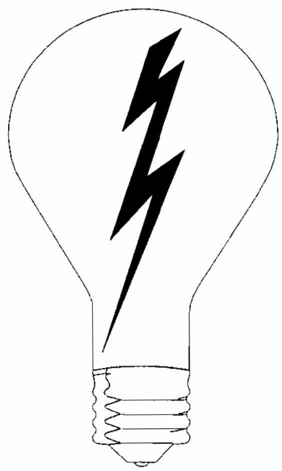
YEAR ENDING 2006

ANNUAL REPORT
OF

NorthWestern Energy

ELECTRIC UTILITY



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

Electric Annual Report

Table of Contents

continued on next page

Sch. 1	IDENTIFICATION	
	Legal Name of Respondent:	NorthWestern Corporation
	Name Under Which Respondent Does Business:	NorthWestern Energy
	Date Utility Service First Offered in Montana:	Electricity - Dec 12, 1912 Natural Gas - Jan 01, 1933 Propane - Oct 13, 1995
	Person Responsible for Report:	Kendall G. Kliewer
	Telephone Number for Report Inquiries:	(406) 497-2759
	Address for Correspondence Concerning Report:	40 East Broadway Street Butte, MT 59701

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

N/A

Sch. 2	**BOARD OF DIRECTORS**	
	Director's Name & Address (City, State)	Remuneration
1		
2	See Northwestern Corporation's Annual Report on Form 10-K	
3	to the SEC for the Corporate Board of Directors.	
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		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		

Sch. 3

OFFICERS

Title	Department Supervised	Name
President & Chief Executive Officer	Executive	Michael Hanson
Vice President, Chief Financial Officer	Tax, Internal Audit & Controls Financial Planning & Analysis Controller & Treasury Functions Information Technology Investor Relations	Brian Bird
Vice President, General Counsel & Corporate Secretary	Legal	Thomas Knapp
Vice President, Retail Operations	MT/SD/NE Retail Operations Engineering & Planning Large Project Development Capital Investment Administration	Curt Pohl
Vice President, Wholesale Operations	Energy Supply Operations Transmission Operations Unregulated Power Supply	David Gates
Vice President, Regulatory & Governmental Affairs	Government & Regulatory Affairs State, Local & Community Relations Labor Relations	Patrick Corcoran
Vice President, Administrative Services	Support Services Safety/Health/Environmental Benefits Records Management	Greg Trandem
Vice President, Customer Care & Communications	Revenue Collections Customer Interaction Customer Care Systems & Support Key Accounts/Customer Education Communications	Bobbi Schroeppel
Internal Audit & Controls Officer	Internal Audit Enterprise Risk Financial system Applications	Michael Nieman
Vice President, Controller	Financial/SEC Reporting Accounting Fixed Assets Accounts Payable Payroll	Kendall Kliewer
Treasurer	Treasury Functions Risk Management Credit	Paul Evans
Assistant Treasurer	Cash Management	Emilie Ng

Reflects active officers as of March 31, 2007.

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		**$ 22,353**	**58.98%**
NorthWestern Corporation:			
Montana Utility Operations	Electric Utility Natural Gas Utility Natural Gas Pipeline Propane Utility Natural Gas Funding Trust - (Bond Transition Financing) 1/		
South Dakota Utility Operations	Electric Utility Natural Gas Utility		
Unregulated Operations		**$ 15,547**	**41.02%**
Colstrip Unit 4 Lease Management Division	Wholesale Electric		
Direct Subsidiaries:			
NorthWestern Services, LLC	Nonregulated natural gas marketing, natural gas pipeline company, HVAC services property management		
Clarkfoot and Blackfoot, LLC	Milltown hydroelectric facility		
NorthWestern Investments, LLC	Investment Corporation		
Risk Partners Assurance, Ltd.	Captive insurance company		
Indirect Subsidiaries:			
Montana Generation, LLC	Non-regulated energy marketing		
Nekota Resources Inc.	Non-regulated intrastate natural gas pipeline company		
Total Corporation		**$ 37,900**	**100.00%**

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

Sch. 5

CORPORATE ALLOCATIONS

Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
Utility Administration Executive Department	Includes the following departments: CEO; COO	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on a % developed using plant, revenues and operating labor.	$2,173,720	68.84%	$983,920
Legal Department	Includes the following departments: Chief Legal, Insurance	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on a % developed using plant, revenues and operating labor.	$7,007,288	68.51%	$3,220,277
Administration & Human Resources	Includes the following departments: Human Resources; Benefits Admin.; Compensation & Payroll, VP Admin, Printing, Rec Mgmt & Aircraft	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on a % developed using plant, revenues and operating labor.	25,926,163	83.81%	5,007,800
Finance / Accounting	Includes the following departments: CFO Treasury, FP&A, Controller, Fixed Assets, Accounting; Tax & Financial Reporting, Investor Relations	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on a % developed using plant, revenues and operating labor.	7,746,020	71.02%	3,160,188
Information Technology	Includes the following departments: IT Sr; VP/CIO; IT Applications Infrastructure, Licensing & Leasing	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on a % developed using plant, revenues and operating labor.	6,269,224	68.84%	2,837,725
Regulatory and Gov't Affairs	Includes the following departments: Regulatory Affairs, Load Research Government Affairs, Reg Support Services, Community Relations	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on a % developed using plant, revenues and operating labor.	3,561,677	80.04%	888,431
Customer Care	Includes the following departments: Customer Care Common, Customer Care Combined, CC MT Only and Corp Communications	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on a % developed using plant, revenues and operating labor.	15,896,016	71.30%	6,399,348
Audit & Controls	Includes the following departments: Audit and Controls, Internal Auditing Project Office, Business Continuity	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on a % developed using plant, revenues and operating labor.	810,862	68.84%	367,031
TOTAL			$69,390,970	75.22%	$22,864,720

Sch. 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO 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 Lease Management Division	Purchased Power	Market Rates	$22,914,151	27.22%	$22,914,151
5						
6						
7						
8						
9	**Total Nonutility Subsidiaries**			$22,914,151		$22,914,151
10	**Total Nonutility Subsidiaries Expenses**			$84,188,940		
11						
12						
13	**Utility Subsidiaries**					
14				$0	0.00%	$0
15	**Total Utility Subsidiaries**			$0		$0
16	**Total Utility Subsidiaries Expenses**			$2,542,740		
17	**TOTAL AFFILIATE TRANSACTIONS**			$22,914,151		$22,914,151

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 Lease Management Wheeling			$469,355	0.77%	$469,355
5						
6						
7						
8						
9	**Total Nonutility Subsidiaries**			$469,355		$469,355
10	**Total Nonutility Subsidiaries Expenses**			$61,271,484		
11						
12						
13	**Utility Subsidiaries**					
14	Canadian Montana Pipeline Gas Transportation			$32,200	3.00%	$32,200
15	**Total Utility Subsidiaries**			$32,200		$32,200
16	**Total Utility Subsidiaries Expenses**			$1,073,508		
17	**TOTAL AFFILIATE TRANSACTIONS**			$501,555		$501,555

Sch. 8	MONTANA UTILITY INCOME STATEMENT - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	400 Operating Revenues	$ 757,313,087	$ 165,973,213	$ 591,339,874	$ 568,959,340	3.93%
3						
4	**Total Operating Revenues**	757,313,087	165,973,213	591,339,874	568,959,340	3.93%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expenses	475,777,308	74,471,990	401,305,318	395,454,503	1.48%
9	402 Maintenance Expense	34,540,170	12,817,568	21,722,602	18,688,166	16.24%
10	403 Depreciation Expense	60,465,627	15,376,056	45,089,571	44,152,859	2.12%
11	404-405 Amort. of Electric Plant	4,163,881	1,193,395	2,970,486	2,997,677	-0.91%
12	406 Amort. of Plant Acquisition Adj.	(4,998,960)	(5,093,874)	94,914	94,914	0.00%
13	407.3 Regulatory Amortizations - Debit	16,039,714	329,324	15,710,390	7,149,685	119.74%
14	407.4 Regulatory Amortizations - Credit	(8,358,898)	408,926	(8,767,824)	(7,417,073)	-18.21%
15	408.1 Taxes Other Than Income Taxes	63,102,117	7,299,101	55,803,016	52,127,571	7.05%
16	409.1 Income Taxes - Federal	31,936,517	8,608,603	23,327,914	221,319	>300.00%
17	- Other	2,525,631	(112,941)	2,638,572	(511,559)	>300.00%
18	410.1 Deferred Income Taxes-Dr.	-	-	-	16,156,906	-100.00%
19	411.1 Deferred Income Taxes-Cr.	(5,310,227)	8,207,671	(13,517,898)		-
20	411.4 Investment Tax Credit Adj.	(494,934)	(494,934)	-	-	-
21	411.6 Gain from Disposition of Property	-	-	-	-	-
22	411.7 Loss from Disposition of Property	-	-	-	-	-
23	411.8 SO2 Allowances	(16,573)	(16,573)	-	-	-
24						
25	**Total Operating Expenses**	669,371,373	122,994,312	546,377,061	529,114,968	3.26%
26	**NET OPERATING INCOME**	$ 87,941,714	$ 42,978,901	$ 44,962,813	$ 39,844,372	12.85%

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 - ELECTRIC					
	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	$ 235,959,631	$ 40,781,263	$ 195,178,368	$ 183,532,173	6.35%
5	442 Commercial	301,131,146	59,509,002	241,622,144	232,137,066	4.09%
6	Industrial	46,433,314	-	46,433,314	45,385,690	2.31%
7	444 Public Street, Highway Lighting					
8	& Other Sales to Public Authorities	15,013,670	1,870,850	13,142,820	12,719,985	3.32%
9	448 Interdepartmental Sales	1,042,770	-	1,042,770	994,302	4.87%
10						
11	**Total Sales to Ultimate Consumers**	599,580,531	102,161,115	497,419,416	474,769,216	4.77%
12	447 Sales for Resale	105,792,577	58,452,702	47,339,875	53,953,576	-12.26%
13						
14	**Total Sales of Electricity**	705,373,108	160,613,817	544,759,291	528,722,792	3.03%
15	449.1 Provision for Rate Refunds			-	-	-
16						
17	**Total Revenue Net of Rate Refunds**	705,373,108	160,613,817	544,759,291	528,722,792	3.03%
18						
19	**Other Operating Revenues**					
20	450 Forfeited Discounts & Late Pymt Rev	452,033	452,033	-	-	-
21	451 Miscellaneous Service Revenue	127,075	119,075	8,000	21,375	-62.57%
22	453 Sales of Water & Water Power	-	-	-	-	-
23	454 Rent From Electric Property	5,931,263	3,609,537	2,321,726	2,423,306	-4.19%
24	456 Other Electric Revenues	45,429,608	1,178,751	44,250,857	37,791,867	17.09%
25						
26	**Total Other Operating Revenue**	51,939,979	5,359,396	46,580,583	40,236,548	15.77%
27	**TOTAL OPERATING REVENUE**	$ 757,313,087	$ 165,973,213	$ 591,339,874	$ 568,959,340	3.93%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Power Production Expenses**					
2	**Steam Power Generation-Operation**					
3	500 Supervision & Engineering	$ 780,279	$ 780,279	$ -	$ -	-
4	501 Fuel	40,915,857	37,627,472	3,288,385	34,638	>300.00%
5	502 Steam Expenses	2,099,708	2,099,708	-	-	-
6	503 Steam from Other Sources	-	-	-	-	-
7	505 Electric Plant	800,739	800,739	-	-	-
8	506 Miscellaneous Steam Power	1,791,043	1,791,043	-	-	-
9	507 Rents	25,787,704	25,787,704	-	-	-
10	**Total Operation-Steam Power Gen.**	72,175,330	68,886,945	3,288,385	34,638	>300.00%
11	**Steam Power Generation-Maintenance**					
12	510 Supervision & Engineering	687,461	687,461	-	-	-
13	511 Structures	639,374	639,374	-	-	-
14	512 Steam Boiler Plant	6,363,774	6,363,774	-	-	-
15	513 Electric Plant	1,184,734	1,184,734	-	-	-
16	514 Miscellaneous Steam Plant	802,015	802,015	-	-	-
17	**Total Maintenance-Steam Power Gen.**	9,677,358	9,677,358	-	-	-
18	**Total Steam Power Generation**	81,852,688	78,564,303	3,288,385	34,638	>300.00%
19	**Hydro Power Generation-Operation**					
20	535 Supervision & Engineering	-	-	-	-	-
21	536 Water for Power	-	-	-	-	-
22	537 Hydraulic Expenses	-	-	-	-	-
23	538 Electric Expenses	-	-	-	-	-
24	539 Miscellaneous Hydraulic Power	-	-	-	-	-
25	540 Rents	-	-	-	-	-
26	**Total Operation-Hydro Power Gen.**	-	-	-	-	-
27	**Hydro Power Generation-Maintenance**					
28	541 Supervision & Engineering	-	-	-	-	-
29	542 Structures	-	-	-	-	-
30	543 Reservoirs, Dams & Waterways	-	-	-	-	-
31	544 Electric Plant	-	-	-	-	-
32	545 Miscellaneous Hydro Plant	-	-	-	-	-
33	**Total Maintenance-Hydro Power Gen.**	-	-	-	-	-
34	**Total Hydraulic Power Generation**	-	-	-	-	-
35	**Other Power Generation-Operation**					
36	546 Supervision & Engineering	60,323	60,323	-	-	-
37	547 Fuel	677,351	677,351	-	-	-
38	548 Generation Expenses	302,265	302,265	-	-	-
39	549 Miscellaneous Other Power	528,561	528,561	-	-	-
40	**Total Operation-Other Power Gen.**	1,568,500	1,568,500	-	-	-
41	**Other Power Generation-Maintenance**					
42	551 Supervision & Engineering	60,974	60,974	-	-	-
43	552 Structures	-	-	-	-	-
44	553 Generating & Electric Plant	161,907	161,907	-	-	-
45	554 Miscellaneous Other Power Plant	41,738	41,738	-	-	-
46	**Total Maintenance-Other Power Gen.**	264,619	264,619	-	-	-
47	**Total Other Power Generation**	1,833,119	1,833,119	-	-	-
48	**Other Power Supply Expenses**					
49	555 Purchased Power	294,656,365	(23,058,837)	317,715,202	316,709,611	0.32%
50	556 System Control & Load Dispatch	148,106	148,106	-	-	-
51	557 Other Expenses	7,225,043	17,850	7,207,193	4,008,102	79.82%
52	**Total Other Power Supply Expenses**	302,029,514	(22,892,881)	324,922,395	320,717,713	1.31%
53	**Total Power Production Expenses**	385,715,321	57,504,541	328,210,780	320,752,351	2.33%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	**Transmission Expenses**					
3						
4	**Transmission-Operation**					
5	560 Supervision & Engineering	3,142,411	382,704	2,759,707	2,567,667	7.48%
6	561 Load Dispatching	492,677	57,108	435,569	1,824,155	-76.12%
7	561.1 Load Dispatch - Reliability	341,838	1,889	339,949	-	-
8	561.2 Load Disp-Monitor/Op	490,759	149,319	341,440	-	-
9	561.3 Load Disp-Srv/Schedu	868,621	132,150	736,471	-	-
10	561.4 Relia Pln/StdDev-RTO	13,730	13,730	-	-	-
11	561.5 Reliab, Plan, Stds	98,651	98,651	-	-	-
12	561.8 Sch,Sys&Ctrl Srv-RTO	11,384	11,384	-	-	-
13	562 Station Expenses	458,546	65,909	392,637	424,655	-7.54%
14	563 Overhead Lines	1,050,664	205,455	845,209	600,032	40.86%
15	564 Underground Lines	-	-	-	-	-
16	565 Transmission of Elec. by Others	8,607,517	4,704,604	3,902,913	4,022,413	-2.97%
17	566 Miscellaneous Transmission	1,779,140	1,714,986	64,154	57,715	11.16%
18	567 Rents	508,659	36,270	472,389	573,287	-17.60%
19	**Total Operation-Transmission**	17,864,597	7,574,159	10,290,438	10,069,924	2.19%
20	**Transmission-Maintenance**					
21	568 Supervision & Engineering	908,310	272,231	636,079	146,048	>300.00%
22	569 Structures	30,243	1,118	29,125	15,538	87.45%
23	569.1 Maintenance of Computer Hardware	181,290	694	180,596	-	-
24	569.2 Maintenance of Computer Software	650,044	1,620	648,424	-	-
25	569.3 Maint-Comm Equip	49,440	49,440	-	-	-
26	570 Station Equipment	1,585,667	192,527	1,393,140	2,119,377	-34.27%
27	571 Overhead Lines	2,556,448	171,834	2,384,614	2,710,175	-12.01%
28	572 Underground Lines	-	-	-	-	-
29	573 Miscellaneous Transmission Plant	-	-	-	2,905	-100.00%
30	**Total Maintenance-Transmission**	5,961,442	689,464	5,271,978	4,994,043	5.57%
31	**Total Transmission Expenses**	23,826,039	8,263,623	15,562,416	15,063,967	3.31%
32						
33	**Distribution Expenses**					
34						
35	**Distribution-Operation**					
36	580 Supervision & Engineering	3,078,167	698,248	2,379,919	1,933,143	23.11%
37	581 Load Dispatching	-	-	-	-	-
38	582 Station Expenses	1,049,178	240,717	808,461	822,489	-1.71%
39	583 Overhead Lines	2,339,316	196,339	2,142,977	2,174,215	-1.44%
40	584 Underground Lines	1,866,789	429,664	1,437,125	1,888,273	-23.89%
41	585 Street Lighting & Signal Systems	1,453,044	5,825	1,447,219	1,298,916	11.42%
42	586 Meters	2,519,630	332,985	2,186,645	2,690,145	-18.72%
43	587 Customer Installations	1,474,045	110,807	1,363,238	1,137,223	19.87%
44	588 Miscellaneous Distribution	3,159,583	1,517,489	1,642,094	1,880,323	-12.67%
45	589 Rents	44,690	-	44,690	34,512	29.49%
46	**Total Operation-Distribution**	16,984,442	3,532,074	13,452,368	13,859,239	-2.94%
47	**Distribution-Maintenance**					
48	590 Supervision & Engineering	1,562,981	389,815	1,173,166	909,580	28.98%
49	591 Structures	-	-	-	959	-100.00%
50	592 Station Equipment	1,434,993	85,168	1,349,825	990,867	36.23%
51	593 Overhead Lines	9,419,411	1,243,741	8,175,670	6,387,950	27.99%
52	594 Underground Lines	1,782,397	141,683	1,640,714	1,315,870	24.69%
53	595 Line Transformers	724,608	51,142	673,466	719,627	-6.41%
54	596 Street Lighting, Signal Systems	122,493	89,536	32,957	107,355	-69.30%
55	597 Meters	1,022,511	(17,292)	1,039,803	882,848	17.78%
56	598 Miscellaneous Distribution Plant	40,569	40,569	-	-	-
57	**Total Maintenance-Distribution**	16,109,963	2,024,362	14,085,601	11,315,056	24.49%
58	**Total Distribution Expenses**	33,094,405	5,556,436	27,537,969	25,174,295	9.39%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	**Customer Accounts Expenses**					
3						
4	**Customer Accounts-Operation**					
5	901 Supervision	-	-	-	-	-
6	902 Meter Reading	1,789,071	600,641	1,188,430	1,137,135	4.51%
7	903 Customer Records & Collection	6,500,714	975,011	5,525,703	4,672,394	18.26%
8	904 Uncollectible Accounts	1,616,304	228,223	1,388,081	725,686	91.28%
9	905 Miscellaneous Customer Accts.	79,896	79,571	325	3,421	-90.51%
10	**Total Customer Accounts Expenses**	9,985,985	1,883,446	8,102,539	6,538,636	23.92%
11						
12	**Customer Service & Information**					
13						
14	**Customer Service-Operation**					
15	907 Supervision	-	-	-	-	-
16	908 Customer Assistance	3,782,434	1,418,009	2,364,425	2,280,953	3.66%
17	909 Inform. & Instruct. Advertising	643,708	143,814	499,894	528,489	-5.41%
18	910 Misc. Customer Service & Info.	656,172	8,448	647,724	609,473	6.28%
19	**Total Customer Service & Info. Expense**	5,082,314	1,570,271	3,512,043	3,418,915	2.72%
20						
21	**Sales Expenses**					
22						
23	**Sales-Operation**					
24	911 Supervision	-	-	-	-	-
25	912 Demonstrating & Selling	159,378	-	159,378	407,649	-60.90%
26	913 Advertising	1,033,202	307,174	726,028	84,187	>300.00%
27	916 Miscellaneous Sales	-	-	-	-	-
28	**Total Sales Expenses**	1,192,580	307,174	885,406	491,836	80.02%
29						
30	**Administrative & General Expenses**					
31						
32	**Admin. & General-Operation**					
33	920 Admin. & General Salaries	17,714,779	4,603,419	13,111,360	14,677,922	-10.67%
34	921 Office Supplies & Expenses	6,826,346	2,882,022	3,944,324	4,558,004	-13.46%
35	922 Admin. Expense Transferred-Cr.	(5,321,582)	(1,651,853)	(3,669,729)	(4,287,814)	14.41%
36	923 Outside Services Employed	6,078,493	2,060,302	4,018,191	6,582,089	-38.95%
37	924 Property Insurance	1,093,434	573,332	520,102	445,621	16.71%
38	925 Injuries & Damages	3,737,117	1,071,195	2,665,922	(93,994)	>300.00%
39	926 Employee Pensions & Benefits	4,802,385	1,281,823	3,520,562	6,800,379	-48.23%
40	927 Franchise Requirements	-	-	-	-	-
41	928 Regulatory Commission Expenses	1,178,687	57,809	1,120,878	685,524	63.51%
42	929 Duplicate Charges-Cr.	-	-	-	-	-
43	930 Miscellaneous General Expenses	11,293,998	660,657	10,633,341	9,853,715	7.91%
44	931 Rents	1,490,389	503,596	986,793	1,102,156	-10.47%
45	**Total Operation-Admin. & General**	48,894,046	12,042,302	36,851,744	40,323,602	-8.61%
46	**Admin. & General-Maintenance**					
47	935 General Plant	2,526,788	161,765	2,365,023	2,379,067	-0.59%
48	**Total Maintenance-Admin. & General**	2,526,788	161,765	2,365,023	2,379,067	-0.59%
49	**Total Admin. & General Expenses**	51,420,834	12,204,067	39,216,767	42,702,669	-8.16%
50	**TOTAL OPER. & MAINT. EXPENSES**	$ 510,317,478	$ 87,289,558	$ 423,027,920	$ 414,142,669	2.15%

Sch.11	MONTANA TAXES OTHER THAN INCOME - ELECTRIC (EXCLUDES UNIT 4)			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	$2,810,776	$2,802,394	0.30%
3	Property Taxes	49,732,577	46,074,477	7.94%
4	Crow Tribe RR and Utility Tax	40,735	40,992	-0.63%
5	City Tax	5,337	5,366	-0.54%
6	Consumer Counsel Tax	364,011	461,627	-21.15%
7	Public Service Commission Tax	1,291,647	1,280,864	0.84%
8	Electric Energy Producer's License Tax	812	2,179	-62.74%
9	Heavy Highway Use Tax	11,172	11,316	-1.27%
10	Vehicle Use Tax	107,208	14,735	>300.00%
11	Wholesale Energy Transaction Tax	1,359,199	1,319,352	3.02%
12	Delaware Franchise Tax	79,542	97,155	-18.13%
13	Excise Tax	-	17,114	-
14				
15				
16	**TOTAL TAXES OTHER THAN INCOME**	$55,803,016	$52,127,571	7.05%
17				
18				

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	Alliance Data System	IT Support Services	$ 2,856,908
2	Alme Construction, Inc.	Construction	152,513
3	Anchor Construction Services	Construction	140,875
4	Appalachian Pipeline Contractor	Gas Pipeline Contractor	4,745,418
5	Areva T&D Energy Automation	Energy Mgmt System Software & Maintenance	349,899
6	Asplundh Tree Expert Co.	Tree Trimming	4,258,213
7	Automotive Rentals Inc	Fleet Management	5,322,493
8	Bill Field Trucking Inc.	Equipment Transportation	369,157
9	Browning, Kaleczyc, Berry & Hoven	Legal Services	103,307
10	Central Air Service Inc.	Aerial Patrol Services	149,360
11	Curtis, Mallet-Prevost, Colt & Mosle LLP	Legal Services	893,780
12	Dept. of Health and Human Services	USBC Services	1,516,886
13	DJ&A P.C. Consulting Engineers & Land Surveyors	Survey Services	122,622
14	Economic Research Services Inc.	Electricity Procurement Services	187,997
15	EDM International Inc.	Anchor Rod Inspection Services	223,439
16	ELM Locating & Utility Service	Locating Services & Excavating Notifications	2,183,275
17	Energy Share of Montana	USBC Services	576,500
18	EPC Services Company	Substation Design & Construction	320,212
19	Falls Construction Company	Construction	150,926
20	Filenet Corporation	Software Maintenance	125,891
21	Flying Horse Communication Inc.	Advertising & Public Relations	1,236,607
22	Haverfield Corp.	Helicopter Inspection Services	135,205
23	High Mountain Inspection Services	Gas Pipeline Inspection Services	182,159
24	Independent Inspection Company	Electric Line Inspection	1,044,108
25	Intergraph Corporation	Software Consultants	171,381
26	Itron, Inc.	Hardware & Software Maintenance	581,213
27	Kema Inc.	USB & DSM Programs & Services	3,828,438
28	Leonard, Street & Dienard	Legal Services	172,433
29	McDaniel Technical Services, Inc.	Gas Pipeline Inspection Services	131,732
30	Moody's Investors Service	Debt Rating Service	160,087
31	Nat'l Center for Appropriate Technology	Lab Testing	390,561
32	Natural Gas Services Inc.	Gas Serviceman	110,754
33	Northwest Energy Efficiency	Energy Services	426,423
34	Par Electric Contractors Inc.	Contractor	6,732,698
35	Power Resource Managers	Power Scheduling & Dispatch	241,850
36	Pro Pipe Services, Inc.	Welding Contractor	615,227
37	Rocky Mountain Contractors Inc.	Contractor	13,241,008
38	Rod Tabbert Construction Inc.	Construction	485,430
39	SAP America	Software Maintenance	1,187,199
40	Spherion Corporation	Temporary Employment Services	159,998
41	State Line Contractors Inc.	Contractor	583,157
42	Terracon	Engineering Services	130,513
43	The Brattle Group	Consultant	214,303
44	The Energy Authority Inc.	Scheduling & Dispatching	206,432
45	Upper Cut Tree Service	Tree Trimming	351,945
46	Utilities Underground Location	Locating Services & Excavating Notifications	124,280
47	Varsity Contractors Inc.	Janitorial Services	210,333
48	Washington Forestry Consultants	Forestry Consultants	262,465
49	Waterman Energy Inc.	Engineering Services	108,250
50	Western Union Financial Services	Customer Services	152,249
51	Zacha Underground Construction Company	Construction	195,040
52			
53	**Total of Payments Set Forth Above**		$ 58,523,149

1/ Due to the multiple % allocations, it is not practical to separately identify amounts charged to the electric or gas utility. Consistent with prior years' presentations, this schedule contains payments of $100,000 or more.

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.			
5				
6				
7	There are two employee PACs, one called			
8	Citizens for Responsible Government /			
9	Employees of NorthWestern Energy, and one			
10	called NorthWestern Public Service			
11	Employee's Political Action Committee. These			
12	are organizations of employees and			
13	shareholders of NorthWestern Energy. All of			
14	the money contributed by members goes to			
15	support political candidates. No company			
16	funds may be spent in support of a political			
17	candidate. Nominal administrative costs for			
18	such things as duplicating, postage and			
19	meeting expenses are paid by the company.			
20	These costs are charged to shareholder			
21	expense.			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50	**TOTAL Contributions**			

Sch. 14	Pension Costs 1/			
1	Plan Name: NorthWestern Energy Pension Plan			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Projected Unit Credit	IRS Code: ____________		
4	Annual Contribution by Employer: Variable	Is the Plan Over Funded? No		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year	$ 333,296,099	$ 319,159,467	4.43%
8	Service cost	8,075,745	7,543,277	7.06%
9	Interest cost	17,957,484	17,314,853	3.71%
10	Plan participants' contributions	-	-	-
11	Amendments	-	2,661,045	-100.00%
12	Actuarial (gain) loss 2/	(9,175,027)	1,950,485	>-300.00%
13	Acquisition	-	-	-
14	Benefits paid	(15,339,417)	(15,333,028)	-0.04%
15	Benefit obligation at end of year	$ 334,814,884	$ 333,296,099	0.46%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 230,694,073	$ 202,894,634	13.70%
18	Actual return on plan assets	27,096,134	11,969,529	126.38%
19	Acquisition	-	-	-
20	Employer contribution	15,750,000	31,162,938	-49.46%
21	Plan participants' contributions	-	-	-
22	Benefits paid	(15,339,417)	(15,333,028)	-0.04%
23	Fair value of plan assets at end of year	$ 258,200,790	$ 230,694,073	11.92%
24	**Funded Status** 2/	$ (76,614,094)	$ (102,602,026)	25.33%
26	Unrecognized net actuarial gain (loss) 2/	-	(2,158,834)	100.00%
27	Unrecognized prior service cost 2/	-	2,661,045	-100.00%
29	Prepaid (accrued) benefit cost 2/	$ (76,614,094)	$ (102,099,815)	24.96%
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	5.75%	5.50%	4.55%
32	Expected return on plan assets	8.00%	8.50%	-5.88%
33	Rate of compensation increase	3.50% Union & 3.57% Non-Union	3.30% Union & 3.37% Non-Union	
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	$ 8,075,745	$ 7,543,277	7.06%
36	Interest cost	17,957,484	17,314,853	3.71%
37	Expected return on plan assets	(18,357,293)	(17,003,988)	-7.96%
38	Amortization of prior service cost	241,913	-	-
39	Recognized net actuarial loss	-	-	-
40	Net periodic benefit cost (SEC Basis)	$ 7,917,849	$ 7,854,142	0.81%
41	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
42	Pension Costs	$ 21,950,000	$ 18,852,000	16.43%
43	Pension Costs Capitalized	$ 4,389,649	$ 1,462,628	200.12%
44	Accumulated Pension Asset (Liability) at Year End	$ (76,614,094)	$ (102,099,815)	24.96%
45	**Number of Company Employees:**			
46	Covered by the Plan	3,186	3,159	0.85%
47	Not Covered by the Plan			
48	Active	1,062	1,052	0.95%
49	Retired	1,222	1,214	0.66%
50	Deferred Vested Terminated	902	893	1.01%

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

2/ Amount reflects the adoption of FAS 158 at December 31, 2006.

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 3/	$ 4,292,508	$ 3,423,486	25.38%
21	Plan participants' contributions			
22	Benefits paid			
23	Fair value of plan assets at end of year 3/	$ 199,305,859	$ 169,953,861	17.27%
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	$ 2,881,684	$ 2,693,943	6.97%
44	Pension Costs Capitalized	576,291	501,676	14.87%
45	Accumulated Pension Asset (Liability) at Year End	Not Applicable		
46	**Number of Company Employees:**	4/	4/	
47	Covered by the Plan - Eligible	1,340	1,342	-0.15%
48	Not Covered by the Plan			
49	Active - Participating	1,265	1,253	0.96%
50	Retired			
51	Vested Former Employees, Retirees and Active-	275	312	-11.86%
52	Noncontributing			

3/ This plan covers all NorthWestern Corporation employees.

4/ 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	$4,691,046	$4,871,039	-3.70%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	5.75%	5.50%	4.55%
8	Expected return on plan assets	8.00%	8.50%	-5.88%
9	Medical Cost Inflation Rate 3/	8.0%,5.0%:10	10.0%,5.0%:10	
10	Actuarial Cost Method	Projected Unit Credit Actuarial, Cost Method Allocated from the Date of Hire to Full Eligibility Date		
11	Rate of compensation increase	3.50% Union & 3.57% Non-Union	3.30% Union & 3.37% 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				
17	**Total Company**	4/	4/	
18	**Change in Benefit Obligation**			
19	Benefit obligation at beginning of year			
20	Service cost			
21	Interest Cost			
22	Plan participants' contributions			
23	Amendments			
24	Actuarial Loss/(Gain)			
25	Acquisition			
26	Benefits paid			
27	Benefit obligation at end of year			
28	**Change in Plan Assets**			
29	Fair value of plan assets at beginning of year			
30	Actual return on plan assets			
31	Acquisition			
32	Employer contribution			
33	Plan participants' contributions			
34	Benefits paid			
35	Fair value of plan assets at end of year			
36	**Funded Status**			
37	Unrecognized net actuarial loss			
38	Unrecognized prior service cost			
39	Prepaid (accrued) benefit cost			
40	**Components of Net Periodic Benefit Costs**			
41	Service cost			
42	Interest cost			
43	Expected return on plan assets			
44	Amortization of prior service cost			
45	Recognized net actuarial loss			
46	Net periodic benefit cost			
47	**Accumulated Post Retirement Benefit Obligation**			
48	Amount Funded through VEBA			
49	Amount Funded through 401(h)			
50	Amount Funded through Other ________________			
51	TOTAL			
52	Amount that was tax deductible - VEBA			
53	Amount that was tax deductible - 401(h)			
54	Amount that was tax deductible - Other ____________			
55	TOTAL			

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

2/ Obtained from NorthWestern Energy-Montana's 2005 FASB 106 Valuation. Assumptions and data are as of December 31, 2005.

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

4/ There is approximately an additional $10,037,080 and $10,544,669 in other company OPEBS liabilities outstanding at December 31, 2006 and 2005, respectively for NorthWestern Corporation's Family Protector Plan and the NorthWestern Energy's Top Hat Contracts in addition to what is reflected for Montana below.

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**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year	$45,277,018	$43,457,500	4.19%
10	Service cost	740,490	688,022	7.63%
11	Interest Cost	2,340,596	2,406,644	-2.74%
12	Plan participants' contributions	-	-	-
13	Amendments	-	-	-
14	Actuarial loss/(gain) 5/	(2,768,590)	1,823,327	-251.84%
15	Acquisition	-	-	-
16	Benefits paid	(2,563,593)	(3,098,475)	17.26%
17	Benefit obligation at end of year	$43,025,921	$45,277,018	-4.97%
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	$10,362,537	$8,333,378	24.35%
20	Actual return on plan assets	1,040,979	636,877	63.45%
21	Acquisition	-	-	-
22	Employer contribution	4,517,784	4,490,757	0.60%
23	Plan participants' contributions	-	-	-
24	Benefits paid	(2,563,593)	(3,098,475)	17.26%
25	Fair value of plan assets at end of year	$13,357,707	$10,362,537	28.90%
26	**Funded Status** 5/	($29,668,214)	($34,914,481)	15.03%
27	Unrecognized net transition (asset)/obligation 5/	-	$5,565,513	-100.00%
28	Unrecognized net actuarial loss/(gain) 5/	-	24,926,576	-100.00%
29	Unrecognized prior service cost 5/	-	152,036	-100.00%
30	Prepaid (accrued) benefit cost 5/	($29,668,214)	($4,270,356)	>-300.00%
31	**Components of Net Periodic Benefit Costs**			
32	Service cost	$740,490	$688,022	7.63%
33	Interest cost	2,340,596	2,406,644	-2.74%
34	Expected return on plan assets	(829,003)	(561,835)	-47.55%
35	Amortization of transitional (asset)/obligation	788,960	788,960	
36	Amortization of prior service cost	28,211	28,211	
37	Recognized net actuarial loss	1,621,792	1,521,037	6.62%
38	Net periodic benefit cost	$4,691,046	$4,871,039	-3.70%
39	**Accumulated Post Retirement Benefit Obligation**			
40	Amount Funded through VEBA	$729,200	$1,954,191	-62.69%
41	Amount Funded through 401(h)	1,476,398	-	-
42	Amount Funded through other - Company funds	2,485,448	2,916,848	-14.79%
43	TOTAL	$4,691,046	$4,871,039	-3.70%
44	Amount that was tax deductible - VEBA	$729,200	$1,954,191	-62.69%
45	Amount that was tax deductible - 401(h)	1,476,398	-	-
46	Amount that was tax deductible - Other	2,485,448	2,916,848	-14.79%
47	TOTAL	$4,691,046	$4,871,039	-3.70%
48	**Montana Intrastate Costs:**			
49	Pension Costs	$4,691,046	$4,871,039	-3.70%
50	Pension Costs Capitalized	938,134	907,103	3.42%
51	Accumulated Pension Asset (Liability) at Year End 5/	($29,668,214)	($4,270,356)	>-300.00%
52	**Number of Montana Employees:**			
53	Covered by the Plan	2,173	2,156	0.79%
54	Not Covered by the Plan	168	159	5.66%
55	Active	1,086	1,061	2.36%
56	Retired	976	968	0.83%
57	Spouses/Dependants covered by the Plan	111	127	-12.60%
	5/ Amount reflects the adoption of FAS 158 at December 31, 2006.			

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

Sch 16	TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)						
	Name/Title	Base Salary (Wages)	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	Bart A. Thielbar Director, Special Projects	188,846	25,685 A	29,774 D 8,300 E 26,903 G 7,698 H	287,207	313,221	-8%
2	Kendall Kliewer Vice President, Controller	179,669	26,297 A 25,000 B	27,534 D 3,750 E 16,998 G 7,952 H	287,200	284,269	1%
3	Paul James Evans Treasurer	178,707	25,786 A 25,000 B	27,047 D 10,964 G 8,174 H	275,679	259,514	6%
4	Curtis T. Pohl Vice President, Retail Operations	189,808		32,713 D 8,075 E 500 F 28,860 G 9,664 H	269,619	325,840	-17%
5	Michael J. Young Senior Corporate Counsel	190,000	15,000 B	27,077 D 6,638 G 9,190 H 11,967 I	259,873	273,978	-5%
6	Bobbi L. Schroeppel Vice President, Customer Care & Communications	164,510	28,814 A	28,132 D 8,300 E 500 F 19,767 G 6,745 H	256,768	256,373	0%
7	Patrick R. Corcoran Vice President, Government & Regulatory Affairs	159,846	23,375 A	12,612 D 8,300 E 20,094 G 29,808 H	254,035	264,981	-4%
8	Christian P. Fonss Director, Tax	159,863	20,262 A	4,796 C 20,493 D 8,899 G 7,595 H	221,907	244,844	-9%
9	Michael L. Nieman Officer, Internal Audit & Control	151,741	17,214 A	28,949 D 400 F 7,309 G 5,221 H	210,833	260,455	-19%
10	Jana L. Quam Director, Human Resources	144,202	17,586 A	24,375 D 5,745 E 6,093 G 7,606 H	205,608	219,623	-6%

Sch 16A

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

1/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the 2006 Employee Incentive Compensation Plan. Amounts were earned in 2006 but paid in the first quarter of 2007. Based on company performance against plan, the incentive plan was funded at 45.3% of target. Individual awards varied from the funded level based on individual performance; however, the plan precludes total payout to exceed plan funding.

B> Discretionary bonus for work on specific projects.

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

C> Merit cash.

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

E> Vehicle allowance.

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

G>These values reflect the compensation expense recognized for restricted stock awards and are calculated using the provisions of SFAS No. 123R, *Share-Based Payments* . This is a change in reporting methodoloy based on SEC reporting requirements and a similar amount is not reflected in the Total Compensation Reported Last Year.

H> Change in pension value over previous year. This is a new requirement for the SEC Summary Compensation Table and is provided here for consistency with SEC reporting requirements. This item was not reported in prior year reports and is not included in the Total Compensation Reported Last Year.

I> Accumulated vacation paid at termination.

Sch 17	TOP FIVE MONTANA MOST HIGHLY COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)						
	Name/Title	Base Salary (Wages)	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	Michael J. Hanson President & Chief Executive Officer	494,231	169,014 A	33,052 B 6,000 C 7,920 D 175,625 F 10,901 G	896,743	976,430	-8%
2	Brian B. Bird Vice President, Chief Financial Officer	287,500	69,537 A	29,646 B 3,000 C 96,505 F 10,722 G	496,910	471,185	5%
3	Thomas J. Knapp Vice President, General Counsel & Corporate Secretary	254,808	48,978 A	32,084 B 9,300 C 39,216 F 11,131 G	395,517	444,097	-11%
4	Gregory G. Trandem Vice President, Administrative Services	199,588	36,240 A	34,374 B 500 E 31,205 F 10,327 G	312,233	529,362	-41%
5	David G. Gates Vice President, Wholesale Operations	189,712	30,283 A	23,105 B 8,300 C 200 E 24,266 F 32,765 G 9,440 H	318,071	269,077	18%

1/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the 2006 Employee Incentive Compensation Plan. Amounts were earned in 2006 but paid in the first quarter of 2007. Based on company performance against plan, the incentive plan was funded at 45.3% of target. Officer awards varied from the funded level based on individual performance; however, the plan precludes total payout to exceed plan funding.

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> Vehicle allowance.

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

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

F>These values reflect the compensation expense recognized for restricted stock awards and are calculated using the provisions of SFAS No. 123R, *Share-Based Payments*. This is a change in reporting methodoloy based on SEC reporting requirements and a similar amount is not reflected in the Total Compensation Reported Last Year.

G> Change in pension value over previous year. This is a new requirement for the SEC Summary Compensation Table and is provided here for consistency with SEC reporting requirements. This item was not reported in prior year reports and is not included in the Total Compensation Reported Last Year.

H> Vacation sold back during the year.

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	$2,454,337,364	$2,334,527,630	5.13%
4	101.1 Property Under Capital Leases	40,209,537	-	-
5	105 Plant Held for Future Use	4,900	4,900	0.00%
6	107 Construction Work in Progress	3,240,549	30,101,840	-89.23%
7	108 Accumulated Depreciation Reserve	(1,183,035,857)	(1,128,254,307)	4.86%
8	108.1 Accumulated Depreciation - Capital Leases	(1,005,236)	-	-
9	111 Accumulated Amortization & Depletion Reserves	(34,727,173)	(28,941,272)	19.99%
10	114 Electric Plant Acquisition Adjustments	3,106,285	3,106,285	0.00%
11	115 Accumulated Amortization-Electric Plant Acq. Adj.	(2,821,543)	(2,726,628)	3.48%
12	116 Utility Plant Adjustment - Goodwill	435,075,587	435,075,587	0.00%
13	117 Gas Stored Underground-Noncurrent	32,141,968	31,274,590	2.77%
14	**Total Utility Plant**	1,746,526,381	1,674,168,625	4.32%
15	**Other Property and Investments**			
16	121 Nonutility Property	5,357,845	8,514,936	-37.08%
17	122 Accumulated Depr. & Amort.-Nonutililty Property	(1,473,243)	(4,417,187)	-66.65%
18	123.1 Investments in Assoc Companies and Subsidiaries	122,047,039	(53,299,065)	>-300.00%
19	124 Other Investments	1,541,359	1,845,926	-16.50%
20	128 Miscellaneous Special Funds	-	-	-
21	LT Portion of Derivative Assets - Hedges	-	8,741,253	0.00%
22	**Total Other Property & Investments**	127,473,000	(38,614,137)	>-300.00%
23	**Current and Accrued Assets**			
24	131 Cash	1,823,151	291,122	>300.00%
25	134 Other Special Deposits	2,965,707	2,830,895	4.76%
26	135 Working Funds	42,010	43,160	-2.66%
27	136 Temporary Cash Investments	-	-	-
28	141 Notes Receivable	49,909	52,535	-5.00%
29	142 Customer Accounts Receivable	65,175,722	70,630,276	-7.72%
30	143 Other Accounts Receivable	18,820,350	13,448,598	39.94%
31	144 Accumulated Provision for Uncollectible Accounts	(3,239,842)	(2,162,014)	49.85%
32	145 Notes Receivable-Associated Companies	-	-	-
33	146 Accounts Receivable-Associated Companies	15,337,813	196,416,015	-92.19%
34	151 Fuel Stock	3,313,948	2,762,036	19.98%
35	154 Plant Materials and Operating Supplies	17,902,740	14,002,088	27.86%
36	164 Gas Stored - Current	39,240,016	23,872,256	64.37%
37	165 Prepayments	9,964,222	8,908,318	11.85%
38	171 Interest and Dividends Receivable	-	-	-
40	172 Rents Receivable	61,624	71,032	-13.24%
41	173 Accrued Utility Revenues	68,858,563	81,299,941	-15.30%
42	174 Miscellaneous Current & Accrued Assets	1,161,255	90,082	>300.00%
43	175 Derivative Instrument Assets (175)	-	-	-
44	(Less) Long-Term Portion of Derivative Instrument Assets	-	-	-
45	176 LT Portion of Derivative Assets - Hedges	-	8,981,894	-100.00%
46	(less) LT Portion of Derivative Assets - Hedges	-	(8,741,253)	-100.00%
47	**Total Current & Accrued Assets**	241,477,188	412,796,981	-43.62%
48	**Deferred Debits**			
49	181 Unamortized Debt Expense	17,255,590	12,982,804	32.91%
50	182 Regulatory Assets	148,502,899	185,104,656	-19.77%
51	183 Preliminary Survey and Investigation Charges	-	-	-
52	184 Clearing Accounts	43,321	27,888	55.34%
53	185 Temporary Facilities	78	78	0.00%
54	186 Miscellaneous Deferred Debits	21,292,515	11,538,413	84.54%
55	189 Unamortized Loss on Reacquired Debt	4,637,192	1,996,826	132.23%
56	190 Accumulated Deferred Income Taxes	45,646,258	42,651,817	7.02%
57	191 Unrecovered Purchased Gas Costs	5,612,870	19,996,548	-71.93%
58	**Total Deferred Debits**	242,990,723	274,299,030	-11.41%
59	**TOTAL ASSETS and OTHER DEBITS**	$ 2,358,467,292	$ 2,322,650,499	1.54%

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	$ 359,624	$ 357,945	0.47%
4	204 Preferred Stock Issued	-	-	-
5	207 Premium on Capital Stock	-	-	-
6	211 Miscellaneous Paid-In Capital	727,327,890	720,856,857	0.90%
7	213 Discount on Capital Stock	-	-	-
8	214 Capital Stock Expense	-	-	-
9	215 Appropriated Retained Earnings	-	-	-
10	216 Unappropriated Retained Earnings	10,697,804	16,888,884	-36.66%
12	217 Reacquired Capital Stock	(9,885,098)	(5,572,604)	77.39%
13	219 Accumulated Other Comprehensive Income	14,271,357	4,963,949	187.50%
14	**Total Proprietary Capital**	742,771,577	737,495,031	0.72%
15	**Long Term Debt**			
16	221 Bonds	621,920,000	621,920,000	0.00%
17	223 Advances in Associated Companies	-	-	-
18	224 Other Long Term Debt	50,000,000	81,000,000	-38.27%
19	226 Unamortized Discount on Long Term Debt-Debit	71,051	1,897,954	-96.26%
20	**Total Long Term Debt**	671,848,949	701,022,046	-4.68%
21	**Other Noncurrent Liabilities**			
22	227 Obligations Under Capital Leases-Noncurrent	39,323,563	1,001,105	>300.00%
23	228.1 Accumulated Provision for Property Insurance	(70,841)	(370,841)	-80.90%
24	228.2 Accumulated Provision for Injuries and Damages	8,617,963	10,355,495	-16.78%
25	228.3 Accumulated Provision for Pensions and Benefits	52,570,168	51,583,876	1.91%
26	228.4 Accumulated Miscellaneous Operating Provisions	180,640,922	173,666,501	4.02%
27	230 Asset Retirement Obligations	3,801,012	3,233,138	17.56%
28	**Total Other Noncurrent Liabilities**	284,882,787	239,469,274	18.96%
29	**Current and Accrued Liabilities**			
30	231 Notes Payable	-	11,591,564	-100.00%
31	232 Accounts Payable	88,243,949	110,736,781	-20.31%
32	233 Notes Payable to Associated Companies	-	-	-
33	234 Accounts Payable to Associated Companies	42,752,662	4,321,765	>300.00%
34	235 Customer Deposits	7,641,259	7,429,497	2.85%
35	236 Taxes Accrued	129,908,326	131,908,694	-1.52%
36	237 Interest Accrued	11,091,501	6,932,860	59.98%
38	238 Dividends Declared	-	-	-
39	241 Tax Collections Payable	1,429,703	1,745,081	-18.07%
40	242 Miscellaneous Current and Accrued Liabilities	60,141,393	26,490,334	127.03%
41	243 Obligations Under Capital Leases-Current	1,414,661	1,142,749	23.79%
42	244 Derivative Instrument Liabilities	4,331,833	-	-
43	245 Derivative Instrument Liabilities - Hedges	-	-	-
44	**Total Current and Accrued Liabilities**	346,955,287	302,299,325	14.77%
45	**Deferred Credits**			
46	252 Customer Advances for Construction	33,501,677	28,060,322	19.39%
47	253 Other Deferred Credits	87,874,078	126,436,775	-30.50%
48	254 Regulatory Liabilities	26,296,808	24,536,916	7.17%
49	255 Accumulated Deferred Investment Tax Credits	4,028,288	4,564,569	-11.75%
50	257 Unamortized Gain on Reacquired Debt	-	-	-
51	281-283 Accumulated Deferred Income Taxes	160,307,841	158,766,241	0.97%
52	**Total Deferred Credits**	312,008,692	342,364,823	-8.87%
53	**TOTAL LIABILITIES and OTHER CREDITS**	$ 2,358,467,292	$ 2,322,650,499	1.38%
54				
55	1/ This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory			
56	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the			
57	equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian			
58	Montana Pipeline Corp.			
59				
60				
61				
62				
63				

NOTES TO FINANCIAL STATEMENTS

(1) Nature of Operations

We are one of the largest providers of electricity and natural gas in the Upper Midwest and Northwest, serving approximately 640,000 customers in Montana, South Dakota and Nebraska under the trade name "NorthWestern Energy." 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 Federal Energy Regulatory (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 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) Pending Merger with Babcock & Brown Infrastructure Limited

On April 25, 2006, we entered into an Agreement and Plan of Merger (Merger Agreement) with Babcock & Brown Infrastructure Limited (BBI), an infrastructure investment company listed on the Australian Stock Exchange, under which BBI will acquire NorthWestern Corporation in an all-cash transaction at $37 per share. The Merger Agreement has been unanimously approved by both companies' Boards of Directors. Our shareholders approved the Merger Agreement at our August 2, 2006 annual meeting.

The transaction is conditioned upon a number of federal and state regulatory approvals or reviews, and satisfaction of other customary closing conditions. We have received approvals or clearances from the following:

- Committee on Foreign Investments in the United States (CFIUS) in July 2006;
- United States Federal Trade Commission and the United States Department of Justice under the Hart-Scott-Rodino Antitrust Improvement Act of 1976 in October 2006;
- Nebraska Public Service Commission (NPSC) in October 2006;
- FERC in October 2006;
- Federal Communications Commission in February 2007.

Due to existing statutory language in South Dakota, we submitted a filing to the South Dakota Public Utilities Commission (SDPUC) to determine if it has jurisdiction over the sale and, if so, for transaction approval. In July, the SDPUC filed a notice with FERC that it intended to intervene and file a protest in the federal proceedings. In October, we reached a settlement agreement under which the SDPUC will not oppose approval of the transaction by FERC, which includes the following provisions:

- We and BBI will not seek rate recovery of costs associated with the transaction;
- The majority of our future Board of Directors will be U.S. citizens with at least one South Dakota resident and at least one independent member who will have substantial utility or financial experience. In addition, the independent member(s) shall serve as chair of the Audit Committee and the Governance Committee;
- We will apply ring fencing provisions of the 2004 Stipulation and Settlement Agreement between us, the Montana Public Service Commission (MPSC) and the Montana Consumer Counsel (MCC) for the benefit of the SDPUC and South Dakota ratepayers;

- We will not borrow money secured by South Dakota regulated utility assets to upstream funds to either BBI or its affiliates without prior approval of the SDPUC; and

- We will maintain our corporate headquarters in Sioux Falls, South Dakota until the later of June 30, 2010 or three years following the effective date of the merger. We will continue to maintain senior management personnel in both South Dakota and Montana.

In December, the SDPUC determined that current state law does not allow them to exercise jurisdiction over the proposed sale.

We must still obtain the approval of the MPSC. We and the intervenors submitted testimony and additional information to the MPSC. The MPSC held a technical hearing from March 14, 2007 through March 16, 2007 and has set a schedule for post-hearing briefs, which requires BBI and us to file a brief on April 6, 2007, the intervenors to file a response on April 27, 2007, and BBI and us to file a reply on May 7, 2007. We anticipate receiving the MPSC's decision during the first half of 2007.

The Merger Agreement contains certain covenants whereby NorthWestern is required to continue to operate in the ordinary course of business and must obtain BBI's consent prior to making certain new investments or divestitures, issuing new debt or common stock or making dividend changes, among other provisions. In addition, the Merger Agreement also contains certain termination rights for both NorthWestern and BBI in which under specified circumstances NorthWestern may be required to pay BBI a termination fee of $50 million and BBI may be required to pay NorthWestern a business interruption fee of $70 million.

The merger will be accounted for as a purchase under GAAP. Under the purchase method of accounting, the assets and liabilities of NorthWestern will be recorded, as of the completion of the transaction, at their respective fair values, and we will record as a utility plant adjustment the excess, if any, of the purchase price over the fair value of our identifiable assets, including intangibles.

During the year ended December 31, 2006, we recorded $13.8 million in pre-tax charges for advisor and professional fees related to the transaction which are included in other deductions on our statement of income. These costs included payment of $8.6 million in transaction fees to our strategic advisor during 2006. Under the terms of this agreement, we will also be required to pay an additional $8.6 million upon closing.

In addition, in November 2006, the remaining shares available under our 2005 Long-Term Incentive Plan were granted in accordance with the terms of the Merger Agreement. These service-based restricted share awards vest over the next five years, however these shares will vest immediately upon closing of the transaction with BBI. If the transaction is completed in 2007 as anticipated, stock-based compensation expense will be approximately $14 million. Upon closing, NorthWestern's common stock will cease to be publicly traded.

(3) Significant Accounting Policies

Financial Statement Presentation and Basis of Accounting

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

- Comparative statements of net income per share are not presented;

- Removal costs of transmission and distribution assets are reflected in the balance sheets as a component of accumulated depreciation of $153.4 million and $142.6 million as of December 31, 2006 and 2005, respectively, in accordance with regulatory treatment as compared to regulatory liabilities for GAAP purposes (see Note 7);

- Goodwill resulting from our emergence from bankruptcy and fresh-start reporting is reflected in the balance sheets as a utility plant adjustment of $435.1 million as of December 31, 2006 and 2005 respectively, in accordance with regulatory treatment, as compared to goodwill for GAAP purposes (see Note 8);

- The write-down of plant values associated with the 2002 acquisition of the Montana operations is reflected in the balance sheets as a component of accumulated depreciation of $192.8 million for both December 31, 2006 and 2005, in accordance with regulatory treatment as compared to plant for GAAP purposes;

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

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

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

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Estimates are used for such items as long-lived asset values and impairment charges, long-lived asset useful lives, tax provisions, uncollectible accounts, 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 respective regulatory authorities, electric and natural gas utility revenues are based on billings rendered to customers. For our Montana operations, as prescribed by the MPSC, operating revenues are recorded monthly on the basis of consumption or services rendered. Customers are billed monthly on a cycle basis. To match revenues with associated expenses, we accrue unbilled revenues for electrical and natural gas services delivered to Montana customers but not yet billed at month-end.

Cash Equivalents

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

Inventories

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

	December 31, 2006	December 31, 2005
Fuel Stock	$ 3,314	$ 2,762
Materials and supplies	17,903	14,002
Gas stored underground (including the non-current portion reflected in utility plant)	71,382	55,147
	$ 92,599	$ 71,911

The storage gas amount as of December 31, 2005 includes $11.7 million related to deferred gas storage arrangements.

Regulation of Utility Operations

Our regulated operations are subject to the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulations* (SFAS No. 71). Accounting under SFAS No. 71 is appropriate provided that (i) rates are established by or subject to approval by independent, third-party regulators, (ii) rates are designed to recover the specific enterprise's cost of service, and (iii) in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be charged to and collected from customers.

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

If all or a separable portion of our operations becomes no longer subject to the provisions of SFAS No. 71, an evaluation of future recovery of the related regulatory assets and liabilities would be necessary. In addition, we would determine any impairment to the carrying costs of deregulated plant and inventory assets.

Derivative Financial Instruments

We are exposed to market risk, including changes in interest rates and the impact of market fluctuations in the price of electricity and natural gas commodities as discussed further in Note 9. In order to manage these risks, we use both derivative and non-derivative contracts that may provide for settlement in cash or by delivery of a commodity, including:

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

SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133), as amended, requires that all derivatives be recognized in the balance sheet, either as assets or liabilities, at fair value, unless they meet the normal purchase and normal sales criteria. The changes in the fair value of recognized derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and the type of hedge transaction.

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

We have applied the normal purchases and normal sales scope exception, as provided by SFAS No. 133 and interpreted by Derivatives Implementation Guidance Issue C15, to certain contracts involving the purchase and sale of gas and electricity at fixed prices in future periods. Revenues and expenses from these contracts are reported on a gross basis in the appropriate revenue and expense categories as the commodities are received or delivered.

Property, Plant and Equipment

Property, plant and equipment are stated at original cost, including contracted services, direct labor and material, allowance for funds used during construction (AFUDC), and indirect charges for engineering, supervision and similar overhead items. All expenditures for maintenance and repairs of utility property, plant and equipment are charged to the appropriate maintenance expense accounts. A betterment or replacement of a unit of property is accounted for as an addition and retirement of utility plant. At the time of such a retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal. Also included in plant and equipment are assets under capital lease, which are stated at the present value of minimum lease payments. Plant and equipment under capital lease were $44.8 million and $6.0 million as of December 31, 2006 and December 31, 2005, respectively.

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. We determine the rate used to compute AFUDC in accordance with a formula established by the FERC. This rate averaged 8.8% and 8.7% for Montana for 2006 and 2005, respectively, and 8.9% and 8.7% for South Dakota for 2006 and 2005, respectively. Interest capitalized totaled $1.0 million for the year ended December 31, 2006 and $1.3 million for the year ended December 31, 2005 for Montana and South Dakota combined.

We may require contributions in aid of construction from customers when we extend service. Amounts used from these contributions to fund capital additions were $8.7 million for the year ended December 31, 2006 and $8.9 million for the year ended December 31, 2005.

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 3.4% for both 2006 and 2005.

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

Stock-based Compensation

Under our equity-based incentive plans, we have granted restricted stock awards to all employees and members of the Board of Directors (Board). We discuss these awards in further detail in Note 18. We adopted SFAS No. 123R, *Share-Based Payment* (SFAS No. 123R), upon emergence from bankruptcy, which was prior to the required effective date of January 1, 2006. SFAS No. 123R requires companies to recognize compensation expense for all equity-based compensation awards issued to employees that are expected to vest. Under SFAS 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 compensation cost recognized to date is reversed.

Income Taxes

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

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

The resolution of tax matters in a particular future period could have a material impact on our statement of operations and provision for income taxes.

Environmental Costs

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

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

Emission Allowances

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

Accounting Standards Issued

In July 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). FIN 48 is an interpretation of FASB Statement No. 109, *Accounting for Income Taxes*, and it seeks to reduce the diversity in practice associated with certain aspects of measurement and recognition in accounting for income taxes by prescribing a recognition threshold and measurement process for recording in the financial statements uncertain tax positions taken or expected to be taken in a tax return. Additionally, FIN 48 provides guidance on the derecognition, classification, accounting in interim periods and expanded disclosure with respect to the uncertainty in income taxes. FIN 48 is effective for us as of January 1, 2007. We are currently in the process of reviewing our uncertain tax positions to determine the impact to our financial statements. 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. Based on our preliminary assessment, we expect to increase our net deferred tax assets by $70 million to $90 million with a corresponding decrease to utility plant adjustments.

In September 2006, the FASB issued SFAS No. 157 *Fair Value Measurements* (SFAS No. 157), which defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. The provisions of SFAS No. 157 are effective as of the beginning of our 2008 fiscal year. We are currently evaluating the impact, if any, adopting SFAS No. 157 will have on our financial statements.

Accounting Standards Adopted

In September 2006, the FASB issued SFAS No. 158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans -- an amendment of FASB Statements No. 87, 88, 106, and 132(R)* (SFAS No. 158). SFAS No. 158 requires that we recognize the overfunded or underfunded status of our defined benefit and retiree medical plans (our Plans) as an asset or liability in our 2006 year-end balance sheet. Upon our emergence from bankruptcy in November 2004, we recognized a liability for the underfunded status of our Plans, therefore the amount recognized upon adoption of SFAS No. 158 as of December 31, 2006 represents adjustments to our discount rate assumption, our actual 2006 return on plan assets, and other factors. This resulted in a reduction to the liability recognized for our Plans of approximately $23.3 million. As we recover certain of these costs in rates, $23.0 million of this adjustment is reflected as a change in regulatory assets. We discuss our employee benefit plans in more detail in Note 17.

(4) Emergence from Bankruptcy

On September 14, 2003 (the Petition Date), we filed a voluntary petition for relief under the provisions of Chapter 11 of the Federal Bankruptcy Code (the Bankruptcy Code) in the United States Bankruptcy Court for the District of Delaware (Bankruptcy Court). On October 19, 2004, the Bankruptcy Court entered an order confirming our Plan of Reorganization (Plan), which became effective on November 1, 2004.

Plan of Reorganization

The consummation of the Plan resulted in, among other things, a new capital structure, the satisfaction or disposition of various types of claims against the Predecessor Company, the assumption or rejection of certain contracts, and the establishment of a new board of directors.

In accordance with the Plan, we issued 31.1 million shares of new common stock to settle claims of debt holders. We also established a reserve of approximately 4.4 million shares of common stock upon emergence to be used to resolve various outstanding litigation matters and distributed pro rata to holders of allowed trade vendor and general unsecured claims in excess of $20,000. As of December 31, 2006, approximately 1.3 million shares have been distributed from this reserve in settlement of claims. Remaining disputed unsecured claims, when allowed, will receive shares out of the reserve set aside upon emergence.

Reorganization Items

The results of operations have been impacted by Reorganization Items, including continued costs incurred related to our reorganization since we filed for protection under Chapter 11 and the impact of fresh-start reporting. The following table provides detail of the charges incurred (in thousands):

	2005
Reorganization Items	
Professional fees (923)	$ 5,490
Interest earned on accumulated cash (419)	—
Miscellaneous non-operating income – effects of the Plan and fresh-start reporting adjustments (421)	2,039
Total Reorganization Items	$ 7,529

The 2005 amount included in effects of the Plan is primarily due to a loss on the reestablishment of a liability that was removed upon emergence from bankruptcy.

(5) Equity Investments

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

	December 31,	
	2006	2005
Clark Fork & Blackfoot, LLC	$ (6,274)	$ (5,752)
Natural Gas Funding Trust	1,379	999
NorthWestern Services, LLC	21,365	18,641
NorthWestern Investments, LLC	103,273	(69,354)
Risk Partners Assurance, Ltd.	2,304	2,167
Total Investments in Subsidiary Companies	$ 122,047	$ (53,299)

(6) Property, Plant and Equipment

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

	December 31,	
	2006	2005
Land and improvements	$ 40,881	$ 40,218
Building and improvements	137,971	134,587
Storage, distribution, and transmission	1,963,790	1,862,074
Generation	143,138	136,908
Construction work in process	3,241	30,102
Other equipment	211,878	163,852
	2,500,899	2,367,741
Less accumulated depreciation	(1,221,590)	(1,159,922)
	$ 1,279,309	$ 1,207,819

We have an electric default supply capacity and energy sale agreement with the owners of a natural gas fired peaking plant that began operating during 2006. In accordance with the agreement, we provide the natural gas necessary to meet demand, and purchase all of the net electrical capacity and output. In our assessment of this contract, we determined that it fits the criteria of a capital lease as set forth in Emerging Issues Task Force 01-8, *Determining Whether an Arrangement Contains a Lease.* Accordingly, during 2006 we recorded an increase to property, plant and equipment and a capital lease obligation of approximately $40.2 million, which represents the present value of future cash payments for the base capacity and facility charges under the contract.

(7) Asset Retirement Obligations

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

Our regulated utility operations have, however, previously recognized removal costs of transmission and distribution assets as a component of depreciation in accordance with regulatory treatment. Generally, the accrual of future non-ARO removal obligations is not required. However, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. Accordingly, the recorded amounts of estimated future removal costs are considered regulatory liabilities pursuant to SFAS No. 71, *Accounting for the Effects of Certain Types of Regulations* (SFAS No. 71). These amounts do not represent SFAS No. 143 legal retirement obligations. As of December 31, 2006 and 2005, we have recognized accrued removal costs of $153.4 million and $142.6 million, respectively, which are classified as accumulated depreciation. In addition, for our generation properties, we have accrued decommissioning costs since the generating units were first put into service in the amount of $13.3 million and $12.8 million as of December 31, 2006 and 2005, respectively, which are classified as accumulated depreciation.

In connection with the adoption of FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47), we have recorded a conditional asset retirement obligation of $3.8 million and $3.2 million, as of December 31, 2006 and 2005, respectively, which increases our property, plant and equipment and other regulatory assets. This is primarily related to Department of Transportation requirements to cut, purge and cap retired natural gas pipeline segments. The initial recording of the obligation had no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset pursuant to SFAS No. 71. We measure the liability at fair value when incurred and capitalize a corresponding amount as part of the book value of the related assets. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the ARO is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period and recorded as a regulatory asset until the settlement of the liability. The change in our conditional ARO during the year ended December 31, 2006, is as follows (in thousands):

Liability at January 1, 2006	$ 3,233
Accretion expense	254
Liabilities incurred	58
Liabilities settled	(57)
Revisions to cash flows	313
Liability at December 31, 2006	$ 3,801

(8) Utility Plant Adjustments

We review our acquisition and utility plant adjustments for impairment annually during the fourth quarter, or more frequently if changes in circumstances or the occurrence of events suggest an impairment exists. Our utility plant adjustment is $435.1 million as of December 31, 2006 and 2005.

(9) Risk Management and Hedging Activities

We are exposed to market risk, including changes in interest rates and the impact of market fluctuations in the price of electricity and natural gas commodities. We employ established policies and procedures to manage our risk associated with these market fluctuations using various commodity and financial derivative and non-derivative instruments, including forward contracts, swaps and options.

Interest Rates

During 2005, we implemented a risk management strategy of utilizing interest rate swaps to manage our interest rate exposures associated with anticipated refinancing transactions of approximately $380 million. These swaps were designated as cash-flow hedges under SFAS No. 133, with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in accumulated other comprehensive income in our Balance Sheets. We reclassify gains and losses on the hedges from accumulated other comprehensive income (AOCI) into interest expense in our Statements of Income during the periods in which the interest payments being hedged occur.

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

In association with the refinancing transactions completed during the second and third quarters of 2006, we settled $170.2 million and $150 million of forward starting interest rate swap agreements, and received aggregate settlement payments of approximately $6.3 million and $8.3 million, respectively. These amounts are being amortized as a reduction to interest expense over the term of the underlying debt as the hedged interest payments are made, which is 17 years and 10 years, respectively. The cash proceeds related to these hedges are reflected in operating activities on the statement of cash flows. As of December 31, 2006 we have no further interest rate swaps outstanding.

Commodity Prices

During the second quarter of 2005, we implemented a risk management strategy of utilizing put options in conjunction with our forward fixed price sales to manage our commodity price risk exposure associated with our lease of a 30% share of the Colstrip Unit 4 generation facility. These transactions were designated as cash-flow hedges of forecasted electric sales of approximately 120,000 MWh in each of the third and fourth quarters of 2006 under the provisions of SFAS No. 133, with unrealized gains and losses being recorded in accumulated other comprehensive income in our Balance Sheets. Due to changes in forward prices for electricity during the fourth quarter of 2005, we utilized unit-contingent forward sales to lock in the remaining output during the third and fourth quarters of 2006, and as a result we undesignated the put options as a hedge of the cash flow variability. During the first quarter of 2006 the put options were sold and we recognized a $1.3 million reduction to cost of sales, reflecting the change in market value since they were undesignated. These cash proceeds are reflected in investing activities on the statement of cash flows. During the third and fourth quarters of 2006, we reclassified unrealized losses of approximately $0.9 million into earnings related to the change in market value prior to the hedges being undesignated. As of December 31, 2006 we have no put options outstanding.

(10) Related-Party Transactions

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

	December 31,	
	2006	2005
Accounts Receivable from Associated Companies:		
Netexit, Inc.	$ -	$ 181,796
Clark Fork & Blackfoot, LLC	5,588	3,827
Nekota Resources, Inc.	7,299	5,443
NorthWestern Energy Marketing, LLC	2,433	2,334
NorthWestern Services, LLC	-	2,998
Risk Partners Assurance, Ltd.	18	18
	$ 15,338	$ 196,416
Accounts Payable to Associated Companies:		
Blue Dot Services, LLC	$ -	$ 1,192
Montana Megawatts I, LLC	-	2,017
Natural Gas Funding Trust	216	26
NorCom Advanced Technologies Inc.	-	85
NorthWestern Investments, LLC	6,771	1,002
NorthWestern Services, LLC	35,766	-
	$ 42,753	$ 4,322

(11) Long-Term Debt and Capital Leases

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

	Due	December 31, 2006	December 31, 2005
Unsecured Debt:			
Senior Unsecured Revolver	2009	$50,000	$81,000
Secured Debt:			
Mortgage bonds—			
South Dakota—7.00%	2023	55,000	55,000
Montana—7.30%	2006		150,000
Montana—6.04%	2016	150,000	
Montana—8.25%	2007	365	365
South Dakota & Montana—5.875%	2014	225,000	225,000
Pollution control obligations—			
South Dakota—5.85%	2023	7,550	7,550
South Dakota—5.90%	2023	13,800	13,800
Montana—6.125%	2023		90,205
Montana—5.90%	2023		80,000
Montana—4.65%	2023	170,205	
Discount on Notes and Bonds	—	(71)	(1,898)
		$ 671,849	$ 701,022

Unsecured Revolving Line of Credit

On June 30, 2005, we entered into an amended and restated credit agreement that replaced our existing $225 million secured credit facility with an unsecured $200 million senior revolving line of credit with lower borrowing costs. The unsecured revolving line of credit will mature on November 1, 2009 and does not amortize. The facility bears interest at a variable rate based upon a grid which is tied to our credit rating from Fitch, Moody's, and S&P. The 'spread' or 'margin' ranges from 0.625% to 1.75% over the London Interbank Offered Rate (LIBOR). The facility currently bears interest at a rate of approximately 6.475%, which is 1.125% over LIBOR. As of December 31, 2006, we had $15.3 million in letters of credit and $50 million of borrowings outstanding under the unsecured revolving line of credit. The weighted average interest rate on the outstanding revolver borrowings was 6.475% as of December 31, 2006.

Commitment fees for the unsecured revolving line of credit were $0.3 million and $0.1 million for the years ended December 31, 2006 and 2005, respectively. Commitment fees for the revolving tranche of the old credit facility were approximately $0.2 million for the first six months of 2005.

The credit facility includes covenants, which require us to meet certain financial tests, including a minimum interest coverage ratio and a minimum debt to capitalization ratio. The amended and restated line of credit also contains covenants which, among other things, limit our ability to incur additional indebtedness, create liens, engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, make restricted payments, make loans or advances, and enter into transactions with affiliates. Many of these restrictive covenants will fall away upon the line of credit being rated "investment grade" by two of the three major credit rating agencies consisting of Fitch, Moody's and S&P. We have received a waiver of change in control covenants to allow for the BBI transaction. As of December 31, 2006, we are in compliance with all of the covenants under the amended and restated line of credit.

Secured Debt

The South Dakota Mortgage Bonds are two series of general obligation bonds we issued under our South Dakota indenture, and the South Dakota Pollution Control Obligations are three obligations under our South Dakota indenture. All of such bonds are secured by substantially all of our South Dakota and Nebraska electric and natural gas assets.

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

Refinancing Transactions

During the second quarter of 2006, we issued $170.2 million of Montana Pollution Control Obligations (PCOs) at a fixed interest rate of 4.65%, and used the proceeds to redeem our 6.125%, $90.2 million and 5.90%, $80.0 million Montana pollution control obligations due in 2023. Consistent with our historical regulatory treatment, the remaining deferred financing costs of approximately $3.8 million were recorded as an unamortized debt expense and will be amortized over the remaining life of the debt. The new PCOs will mature on August 1, 2023, and are secured by our Montana electric and natural gas assets. This transaction will reduce our annual interest on long-term debt by approximately $2.4 million.

During the third quarter of 2006, we issued $150 million of Montana First Mortgage Bonds at a fixed interest rate of 6.04% and used the proceeds to redeem our 7.30%, $150 million Montana first mortgage bonds due December 1, 2006. Consistent with our historical regulatory treatment, the remaining deferred financing costs and prepayment penalty of $0.8 million were recorded as an unamortized debt expense and will be amortized over the remaining life of the debt. The new first mortgage bonds will mature September 1, 2016, and are secured by our Montana electric and natural gas assets. This transaction will reduce our annual interest on long-term debt by approximately $1.9 million.

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt, during the next five years are $7.7 million in 2007, $7.8 million in 2008, $57.1 million in 2009, $7.3 million in 2010 and $7.8 million in 2011.

(12) Comprehensive Income (Loss)

The Financial Accounting Standards Board defines comprehensive income as all changes to the equity of a business enterprise during a period, except for those resulting from transactions with owners. For example, dividend distributions are excepted. Comprehensive income consists of net income and other comprehensive income (OCI). Net income may include such items as income from continuing operations, discontinued operations, extraordinary items, and cumulative effects of changes in accounting principles. OCI may include foreign currency translations, adjustments of minimum pension liability, and unrealized gains and losses on certain investments in debt and equity securities. Due to our emergence from bankruptcy we made adjustments for fresh-start reporting in accordance with SOP 90-7. These adjustments resulted in removal of items recorded in accumulated OCI of $6.0 million. Comprehensive income (loss) is calculated as follows (in thousands):

	December 31,	
	2006	2005
Net income	$ 37,900	$ 59,467
Other comprehensive income:		
Reclassification of net gains on hedging instruments from OCI to net income	(3,443)	—
Net unrealized gain on derivative instruments qualifying as hedges, net of tax of $3,045 in 2005	12,588	4,885
Foreign currency translation adjustment	—	56
Total other comprehensive income	9,145	4,941
Total comprehensive income	$ 47,045	$ 64,408

The after tax components of accumulated other comprehensive income were as follows (in thousands):

	December 31,	
	2006	2005
Balance at end of period,		
Unrealized gain on derivative instruments qualifying as hedges	$ 14,030	$ 4,885
Adjustment to initially apply SFAS No. 158	162	—
Foreign currency translation adjustment	79	79
Accumulated other comprehensive income	$ 14,271	$ 4,964

(13) Financial Instruments

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

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

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

- Fair values for debt were determined based on interest rates that are currently available to us for issuance of debt with similar terms and remaining maturities, except for publicly traded debt, which is based on market prices.

The fair-value estimates presented herein are based on pertinent information available to us as of December 31, 2006 and December 31, 2005. Although we are not aware of any factors that would significantly affect the estimated fair-value amounts, such amounts have not been comprehensively revalued for purposes of these financial statements since that date, and current estimates of fair value may differ significantly from the amounts presented herein.

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

	December 31, 2006		December 31, 2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Assets:				
Cash and working funds	$ 1,865	$ 1,865	$ 334	$ 334
Special deposits	2,966	2,966	2,831	2,831
Investments	1,541	1,541	1,846	1,846
Liabilities:				
Long-term debt (including current portion)	671,849	674,131	701,022	703,363

(14) 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,	
	2006	2005
Excess tax depreciation	$ (96,967)	$ (120,652)
Regulatory assets	(20,392)	(33,594)
Regulatory liabilities	1,264	(839)
Unbilled revenue	2,980	3,971
Unamortized investment tax credit	2,169	2,458
Compensation accruals	3,680	1,605
Reserves and accruals	21,540	31,084
Goodwill amortization	(42,155)	(33,395)
Net operating loss carryforward (NOL)	13,338	43,012
AMT credit carryforward	3,186	3,186
Capital loss carryforward	6,376	—
Valuation allowance	(10,256)	(10,461)
Other, net	575	(2,489)
	$ (114,662)	$ (116,114)

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 $10.3 million as of December 31, 2006 against capital loss carryforwards and certain state NOL carryforwards as we do not believe these assets will be realized.

At December 31, 2006 we estimate our total federal NOL carryforward to be approximately $418.1 million. If unused, $246.0 million will expire in the year 2023, and $172.0 million will expire in the year 2025. Our state NOL carryforward as of December 31, 2006 is estimated to be approximately $549.6 million. If unused, $378.9 million will expire in 2010, $33.8 million will expire in 2011, and $136.8 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.

Due to our NOL carryforward, years 2000 and forward remain subject to examination by the IRS.

(15) Jointly Owned Plants

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

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

	Big Stone (S.D.)	Neal #4 (Iowa)	Coyote I (N.D.)
December 31, 2006			
Ownership percentages	23.4%	8.7%	10.0%
Plant in service	$ 52,948	$ 29,930	$ 42,797
Accumulated depreciation	34,588	19,309	24,393
December 31, 2005			
Ownership percentages	23.4%	8.7%	10.0%
Plant in service	$ 53,022	$ 28,870	$ 42,542
Accumulated depreciation	33,188	18,541	23,468

(16) Operating Leases

We lease a generation facility, vehicles, office equipment, an airplane and office and warehouse facilities under various long-term operating leases. At December 31, 2006, future minimum lease payments for the next five years under non-cancelable lease agreements are as follows (in thousands):

2007	$ 34,457
2008	33,386
2009	32,668
2010	32,334
2011	14,520

Lease and rental expense incurred was $30.9 million and $31.0 million for the years ended December 31, 2006 and 2005, respectively.

In January 2005, we exercised an option to extend the term of our Colstrip Unit 4 generation facility lease an additional eight years. By extending the lease term, our annual lease payment remained at $32.2 million through 2010 and decreased to $14.5 million for the remainder of the lease. Beginning in 2005 our lease expense was reduced to $22.1 million annually based on a straight-line calculation over the full term of the lease. We finalized the purchase of the owner participant interest of a portion of this facility, representing approximately 79 megawatts of our leased interest, in March 2007, reducing the annual lease payments to $20.8 million annually through 2010, and $9.3 million annually through 2018.

(17) 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. Pension costs in Montana and other postretirement benefit costs in South Dakota are included in rates on a pay as you go basis for regulatory purposes. In 2005, we applied for and received an accounting order from the MPSC to utilize a five-year average of funding cost in our costs of service, therefore we maintain a regulatory asset and amortize it based on our five-year average funding requirement in

Montana. Pension costs in South Dakota and other postretirement benefit costs in Montana are included in rates on an accrual basis for regulatory purposes. (See Note 19, Regulatory Assets and Liabilities, for the regulatory assets related to our pension and other postretirement benefit plans.) The prior service costs are amortized on a straight-line basis over the average remaining service period of active participants. Actuarial gains and losses in excess of 10% of the greater of the benefit obligation or the market-related value of assets are normally amortized over the average remaining service period of active participants. However as a result of fresh-start reporting, we adjusted our qualified pension and other postretirement benefit plans to their projected benefit obligation by recognizing all previously unamortized actuarial gains and losses upon emergence. The generation of any future amounts subsequent to emergence will be amortized under the same method as discussed above.

Adoption of SFAS 158

As discussed in Note 3, we adopted SFAS No. 158 as of December 31, 2006, which requires that we recognize the overfunded or underfunded status of our defined benefit and retiree medical plans (our Plans) as an asset or liability in our 2006 year-end balance sheet. Upon our emergence from bankruptcy in November 2004, we recognized a liability for the underfunded status of our Plans, therefore the amount recognized upon adoption of SFAS No. 158 as of December 31, 2006 represents adjustments to our discount rate assumption, our actual 2006 return on plan assets, and other factors. In addition, as we account for the effects of regulation under SFAS No. 71, for those plans which are able to recover the costs from our customers, the change is reflected as an adjustment to regulatory assets rather than other comprehensive income.

The following table illustrates the impact of adoption of SFAS No. 158 on the financial statements as of December 31, 2006 (in thousands):

	Before Application of SFAS No. 158	Adjustments	After Application of SFAS No. 158
Regulatory asset	$ 139,159	$ (23,037)	$ 116,122
Total assets	139,159	(23,037)	116,122
Pension liability	107,700	(21,237)	86,463
Other postretirement liability	39,736	(2,063)	37,673
Deferred tax liability	120,752	(101)	120,651
Total liabilities	268,188	(23,401)	244,787
Accumulated other comprehensive income	14,109	162	14,271
Total shareholder's equity	$ 14,109	$ 162	$ 14,271

Benefit Obligation

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,	
	2006	2005	2006	2005
Reconciliation of Benefit Obligation				
Obligation at beginning of period	$386,915	$ 373,979	$55,620	$ 52,391
Service cost	9,049	8,531	741	688
Interest cost	20,791	20,174	2,775	2,853
Actuarial (gain) loss	(10,265)	1,236	(2,705)	1,705
Plan amendments	—	2,661	—	—
Fresh-start reporting adjustments	—	—	—	2,561
Gross benefits paid	(18,928)	(19,666)	(3,368)	(4,578)
Benefit obligation at end of period	$387,562	$ 386,915	$53,063	$ 55,620

The total projected benefit obligation and fair value of plan assets for the pension plans with projected benefit obligations in excess of plan assets were $387.6 million and $301.1 million, respectively, as of December 31, 2006. The total accumulated benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets were $385.4 million and $301.1 million, respectively, as of December 31, 2006.

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 $386.9 million and $271.1 million, respectively, as of December 31, 2005. 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 $384.8 million and $271.1 million, respectively, as of December 31, 2005.

The NorthWestern Energy pension plan was amended effective January 1, 2005 to increase the retirement death benefit from 50% to 100% of the accrued benefit. This is reflected in the plan amendment amount above.

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, 2006	December 31, 2005	December 31, 2006	December 31, 2005
Accrued benefit cost	$ (107,700)	$ (117,585)	$ (41,768)	$ (44,333)
Intangible asset		502	—	—
Amounts not yet reflected in net periodic benefit cost:				
Prior service cost	(2,419)	—	—	—
Accumulated gain	23,656	—	2,063	
Net amount recognized	$ (86,463)	$ (117,083)	$ (39,705)	$ (44,333)

Plan Assets and Funded Status

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2006	2005	2006	2005
Reconciliation of Fair Value of Plan Assets				
Fair value of plan assets at beginning of period	$271,103	$244,643	$10,363	$8,333
Return on plan assets	30,917	14,754	1,041	637
Employer contributions	18,007	31,372	5,322	5,971
Gross benefits paid	(18,927)	(19,666)	(3,368)	(4,578)
Fair value of plan assets at end of period	$301,100	$271,103	$13,358	$10,363
Funded Status	$(86,463)	$(115,812)	$(39,705)	$(45,258)
Unrecognized net actuarial (gain) loss	—	(3,932)	—	925
Unrecognized prior service cost	—	2,661	—	—
Accrued benefit cost	$(86,463)	$(117,083)	$(39,705)	$(44,333)

Our investment goals with respect to managing the pension and other postretirement assets is to achieve and maintain a reasonably funded status for the pension plans, improve the status of the health and welfare plan, minimize contribution requirements, and seek long-term growth by placing primary emphasis on capital appreciation and secondary emphasis on income, while minimizing risk.

Our investment policy for fixed income investments are oriented toward risk averse, investment-grade securities rated "A" or higher and are required to be diversified among individual securities and sectors (with the exception of U.S. Government securities, in which the plan may invest the entire fixed income allocation). There is no limit on the maximum maturity of securities held. In addition, the NorthWestern Corporation pension plan assets also includes a participating group annuity contract in the John Hancock General Investment Account, which consists primarily of fixed-income securities, reflected at current market values with a market adjustment.

Equity investments can include convertible securities, and are required to be diversified among industries and economic sectors. Limitations are placed on the overall allocation to any individual security at both cost and market value and international equities investments are diversified by country. In addition, there are limitations on investments in emerging markets.

Our investment policy prohibits short sales, margin purchases, securities lending and similar speculative transactions as well as any transactions that would threaten tax exempt status of the fund, actions that would create a conflict of interest or transactions between fiduciaries and parties in interest as defined under ERISA. With respect to international investments, foreign currency hedging is allowed under the policy for the purpose of hedging currency risk and to effect securities transactions. Permissible investments include foreign currencies in both spot and forward markets, options, futures, and options on futures in foreign currencies.

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

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

The percentage of fair value of plan assets held in the following investment types by the NorthWestern Energy pension plan, NorthWestern Corporation pension plan and NorthWestern Energy Health and Welfare Plan as of December 31, 2006 and December 31, 2005, are as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31, 2006	December 31, 2005	December 31, 2006	December 31, 2005	December 31, 2006	December 31, 2005
Cash and cash equivalents	1.9%	2.0%	0.7%	1.1%	—%	—%
Debt securities	30.5	32.3	—	—	28.3	27.2
Domestic equity securities	56.1	55.2	57.0	51.5	71.3	72.3
International equity securities	11.5	10.5	11.6	9.8	0.4	0.5
Participating group annuity contracts	—	—	30.7	37.6	—	—
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

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 continually evaluate the potential for liquidating and reinvesting the assets held in participating group annuity contracts as rebalancing and diversification opportunities are currently limited with respect to this portion of plan assets.

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2006 and December 31, 2005. 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 2006, we set the discount rate using a yield curve analysis, which projects benefit cash flows into the future and then discounts those cash flows to the measurement date using a yield curve. For our analysis we reviewed both the yield curve of our actuaries and Citigroup. Based on this analysis, we increased our discount rate 0.25% to 5.75%. We previously set the discount rate based upon our review of the Citigroup Pension Index and Moody's Aa bond rate index. The expected long-term rate of return assumption on plan assets for both the NorthWestern Energy and NorthWestern Corporation 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 pension and postretirement portfolios. Over the 15-year period ending December 31, 2003, the returns on these portfolios, assuming they were invested at the current target asset allocation in prior periods, would have been a compound annual average of approximately 10.5%. Considering this information and future expectations for asset returns, we selected an 8.5% long-term rate of return on assets assumption for 2005. We have reduced this assumption to 8.0% for 2006 and 2007.

The health care cost trend rates are established through a review of actual recent cost trends and projected future trends. Our retiree medical trend assumptions are the best estimate of expected inflationary increases to our healthcare costs. Due to the relative size of our retiree population (under 700 members), the assumptions used are based upon both nationally expected trends and our specific expected trends. Our average increase remains consistent with the nationally expected trends.

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

	Pension Benefits		Other Post-retirement Benefits	
	Year ended December 31,		Year Ended December 31,	
	2006	2005	2006	2005
Discount rate	5.75 %	5.50%	5.50-5.75 %	5.50%
Expected rate of return on assets	8.00 %	8.50%	8.00 %	8.50%
Long-term rate of increase in compensation levels(nonunion)	3.61 %	3.64%	3.57 %	3.64%
Long-term rate of increase in compensation levels (union)	3.50 %	3.50%	3.50 %	3.50%

The postretirement benefit obligation is calculated assuming that health care costs increased by 8% in 2006 and the rate of increase in the per capita cost of covered health care benefits thereafter was assumed to decrease gradually to 5% by the year 2010.

Net Periodic Cost

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

	Pension Benefits		Other Post-retirement Benefits	
	Year Ended December 31,		Year Ended December 31,	
	2006	2005	2006	2005
Components of Net Periodic Benefit Cost				
Service cost	$ 9,049	$ 8,531	$ 741	$ 688
Interest cost	20,791	20,174	2,775	2,853
Expected return on plan assets	(21,458)	(20,347)	(829)	(562)
Amortization of transitional obligation	—	—	—	—
Amortization of prior service cost	242	—	—	—
Recognized actuarial (gain) loss	—	—	117	—
	8,624	8,358	2,804	2,979
Additional (income) or loss recognized:				
Curtailment	—	—	—	—
Special termination benefits	—	—	—	—
Settlement cost	—	—	—	—
Net Periodic Benefit Cost	$ 8,624	$ 8,358	$ 2,804	$ 2,979

We estimate amortizations from regulatory assets into net periodic cost during 2007 will be as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
Prior service cost	$ 242	$ —
Accumulated gain	—	—

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	$206
on postretirement benefit obligation	2,072
Effect of a one percentage point decrease in assumed health care cost trend	
on total service and interest cost components	$(176)
on postretirement benefit obligation	(1,829)

Cash Flows

On August 17, 2006 the Pension Protection Act of 2006 was signed into law, with changes that impact the funding calculation for benefit plans. We anticipate making contributions of approximately $27.5 million to our pension and other postretirement benefit plans in 2007. Pension funding is based upon annual actuarial studies prepared for each plan. 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
2007	$19,889	$4,497
2008	20,256	4,400
2009	20,555	4,461
2010	21,342	4,583
2011	22,260	4,503
2012-2016	130,449	23,254

Predecessor Company

The Predecessor Company filed several motions to terminate various nonqualified benefit plans and individual supplemental retirement contracts for former employees. All liabilities associated with these plans were removed from our balance sheet upon emergence based on our expectation that these claims would be settled through the shares from the reserve established for Class 9 claimants. Various claimants objected to the Bankruptcy Court's jurisdiction to terminate such plans and/or contracts. In July 2005, the Bankruptcy Court approved share-based settlements with most of the participants in the various nonqualified plans and supplemental retirement contracts. However, the Bankruptcy Court determined that it did not have jurisdiction to consider a motion to terminate various individual supplemental retirement contracts, therefore in 2005 we reestablished a liability of approximately $2.6 million and have resumed payments on those individual supplemental retirement contracts not covered by the Bankruptcy Court's jurisdiction.

Defined Contribution Plans

Our defined contribution plan permits employees to defer receipt of compensation as provided in Section 401(k) of the Internal Revenue Code. Under the plan, employees may elect to direct a percentage of their gross compensation to be contributed to the plan. We contribute various percentage amounts of the employee's gross compensation contributed to the plan. Matching contributions were $4.3 million for 2006 and $3.4 million for 2005.

(18) 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 700,000 shares were set aside for restricted stock grants, in addition to 228,315 shares of restricted stock granted upon our emergence from bankruptcy. We may issue new shares or reuse forfeited shares in order to deliver shares to employees for equity grants. Pursuant to the terms of the Merger Agreement with BBI, which provides that all of the shares available under our long term incentive plans may be awarded before completion of the transaction, 400,025 shares of restricted stock were granted in November 2006. As of December 31, 2006 there were 57,023 shares of common stock of the initial 700,000 shares remaining available for grants under this plan. The stock vests to participants at various times ranging from one to five years if the service requirements are met. Nonvested shares do not receive dividend distributions. The long-term incentive plans provide for accelerated vesting in the event of a change in control. The proposed transaction with BBI would trigger this acceleration.

In accordance with SFAS No. 123R, we account for our service-based restricted stock awards using the fixed accounting method, whereby we amortize the value of the market price of the underlying stock on the date of grant (grant-date fair value) to compensation expense over the service period either ratably or in tranches. We reverse any expense associated with restricted stock that is canceled or forfeited during the performance or service period. Compensation expense recognized for restricted stock awards was $3.6 million for the year ended December 31, 2006 and $4.7 million for the year ended December 31, 2005. The total income tax benefit recognized in the income statement for these restricted stock awards was $1.5 million for the year ended December 31, 2006 and $1.8 million for the year ended December 31, 2005.

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

	Year Ended December 31, 2006	Weighted-Average Grant-Date Fair Value	Year Ended December 31, 2005	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	35,164	$ 20.00	114,151	$ 20.00
Granted	503,337	34.42	97,651	30.79
Vested	57,393	29.94	175,558	26.00
Forfeited	5,003	34.39	1,080*	20.00
Remaining nonvested grants	476,105	29.54	35,164	20.00

* This amount represents shares forfeited from awards granted upon our emergence from bankruptcy. Forfeited shares from this grant are cancelled. Forfeited shares from all other grants are available to be reissued.

As of December 31, 2006 we had $14.1 million of unrecognized compensation cost related to nonvested portion of outstanding restricted stock awards, which is reflected in other paid-in capital in our Balance Sheet. If the transaction with BBI is not completed, the cost is expected to be recognized over a weighted-average period of 2.5 years. The total fair value of shares vested was $1.7 million for the year ended December 31, 2006 and $4.6 million for the year ended December 31, 2005.

Director's Deferred Compensation

Nonemployee directors may elect to defer up to 100% of any qualified compensation that would be otherwise payable to him or her, subject to compliance with our 2005 Deferred Compensation Plan for Nonemployee Directors and Section 409A of the Internal Revenue Code. The deferred compensation may be invested in NorthWestern stock or in designated investment funds. Compensation deferred in a particular month is recorded as a deferred stock unit (DSU) on the first of the following month based on the closing price of NorthWestern stock or the designated investment fund. A DSU entitles the grantee to receive one share of common stock for each DSU at the end of the deferral period. The value of these DSUs are marked-to-market on a quarterly basis with an adjustment to directors compensation expense. Based on the election of the nonemployee director, following separation from service on the Board, other than on account of death, he or she shall be paid a distribution either in a lump sum or in approximately equal installments over a designated number years (not to exceed 10 years). During the years ended December 31, 2006 and 2005, DSUs issued to members of our Board totaled 22,805 and 20,934, respectively. Total compensation expense attributable to the DSUs during the years ended December 31, 2006 and 2005 was approximately $0.9 million and $0.7 million, respectively.

(19) Regulatory Assets and Liabilities

We prepare our financial statements in accordance with the provisions of SFAS No. 71, as discussed in Note 3 to the Financial Statements. Pursuant to this pronouncement, certain expenses and credits, normally reflected in income as incurred, are deferred and recognized when included in rates and recovered from or refunded to the customers. Regulatory assets and liabilities are recorded based on management's assessment that it is probable that a cost will be recovered or that an obligation has been incurred. Accordingly, we have recorded the following major classifications of regulatory assets and liabilities that will be recognized in expenses and revenues in future periods when the matching revenues are collected or refunded. Of these regulatory assets and liabilities, energy supply costs are the only items earning a rate of return. The remaining regulatory items have corresponding assets and liabilities that will be paid for or refunded in future periods. Because these costs are recovered as paid, they do not earn a return. We have specific orders to cover approximately 91% of our regulatory assets and approximately 95% of our regulatory liabilities.

	Note Ref.	Remaining Amortization Period	December 31, 2006	December 31, 2005
Pension	17	Undetermined	$ 87,397	$ 123,326
SFAS No. 106	17	Undetermined	28,725	33,096
Income taxes	14	Plant Lives	9,453	9,184
State & local taxes & fees		1 Year	5,105	5,697
Other		Various	17,823	13,802
Total regulatory assets			$ 148,503	$ 185,105
Gas storage sales		33 Years	$ 13,774	$ 14,195
Supply costs		1 Year	9,061	7,981
Other		Various	3,462	2,361
Total regulatory liabilities			$ 26,297	$ 24,537

Pension and SFAS No. 106

Through fresh-start reporting in 2004 we adjusted our qualified pension and other postretirement benefit plans to their projected benefit obligation by recognition of all previously unamortized actuarial gains and losses. A pension regulatory asset has been recognized for the obligation that will be included in future cost of service. Historically, the MPSC rates have allowed recovery of pension costs on a cash basis. In 2005, the MPSC authorized the recognition of pension costs based on an average of the funding to be made over a 5-year period for the calendar years 2005 through 2009. The SDPUC allows recovery of pension costs on an accrual basis. A regulatory asset has been recognized for the SFAS No. 106 fair value adjustments resulting from fresh-start reporting. The MPSC allows recovery of SFAS No. 106 costs on an accrual basis.

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. On December 1, 2006, we filed with the MPSC for an automatic rate adjustment, which reflected 100% of the under recovery for 2006 and estimated amounts for 2007. In January 2007, the MPSC issued an order allowing recovery of the 2006 actual increase and the 2007 estimated increase, reduced by 40% for an income tax deduction. While we have recorded a regulatory asset consistent with the MPSC's authorization, we are disputing the reduction by the MPSC and have filed a Petition for Judicial Review in Montana District Court regarding this issue. We anticipate resolving this matter in 2007; however we cannot currently predict an outcome.

Gas Storage Sales

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

(20) Regulatory Matters

The MPSC, the SDPUC, the NPSC, and the FERC approve the rates that we charge our customers for our regulated businesses, as applicable. There have been no significant regulatory matters in South Dakota or Nebraska during the past three years. Current regulatory issues are discussed below.

On September 29, 2006 we submitted an informational filing to the MPSC outlining our cost of providing electric and natural gas delivery service in Montana. The informational filing is based on actual costs in 2005, adjusted for known and measurable cost changes that occurred in 2006 and is a result of a 2004 stipulation and settlement agreement between NorthWestern, the MPSC and the Montana Consumer Counsel. The filing demonstrates a revenue deficiency of approximately $29.1 million in electric rates and $12.3 million in natural gas rates; however, we did not seek a rate adjustment, as we would like the MPSC to give priority to its approval of the transaction with BBI.

On October 17, 2006, we filed an application with the FERC requesting an increase in transmission rates in Montana under the open access transmission tariff. While the request presents a net increase of $28.8 million in overall transmission costs, the rate adjustment pertains only to wholesale transmission and retail choice customers. Therefore, the portion of the requested cost increase pertaining to the remaining Montana retail default supply customer loads, which represents approximately 70% of this increase, is subject to MPSC jurisdictional rates, and will not result in increased revenues. Since the last transmission rate adjustment, which was filed in March 1998, our cost of service has increased and the type of transmission service that we provide has changed as partial retail access has developed in Montana. The overall net effect of this filing for affected customers is expected to be an average rate increase of between 6 – 18%, depending on the type of customer.

(21) 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 megawatt hour through 2029. Our gross contractual obligation related to the QFs is approximately $1.6 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, 2006	December 31, 2005
Beginning QF liability	$ 140,467	$ 143,381
Unrecovered amount	(3,460)	(8,626)
Interest expense	10,886	10,600
Contract amendment	—	(4,888)
Ending QF liability	$ 147,893	$ 140,467

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

	Gross Obligation	Recoverable Amounts	Net
2007	$58,420	$(52,567)	$5,853
2008	60,574	(53,060)	7,514
2009	62,598	(53,583)	9,015
2010	64,580	(54,086)	10,494
2011	66,067	(54,628)	11,439
Thereafter	1,263,849	(962,297)	301,552
Total	$1,576,088	$(1,230,221)	$345,867

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 24 years. Costs incurred under these contracts were approximately $447.1 million for the year ended December 31, 2006 and $433.9 million for the year ended December 31, 2005. As of December 31, 2006 our commitments under these contracts are $535 million in 2007, $350 million in 2008, $292 million in 2009, $274 million in 2010, $133 million in 2011, and $528 million thereafter. These commitments are not reflected in our Financial Statements.

Environmental Liabilities

Environmental laws and regulations are continually evolving, and, therefore, the character, scope, cost and availability of the measures we may be required to take to ensure compliance with evolving laws or regulations cannot be accurately predicted. The range of exposure for environmental remediation obligations at present is estimated to range between $20.4 million to $56.1 million. As of December 31, 2006, we have a reserve of approximately $34.1 million. We anticipate that as environmental costs become fixed and reliably determinable, we will seek insurance reimbursement and/or authorization to recover these in rates; therefore, we do not expect these costs to have a material adverse effect on our financial position, ongoing operations, or cash flows.

The Clean Air Act Amendments of 1990 and subsequent amendments stipulate limitations on sulfur dioxide and nitrogen oxide emissions from coal-fired power plants. We comply with these existing emission requirements through purchase of sub-bituminous coal, and we believe that we are in compliance with all presently applicable environmental protection requirements and regulations with respect to these plants. Recent legislation has been proposed, which may require further limitations on emissions of these pollutants along with limitations on carbon dioxide, particulate matter, and mercury emissions. The recent regulatory and legislative proposals are subject to normal administrative processes, and we cannot make any prediction as to whether the proposals will pass or the impact of those actions. In November 2006, The Sierra Club sent a Notice of Intent to File a Suit to the owners, including us, of Big Stone I, asserting that it would file a lawsuit in 60 days alleging that the plant failed to obtain permits for certain projects undertaken in 1995, 2001 and 2005 and otherwise failed to comply with the Clean Air Act. The owners intend to vigorously defend against any lawsuit filed by The Sierra Club.

Coal-Fired Plants

Citing its authority under the Clean Air Act, the EPA has finalized Clean Air Mercury Regulations (CAMR) that affect coal-fired plants. These regulations establish a cap-and-trade program to take effect in two phases, with a first phase to begin in January 2010, and a second phase with more stringent caps to begin in January 2018. Under CAMR, each state is allocated a mercury emissions cap and is required to develop regulations to implement the requirements, which can follow the federal requirements or be more restrictive.

Montana has finalized its own, more stringent rules that would require every coal-fired generating plant in the state to achieve by 2010 reduction levels more stringent than CAMR's 2018 cap. Because enhanced chemical injection technologies may not be sufficiently developed to meet this level of reductions by 2010, there is a risk that adsorption/absorption technology with fabric filters at the Colstrip Unit 4 generation facility would be required, which could represent a material cost. We expect the Montana mercury rules to be challenged. If those rules are overturned and we are instead required to comply with CAMR, achievement of the 2010 and

2018 requirements may be possible 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 new rules.

Manufactured Gas Plants

Approximately $28.6 million of our environmental reserve accrual is related to manufactured gas plants. Two formerly operated manufactured gas plants located in Aberdeen and Mitchell, South Dakota, have been identified on the Federal Comprehensive Environmental Response, Compensation, and Liability Information System (CERCLIS) list as contaminated with coal tar residue. At this time, no material remediation is necessary at the Mitchell location. In January 2007, we received a letter from the South Dakota Department of Environment and Natural Resources (SD DENR) that this location is at a No Further Action Status. We are currently investigating and characterizing the Aberdeen site pursuant to work plans approved by the SD DENR and some remedial activities commenced at the Aberdeen site in 2006. Our current reserve for remediation costs at the Aberdeen site is approximately $15.4 million, and we estimate that approximately $13 million of this amount will be incurred during the next five years. During 2006, we incurred remediation costs of approximately $0.4 million.

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, and we are evaluating the results of these reports. We plan to conduct additional site investigation and assessment work at these locations in 2007. At present, we cannot determine with a reasonable degree of certainty the nature and timing of any remediation cleanup 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 the existence of exceedences of regulated pollutants in the groundwater. We conducted additional groundwater monitoring during 2005 at the Butte and Missoula sites and have analyzed the data and presented it to the MDEQ. At this time, we believe that natural attenuation should address the problems at these sites; however, additional groundwater monitoring will be necessary. Closure of the Butte and Missoula sites is expected shortly. Recent monitoring of groundwater at the Helena manufactured gas plant site suggests that groundwater remediation may be necessary to prevent certain contaminants from migrating offsite. We have evaluated the results of a pilot program meant to promote aerobic degradation of certain targeted contaminants. Further data collection is necessary to complete the evaluation and assess other remediation technologies to determine the optimal remedial technology for this site. Monitoring of groundwater at this site will be necessary for an extended time. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of additional remediation at the Helena site.

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

Milltown Mining Waste

Our subsidiary, Clark Fork and Blackfoot, LLC (CFB), owns the Milltown Dam hydroelectric facility, a three megawatt generation facility located at the confluence of the Clark Fork and Blackfoot Rivers. In April 2003, the Environmental Protection Agency (EPA) announced its proposed remedy to address the mining waste contamination located in the Milltown Reservoir. This remedy proposed partial removal of the contaminated sediments located within the Milltown Reservoir, together with the removal of the Milltown Dam and powerhouse (this remedy was incorporated into the EPA's formal Record of Decision issued on December 20, 2004). In light of this pre-Record of Decision announcement, we entered into a stipulation (Stipulation) with Atlantic Richfield, the EPA, the Department of the Interior, the State of Montana and the Confederated Salish and Kootenai Tribes (collectively the Government Parties), which capped NorthWestern's and CFB's collective liability to Atlantic Richfield and the Government Parties at $11.4 million. In April 2006, we released escrowed amounts of $2.5 million and $7.5 million to the State of Montana and Atlantic

Richfield, respectively, in accordance with the terms of the consent decree described below. Pursuant to the terms of the consent decree, the parties expect that the remaining financial obligation of $1.4 million to the State of Montana will be covered through a combination of any refund of premium upon cancellation of the catastrophic release policy described below, and the sale or transfer of land and water rights associated with the Milltown Dam operations.

On July 18, 2005, CFB and we executed the Milltown Reservoir superfund site consent decree, which incorporated the terms set forth in the Stipulation. The consent decree was approved by the Federal District Court for the District of Montana on February 8, 2006 and became effective on April 10, 2006. In light of the material environmental risks associated with the catastrophic failure of the Milltown Dam, we secured a 10-year, $100 million environmental insurance policy, effective May 31, 2002, to mitigate the risk of future environmental liabilities arising from the structural failure of the Milltown Dam caused by an act of God. We are obligated under the settlement to continue to maintain the environmental insurance policy until the Milltown Dam is removed during implementation of the remedy.

<u>Other</u>

We continue to manage polychlorinated biphenyl (PCB)-containing oil and equipment in accordance with the EPA's Toxic Substance Control Act regulations. We, along with other potentially responsible parties, are currently negotiating with EPA over remediation of an oil recycling facility in Oregon to which waste oil had been transported by The Montana Power Company and others. We anticipate that these negotiations will be successfully resolved during 2007. 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 perform a comprehensive evaluation of our environmental reserve. Based upon information available to our consultants 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 and our third-party consultant may not know all sites for which we are alleged or will be found to be responsible for remediation; and
- Absent performance of certain testing at sites where we have been identified as responsible for remediation, we cannot estimate with a reasonable degree of certainty the total costs of remediation.

Legal Proceedings

<u>Magten/Law Debenture/QUIPS Litigation</u>

On April 16, 2004, Magten Asset Management Corporation (Magten) and Law Debenture Trust Company (Law Debenture) initiated an adversary proceeding, which we refer to as the QUIPS Litigation, against NorthWestern seeking among other things, to void the transfer of certain assets and liabilities of CFB to us. In essence, Magten and Law Debenture are asserting that the transfer of the transmission and distribution assets acquired from the Montana Power Company was a fraudulent conveyance because such transfer allegedly left CFB insolvent and unable to pay certain claims. The plaintiffs also assert that they are creditors of CFB as a result of Magten owning a portion of the Series A 8.5% Quarterly Income Preferred Securities for which Law Debenture serves as the Indenture Trustee. Plaintiffs seek, among other things, the avoidance of the transfer of assets, declaration that the assets were fraudulently transferred and are not property of our bankruptcy estate, the imposition of constructive trusts over the transferred assets and the return of such assets to CFB. On September 29, 2006, the Delaware District Court, which has jurisdiction over this lawsuit, denied NorthWestern's Motion for a Protective Order to limit the scope of discovery sought by plaintiffs. Discovery has commenced and the District Court has scheduled trial, if any, to be held in December 2007. We intend to vigorously defend against the QUIPS litigation.

On April 19, 2004, Magten also filed a complaint against certain former and current officers of CFB in U.S. District Court in Montana, seeking compensatory and punitive damages for alleged breaches of fiduciary duties by such officers in connection with the same transaction described above which is at issue in the QUIPS Litigation, namely the transfer of the transmission and distribution assets acquired from the Montana Power Company to NorthWestern. Those officers have requested CFB to indemnify them for their legal fees and costs in defending against the lawsuit and any settlement and/or judgment in such lawsuit. That lawsuit was transferred to the Federal District Court in Delaware in July 2005 and is consolidated with the QUIPS Litigation for purposes of discovery and pre-trial matters. In February 2007, those officers asked the Federal District Court in Delaware for leave to file a motion to dismiss the complaint and Magten has filed a motion to amend its complaint to add Law Debenture as an additional plaintiff.

In July 2006, Magten served a complaint against The Bank of New York (BNY) in an action filed in New York State court, seeking damages for alleged breach of contract, breach of fiduciary duty and negligence in connection with the same transaction described above which is at issue in the QUIPS Litigation. Specifically, Magten alleges that BNY, as the Indenture Trustee at the time of the 2002 transfer of assets from Montana Power Company to NorthWestern, should have taken steps to protect the QUIPS holders' interests by seeking to set aside the transfer and imposing a constructive trust on the assets. The New York State court is considering BNY's motion to dismiss Magten's complaint. BNY has asserted a right to indemnification by NorthWestern for legal fees and costs incurred in defending against Magten's claims pursuant to the terms of the Indenture governing the QUIPS under which BNY served as Trustee. It is our position that any such recovery should be payable from the disputed claim reserve although the Plan of Reorganization Creditors Committee has objected to this position.

On April 15, 2005, Magten and Law Debenture filed an adversary complaint in the Bankruptcy Court against NorthWestern Corporation, Gary Drook, Michael Hanson, Brian Bird, Thomas Knapp and Roger Schrum seeking to revoke the Confirmation Order on the grounds that it was procured by fraud as a result of the alleged failure to adequately fund the Class 9 Disputed Claims Reserve with enough shares of New Common Stock to satisfy a potential full recovery on all pending claims against NorthWestern's bankruptcy estate which were outstanding at the time the Plan became Effective on November 1, 2004. The plaintiffs also alleged breach of fiduciary duty on the part of certain former and current officers in connection with the alleged under-funding of the Disputed Claims Reserve. NorthWestern filed a motion to dismiss or stay the litigation and on July 26, 2005, the Bankruptcy Court ordered a stay of the litigation pending resolution of Magten's appeal of the Order confirming our Plan of Reorganization. NorthWestern intends to seek dismissal of this action and to the extent such action is not dismissed, NorthWestern intends to vigorously defend this action.

Twice during 2005, Magten, Law Debenture, the Plan Committee and NorthWestern unsuccessfully engaged in mediation to resolve the pending appeals and other pending litigation described above. At this time, we cannot predict the impact or resolution of any of these actions or reasonably estimate a range of possible loss, which could be material. We intend to vigorously defend against the adversary proceedings, lawsuits, appeals and any subsequently filed similar litigation. While we cannot currently predict the impact or resolution of this litigation, the plaintiffs' claims with respect to the QUIPs Litigation will be treated as general unsecured, or Class 9, claims and will be satisfied out of the Class 9 Disputed Claims Reserve established under the Plan.

McGreevey Litigation

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

In June 2006, we and the McGreevey plaintiffs entered into an agreement to settle the claims brought by the McGreevey plaintiffs in all of the actions stated above through a covenant not to execute by McGreevey plaintiffs against us and by us quit claiming any interest we had in any claims we may or may not have under any applicable directors and officers liability insurance policy, against any insurers for contractual or extracontractual damages, and against certain defendants in the McGreevey lawsuits. This agreement was finally approved by the Bankruptcy Court in November 2006. In February 2007, together with the plaintiffs, we filed a motion to dismiss the claims against us in the McGreevey lawsuits and no objections have been filed. The federal court denied the motions to dismiss on the basis that the plaintiffs' lawyers had not been appointed as class counsel and no class had been certified.

We are in discussions with the plaintiffs' lawyers to determine how they will fulfill their obligations under the settlement agreement which was approved by the bankruptcy court.

City of Livonia

In November 2005, we and our directors were named as defendants in a shareholder class action and derivative action entitled *City of Livonia Employee Retirement System v. Draper, et al.*, pending in the U.S. District Court for the District of South Dakota. The plaintiff claims, among other things, that the directors breached their fiduciary duties by not sufficiently negotiating with Montana Public Power Inc. and Black Hills Corporation, two entities that had made public, unsolicited offers to purchase NorthWestern. On April 26, 2006, Livonia amended its complaint to add allegations that our directors had erred in choosing the BBI offer because it was not the most attractive offer they had received for the company. The parties have entered into a settlement agreement which provides that NorthWestern will redeem the existing shareholder rights plan either following shareholder approval of the Merger Agreement with BBI or upon termination of the Merger Agreement with BBI – whichever occurs first. The Board may adopt a new shareholder rights plan if the shareholders approve adoption of such a plan in advance or, in the event that circumstances require timely implementation of such a plan, the Board seeks and receives approval from shareholders within 12 months after adoption. After limited confirmatory discovery, the settlement agreement has been filed. In December 2006 the federal court indicated it would not approve the settlement because it did not provide any benefit to the class members. Based on the federal court's order, the plaintiffs agreed to dismiss the lawsuit with prejudice on the condition that the federal court would retain jurisdiction over any award of attorneys' fees. The plaintiffs' lawyers motion seeking discovery in advance of its motion for an award of attorneys' fees was denied by the federal court which set a briefing schedule for plaintiffs' motion for attorneys' fees. We expect briefing to be completed within the next 30-45 days and a decision by the federal court in the next three months.

Other Litigation

In April 2005, a group of former employees of the Montana Power Company filed a lawsuit in the state court of Montana against us and certain officers styled *Ammondson, et al. v. NorthWestern Corporation, et al.*, Case No. DV-05-97. The former employees have alleged that by moving to terminate their supplemental retirement contracts in our bankruptcy proceeding without having listed them as claimants or giving them notice of the disclosure statement and Plan, that we breached those contracts, and breached a covenant of good faith and fair dealing under Montana law and by virtue of filing a complaint in our Bankruptcy Case against those employees from seeking to prosecute their state court action against NorthWestern, we had engaged in malicious prosecution and should be subject to punitive damages. On May 4, 2005, the Bankruptcy Court found that it did not have jurisdiction over these contracts, dismissed our action against these former employees, and transferred our motion to terminate the contracts to Montana state court where the former employees' lawsuit is pending. We unsuccessfully engaged in mediation of this dispute in November 2005 and September 2006. We recorded a loss of $2.6 million in the third quarter of 2005 to reestablish a liability for the present value of amounts due to these former employees under their supplemental retirement contracts and reestablished monthly payments to these former employees under the terms of their contracts. In February 2007, a jury verdict was rendered against us in Montana state court, which ordered us to pay $17.4 million in compensatory and $4.0 million in punitive damages in a case called *Ammondson, et al. v. NorthWestern Corporation, et al.* Due to the verdict, we recognized a loss of $19.0 million in our 2006 results of operations to increase our recorded liability related to this claim. The Montana state court reviewed the amount of the punitive damages under state law and did not alter the amount of punitive damages. We intend to file post trial motions and post a bond and file an appeal if necessary; however, there can be no assurance that we will prevail in our efforts. In addition, we expect to incur additional legal and court costs related to these proceedings.

In December 2003, the SEC notified NorthWestern that it had issued a formal order of private investigation and subsequently subpoenaed documents from NorthWestern, NorthWestern Communications Solutions, Expanets and Blue Dot. Since December 2003, we have periodically received and continue to receive subpoenas and informal requests from the SEC requesting documents and testimony from former and current employees as well as third parties regarding these matters. In January 2006, the SEC issued Wells Notices to several former officers, a current officer and a then current employee, associated with NorthWestern and NorthWestern Communications Solutions. In July 2006, additional Wells Notices were issued to former officers and directors of NorthWestern and Expanets. A Wells Notice is an indication that the SEC staff has made a preliminary decision to recommend enforcement action that provides recipients with an opportunity to respond to the SEC staff before a formal recommendation is finalized. In December 2006, the SEC filed a complaint alleging securities law violations related to NorthWestern Communications Solutions against the former officers, a current officer and a then current employee. All the individuals agreed to settle the allegations of the complaint against them except our current officer. The current officer has been removed from his officer position pending the outcome of the complaint. There have been no findings or adjudication of the underlying allegations in the Wells Notices, and the SEC's investigation is ongoing and it could issue additional Wells Notices. In addition, certain of our former directors and several former and current employees of NorthWestern and our subsidiary affiliates have been interviewed by representatives of the FBI and IRS concerning certain of the allegations made in the now resolved class action securities and derivative litigation as well as other matters. We have not been advised that NorthWestern is the subject of any FBI or IRS investigation. We are not aware of any other governmental inquiry or investigation related to these matters. On March 7, 2007, the SEC commenced and simultaneously settled an administrative proceeding with NorthWestern and the SEC's investigation into Northwestern's restatement of our first three quarters of quarterly reports in 2002. NorthWestern agreed, without admitting any wrongdoing, to cease-and-desist from future violations of the securities laws. Specifically, NorthWestern agreed to cease-and-desist from committing or causing any violations and any future violations of Sections 13(a), 13(b)(2)(A) and 13(b)(2)(B) of the Securities Exchange Act of 1934, and Rules 12b-20, 13a-11, and 13a-13 promulgated thereunder. NorthWestern will pay no monetary fine, nor be otherwise penalized under the settlement. This settlement ends the SEC investigation regarding us.

Relative to our leasehold interest 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 & 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 & 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 due to the application of statute of limitations. The state of Montana issued a demand to WECO in May 2005 consistent with the MMS position outlined above on these transportation revenues. Further, on September 28, 2006, the MMS issued an order to pay additional royalties in the amount of $1.6 million on the basis of an audit of WECO's royalty payments during the three years 2002 to 2004. WECO has appealed these orders and we are monitoring the process. The Colstrip Units 3 & 4 owners and WECO currently dispute the responsibility of the expenses if the MMS position prevails. We believe that the Colstrip Units 3 & 4 owners have reasonable defenses in this matter based on our review. However, if the MMS position prevails and WECO prevails in passing the expense responsibility to the owners, our share of the alleged additional royalties would be 15 percent, or approximately $1.2 million, and ongoing royalty expenses related to coal transportation.

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

Disputed Claims Reserve

Upon consummation of our Plan of Reorganization, we established a reserve of approximately 4.4 million shares of common stock from the shares allocated to holders of our trade vendor claims in excess of $20,000 and holders of Class 9 unsecured claims. The shares held in this reserve may be used to resolve various outstanding unsecured claims and unliquidated litigation claims, as these claims were not resolved or deemed allowed upon consummation of our Plan. We have surrendered control over the common stock provided and the shares reserve is administered by our transfer agent; therefore we recognized the issuance of the common stock upon emergence. If excess shares remain in the reserve after satisfaction of all obligations, such amounts would be reallocated pro rata to the allowed Class 7 and 9 claimants. If the BBI transaction is completed, the merger consideration received for these shares will be retained by our transfer agent until resolution of the remaining claims.

(22) Common Stock

Successor Company

The Successor Company is a Delaware corporation and filed a new certificate of incorporation (New Articles). The New Articles authorized 250,000,000 shares 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. As a result of the Predecessor Company's emergence from bankruptcy, the Successor Company issued 35,500,000 shares of common stock in settlement of claims. Pursuant to the Plan, such stock had an agreed value of $710.0 million. Accordingly, the Successor Company recorded common stock and additional paid-in capital of $355,000 and $709.6

million, respectively, in the Balance Sheet as of October 31, 2004. In addition, the Plan reserved 2,265,957 shares of new common stock for the New Incentive Plan, of which 228,315 shares were granted for Special Recognition Grants (see Note 18).

Concurrent with our emergence from bankruptcy we issued 4,620,333 warrants, each entitling the holder thereof to purchase one share of common stock, to certain holders of class 8(a) and 8(b) claims in settlement of their allowed claim. These warrants are exercisable from November 1, 2004 through November 1, 2007 at a current adjusted strike price of $26.24. We recognized $3.8 million of expense associated with these warrants as a reduction of cancellation of indebtedness income.

Repurchase of Common Stock

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

We also retired 16,664 shares and 95,799 shares of common stock during the years ended December 31, 2006 and 2005, respectively, which were tendered by employees to us to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock awards. These shares were retired based on their fair market value on the vesting date.

Sch.19	MONTANA PLANT IN SERVICE - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year MT Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	**Intangible Plant**					
3	301 Organization	$ 19,995	$ -	$19,995	$19,995	0.00%
4	302 Franchises and Consents	2,004	-	2,004	2,004	0.00%
5	303 Miscellaneous Intangible Plant	1,175,945	-	1,175,945	952,519	23.46%
6	**Total Intangible Plant**	1,197,944	-	1,197,944	974,518	22.93%
7						
8	**Production Plant**					
9						
10	**Steam Production**					
11	310 Land and Land Rights	-	-	-	-	-
12	311 Structures and Improvements	-	-	-	-	-
13	312 Boiler Plant Equipment	-	-	-	-	-
14	313 Engines, Engine Driven Generator	-	-	-	-	-
15	314 Turbogenerator Units	-	-	-	-	-
16	315 Accessory Electric Equipment	-	-	-	-	-
17	316 Misc. Power Plant Equipment	-	-	-	-	-
18	**Total Steam Production Plant**	-	-	-	-	-
19						
20	**Nuclear Production**					
21	320 - 325 Not Applicable	-	-	-	-	-
22	**Total Nuclear Production Plant**	-	-	-	-	-
23						
24	**Hydraulic Production**					
25	330 Land and Land Rights	-	-			-
26	331 Structures and Improvements	-	-	-	-	-
27	332 Reservoirs, Dams and Waterways	-	-	-	-	-
28	333 Water Wheel, Turbine, Generators	-	-	-	-	-
29	334 Accessory Electric Equipment	-	-	-	-	-
30	335 Misc. Power Plant Equipment	-	-	-	-	-
31	336 Roads, Railroads and Bridges	-	-	-	-	-
32	**Total Hydraulic Production Plant**	-	-	-	-	-
33						
34	**Other Production**					
35	340 Land and Land Rights					
36	341 Structures and Improvements	19,232	19,232	-	-	-
37	342 Reservoirs, Dams and Waterways	112,084	112,084	-	-	-
38	343 Water Wheel, Turbine, Generators	-		-	-	-
39	344 Accessory Electric Equipment	2,247,016	2,247,016	-	-	-
40	345 Misc. Power Plant Equipment	261,022	261,022	-	-	-
41	346 Roads, Railroads and Bridges	7,268	7,268	-	-	-
42	**Total Other Production Plant**	2,646,622	2,646,622	-	-	-
43	**Total Production Plant**	2,646,622	2,646,622	-	-	-

Sch. 19 cont.	MONTANA PLANT IN SERVICE - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year MT Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	**Transmission Plant**					
3	350 Land and Land Rights	17,822,667	-	17,822,667	17,632,476	1.08%
4	352 Structures and Improvements	9,849,528	-	9,849,528	7,035,455	40.00%
5	353 Station Equipment	140,309,026	-	140,309,026	132,033,299	6.27%
6	354 Towers and Fixtures	23,642,089	-	23,642,089	23,503,803	0.59%
7	355 Poles and Fixtures	135,596,932	726,593	134,870,339	126,932,735	6.25%
8	356 Overhead Conductors & Devices	116,219,547	608,887	115,610,660	111,539,824	3.65%
9	357 Underground Conduit	137,878	102,286	35,592	35,592	0.00%
10	358 Undergrnd Conductors & Devices	1,410,535	554,036	856,499	856,499	0.00%
11	359 Roads and Trails	1,912,449	44,906	1,867,543	1,867,543	0.00%
12	**Total Transmission Plant**	446,900,651	2,036,708	444,863,943	421,437,226	5.56%
13						
14	**Distribution Plant**					
15	360 Land and Land Rights	3,918,528	601	3,917,927	3,867,785	1.30%
16	361 Structures and Improvements	5,571,125	141,867	5,429,258	5,275,964	2.91%
17	362 Station Equipment	105,195,213	1,975,474	103,219,739	100,166,642	3.05%
18	363 Storage Battery Equipment	-	-	-	-	-
19	364 Poles, Towers, and Fixtures	132,467,494	291,819	132,175,675	126,275,687	4.67%
20	365 Overhead Conductors & Devices	83,247,262	377,424	82,869,838	77,550,207	6.86%
21	366 Underground Conduit	43,707,024	179,503	43,527,521	37,006,434	17.62%
22	367 Undergrnd Conductors & Devices	93,080,163	2,628,506	90,451,657	84,548,355	6.98%
23	368 Line Transformers	152,209,894	715,091	151,494,803	142,879,578	6.03%
24	369 Services	77,115,015	190,140	76,924,875	72,270,180	6.44%
25	370 Meters	47,237,042	67,143	47,169,899	44,964,100	4.91%
26	371 Installations on Cust. Premises	-	-	-	-	-
27	372 Leased Property on Cust. Premises	-	-	-	-	-
28	373 Street Lighting and Signal Systems	50,925,219	19,872	50,905,347	47,312,876	7.59%
29	**Total Distribution Plant**	794,673,979	6,587,440	788,086,539	742,117,808	6.19%
30						
31	**General Plant**					
32	389 Land and Land Rights	402,051	-	402,051	402,661	-0.15%
33	390 Structures and Improvements	7,566,300	144,521	7,421,779	7,436,970	-0.20%
34	391 Office Furniture and Equipment	1,046,919	-	1,046,919	844,862	23.92%
35	392 Transportation Equipment	25,636,265	87,696	25,548,569	22,740,543	12.35%
36	393 Stores Equipment	400,192	-	400,192	409,608	-2.30%
37	394 Tools, Shop & Garage Equipment	4,018,009	24,013	3,993,996	4,101,537	-2.62%
38	395 Laboratory Equipment	3,317,021	4,774	3,312,247	3,503,038	-5.45%
39	396 Power Operated Equipment	2,133,362	-	2,133,362	2,181,247	-2.20%
40	397 Communication Equipment	18,801,814	74,172	18,727,642	18,037,424	3.83%
41	398 Miscellaneous Equipment	192,964	37,470	155,494	144,821	7.37%
42	399 Other Tangible Equipment	-	-	-	-	-
43	**Total General Plant**	63,514,897	372,646	63,142,251	59,802,711	5.58%
44	**Total Plant in Service**	1,308,934,093	11,643,416	1,297,290,677	1,224,332,263	5.96%
45						
46	4101 El Plant Allocated from Common	59,321,698	-	59,321,698	57,498,930	3.17%
47	105 El Plant Held for Future Use	-	-	-	-	-
48	107 El Construction Work in Progress	742,090	-	742,090	18,515,965	-95.99%
49	114.2 El Plant Acquisition Adjustment	3,106,285	-	3,106,285	3,106,285	0.00%
50						
51	**TOTAL ELECTRIC PLANT**	$1,372,104,166	$11,643,416	$1,360,460,750	$1,303,453,443	4.37%

MONTANA PLANT IN SERVICE - ELECTRIC (EXCLUDES UNIT 4)

	CONSOLIDATED PLANT IN SERVICE	December 31, 2006	2005
1			
2	Montana Electric	$ 1,297,290,677	$ 1,224,332,263
3	Yellowstone National Park	11,643,416	11,451,368
4	Colstrip Unit 4	79,416,087	74,391,022
5	Montana Natural Gas (Includes CMP)	438,067,538	416,333,506
6	Common	88,828,986	86,181,588
7	Townsend Propane	1,437,828	1,410,712
8	South Dakota Electric	381,737,459	365,273,507
9	South Dakota Natural Gas	106,888,501	101,740,399
10	South Dakota Common	45,479,695	50,180,127
11	Asset Retirement Obligation	3,547,177	3,233,138
12	**TOTAL PLANT**	$ 2,454,337,364	$ 2,334,527,630

Sch. 20	MONTANA DEPRECIATION SUMMARY - ELECTRIC (EXCLUDES UNIT 4)					
Functional Plant Class	Montana Plant Cost	This Year MT Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	Current Avg. Rate
Accumulated Depreciation						
Steam Production	$ -	$ -	$ -	$ -	$ -	-
Nuclear Production	-	-	-	-	-	-
Hydraulic Production	-	-	-	-	-	-
Other Production	-	1,945,332	1,945,332	-	-	-
Transmission	420,108,035	180,687,505	1,510,449	179,177,056	167,450,269	2.94%
Distribution	740,372,726	356,372,457	3,410,119	352,962,338	326,176,813	3.83%
General and Intangible	60,352,569	35,582,062	222,224	35,359,838	33,320,434	5.56%
Common	55,511,995	24,733,582	-	24,733,582	21,205,395	7.12%
Total Accum Depreciation	$1,276,345,325	$599,320,938	$7,088,124	$592,232,814	$548,152,911	3.61%

Consolidated Accumulated Depreciation	December 31, 2006	December 31, 2005
Montana Electric	$567,499,232	$526,947,516
Yellowstone National Park	7,088,124	6,734,257
Colstrip Unit 4	35,695,257	34,186,431
Montana Natural Gas (Includes CMP)	178,480,022	168,312,284
Common	36,603,175	31,417,118
Townsend Propane	443,648	399,982
South Dakota Electric	200,651,799	193,756,781
South Dakota Natural Gas	44,276,873	41,288,807
South Dakota Common	16,336,309	16,039,957
Acquisition Writedown	130,830,517	138,214,749
Basin Creek Capital Lease	1,005,236	
FIN 47	120,638	
CWIP-Capital Retirement Clearing	-262,564	-102,303
Total Consolidated Accum Depreciation	$1,218,768,266	$1,157,195,579

Sch. 21	MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)- ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
151	Fuel Stock	$ 290,330		$ 290,330	$ 239,620	100.00%
154	Plant Materials & Operating Supplies					
	Assigned and Allocated to:					
	Operation & Maintenance	-		-	-	-
	Construction	-		-	-	-
	Production Plant	-		-	-	-
	Transmission Plant	886,309		886,309	632,710	40.08%
	Distribution Plant	7,956,769		7,956,769	6,516,218	22.11%
	Total MT Materials and Supplies	$9,133,408		$9,133,408	$7,388,548	23.62%

Consolidated Fuel Stock	December 31, 2006	December 31, 2005
Montana Electric	$290,330	$239,620
Colstrip Unit 4	722,972	730,497
South Dakota Electric	2,300,646	1,791,919
Total Fuel Stock	$3,313,948	$2,762,036

Consolidated Materials and Supplies	December 31, 2006	December 31, 2005
Montana Electric	$8,843,078	$7,148,928
Montana Natural Gas	3,272,151	1,810,869
Colstrip Unit 4	1,473,527	1,436,641
South Dakota Electric	4,313,984	3,605,650
Total Consolidated Materials and Supplies	$17,902,740	$14,002,088

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - ELECTRIC		
Commission Accepted - Most Recent 1/	% Capital Structure	% Cost Rate	Weighted Cost
Docket Number: 2000.8.113			
Order Number : 6271c			
Common Equity	43.00%	10.75%	4.62%
Preferred Stock	6.97%	6.40%	0.45%
QUIPS Preferred	7.86%	8.54%	0.67%
Long Term Debt	42.17%	6.46%	2.72%
Other			
TOTAL	100.00%		8.46%
NorthWestern Corporation Consolidated	% Capital Structure	% Cost Rate 2/	Weighted Cost
Common Equity	51.46%	10.75%	5.53%
Preferred Stock	0.00%	0.00%	0.00%
QUIPS Preferred	0.00%	0.00%	0.00%
Long Term Debt	48.54%	5.76%	2.80%
Other			
TOTAL	100.00%		8.33%

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

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

Sch. 23

STATEMENT OF CASH FLOWS

	Description	This year	Last year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2	**Cash Flows from Operating Activities:**			
3	Net Income	$ 37,900,165	$ 59,466,590	-36.27%
4	Noncash Charges (Credits) to Income:			
5	Depreciation	75,150,690	73,609,317	2.09%
6	Amortization, Net	(909,060)	(625,151)	-45.41%
7	Other Noncash Charges to Net Income, Net	(191,334)	1,105,356	-117.31%
8	Deferred Income Taxes, Net	1,594,907	45,972,349	-96.53%
9	Investment Tax Credit Adjustments, Net	(536,281)	(534,881)	-0.26%
10	Change in Operating Receivables, Net	761,456	19,613,947	-96.12%
11	Change in Materials, Supplies & Inventories, Net	(19,820,325)	(3,939,833)	>-300.00%
12	Change in Operating Payables & Accrued Liabilities, Net	33,517,935	12,827,782	161.29%
13	Allowance for Funds Used During Construction (AFUDC)	(623,697)	(758,738)	17.80%
14	Change in Other Assets & Liabilities, Net	192,405	(74,366,002)	100.26%
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	(2,428,010)	(233,242)	>-300.00%
17	Change in Regulatory Assets	20,676,673	6,832,092	202.64%
18	Change in Regulatory Liabilities	1,759,892	(1,013,026)	273.73%
19	Proceeds from hedging activities	14,546,654	-	-
20	**Net Cash Provided by/(Used in) Operating Activities**	161,592,070	137,956,560	17.13%
21	**Cash Inflows/Outflows From Investment Activities:**			
22	Construction/Acquisition of Property, Plant and Equipment	(100,580,122)	(79,178,268)	-27.03%
23	(Net of AFUDC)			
24	Proceeds from Sale of Assets	24,168,975	5,005,009	>300.00%
25	Proceeds from Hedging Activities	5,356,360	-	-
26	Other Investing Activities:			
27	Proceeds from Sales of Investments	-	4,677,608	-100.00%
28	Purchase of Investment Securities	-	(118,800,000)	100.00%
29	Proceeds from Sales of Investment Securities	-	118,800,000	-100.00%
30	Distribution from Subsidiaries	7,694,557	45,719,640	-83.17%
31	**Net Cash Provided by/(Used in) Investing Activities**	(63,360,230)	(23,776,011)	-166.49%
32	**Cash Flows from Financing Activities:**			
33	Proceeds from Issuance of:			
34	Long-Term Debt	320,205,000	-	-
35	Payment for Retirement of:			
36	Credit Facilities Borrowings/Repayments, Net	(31,000,000)	81,000,000	-138.27%
37	Long-Term Debt	(320,278,500)	(165,386,000)	-93.66%
38	Capital Lease Obligations, Net	(1,163,520)	(4,612,569)	74.78%
39	Dividends on Common Stock	(44,091,245)	(35,634,163)	-23.73%
40	Other Financing Activities:			
41	Exercise of Warrants	2,895,841	132,092	>300.00%
42	Deferred Gas Storage Financing	(11,718,029)	2,475,214	>-300.00%
43	Debt Financing Costs	(7,238,014)	(2,398,161)	-201.82%
44	Treasury Stock Purchases	(4,312,494)	(5,572,604)	22.61%
45	**Net Cash Provided by (Used in) Financing Activities**	(96,700,961)	(129,996,191)	25.61%
46	**Net Increase/(Decrease) in Cash and Cash Equivalents**	1,530,879	(15,815,641)	109.68%
47	**Cash and Cash Equivalents at Beginning of Year**	334,282	16,149,923	-97.93%
48	**Cash and Cash Equivalents at End of Year**	$ 1,865,161	$ 334,282	>300.00%

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 Corp.

Sch. 24

MONTANA LONG TERM DEBT 1/

Description	Issue Date	Maturity Date	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem./Disc.	Total Cost %
First Mortgage Bonds								
6.04% Series, Due 2016	09/13/06	09/01/16	$150,000,000	$148,488,952	$149,928,950	6.040%	$9,215,616	6.15%
5.875% Series, Due 2014	11/01/04	11/01/14	161,000,000	161,000,000	161,000,000	5.875%	9,934,663	6.17%
Total First Mortgage Bonds			$311,000,000	$309,488,952	$310,928,950		$19,150,279	6.16%
Pollution Control Bonds								
4.65% Series, Due 2023	04/27/06	08/01/23	$170,250,000	$164,451,956	$170,205,000	4.650%	$8,248,090	4.85%
Total Pollution Control Bonds			$170,250,000	$164,451,956	$170,205,000		$8,248,090	4.85%
Other Long Term Debt								
Cost Associated with Prior Debt Retirements	N/A	N/A					$296,467	N/A
Other Capital Leases - Fleet Lease	09/24/02	08/27/09	$6,179,475	$6,179,475	$496,152		$33,391	6.73%
Total Other Long Term Debt			$6,179,475	$6,179,475	$496,152		$329,858	
TOTAL LONG TERM DEBT			$487,429,475	$480,120,383	$481,630,102		$27,728,227	5.76%

1/ Total Long-Term Debt does not include amounts due within 1 year - $365,000.
Total Capital Leases does not include the Fleet Lease amounts due within 1 year - $468,542. It also does not include amounts associated with the Basin Creek contract, which totals $39,757.891.

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	35,602,837	$20.92				$32.11	$31.05	
February	35,568,099	21.08				32.88	30.78	
March	35,578,847	21.11	$0.59	$0.31		32.70	31.00	
April	35,493,269	21.12				35.24	30.07	
May	35,493,837	21.04				35.24	34.21	
June	35,494,337	20.84	(0.07)	0.31		34.95	33.83	
July	35,494,948	20.96				34.80	33.73	
August	35,518,748	21.11				35.08	34.43	
September	35,522,644	20.88	0.32	0.31		35.20	34.72	
October	35,622,458	21.01				35.73	34.95	
November	35,637,115	21.16				35.85	35.26	
December	35,637,860	20.84	0.23	0.31		35.85	35.19	
TOTAL Year End	35,554,498	$20.84	$1.07	$1.24	-15.89%	$35.38		33.1

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for the twelve months ended December 31, 2006.

Sch. 27	MONTANA EARNED RATE OF RETURN - ELECTRIC				
		Description	This Year	Last Year	% Change
1		**Rate Base**			
2	101	Plant in Service	$1,317,262,783	$1,260,496,102	4.50%
3	108	Accumulated Depreciation	(574,301,737)	(532,594,413)	-7.83%
4					
5	**Net Plant in Service**		$742,961,046	$727,901,689	2.07%
6		Additions:			
7	154, 156	Materials & Supplies	$6,814,452	$5,722,141	19.09%
8	165	Prepayments			
9		Other Additions 1/	25,505,105	28,787,867	-11.40%
10					
11	**Total Additions**		$32,319,557	$34,510,008	-6.35%
12		Deductions:			
13	190	Accumulated Deferred Income Taxes	$83,639,988	$82,478,142	1.41%
14	252	Customer Advances for Construction	25,137,316	21,593,159	16.41%
15	255	Accumulated Def. Investment Tax Credits			
16		Other Deductions	10,457,452	9,428,335	10.92%
17					
18	**Total Deductions**		$119,234,756	$113,499,636	5.05%
19	**Total Rate Base**		$656,045,847	$648,912,061	1.10%
20	**Net Earnings**		$44,962,813	$39,844,372	12.85%
21	**Rate of Return on Average Rate Base**		6.854%	6.140%	11.62%
22	**Rate of Return on Average Equity 2/**		6.723%	4.881%	37.74%
23					
24		**Major Normalizing and**			
25		**Commission Ratemaking Adjustments**			
26		Rate Schedule Revenues	$2,618,920	$2,089,860	25.32%
27		Electric Supply Cost 3/	4,361,795	0	-
28					
29		Non-Allowables:			
30		Advertising	735,159	120,174	>300.00%
31		Dues, Contributions, Other	86,614	56,633	52.94%
32					
33		Associated Income Taxes 4/	(3,719,255)	(2,875,472)	-29.34%
34					
35	**Total Adjustments**		$4,083,234	($608,805)	>300.00%
36	**Revised Net Earnings**		$49,046,046	$39,235,567	25.00%
37	**Adjusted Rate of Return on Average Rate Base**		7.476%	6.046%	23.64%
38	**Adjusted Rate of Return on Average Equity 2/**		8.166%	5.305%	53.93%
39					
40	1/ Other additions includes a FAS 109 Regulatory Asset that provides an offset to the accumulated				
41	deferred taxes.				
42					
43	2/ Return on Equity calculated using the capital structure approved in Docket D2000.8.113.				
44					
45	3/ During March 2006, we signed a stipulation with the Montana Consumer Counsel (MCC) to settle				
46	various issues regarding our 2005 and 2006 electric tracker filings. This stipulation was approved				
47	in Docket No. D2000.5.5.88.				
48					
49	4/ Associated Income taxes include an interest synchronization adjustment based upon the approved				
50	capital structure in Docket D2000.8.113.				
51					

Sch. 27	cont.	MONTANA EARNED RATE OF RETURN - ELECTRIC		
[illegible]	Description	This Year	Last Year	% Change
1				
2	**Detail - Other Additions**			
3	FAS 109 Regulatory Asset	$21,207,711	$24,610,899	-13.83%
4	Cost of Refinancing Debt	2,338,562	1,782,840	31.17%
5	SAP Development Costs	1,958,832	2,394,128	-18.18%
6				
7	**Total Other Additions**	$25,505,105	$28,787,867	-11.40%
8				
9	**Detail - Other Deductions**			
10	Personal Injury and Property Damage	($4,380,715)	($4,813,349)	8.99%
11	Gross Cash Requirements	12,101,027	11,304,852	7.04%
12	Storm Damage Reserve	(220,841)	46,379	>-300.00%
13	USBC Expenses	2,957,981	2,890,453	2.34%
14				
15	**Total Other Deductions**	$10,457,452	$9,428,335	10.92%
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				

Sch. 28	MONTANA COMPOSITE STATISTICS - ELECTRIC (EXCLUDES UNIT 4 & YNP)		
		Description	Amount
1			
2		**Plant (Intrastate Only)**	
3			
4	101	Plant in Service (Includes Allocation from Common)	$ 1,356,612,375
5	105	Plant Held for Future Use	-
6	107	Construction Work in Progress	742,090
7	114	Plant Acquisition Adjustments	3,106,285
8	151-163	Materials & Supplies	9,133,408
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	592,232,814
11	252	Contributions in Aid of Construction	27,216,507
12	**NET BOOK COSTS**		750,144,837
13			
14		**Revenues & Expenses**	
15			
16	400	Operating Revenues	591,339,874
17			
18	**Total Operating Revenues**		591,339,874
19			
20	401-402	Other Operating Expenses (including regulatory amortizations)	429,970,486
21	403-407	Depreciation & Amortization Expenses	48,154,971
22	408.1	Taxes Other than Income Taxes	55,803,016
23	409-411	Federal & State Income Taxes	12,448,588
24			
25	**Total Operating Expenses**		546,377,061
26	**Net Operating Income**		44,962,813
27			
28	415-421.1	Other Income	10,232,484
29	421.2-426.5	Other Deductions	554,350
30	**NET INCOME BEFORE INTEREST EXPENSE**		54,640,947
31			
32		**Average Customers (Intrastate Only)**	
33		Residential	257,957
34		Commercial & Industrial	57,953
35		Other (including interdepartmental)	4,061
36			
37	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		319,971
38			
39		**Other Statistics (Intrastate Only)**	
40		Average Annual Residential Use (Kwh)	8,462
41		Average Annual Residential Cost per (Kwh)	$0.089
42		Average Residential Monthly Bill	$63.05
43			
44		Plant in Service (Gross) per Customer	$4,240

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,234	456	111	5	572
2	Alberton	374	372	80	14	466
3	Alder	116	195	73	16	284
4	Amsterdam		124	34	6	164
5	Anaconda	9,417	4,174	753	50	4,977
6	Armington		1	-	-	1
7	Arrow Creek		4	3	-	7
8	Augusta	284	232	91	2	325
9	Avon	124	92	55	2	149
10	Barber		49	9		58
11	Basin	255	157	68	1	226
12	Bearcreek	83	59	14	3	76
13	Belfry	219	195	66	16	277
14	Belgrade	5,728	6,644	1,401	79	8,124
15	Belt	633	628	222	16	866
16	Benchland		7	6	-	13
17	Big Sandy	703	343	139	5	487
18	Big Sky	1,221	2,584	498	12	3,094
19	Big Timber	1,650	1,181	364	28	1,573
20	Billings	89,847	42,265	7,240	689	50,194
21	Black Eagle		443	146	14	603
22	Bonner	1,693	77	24	3	104
23	Boulder	1,300	765	232	24	1,021
24	Box Elder	794	142	66	8	216
25	Bozeman	27,509	21,763	4,391	321	26,475
26	Brady		89	35	5	129
27	Bridger	745	402	141	14	557
28	Broadview	150	209	144	2	355
29	Buffalo		-	-	3	3
30	Butte	33,892	13,807	2,271	297	16,375
31	Cameron		268	93	5	366
32	Canyon Creek		169	32	5	206
33	Carter	62	118	68	4	190
34	Cascade	819	1,025	262	23	1,310
35	Centerville		13	11	1	25
36	Checkerboard		54	11	1	66
37	Chester	871	481	268	12	761
38	Chinook	1,386	808	297	17	1,122
39	Choteau	1,781	959	350	20	1,329
40	Churchill		662	132	20	814
41	Clancy	1,406	792	120	12	924
42	Clinton	549	99	37	3	139
43	Coffee Creek		56	22	1	79
44	Colstrip	2,346	946	197	32	1,175
45	Columbus	1,748	940	301	20	1,261
46	Conrad	2,753	1,237	472	22	1,731
47	Corbin		-	1	-	1
48	Corvallis	443	726	159	37	922
49	Craig		93	32	3	128
50	Custer	145	-	3	-	3

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Darby	710	760	224	18	1,002
2	De Borgia		135	34	1	170
3	Deer Lodge	3,421	2,018	515	77	2,610
4	Denton	301	180	77	2	259
5	Dillon	3,752	1,849	505	55	2,409
6	Divide		61	12	3	76
7	Dodson	122	113	64	5	182
8	Drummond	318	355	196	24	575
9	Dutton	389	250	119	4	373
10	East Helena	1,642	2,657	344	30	3,031
11	Edgar		233	73	12	318
12	Elliston	225	203	61	3	267
13	Ennis	840	1,572	502	31	2,105
14	Fairfield	659	394	152	17	563
15	Florence	901	354	128	14	496
16	Floweree		111	54	1	166
17	Fort Balknap	1,262	445	99	25	569
18	Fort Benton	1,594	807	338	31	1,176
19	Fort Harrison		-	88	2	90
20	Fromberg	486	303	69	8	380
21	Gallatin Gateway		981	283	18	1,282
22	Gardiner	851	720	267	12	999
23	Garrison	112	111	52	8	171
24	Geraldine	284	268	147	2	417
25	Geyser		67	33	3	103
26	Gildford	185	94	68	2	164
27	Glasgow	3,253	1,687	617	68	2,372
28	Glen		2	-	1	3
29	Gold Creek		68	35	4	107
30	Gransdale		24	4	1	29
31	Great Falls	56,690	27,189	4,823	386	32,398
32	Greycliff	56	50	28	9	87
33	Hall		230	65	16	311
34	Hamilton	3,705	4,957	1,292	116	6,365
35	Hardin	3,384	1,431	431	23	1,885
36	Harlem	848	447	197	27	671
37	Harlowton	1,062	653	257	8	918
38	Harrison	162	168	54	17	239
39	Haugan	69	73	36	3	112
40	Havre	10,594	4,811	1,103	192	6,106
41	Helena	45,819	21,153	4,352	360	25,865
42	Hingham	157	106	63	2	171
43	Hinsdale		141	48	8	197
44	Hobson	244	157	54	7	218
45	Huson		126	31	2	159
46	Iverness	103	39	26	1	66
47	Jardine		2	2	-	4
48	Jeffers		2	1	-	3
49	Jefferson City	295	256	44	4	304
50	Joliet	575	384	94	13	491

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Joplin	210	97	52	2	151
2	Judith Gap	164	88	45	5	138
3	Kremlin	126	65	36	1	102
4	Laurel	6,255	2,962	442	24	3,428
5	Lavina	209	181	98	11	290
6	Lennep		17	11	-	28
7	Lewistown	5,813	3,232	881	53	4,166
8	Lincoln	1,100	1,028	210	19	1,257
9	Livingston	6,851	4,438	1,012	54	5,504
10	Logan		66	17	2	85
11	Lohman		26	18	7	51
12	Lolo	3,388	1,222	175	18	1,415
13	Loma	92	72	42	3	117
14	Lothair		15	10	-	25
15	Malta	2,120	1,320	457	48	1,825
16	Manhattan	1,396	962	217	59	1,238
17	Martinsdale		115	70	5	190
18	Marysville		61	28	2	91
19	Maxville		2	-	-	2
20	McAllister		167	39	4	210
21	Melrose		1	-	-	1
22	Melstone	136	156	291	8	455
23	Melville		78	52	5	135
24	Milltown		79	23	5	107
25	Missoula	57,053	31,970	5,817	623	38,410
26	Moccasin		46	27	1	74
27	Molt		26	22	-	48
28	Monarch		326	49	3	378
29	Montana City		929	155	-	1,084
30	Moore	186	104	37	3	144
31	Musselshell	60	62	27	1	90
32	Nashua	325	196	59	4	259
33	Neihart	91	187	32	2	221
34	Nevada City		1	9	-	10
35	Norris		58	35	1	94
36	Nye		46	5	-	51
37	Paradise	184	157	59	9	225
38	Park City	870	402	58	4	464
39	Philipsburg	914	1,647	274	28	1,949
40	Plains	1,126	1,463	408	25	1,896
41	Pony		122	24	3	149
42	Power	171	81	43	4	128
43	Pray		20	1	1	22
44	Radersburg	70	79	27	2	108
45	Ramsay		50	26	-	76
46	Raynesfort		64	36	3	103
47	Red Lodge	2,177	1,788	380	17	2,185
48	Reedpoint	185	150	59	4	213
49	Ringling		44	31	3	78
50	Rocker		22	16	3	41

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Rocvale		2	-	-	2
2	Roscoe		82	10		92
3	Roundup	1,931	1,085	395	18	1,498
4	Rudyard	275	152	67	2	221
5	Ryegate	268	148	65	9	222
6	Saco	224	156	94	2	252
7	Saint Marie	183	178	47	3	228
8	Saint Regis	315	433	153	14	600
9	Saltese		36	22	1	59
10	Sand Coulee		145	39	4	188
11	Sapphire Village		61	6	-	67
12	Shawmut		45	30	2	77
13	Sheridan	659	827	224	31	1,082
14	Silesia		32	7	1	40
15	Silverbow		15	4	1	20
16	Springdale		35	15	6	56
17	Square Butte		43	25	2	70
18	Stanford	454	331	187	5	523
19	Stevensville	1,553	1,832	514	64	2,410
20	Stockett		162	51	2	215
21	Sumatra		-	3	-	3
22	Superior	893	835	263	28	1,126
23	Taft		-	1	-	1
24	Tampico		13	7	-	20
25	Thompson Falls	1,321	1,028	334	33	1,395
26	Three Forks	1,728	1,298	435	55	1,788
27	Toston	105	48	34	18	100
28	Townsend	1,867	1,151	294	20	1,465
29	Tracy		94	13	4	111
30	Turah		7	2	-	9
31	Twin Bridges	400	311	143	20	474
32	Twodot		49	47	3	99
33	Ulm	750	403	119	9	531
34	Utica		2	4	1	7
35	Valier	498	354	179	22	555
36	Vaughn	701	216	36	5	257
37	Victor	859	763	244	25	1,032
38	Virginia City	130	159	89	1	249
39	Wagner		45	23	1	69
40	Walkerville		255	28	4	287
41	Warm Springs		-	3	-	3
42	Washoe		12	4		16
43	West Yellowstone		-	5	-	5
44	White Sulphur Springs	984	776	329	46	1,151
45	Whitehall	1,044	955	256	49	1,260
46	Wickes		2	-	-	2
47	Williamsburg		-	1	-	1
48	Willow Creek	209	137	54	14	205
49	Windham		51	30	1	82
50	Winston	73	106	31	2	139

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Wolf Creek		392	139	10	541
2	Zurich		103	70	10	183
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						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	**Total**	446,046	257,957	56,823	5,176	319,956

1/ Customer populations represent an average of the 12 month period from 01/01/06 through 12/31/06. YNP customer counts have been excluded.

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
3	Executive	6	6	6
4	Financial, Risk Mgmt. & Information Services	112	108	110
5	Human Resources & Administration	27	27	27
6	Utility Services & Division Administration	661	664	663
7	Regulatory Affairs	21	21	21
8	Transmission	164	168	166
9	Legal	7	6	7
10				
11				
12				
13				
14				
15				
16				
17	**TOTAL EMPLOYEES**	998	1,000	999

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

Sch. 31	MONTANA CONSTRUCTION BUDGET 2007 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3			
4	Millcreek Substation - phase shift transformer	$2,026,571	$2,026,571
5	Billings Steam Plant-8th 100KV reconductor	1,442,908	1,442,908
6	Bozeman Riverside bank #2 changeout	1,632,662	1,632,662
7	Billings Meridian sub bank #2 addition	1,139,669	1,139,669
8	New connect transformer purchases	5,950,000	5,950,000
9			
10	All Other Projects < $1 Million Each MT	33,557,635	33,557,635
11	All Other Projects SD	14,366,200	
12	**Total Electric Utility Construction Budget**	60,115,645	45,749,445
13			
14	**Natural Gas Operations**		
15	Gas Transmission - Helena are pipleine integrity	3,280,565	3,280,565
16	Gas Transmission - Gold Creek pipeline loop	2,117,236	2,117,236
17	Gas Transmission - Morel 20" valve 10-11 loop	3,043,938	3,043,938
18	Gas Distribution - Bozeman gas upgrade 12" main	2,315,470	2,315,470
19			
20	All Other Projects < $1 Million Each MT	8,495,077	8,495,077
21	All Other Projects SD/NE	3,238,017	
22	**Total Natural Gas Utility Construction Budget**	22,490,303	19,252,286
23			
24	**Common**		
25	07 MT Fleet replacements	4,039,000	4,039,000
26			
27	All Other Projects < $1 Million Each MT	2,631,886	2,631,886
28	(Includes IS, Communications, Facillities, Cust Serv)		
29	All Other Projects SD/NE	1,443,154	
30			
31	**Total Common Utility Construction Budget**	8,114,040	6,670,886
32			
33	CU4 capital additions - PPL invoice	4,100,000	4,100,000
34			
35	All Other Projects < $1 Million Each	-	-
36			
37			
38			
39	**Total Colstrip Unit 4 Construction Budget**	4,100,000	4,100,000
40	**TOTAL CONSTRUCTION BUDGET**	$94,819,988	$75,772,617

Sch. 32	TOTAL SYSTEM & MONTANA PEAK AND ENERGY					
		System Peak and Energy				
		Peak Day	Peak Hour	Peak Day Volume Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	January	9	1900	1,430	729,530	157,696
2	February	16	1900	1,587	729,452	190,602
3	March	14	2000	1,333	725,804	209,393
4	April	24	1100	1,244	657,857	161,777
5	May	18	1700	1,394	581,922	115,905
6	June	28	1600	1,518	591,613	117,447
7	July	25	1700	1,644	692,014	131,921
8	August	7	1700	1,530	760,201	199,448
9	September	5	1700	1,343	749,883	201,986
10	October	30	1900	1,391	680,770	151,405
11	November	28	1900	1,605	698,143	185,035
12	December	18	1900	1,563	708,714	177,248
13	**TOTALS**				8,305,903	1,999,863
14		Montana Peak and Energy				
15		Peak	Peak	Peak Day Volume	Total Monthly Volumes	Non-Requirements
16		Day	Hour	Megawatts	Energy (Mwh)	Sales For Resale (Mwh)
17	January					
18	February					
19	March					
20	April					
21	May					
22	June					
23	July			SAME AS ABOVE		
24	August					
25	September					
26	October					
27	November					
28	December					
29	**TOTALS**				-	-

Sch. 33	MONTANA SYSTEM SOURCES & DISPOSITION OF ENERGY			
	Sources	Megawatthours	Dispositions	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	1,560,996		
3	Nuclear	-	**Sales to Ultimate Consumers**	5,749,688
4	Hydro - Conventional		(Include Interdepartmental) 1/	
5	Hydro - Pumped Storage	-		
6	Other	576	Sales for Resale	
7	(Less) Energy for Pumping	-	Requirement Sales	
8	**Net Generation**	1,561,572	Non-Requirement Sales	1,999,863
9	**Purchases**	6,503,800	**Sales for Resale**	1,999,863
10	Power Exchanges		Energy Furnished w/o Charge	
11	Received	172,820		
12	Delivered	170,898		-
13	**Net Power Exchanges**	1,922	**Energy Furnished**	-
14	Transmission Wheeling for Others		Energy Used Within Utility	
15	Received	9,568,805	Electric Department	
16	Delivered	9,330,196	(Less) Station Use	-
17	**Net Transmission Wheeling**	238,609	**Net Energy Used Within Util.**	-
18	**Transmission by Others Losses**	-	**Energy Losses**	556,352
19	**TOTAL SOURCES**	8,305,903	**TOTAL DISPOSITIONS**	8,305,903

1/ The megawatts hours listed above do not include sales to billed choice customers, consistent with the presentation used in the corresponding schedule on FERC Form 1, and does include Colstrip Unit 4 in the Generation and Sales for Resale sections.

Sch. 34	SOURCES OF MONTANA ELECTRIC SUPPLY /1				
	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Purchases	Small Power Producers	Colstrip Energy, Ltd.	0.0	305,830
2	Purchases	Small Power Producers	Billings Generation, Inc.	0.0	424,898
3	Purchases	Small Power Producers	State of Montana - DNRC	0.0	48,249
4	Purchases	Small Power Producers	Others	0.0	17,596
5	Subtotal			0.0	796,573
6	Purchases	Nonassociated Utilities	PPL Montana	0.0	3,536,694
7	Subtotal			0.0	3,536,694
8	Default Supply Purch Power		Avista Energy	0.0	231,596
9	Default Supply Purch Power		Avista Utility	0.0	13,756
9	Default Supply Purch Power		BPA	0.0	41,164
10	Default Supply Purch Power		Benton County PUD	0.0	14,853
11	Default Supply Purch Power		Franklin County PUD	0.0	8,531
12	Default Supply Purch Power		Grays Harbor PUD	0.0	17,675
13	Default Supply Purch Power		Idaho Power	0.0	268
14	Default Supply Purch Power		Portland General Electric	0.0	321,854
15	Default Supply Purch Power		Powerex	0.0	313,563
16	Default Supply Purch Power		Puget Sound Energy	0.0	24,003
17	Default Supply Purch Power		City of Seattle	0.0	36,720
18	Default Supply Purch Power		BP Energy	0.0	323,400
19	Default Supply Purch Power		Rainbow Energy	0.0	107,157
20	Default Supply Purch Power		Eugene Water & Electric Board	0.0	115
21	Default Supply Purch Power		Grant County PUD	0.0	25
22	Default Supply Purch Power		Tiber Dam	0.0	45,044
23	Default Supply Purch Power		Judith Gap	0.0	406,925
24	Default Supply Purch Power		Cargill Power Markets	0.0	5,289
25	Default Supply Purch Power		Morgan Stanley	0.0	39,600
26	Default Supply Purch Power		Conoco Phillips	0.0	840
27	Default Supply Purch Power		United Materials of Great Falls	0.0	3,471
28	Default Supply Purch Power		Basin Creek Electric	0.0	45,793
29	Default Supply Purch Power		Deutsche Bank	0.0	800
30	Default Supply Purch Power		The Energy Authority	0.0	257
31	Default Supply Purch Power		Milltown Dam	0.0	2,326
32	Subtotal			0.0	2,005,025
33	Imbalance Transactions	Investor Owned	Avista Energy		104,302
34	Imbalance Transactions	Investor Owned	Idaho Power		57,848
35	Subtotal			0.0	162,150
36	Reserve Sharing				3,358
37	Total				6,503,800
38					
39	\1 An outage report does not accompany Schedule 34 because of the sale of almost all of our generation assets				
40	in December 1999.				

Sch. 35

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (MWH)	Achieved Savings (MWH)	Difference (MWH)
1							
2	2006 Residential Lighting Program	$1,114,882	$946,148	17.83%	10,097	13,245	3,148
3							
4	2006 Commercial Lighting Program	$148,533	$175,325	-15.28%	2,628	2,524	(104)
5							
6	2006 Commercial Fuel Switch Program	$ -	$19,792	-100.00%	zero	zero	N/A
7							
8	2006 E+ Business Partners Program	$757,397	$426,480	77.59%	4,993	2,820	(2,173)
9							
10	E+ Residential New Construction Program	$113,303	$32,623	247.31%	100	81	(19)
11							
12	E+ Residential Electric Savings Program	$36,462	$6,697	444.45%	50	38	(12)
13							
14	E+ Electric Motor Rebate Program	$15,134	$2,085	625.85%	10	1	(9)
15							
16	2006 Northwest Energy Efficiency Alliance (NEEA)	$461,654	$376,555	22.60%	7,653	9,636	1,983
17							
18	Other DSM Programs Under Development	$12,896	$254,367	-94.93%	zero	zero	N/A
19							
20							
21							
22	A program participant is a Montana residential and/or						
23	commercial electric customer who installs eligible						
24	energy conservation measures and receives financial						
25	incentives/rebates.						
26							
27							
28							
29							
30							
31							
32							
33							
34	**TOTAL**	$2,660,261	$2,240,072	18.76%	25,531	28,345	2,814

Electric Universal System Benefits Programs

Sch. 35a	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings		Most recent program evaluation
					MWh	MW	
1	Local Conservation						
2	E+ Residential Audit/Sm. Comm Audit	1,098,814	247,350	1,346,164	2345	0.236	1994
3	E+ Business Partners / Irrigation Projects	800	-	800	27	0.015	1994
4	NWE Promotion	79,279	-	79,279			
5	NWE Labor	49,085	-	49,085			
6	NWE Admin. Non-labor	13,465	-	13,465			
7	USB Interest & Svc Chg	(2,459)	-	(2,459)			
8	Market Transformation						
9	E+ Commercial Lighting	-	-	-			
10	NW Energy Efficiency Alliance *(a)*	-	-	-			
11	Motor Management Training	3,329	6,671	10,000			
12	Energy Star Homes	-	-	-			n/a
13	Building Operator Certification	-	-	-			n/a
14	Vendor Miser	-	-	-	11	-	*(b)*
15	NWE Promotion	4,287	-	4,287			
16	NWE Labor	12,590	-	12,590			
17	NWE Admin. Non-labor	194	-	194			
18	USB Interest & Svc Chg	(141)	-	(141)			
19	Renewable Resources						
20	Generation/Education	48,224	698,729	746,953	13	0.008	n/a
21	Green Power Product Offering	(3,458)	-	(3,458)			
22	NWE Promotion	3,730	-	3,730			
23	NWE Labor	66,404	-	66,404			
24	NWE Admin. Non-labor	645	-	645			
25	USB Interest & Svc Chg	(1,253)	-	(1,253)			
26	Research & Development						
27	R&D/ Infrastructure	49,270	43,785	93,055			n/a
28	NWE Promotion	2,843	-	2,843			
29	NWE Labor	14,506	-	14,506			
30	NWE Admin. Non-labor	88	-	88			
31	USB Interest & Svc Chg	(172)	-	(172)			
32	Low Income						
33	Bill Assistance	1,809,454	-	1,809,454			n/a
34	Supp'l Bill Assistance	-	-	-			
35	Free Weatherization	732,516	230,327	962,843	444	0.054	1994
36	Elec Wx Incentives	-	14,232	14,232			
37	Fuel Switch Analyses	7,172		7,172			
38	Energy Share	575,000	-	575,000			n/a
39	2005 Gas USB Shortfall Recovery	428,529	-	428,529			
40	NWE Promotion	13,067	-	13,067			
41	NWE Labor	50,157	-	50,157			
42	NWE Admin. Non-labor	6,943	-	6,943			
43	USB Interest & Svc Chg	(7,704)	-	(7,704)			
44	Large Customer Self Directed						
45	Self-Directed Energy Reduction	2,290,971	558,119	2,849,090			
46	Self-Directed to Low Income	177,126	-	177,126			
47	USB Interest & Svc Chg	(5,666)	-	(5,666)			
48	NWE Labor	12,668	-	12,668			
49	NWE Admin. Non-labor	-	-	-			
50	NWE Reallocate to Low-Income	-	-	-			
51	Total	$ 7,530,306	$ 1,799,212	$ 9,329,518	2840	0.312	
52	Number of customers that received low income rate discounts				12182		
53	Average monthly bill discount amount ($/mo)				$ 12.38		
54	Average LIEAP-eligible household income				n/a		
55	Number of customers that received weatherization assistance				712	*(c)*	
56	Expected average annual bill savings from weatherization				624	Kwh	
57	Number of residential audits performed on-site				1843		
58	Number of residential audits performed off-site				3786		

(a) NW Energy Efficiency Alliance program was moved from the USB program and became a DSM funded program in 2006.

(b) Vendor Miser equipment was purchased in a year previous to 2006. 2 units were installed during 2006.

(c) Total of all homes weatherized in 2006 including electric and gas USB funds.

Sch. 35b	Montana Conservation & Demand Side Management Programs					
	Program Description (These are electric USB Programs)	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2	E+ Energy Audit for the Home or Business	$ 1,098,814	$ -	$ 1,098,814	1295	1997
3	E+ Business Partners/Irrigation (Choice customers only)	$ 800	$ -	$ 800	2	Note 1
4						
5						
6						
7						
8	Demand Response					
9						
10						
11						
12						
13						
14						
15	Market Transformation					
16	E+ Commercial Lighting (Choice customers only)	$ -	$ -	$ -	0	Note 1
17	Motor Management Training	$ 3,329	$ -	$ 3,329	0	Note 1
18	Energy Star Home/Products	$ -	$ -	$ -	0	Note 1
19	Building Operator Certification	$ 40,481	$ -	$ 40,481	565	Note 1
20						
21						
22	Renewables and Research & Development					
23	Generation/Education	$ 65,688	$ -	$ 65,688	341	Note 1
24	Green Power Product	$ (3,458)	$ -	$ (3,458)	0	
25	R&D / Infrastructure	$ 31,806	$ -	$ 31,806	0	
26						
27						
28						
29	Low Income					
30	Free Weatherization	$ 732,516	$ -	$ 732,516	444	Note 1
31	Electric Weatherization Incentives	$ 14,232	$ -	$ 14,232	N/A	
32	Fuel Switching Analysis	$ 7,172	$ -	$ 7,172	N/A	
33						
34						
35	Other					
36						
37						
40						
41						
42						
45						
46	Total					
	Note 1: These and other NWE DSM programs are undergoing a comprehensive evaluation that will be completed June 1, 2007.					

Sch. 36	MONTANA CONSUMPTION AND REVENUES - ELECTRIC (EXCLUDES UNIT 4 & YNP)						
		Operating Revenues		MWH Sold		Average Customers	
		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	**Sales of Electricity**						
2							
3	Residential	$195,178,368	$183,532,173	2,182,730	2,102,419	257,957	252,968
4	Commercial & Industrial	288,055,458	277,522,756	6,191,139	6,128,695	57,953	56,640
5	Public Street & Highway Lighting	13,142,820	12,719,985	60,750	60,656	3,793	3,812
6	Sales to Other Utilities	47,339,875	53,953,576	1,268,138	1,295,398	15	14
7	Interdepartmental	1,042,770	994,302	13,180	12,399	253	248
8							
9	**TOTAL SALES**	$544,759,291	$528,722,792	9,715,937	9,599,567	319,971	313,682
10							
11							
12							
13							
14							
15							
16							