, which providing for relief under PPA by allowing smoothing of assets, and decreasing the funding targets for each year through 2011. Asset smoothing allows the use of asset averaging, including expected returns, for a 24-month period in the determination of funding requirements. We anticipate making contributions of approximately $49.9 million to our pension and other postretirement benefit plans in 2009. For our postretirement welfare benefits, our policy is to contribute an amount equal to the annual actuarially determined cost that is also recoverable in rates. We generally fund our 401(h) and VEBA trusts monthly, subject to our liquidity needs and the maximum deductible amounts allowed for income tax purposes.

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

	Pension Benefits	Other Postretirement Benefits
2009	$ 20,856	$ 3,743
2010	21,642	3,881
2011	22,551	3,815
2012	23,410	3,816
2013	24,936	3,959
2014-2018	146,139	21,359

Defined Contribution Plan

Our defined contribution plan permits employees to defer receipt of compensation as provided in Section 401(k) of the Internal Revenue Code. Under the plan, employees may elect to direct a percentage of their gross compensation to be contributed to the plan. We contribute various percentage amounts of the employee's gross compensation contributed to the plan. Matching contributions for the year ended December 31, 2008 and 2007 were $5.3 million and $4.7 million, respectively.

(16) Stock-Based Compensation

Restricted Stock Awards

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

In accordance with SFAS No. 123R, we account for our service-based restricted stock awards using the fixed accounting method, whereby we amortize the value of the market price of the underlying stock on the date of grant (grant-date fair value) to compensation expense over the service period either ratably or in tranches. We reverse any expense associated with restricted stock that is canceled or forfeited during the performance or service period. Compension recognized for restricted stock awards was $3.2 million and $7.0

million for the years ended December 31, 2008 and 2007, respectively. For the years ended December 31, 2008 and 2007, an income tax benefit was recognized of $0.2 million and $4.4 million, respectively.

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

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

As of December 31, 2008, we had $2.2 million of unrecognized compensation cost related to the nonvested portion of outstanding restricted stock awards, which is reflected in other paid-in capital in our Balance Sheets. The cost is expected to be recognized over a weighted-average period of 1.5 years. The total fair value of shares vested was $4.7 million and $3.4 million for the years ended December 31, 2008 and 2007, respectively.

Director's Deferred Compensation

Nonemployee directors may elect to defer up to 100% of any qualified compensation that would be otherwise payable to him or her, subject to compliance with our 2005 Deferred Compensation Plan for Nonemployee Directors and Section 409A of the Internal Revenue Code. The deferred compensation may be invested in NorthWestern stock or in designated investment funds. Compensation deferred in a particular month is recorded as a deferred stock unit (DSU) on the first of the following month based on the closing price of NorthWestern stock or the designated investment fund. The DSUs are marked-to-market on a quarterly basis with an adjustment to directors compensation expense. Based on the election of the nonemployee director, following separation from service on the Board, other than on account of death, he or she shall be paid a distribution either in a lump sum or in approximately equal installments over a designated number years (not to exceed 10 years). During the years ended December 31, 2008 and 2007, DSUs issued to members of our Board totaled 33,750 and 30,563, respectively. Total compensation expense attributable to the DSUs during the years ended December 31, 2008 and 2007 was approximately $0.2 million and $0.7 million, respectively.

(17) Regulatory Assets and Liabilities

We prepare our financial statements in accordance with the provisions of SFAS No. 71, as discussed in Note 2. Pursuant to this pronouncement, certain expenses and credits, normally reflected in income as incurred, are deferred and recognized when included in rates and recovered from or refunded to the customers. Regulatory assets and liabilities are recorded based on management's assessment that it is probable that a cost will be recovered or that an obligation has been incurred. Accordingly, the following table reflects our major classifications of regulatory assets and liabilities (in thousands of dollars) 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, supply costs are the only items earning a rate of return. The remaining regulatory items have corresponding assets and liabilities that will be paid for or refunded in future periods. Because these costs are recovered as paid, they do not earn a return. We have specific orders to cover approximately 97% of our regulatory assets and 100% of our regulatory liabilities.

	Note Reference	Remaining Amortization Period	December 31, 2008	December 31, 2007
Pension	15	Undetermined	$ 148,534	$ 47,091
Postretirement benefits	15	Undetermined	25,010	21,099
Environmental clean-up		Various	15,904	14,765
Energy supply derivatives		1 Year	29,156	51
Income taxes	12	Plant Lives	16,466	11,279
Other		Various	18,360	13,894
Total regulatory assets			**$ 253,430**	**$ 108,179**
Gas storage sales		31 Years	$ 12,933	$ 13,354
Supply costs		1 Year	5,465	7,491
Energy supply derivatives		1 Year	3,785	5,720
Environmental clean-up		2 Years	1,411	2,208
State & local taxes & fees		1 Year	9,701	1,462
Other		Various	4,089	1,903
Total regulatory liabilities			**$ 37,384**	**$ 32,138**

Pension and Postretirement Benefits

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

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

Environmental clean-up

Environmental clean-up costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss the specific sites and clean-up requirements further in Note 20. In December 2007, the SDPUC approved our settlement with SDPUC Staff related to our natural gas rate case, which included a provision allowing us to include approximately $1.4 million annually in rates to recover MGP environmental clean-up costs. This was partially offset by a requirement to return approximately $2.3 million ($0.8 million annually) of previous insurance recoveries to customers. The SDPUC's approval of our settlement provides reasonable assurance that we will recover future South Dakota related MGP costs. Therefore, we recorded net regulatory assets (with a corresponding reduction to 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 regulatory liability was established in 2000 and 2001 based on gains on cushion gas sales in Montana. This gain is being flowed to customers over a period that matches the depreciable life of surface facilities that were added to maintain deliverability from the field after the withdrawal of the gas. This regulatory liability is a reduction of rate base.

(18) Regulatory Matters

Colstrip Unit 4

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

The 2007 Montana House Bill 25 (HB 25), labeled *The Generation Reintegration Act*, largely removed the remaining remnants of deregulation from Montana law that began in 1997 by eliminating customer choice for all customers except for the largest industrial customers using more than five MWs, and permits utilities to build and own electric generation assets that would be included in utility cost of service. In addition, the bill provided for a timely advanced approval process for electricity supply resource projects and requires carbon offsets to reduce carbon dioxide emissions.

Consistent with this bill and in accordance with the agreement with the purchaser, on June 30, 2008, we submitted a filing with the MPSC to initiate a review process to determine if it would be in the public interest to place our interest in Colstrip Unit 4 into rate base at an equivalent value to the negotiated selling price including certain adjustments. The determination of the selling price was based on a number of factors, including the existing below market commitments of 111 MWs to our Montana regulated electric supply load. The MPSC accepted the application and ordered the asset be placed into utility rate base effective January 1, 2009, at a value of $407 million. The order included a capital structure of 50% equity and 50% debt, an authorized return on equity of 10% and cost of debt of 6.5%, which are set for 34 years or the life of the plant. The difference in rate base value of $407 million and the negotiated price of $404 million reflects termination fees of approximately $6.3 million offset by avoided sale transaction fees of approximately $3.3 million.

Mill Creek Generating Station

In August 2008, we filed a request with the MPSC for advanced approval to construct a 150 MW natural gas fired facility at an estimated cost of $206 million. The Mill Creek Generating Station would provide regulating resources to balance our transmission system in Montana to maintain reliability and enable additional wind power to be integrated onto the network to meet future renewable energy portfolio needs. As part of the MPSC filing, we requested a capital structure of 50% equity and 50% debt and an authorized return on equity of 10.75%. A procedural schedule is currently in place and we anticipate an MPSC decision during the second quarter of 2009.

Pension Accounting Order

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

Property Tax Settlement

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

Montana Electric and Natural Gas Rate Case

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

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

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

FERC Transmission Rate Case

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

(19) Commitments and Contingencies

Qualifying Facilities Liability

In Montana we have certain contracts with Qualifying Facilities, or QFs. The QFs require us to purchase minimum amounts of energy at prices ranging from $65 to $138 per MWH through 2029. Our estimated gross contractual obligation related to the QFs is approximately $1.5 billion through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $1.2 billion through 2029. Upon adoption of fresh-start reporting, we computed the fair value of the remaining liability of approximately $367.9 million to be approximately $143.8 million based on the net present value (using a 7.75% discount factor) of the difference between our obligations under the QFs and the related amount recoverable.

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

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

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

	Gross Obligation	Recoverable Amounts	Net
2009	$ 61,586	$ 53,322	$ 8,264
2010	63,589	53,835	9,754
2011	65,323	54,357	10,966
2012	67,111	54,904	12,207
2013	69,816	55,462	14,354
Thereafter	1,131,757	853,215	278,542
Total	$ 1,459,182	$ 1,125,095	$ 334,087

Long Term Supply and Capacity Purchase Obligations

We have entered into various commitments, largely purchased power, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 23 years. Costs incurred under these contracts were approximately $563.0 million and $442.8 million for the years ended December 31, 2008 and 2007, respectively. As of December 31, 2008 our commitments under these contracts are $480 million in 2009, $339 million in 2010, $156 million in 2011, $144 million in 2012, $131 million in 2013, and $487 million thereafter. These commitments are not reflected in our Financial Statements.

Environmental Liabilities

Our liability for environmental remediation obligations is estimated to range between $22.0 million to $43.2 million. As of December 31, 2008, we have a reserve of approximately $31.5 million. Environmental costs are recorded when it is probable we are liable for the remediation and we can reasonably estimate the liability. Over time, as specific laws are implemented and we gain experience in operating under them, a portion of the costs related to such laws will become determinable, and we may seek authorization to recover such costs in rates or seek insurance reimbursement as applicable; therefore, we do not expect these costs to have a material adverse effect on our financial position or ongoing operations.

Manufactured Gas Plants - Approximately $26.9 million of our environmental reserve accrual is related to manufactured gas plants. A formerly operated manufactured gas plant located in Aberdeen, South Dakota, has been identified on the Federal Comprehensive Environmental Response, Compensation, and Liability Information System (CERCLIS) list as contaminated with coal tar residue. We are currently investigating, characterizing, and initiating remedial actions at the Aberdeen site pursuant to work plans approved by the South Dakota Department of Environment and Natural Resources. In 2007, we completed remediation of sediment in a short segment of Moccasin Creek that had been impacted by the former manufactured gas plant operations. Our current reserve for remediation costs at this site is approximately $13.4 million, and we estimate that approximately $10 million of this amount will be incurred during the next five years.

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

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

Milltown Dam Removal - Our subsidiary, Clark Fork and Blackfoot, LLC (CFB), owns the former Milltown Dam site, and previously operated a three MW hydroelectric generation facility located at the confluence of the Clark Fork and Blackfoot Rivers. Dam removal activities were initiated during the first quarter of 2008 and are expected to be complete in 2009. Our remaining obligation to the State of Montana related to this site is approximately $0.6 million, which will be solely funded through the transfer of land and water rights associated with the former Milltown Dam operations to the State of Montana.

Coal-Fired Plants - We have a joint ownership interest in four electric generating plants, all of which are coal fired and operated by other companies. We have an undivided interest in these facilities and are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated. In addition, a significant portion of the electric supply we procure in the market is generated by coal-fired plants.

Global Climate Change - There is a growing concern nationally and internationally about global climate change and the contribution of emissions of greenhouse gases including, most significantly, carbon dioxide. This concern has led to increased interest in legislation at the federal level, actions at the state level, as well as litigation relating to greenhouse emissions, including a US Supreme Court decision holding that the EPA relied on improper factors in deciding not to regulate carbon dioxide emissions from motor vehicles under the Clean Air Act. Increased pressure for carbon dioxide emissions reduction also is coming from investor organizations. Specifically, coal-fired plants have come under scrutiny due to their emissions of carbon dioxide.

In addition, there is a gap between proposed emissions reduction levels and the current capabilities of technology, as there is no currently available commercial scale technology that would achieve the proposed reduction levels. Such technology may not be available within a timeframe consistent with the implementation of climate change legislation or at all. To the extent that such technology does become available, we can provide no assurance that it will be suitable for installation at the generation facilities we have a joint interest in, or on a cost effective basis. If legislation or regulations are passed at the federal or state levels imposing mandatory reductions of carbon dioxide and other greenhouse gases on generation facilities, the cost to us and / or our customers could be significant.

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

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

Clean Air Mercury Rule – In March 2005, the EPA issued the Clean Air Mercury Regulations (CAMR) to reduce the emissions of mercury from coal-fired facilities through a market-based cap-and-trade program. Although the U.S. Court of Appeals for the District of Columbia Circuit struck down CAMR, the state of Montana has finalized its own rules more stringent than CAMR's 2018 cap that would require every coal-fired generating plant in the state to achieve reduction levels by 2010. The joint owners currently plan to install chemical injection technologies to meet these requirements. We estimate our share of the capital cost would be approximately $1 million, with ongoing annual operating costs of approximately $3 million. If the Montana rules are maintained in their current form and enhanced chemical injection technologies are not sufficiently developed to meet the Montana levels of reduction by 2010, then adsorption/absorption technology with fabric filters at the Colstrip Unit 4 generation facility would be required, which could represent a material cost. Recent tests have shown that it may be possible to meet the Montana rules with more refined chemical injection technology combined with adjustments to boiler/fireball dynamics at a minimal cost. We are continuing to work with the other Colstrip owners to determine the ultimate financial impact of these rules.

Other

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

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

- We may not know all sites for which we are alleged or will be found to be responsible for remediation; and
- Absent performance of certain testing at sites where we have been identified as responsible for remediation, we cannot estimate with a reasonable degree of certainty the total costs of remediation.

Legal and Other Contingencies

Colstrip Energy Limited Partnership

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

Colstrip Unit 4 Coal Royalties

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

Blue Dot Bankruptcy

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

Bozeman Explosion

On March 5, 2009, a natural gas explosion occurred in downtown Bozeman, Montana. The explosion resulted in one fatality, the destruction of three buildings (and the several places of business located within the destroyed buildings), and ancillary damage to nearby buildings and vehicles. Our investigation of this incident is ongoing. While litigation has not been commenced with respect to this incident, claims have been made against NorthWestern. We have paid our deductible and tendered the defense of any claims which may arise out of this incident to our insurance carrier. Our total available insurance coverage is approximately $150 million.

McCarthy

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

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

(20) Common Stock

We have 250,000,000 shares authorized consisting of 200,000,000 shares of common stock with a $0.01 par value and 50,000,000 shares of preferred stock with a $0.01 par value. Of these shares, 2,265,957 shares of common stock are reserved for the incentive plan awards. For further detail of grants under this plan see Note 16.

Repurchase of Common Stock

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

Shares tendered by employees to us to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock awards totaled 41,289 and 33,196 during the years ended December 31, 2008 and 2007, respectively, and are reflected in treasury stock. These shares were credited to treasury stock based on their fair market value on the vesting date.

Sch. 19	MONTANA PLANT IN SERVICE - PROPANE			
	Account Number & Title	This Year Utility	Last Year Utility	% Change
1	**Local Storage Plant**			
2	3360 Land and Land Rights	$64,954	$64,954	0.00%
3	3363 Other Equipment	381,748	381,748	0.00%
4	**Total Local Storage Plant**	446,702	446,702	0.00%
5				
6	**Distribution Plant**			
7	3376 Mains	489,621	489,621	0.00%
8	3380 Services	480,149	437,678	9.70%
9	3381 Customers Meters and Regulators	31,995	27,276	17.30%
10	3382 Meter Installations		-	-
11	3389 Other Equipment	51,888	51,888	0.00%
12	**Total Distribution Plant**	1,053,653	1,006,463	4.69%
13	**Total Propane Plant in Service**	1,500,355	1,453,165	3.25%
14				
15	3107 Propane Construction Work in Progress		-	-
16	3117 Gas in Underground Storage	15,385	17,729	-13.22%
17				
18				
19	**TOTAL PROPANE PLANT**	$1,515,740	$1,470,894	3.05%
20				
21				
22	**CONSOLIDATED**	December 31,		
23	**PLANT IN SERVICE**	2008	2007	
24				
25	Montana Electric	$ 1,394,151,266	$ 1,343,863,437	
26	Yellowstone National Park	11,699,040	11,658,388	
27	Colstrip Unit 4	87,205,999	83,990,140	
28	Montana Natural Gas (Includes CMP)	489,072,577	464,510,969	
29	Common	92,523,261	88,234,399	
30	Townsend Propane	1,500,355	1,453,165	
31	South Dakota Electric	409,396,824	391,601,736	
32	South Dakota Natural Gas	135,070,061	122,382,899	
33	South Dakota Common	42,027,354	42,726,864	
34	Asset Retirement Obligation	6,269,604	3,907,613	
35	**TOTAL PLANT**	$ 2,668,916,341	$ 2,554,329,610	

Sch. 20	MONTANA DEPRECIATION SUMMARY - PROPANE				
	Functional Plant Class	Plant Cost	This Year	Last Year	Current Avg. Rate
1	**Accumulated Depreciation**				
2					
3	Local Storage Plant	$446,702	$188,937	$180,195	1.96%
4					
5	Distribution	1,006,463	332,473	300,144	3.21%
6					
7					
8	**Total Accumulated Depreciation**	$1,453,165	$521,410	$480,339	
9					
10					
11					
12					

	Consolidated	December 31,	
13	**Consolidated**	December 31,	
14	**Accumulated Depreciation**	2008	2007
15			
16	Montana Electric	$652,606,520	$610,454,677
17	Yellowstone National Park	7,755,794	7,462,625
18	Colstrip Unit 4	38,674,170	37,664,198
19	Montana Natural Gas (Includes CMP)	198,176,878	188,681,195
20	Common	43,541,925	39,653,707
21	Townsend Propane	521,410	480,339
22	South Dakota Electric	217,665,844	207,981,811
23	South Dakota Natural Gas	53,212,037	48,947,473
24	South Dakota Common	15,161,327	15,157,562
25	Acquisition Writedown	115,982,411	123,364,837
26	Basin Creek Capital Lease	5,026,172	3,015,704
27	FIN 47	403,740	255,716
28	CWIP-Capital Retirement Clearing	-589,906	-648,326
29	**Total Consolidated Accum Depreciation**	$1,348,138,322	$1,282,471,518

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - PROPANE			
	Commission Accepted - Most Recent	% Capital Structure	% Cost Rate	Weighted Cost
1				
2	Docket Number:			
3	Order Number :			
4	Not Applicable	Not Applicable		
5	Common Equity			
6	Preferred Stock			
7	QUIPS Preferred			
8	Long Term Debt			
9	Other			
10	**TOTAL**	0.00%		0.00%
11				
12		% Capital		Weighted
13	**NorthWestern Corporation Consolidated**	Structure	% Cost Rate 1/	Cost
14				
15	Common Equity	54.63%	10.75%	5.87%
16	Preferred Stock	0.00%	0.00%	0.00%
17	QUIPS Preferred	0.00%	0.00%	0.00%
18	Long Term Debt	45.37%	5.76%	2.61%
19	Other			
20	**TOTAL**	100.00%		8.48%
21				
22	1/ The cost of debt represents Montana jurisdiction only, as reflected on Schedule 24.			
23				
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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	$ 67,601,004	$ 53,191,154	27.09%
4	Noncash Charges (Credits) to Income:			
5	Depreciation	79,758,326	81,031,947	-1.57%
6	Amortization, Net	(1,043,731)	(556,565)	-87.53%
7	Other Noncash Charges to Net Income, Net	4,994,829	(2,465,509)	>300.00%
8	Deferred Income Taxes, Net	41,424,645	29,773,876	39.13%
9	Investment Tax Credit Adjustments, Net	(580,189)	(531,229)	-9.22%
10	Change in Operating Receivables, Net	1,389,563	26,635,221	-94.78%
11	Change in Materials, Supplies & Inventories, Net	(7,197,797)	(3,124,179)	-130.39%
12	Change in Operating Payables & Accrued Liabilities, Net	11,451,044	(977,858)	>300.00%
13	Allowance for Funds Used During Construction (AFUDC)	(641,253)	(507,828)	-26.27%
14	Change in Other Assets & Liabilities, Net	(23,159,947)	(2,935,660)	>-300.00%
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	(8,683,838)	(3,572,780)	-143.06%
17	Change in Regulatory Assets	20,470,034	22,912,870	-10.66%
18	Change in Regulatory Liabilities	7,180,108	(2,158,411)	>300.00%
19	**Net Cash Provided by/(Used in) Operating Activities**	192,962,798	196,715,050	-1.91%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(124,562,480)	(117,084,191)	-6.39%
22	(Net of AFUDC)			
23	Proceeds from Sale of Assets	199,613	1,841,686	-89.16%
24	Other Investing Activities:			
25	Investments in and Advances to Assoc. and Subsidiary Companies	-	(141,256,832)	100.00%
26	Distribution from Subsidiaries	-	-	-
27	**Net Cash Provided by/(Used in) Investing Activities**	(124,362,867)	(256,499,337)	51.52%
28	**Cash Flows from Financing Activities:**			
29	Proceeds from Issuance of:			
30	Long-Term Debt	55,000,000	-	100.00%
31	Credit Facilities Borrowings/Repayments, Net	96,000,000	-	100.00%
32	Long-Term Debt of Subsidiary Companies	-	100,000,000	-100.00%
33	Payment for Retirement of:			
34	Credit Facilities Borrowings/Repayments, Net	-	(38,000,000)	100.00%
35	Long-Term Debt	(76,350,000)	(365,000)	>-300.00%
36	Long-Term Debt of Subsidiary Companies	(13,226,580)	(8,793,384)	-50.42%
37	Capital Lease Obligations, Net	(1,388,310)	(1,133,573)	-22.47%
38	Dividends on Common Stock	(49,833,215)	(47,286,168)	-5.39%
39	Other Financing Activities:			
40	Exercise of Warrants	-	68,833,514	-100.00%
41	Debt Financing Costs	(1,550,011)	(1,734,317)	10.63%
42	Treasury Stock Purchases	(78,706,635)	(895,688)	>-300.00%
43	**Net Cash Provided by (Used in) Financing Activities**	(70,054,751)	70,625,385	-199.19%
44	**Net Increase/(Decrease) in Cash and Cash Equivalents**	(1,454,820)	10,841,098	-113.42%
45	**Cash and Cash Equivalents at Beginning of Year**	12,706,259	1,865,161	>300.00%
46	**Cash and Cash Equivalents at End of Year**	$ 11,251,439	$ 12,706,259	-11.45%
47				
48	This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory			
49	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity			
50	method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana			
51	Pipeline Corp.			
52				

MONTANA LONG TERM DEBT 1/

Sch. 24	Description	Issue Date	Maturity Date	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem./Disc.	Total Cost %
2	**First Mortgage Bonds**								
3	6.04% Series, Due 2016	09/13/06	09/01/16	$150,000,000	$148,302,298	$149,943,650	6.040%	$9,307,440	6.21%
4	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%
5	**Total First Mortgage Bonds**			$311,000,000	$309,302,298	$310,943,650		$19,242,103	6.19%
7	**Pollution Control Bonds**								
8	4.65% Series, Due 2023	04/27/06	08/01/23	$170,250,000	$164,451,956	$170,205,000	4.650%	$8,467,855	4.98%
10	**Total Pollution Control Bonds**			$170,250,000	$164,451,956	$170,205,000		$8,467,855	4.98%
12	**Other Long Term Debt**								
13	Other Capital Leases - Fleet Lease	09/24/02	08/27/09	$6,179,475	$6,179,475	$78,944		$13,620	3.82%
14	**Total Other Long Term Debt**			$6,179,475	$6,179,475	$78,944		$13,620	
15	**TOTAL LONG TERM DEBT**			$487,429,475	$479,933,729	$481,227,594		$27,723,578	5.76%

1/ Total Long Term Debt does not include amounts due within 1 year of $103,515. It also does not include amounts associated with the Basin Creek contract, which totals $37,808,587.

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										
12										
13										
14										
15										
16										
17										
18										
19										
20										
21										
22										
23										
24										
25										
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 High	Market Price Low	Price/ Earnings Ratio
January	38,972,551	$21.36				$29.60	$27.13	
February	38,972,551	21.58				29.70	25.67	
March	38,972,551	21.41	$0.60	$0.33		26.33	24.04	
April	38,972,551	21.51				26.13	24.54	
May	38,972,551	21.63				26.67	23.71	
June	38,972,551	21.35	0.24	0.33		26.80	25.24	
July	38,190,492	21.42				28.50	23.78	
August	38,256,793	21.45				26.39	23.69	
September	35,910,281	21.00	0.35	0.33		26.69	21.79	
October	35,910,281	21.08				25.49	16.47	
November	35,928,050	21.15				21.34	17.02	
December	35,928,118	21.25	0.59	0.33		23.65	19.27	
TOTAL Year End	37,975,554	$21.25	$1.78	$1.32	25.84%	$23.47		13.2

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for the twelve months ended December 31, 2008.

Sch. 27	MONTANA EARNED RATE OF RETURN - PROPANE			
	Description	This Year	Last Year	% Change
1	**Rate Base**			
2	101 Plant in Service	$1,473,499	$1,443,712	2.06%
3	108 Accumulated Depreciation	(500,925)	(462,493)	-8.31%
4				
5	**Net Plant in Service**	972,574	981,219	-0.88%
6	Additions:			
7	Other Additions	24,789	28,471	-12.93%
8				
9	**Total Additions**	24,789	28,471	-12.93%
10	Deductions:			
11	190 Accumulated Deferred Income Taxes	153,416	173,623	-11.64%
12				
13	**Total Deductions**	153,416	173,623	-11.64%
14	**Total Rate Base**	843,947	836,067	0.94%
15	**Net Earnings**	($376,803)	($257,465)	-46.35%
16	**Rate of Return on Average Rate Base**	-44.648%	-30.795%	-44.98%
17	**Rate of Return on Average Equity**	Not applicable	Not applicable	
18				
19	**Major Normalizing and**			
20	**Commission Ratemaking Adjustments**			
21				
22				
23		None		
24				
25				
26				
27				
28				
29	**Total Adjustments**			
30	**Revised Net Earnings**			
31	**Adjusted Rate of Return on Average Rate Base**			
32	**Adjusted Rate of Return on Average Equity**			
33				
34	**Detail - Other Additions**			
35	Propane on Hand	24,789	28,471	-12.93%
36				
37	**Total Other Additions**	24,789	28,471	-12.93%
38				
39	**Detail - Other Deductions**			
40				
41	**Total Other Deductions**	$0	$0	-
42				
43				
44				
45				
46				

Sch. 28	MONTANA COMPOSITE STATISTICS - PROPANE		
		Description	Amount
1			
2		**Plant**	
3			
4	101	Plant in Service	$1,500,355
5	107	Construction Work in Progress	
6	117	Gas in Underground Storage	15,385
7	108, 111	Depreciation & Amortization Reserves	521,410
8			
9	**NET BOOK COSTS**		994,330
10			
11		**Revenues & Expenses**	
12			
13	400	Operating Revenues	446,357
14			
15	**Total Operating Revenues**		446,357
16			
17	401-402	Operation & Maintenance Expenses	976,859
18	403-407	Depreciation Expense	41,071
19	408.1	Taxes Other than Income Taxes	52,759
20	409-411	Federal & State Income Taxes	(247,529)
21			
22	**Total Operating Expenses**		823,160
23	**Net Operating Income**		(376,803)
24			
25	415-421.1	Other Income	-
26	421.2-426.5	Other Deductions	-
27	**NET INCOME BEFORE INTEREST EXPENSE**		$ (376,803)
28			
29		**Average Customers**	
30		Residential	488
31		Commercial / Industrial	57
32			
33	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		545
34			
35		**Other Statistics**	
36		Average Annual Residential Use (Dkt)	69.4
37		Average Annual Residential Cost per (Dkt)	$9.4890
38		Average Residential Monthly Bill	$54.90
39			
40		Plant in Service (Gross) per Customer	$2,753

Sch. 29	Montana Customer Information- Propane, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Townsend	1,867	488	57	-	545
2						
3						
4						
5						
6						
7						
8						
9	**Total**	1,867	488	57	-	545
10						
11						
12	1/ Customer populations represent an average of the 12 month period from 01/01/08 through 12/31/08.					

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
3	Executive	7	5	6
4	Safety, Health & Environmental	13	13	13
5	Financial, Risk Mgmt. & Information Services	117	112	115
6	Human Resources & Administration	25	23	24
7	Utility Services & Division Administration	642	675	659
8	Regulatory Affairs	21	22	22
9	Transmission	177	175	176
10	Legal	6	8	7
11				
12				
13				
14				
15				
16				
17	**TOTAL EMPLOYEES**	1,008	1,033	1,021

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

Sch. 31	MONTANA CONSTRUCTION BUDGET 2009 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3			
4	BZN Big Sky Meadow Substation 25MVA	$1,500,000	$1,500,000
5	BZN Sourdough 4.16 Cutover to 12.5	995,081	995,081
6	Elec Dist MDOT Relocations	1,600,000	1,600,000
7	Elec Trans Jack Rabbit Auto 100MVA Bank Replacement	2,600,424	2,600,424
8	Elec Trans Woodside-Victor "A" MDOT Reroute	835,515	835,515
9	MT Growth Transformer purchases	5,600,000	5,600,000
10			
11	All Other Projects < $1 Million Each MT	35,764,106	35,764,106
12	All Other Projects SD	19,408,460	
13	**Total Electric Utility Construction Budget**	68,303,586	48,895,126
14			
15	**Natural Gas Operations**		
16	Gas Trans Meriwether Rd Compressor Station	4,007,728	4,007,728
17	Gas Transmission - Pipeline Integrity Management Projects	3,340,268	3,340,268
18	Gas Transmission MDOT relocations	938,580	938,580
19			
20			
21	All Other Projects < $1 Million Each MT	12,331,394	12,331,394
22	All Other Projects SD/NE	3,584,166	
23	**Total Natural Gas Utility Construction Budget**	24,202,136	20,617,970
24			
25	**Common**		
26	MT Fleet and Equipment replacements	3,307,000	3,307,000
27	IT AM-FM GIS and automated scheduling	1,175,000	1,175,000
28	Communications - mobile radios	929,436	929,436
29	All Other Projects < $1 Million Each MT	2,799,205	2,799,205
30	(Includes IT, Communications, Facillities, Cust Serv)		
31	All Other Projects SD/NE	4,378,308	
32			
33	**Total Common Utility Construction Budget**	12,588,949	8,210,641
34			
35	CU4 capital additions - PPL invoice	4,200,000	4,200,000
36			
37	All Other Projects < $1 Million Each	-	-
38			
39			
40			
41	**Total Colstrip Unit 4 Construction Budget**	4,200,000	4,200,000
42	**TOTAL CONSTRUCTION BUDGET**	$109,294,671	$81,923,737

Sch. 33	MONTANA SOURCES OF PROPANE SUPPLY				
		Dekatherm Volumes		Avg. Commodity Cost	
		2008 Year	2007 Year	2008 Year	2007 Year
1	**Name of Supplier**				
2					
3	Superior Propane		25,678		$14.1916
4	Farstad Oil, Inc.	51,217	19,790	$17.2281	$13.8768
5					
6	**Total Propane Supply Volumes**	51,217	45,468	$17.2281	$14.0546

Sch. 35	MONTANA CONSUMPTION AND REVENUES - PROPANE						
		Operating Revenues		Dkt Sold		Average Customers	
		2008 Year	2007 Year	2008 Year	2007 Year	2008 Year	2007 Year
1	**Sales of Propane**						
2							
3	Residential	$321,486	$289,727	33,880	30,352	488	467
4	Commercial / Industrial	124,871	109,081	13,484	11,807	57	49
5							
6							
7	**TOTAL SALES**	$446,357	$398,808	47,364	42,159	545	516