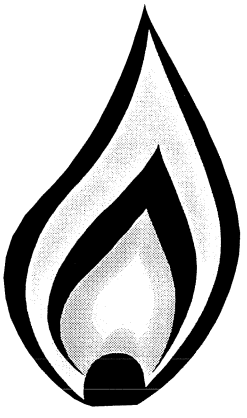
YEAR 2004

ANNUAL REPORT
OF

NorthWestern Energy

GAS UTILITY



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

NATURAL GAS ANNUAL REPORT

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Sch. 1

IDENTIFICATION

Legal Name of Respondent:	NorthWestern Corporation
Name Under Which Respondent Does Business:	NorthWestern Energy
Date Utility Service First Offered in Montana:	Electricity - Dec 12, 1912 Natural Gas - Jan 01, 1933 Propane - Oct 13, 1995
Person Responsible for Report:	Patrick Corcoran
Telephone Number for Report Inquiries:	(406) 497-2202
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.

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		
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Sch. 3

OFFICERS

	Title	Department Supervised	Name
1	President (former Chief Operating Officer)	Operations	Michael J. Hanson
2			
3	Vice President,	Human Resources	Roger Schrum
4	Human Resources & Communications	Communications	
5		Benefits & Compensation	
6		Investor, Community & Employee Relations	
7			
8	Chief Financial Officer	Tax, Internal Audit/Compliance	Brian Bird
9		Financial Planning & Analysis	
10		Controller & Treasury Functions	
11			
12	General Counsel	Legal	Thomas J. Knapp
13			
14			
15	Vice President	IT Applications & Infastructure	Bart Thielbar
16	Information Technology	Systems Continuity	
17		Licensing & Leasing	
18		Telecommunications	
19			
20	Vice President,	Distribution Planning, Operations & Maintenance	Curt Pohl
21	Distribution Operations	Distribution Engineering & Performance	
22		General Construction & Maintenance	
23			
24	Vice President,	Transmission Contracts & Scheduling	David G. Gates
25	Transmission Operations	Electric & Gas Transmission & Storage	
26		General Production & Generation	
27		Transmission Operations & Regional Issues	
28			
29	Vice President,	Regulatory Affairs	Patrick R. Corcoran
30	Regulatory & Governmental Affairs	Energy Supply	
31			
32	Vice President,	Support Services	Greg Trandem
33	Support Services	Safety/Health/Environmental	
34		Process Improvement	
35			
36	Vice President,	Revenue Collections	Bobbi Schroeppel
37	Customer Care	Call Center	
38		Systems Infastructure & Support	
39		Customer/Supplier Relations	
40			
41	Vice President,	Legal	Alan Dietrich
42	Legal Administration & Corporate		
43	Secretary		
44			
45	Internal Audit/	Internal Audit	Michael Nieman
46	Compliance Officer	Compliance	
47			
48	Controller	Financial/SEC Reporting	Kendall Kliewer
49		Accounting	
50		Fixed Assets	
51		Accounts Payable	
52			
53	Treasurer	Treasury Functions	Paul Evans
54			
55	Former President &	Executive	Gary G. Drook
56	Chief Executive Officer		
57			
58	Former Vice President	Government Relations	Dennis Lopach
59	Administration	State, Local & Community Relations	
60			
61	Former Director,	Legal	Eric Jacobsen
62	Strategic Development		

Reflects activie officers as of December 31, 2004.

Sch. 4

CORPORATE STRUCTURE

Subsidiary/Company Name	Line of Business	Earnings (000)	% of Total
Regulated Operations (Jurisdictional & Non-Jurisdictional)		**$ 554,289**	**101.81%**
NorthWestern Corporation	Parent Company		
Montana Utility Operations	Electric Utility Wholesale Electric 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		**$ (9,856)**	**-1.81%**
Direct Subsidiaries:			
NorthWestern Services Company	Natural gas marketing, natural gas pipeline company, HVAC services, and property management.		
Clarkfoot and Blackfoot, LLC	Milltown hydroelectric facility		
NorthWestern Investments, LLC	Investment Corporation		
Risk Partners Assurance, Ltd.	Captive insurance company		
Indirect Subsidiaries:			
NorthWestern Energy Development, LLC	Non-regulated energy interest		
NorthWestern Generation I, LLC	Holds interest in MT Megawatts I, LLC		
Montana Megawatts I, LLC	Interest in MT First Megawatts project		
NorthWestern Energy Marketing, LLC	Non-regulated energy marketing		
Nekota Resources Inc.	Non-regulated intrastate natural gas pipeline		
Netexit, Inc.	Discontinued communications services		
Blue Dot Services, Inc.	Discontinued HVAC services		
Total Corporation		**$ 544,433**	**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	$ to MT El & Gas Utilities	MT %	$ to Other
1					
2					
3	Utility Administration				
4	Executive Department	Includes the following departments:	$3,506,525	69.90%	$1,510,284
5		CEO; COO; Corp Aircraft			
6					
7					
8	Legal Department	Includes the following departments:	$16,265,051	75.41%	$5,303,078
9		Chief Legal, Record Mgmt,Insurance			
10					
11					
12	Communications &Human Resources	Includes the following departments: Human	13,735,541	84.29%	2,559,147
13		Resources; Benefits Admin.; Compensation &			
14		Labor Relations; Employment; Payroll			
15					
16					
17	Finance / Accounting	Includes the following departments: CFO	7,759,674	71.28%	3,126,247
18		Treasury, FP&A, Controller, Fixed Assets,			
19		Accounting; Tax & Financial Reporting			
20					
21					
22	Asset Management	Includes the following departments:	1,681,021	69.60%	734,223
23		Administrative; Mailing Services &			
24		Printing Services			
25					
26					
27	Information Technology	Includes the following departments:	6,888,067	68.25%	3,204,604
28		IT Sr; VP/CIO; IT Applications			
29		Infrastructure, Licensing & Leasing			
30					
31					
32	Regulatory and Gov't Affairs	Includes the following departments:	2,910,679	84.26%	543,828
33		Regulatory Affairs, Load Research			
34		Government Affairs, Reg Support Services			
35					
36					
37	Customer Service	Includes the following departments:	13,026,819	73.98%	4,581,182
38		Customer Care Common, Customer Care			
39		Combined, Costmer Care MT Only			
40					
41					
42	Audit & Controls	Includes the following departments:	1,496,545	68.91%	675,128
43		Audit and Controls, Internal Auditing			
44		Project Office			
45					
46					
47					
48					
49					
50					
51					
52	**TOTAL**		$67,269,922	75.16%	$22,237,721
53					
54					
55					
56					
57					
58					

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	Nonutility Subsidiaries					
2						
3						
4						
5						
6	Colstrip Unit 4 - Lease Management Division	Purchased Power	Market Rates	22,587,754	25.37%	22,587,754
7						
8						
31						
32	**TOTAL Nonutility Subs**			22,587,754		22,587,754
33	**Total Nonutility Subs Revenues**			89,022,205		
34						
35	**Utility Subsidiaries**					
36	**Total Utility Subsidiaries**					
37	**Total Utility Sub Revenues**			3,759,302		
38	**TOTAL AFFILIATE TRANSACTIONS**			22,587,754		22,587,754

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						$0
4	This schedule no longer applies.					
5						
6						0
7						0
8						0
9	**Total Nonutility Subsidiaries**			-		-
10	**Total Nonutility Subsidiaries Expenses**					
11						
12						
13	**Utility Subsidiaries**					
14						-
15	**Total Utility Subsidiaries**			-		-
16	**Total Utility Subsidiaries Expenses**					
17	**TOTAL AFFILIATE TRANSACTIONS**			$0		$0

Sch. 8

MONTANA UTILITY INCOME STATEMENT - NATURAL GAS (INCLUDES CMP)

	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	400 Operating Revenues	$ 347,901,124	$ 93,387,109	$ 254,514,015	$ 177,868,109	43.09%
3						
4	**Total Operating Revenues**	347,901,124	93,387,109	254,514,015	177,868,109	43.09%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expense	299,740,474	100,493,163	199,247,311	120,717,989	65.05%
9	402 Maintenance Expense	4,559,472	796,458	3,763,014	3,991,305	-5.72%
10	403 Depreciation Expense	14,502,436	3,761,636	10,740,800	10,593,894	1.39%
11	404-405 Amort. & Depletion of Gas Plant	2,122,433	814,441	1,307,992	1,192,524	9.68%
12	406 Amort. of Plant Acquisition Adj.	(2,288,552)	(2,288,552)	-	-	-
13	408.1 Taxes Other Than Income Taxes	17,873,014	2,354,837	15,518,177	15,937,102	-2.63%
14	409.1 Income Taxes-Federal	709,703	(639,676)	1,349,379	(7,753,113)	117.40%
15	-Other	1,114,070	1,228,606	(114,536)	(40,737)	-181.16%
16	410.1 Deferred Income Taxes-Dr.	35,854,781	751,199	35,103,582	14,280,376	145.82%
17	411.1 Deferred Income Taxes-Cr.	(41,906,700)	(10,862,266)	(31,044,434)	(1,801,127)	>-300.00%
18	411.4 Investment Tax Credit Adj.	(192,537)	(192,537)	-	(1)	100.00%
19						
20	**Total Operating Expenses**	332,088,594	96,217,309	235,871,285	157,118,212	50.12%
21	**NET OPERATING INCOME**	$ 15,812,530	$ (2,830,200)	$ 18,642,730	$ 20,749,897	-10.16%

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

The financial results reported include income taxes that are based upon NorthWestern's tax basis for plant assets purchased from the Montana Power Company. This tax basis differs from amounts included in the most recently decided rate proceeding and results in a lower deferred tax credit. This change was made in order to prevent any possible violation of the normalization requirements of the federal income tax code. The change results in an increase in the reported rate base.

Sch. 9

MONTANA REVENUES - NATURAL GAS (INCLUDES CMP)

	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	**Core Distribution Business Units**					
3	**(DBUs)**					
4	440 Residential	$ 170,798,580	$ 55,253,661	$ 115,544,919	$ 86,467,860	33.63%
5	442.1 Commercial	92,701,730	35,797,316	56,904,414	42,599,960	33.58%
6	442.2 Industrial Firm	1,798,428	-	1,798,428	1,463,246	22.91%
7	445 Public Authorities	436,789	-	436,789	284,199	53.69%
8	448 Interdepartmental Sales	442,228	-	442,228	331,872	33.25%
9	491.2 CNG Station	3,346	-	3,346	2,971	12.61%
10						
11	**Total Sales to Core DBUs**	266,181,101	91,050,977	175,130,124	131,150,108	33.53%
12						
13	447 Sales for Resale 1/	61,028,066	-	61,028,066	31,652,646	92.81%
14						
15	**Total Sales of Natural Gas**	61,028,066	-	61,028,066	31,652,646	92.81%
16						
17	**Transportation**					
18						
19	489 Transportation (inc. CMP)	16,904,489	1,682,984	15,221,505	12,301,297	23.74%
20	495 Off System Storage	82,868	-	82,868	555,235	-85.08%
21						
22	**Total Revenues From Transportation**	16,987,357	1,682,984	15,304,373	12,856,532	19.04%
23						
24	**Other Operating Revenue**					
25						
26	Miscellaneous Revenues	3,704,600	653,148	3,051,452	2,208,823	38.15%
27						
28	**Total Other Operating Revenue**	3,704,600	653,148	3,051,452	2,208,823	38.15%
29	**TOTAL OPERATING REVENUE**	$ 347,901,124	$ 93,387,109	$ 254,514,015	$ 177,868,109	43.09%

30 1/ In 2003, NorthWestern entered into approximately 3.3 bcf of fixed price natural gas contracts to hedge customer price risk during
31 the 2003-2004 winter season. These fixed price contracts at the AECO hub systematically offset medium-term on-system supply,
32 which are purchased from a third party on NorthWestern's system at a floating daily index price. For the 2004-2005 winter season,
33 the 3.3 bcf of hedging was accomplished by putting additional gas in underground storage during the spring and summer at
34 prices below the winter market price. Other sales for both periods were conducted due to excess supply on system or exchanges
35 for in-ground storage from customers. All purchases and sales were conducted as regulated activity for the Montana
36 customers and such net cost will be recovered in rates.
37

Sch. 10 **MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)**

	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Gas Raw Materials**					
2	**Gas Raw Materials-Operation**					
3	735 Miscellaneous Production Expenses	$ 47,841	$ 47,841	$ -	$ -	-
4	**Total Operation-Gas Raw Materials**	$ 47,841	$ 47,841	-	-	-
5						
6	**Gas Raw Materials-Maintenance**					
7	741 Structures & Improvements	$ 73,130	$ 73,130	-	-	-
8	**Total Maintenance-Gas Raw Materials**	$ 73,130	$ 73,130	-	-	-
9	**Total Gas Raw Materials**	$ 120,971	$ 120,971	-	-	-
10	**Production Expenses**					
11						
12	**Production & Gathering-Operation**					
13	750 Supervision & Engineering	-	-	-	-	-
14	751 Maps & Records	-	-	-	-	-
15	752 Gas Wells Expenses	-	-	-	-	-
16	753 Field Lines Expenses	-	-	-	-	-
17	754 Field Compressor Station Expense	-	-	-	-	-
18	755 Field Comp. Station Fuel & Power	-	-	-	-	-
19	756 Field Meas. & Reg. Station Expense	-	-	-	-	-
20	757 Dehydration Expense	-	-	-	-	-
21	758 Gas Well Royalties	-	-	-	-	-
22	759 Other Expenses	-	-	-	-	-
23	760 Rents	-	-	-	-	-
24	**Total Oper.-Production & Gathering**	-	-	-	-	-
25						
26	**Other Gas Supply Expense-Operation**					
27	800 NG Wellhead Purchases	153,703,809	-	153,703,809	116,252,316	32.22%
28	800 NG Wellhead Purchases, Intraco.	-	-	-	-	-
29	803 NG Transmission Line Purchases	766,712	-	766,712	352,438	117.55%
30	805 Other Gas Purchases	86,823,936	75,678,316	11,145,620	(5,959,470)	287.02%
31	805 Purchased Gas Cost Adjustments	-	-	-	-	-
32	805 Incremental Gas Cost Adjustments	-	-	-	-	-
33	805 Deferred Gas Cost Adjustments	-	-	-	-	-
34	806 Exchange Gas	-	-	-	-	-
35	807 Well Expenses-Purchased Gas	517,276	171,908	345,368	260,125	32.77%
36	807 Purch. Gas Meas. Stations-Oper.	-	-	-	-	-
37	807 Purch. Gas Meas. Stations-Maint.	-	-	-	-	-
38	807 Purch. Gas Calculations Expenses	-	-	-	-	-
39	808 Other Purchased Gas Expenses	-	-	-	-	-
40	808 Gas Withdrawn from Storage -Dr.	(732,614)	-	(732,614)	645,095	-213.57%
41	809 Gas Delivered to Storage -Cr.	-	-	-	(3,852)	100.00%
42	810 Gas Used-Comp. Station Fuel-Cr.	-	-	-	-	-
43	811 Gas Used-Products Extraction-Cr.	-	-	-	-	-
44	812 Gas Used-Other Utility Oper.-Cr.	-	-	-	-	-
45	813 Other Gas Supply Expenses	-	-	-	-	-
46	**Total Other Gas Supply Expenses**	241,079,119	75,850,224	165,228,895	111,546,652	48.13%
47	**Total Production Expenses**	241,079,119	75,850,224	165,228,895	111,546,652	48.13%

Sch. 10 **MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)**

	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Storage Expenses**					
2						
3	**Underground Storage-Operation**					
4	814 Supervision & Engineering	68,104	-	68,104	94,128	-27.65%
5	815 Maps & Records	221	-	221	496	-55.40%
6	816 Wells	165,060	-	165,060	148,613	11.07%
7	817 Lines	21,738	-	21,738	15,473	40.49%
8	818 Compressor Station	310,069	-	310,069	291,228	6.47%
9	819 Compressor Station Fuel & Power	-	-	-	-	-
10	820 Measuring & Regulating Station	18,498	-	18,498	29,926	-38.19%
11	821 Purification	71,295	-	71,295	82,220	-13.29%
12	824 Other Expenses	98,065	-	98,065	88,987	10.20%
13	825 Storage Well Royalties	100,227	-	100,227	97,914	2.36%
14	826 Rents	-	-	-	-	-
15	**Total Operation-Underground Storage**	853,277	-	853,277	848,985	0.51%
16						
17	**Underground Storage-Maintenance**					
18	830 Supervision & Engineering	-	-	-	160	-100.00%
19	831 Structures & Improvements	9,012	-	9,012	9,492	-5.06%
20	832 Reservoirs & Wells	5,733	-	5,733	1,242	>300.00%
21	833 Lines	26,033	-	26,033	21,001	23.96%
22	834 Compressor Station Equipment	79,193	-	79,193	188,640	-58.02%
23	835 Meas. & Reg. Station Equipment	7,660	-	7,660	13,730	-44.21%
24	836 Purification Equipment	22,233	-	22,233	8,043	176.41%
25	837 Other Equipment	14,423	-	14,423	7,459	93.37%
26	**Total Maintenance-Underground Storage**	164,287	-	164,287	249,767	-34.22%
27	**Total Underground Storage Expenses**	1,017,564	-	1,017,564	1,098,752	-7.39%
28	**Transmission Expenses**					
29	**Transmission-Operation**					
30	850 Supervision & Engineering	1,979,463	-	1,979,463	1,728,535	14.52%
31	851 System Control & Load Dispatching	506,374	-	506,374	503,645	0.54%
32	853 Compressor Station Labor & Expense	686,637	-	686,637	630,368	8.93%
33	855 Other Fuel & Power for Comp. Stat.	-	-	-	2	-100.00%
34	856 Mains	704,596	-	704,596	499,503	41.06%
35	857 Measuring & Regulating Station	592,080	-	592,080	719,131	-17.67%
36	858 Transmission & Comp.-By Others	-	-	-	-	-
37	859 Other Expenses	1,495,504	-	1,495,504	818,701	82.67%
38	860 Rents	-	-	-	51	-100.00%
39	**Total Operation-Transmission**	5,964,654	-	5,964,654	4,899,936	21.73%
40	**Transmission-Maintenance**					
41	861 Supervision & Engineering	-	-	-	-	-
42	862 Structures & Improvements	261,959	-	261,959	480,258	-45.45%
43	863 Mains	421,991	-	421,991	350,897	20.26%
44	864 Compressor Station Equipment	367,254	-	367,254	342,079	7.36%
45	865 Meas. & Reg. Station Equipment	250,956	-	250,956	219,348	14.41%
46	867 Other Equipment	19,269	-	19,269	20,038	-3.84%
47	**Total Maintenance-Transmission**	1,321,429	-	1,321,429	1,412,620	-6.46%
48	**Total Transmission Expenses**	7,286,083	-	7,286,083	6,312,556	15.42%

Sch. 10 **MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)**

	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Distribution Expenses**					
2	**Distribution-Operation**					
3	870 Supervision & Engineering	1,434,601	656,800	777,801	791,133	-1.69%
4	871 Load Dispatching	201,991	201,991	-	-	-
5	872 Compressor Station Labor & Expense	219	-	219	-	-
6	873 Compressor Station Fuel and Power	-	-	-	-	-
7	874 Mains and Services	2,553,147	1,047,971	1,505,176	1,017,970	47.86%
8	875 Meas. & Reg. Station-General	132,525	53,895	78,630	11,220	>300.00%
9	876 Meas. & Reg. Station-Industrial	850	-	850	4,149	-79.51%
10	877 Meas. & Reg. Station-City Gate	5,318	1,809	3,509	26,556	-86.79%
11	878 Meter & House Regulator	1,286,396	495,553	790,843	722,545	9.45%
12	879 Customer Installations	2,114,251	133,821	1,980,430	2,019,053	-1.91%
13	880 Other Expenses	3,269,615	1,067,126	2,202,489	1,770,205	24.42%
14	881 Rents	17,177	-	17,177	16,059	6.97%
15	**Total Operation-Distribution**	11,016,090	3,658,966	7,357,124	6,378,890	15.34%
16	**Distribution-Maintenance**					
17	885 Supervision & Engineering	403,812	286,440	117,372	56,935	106.15%
18	886 Structures & Improvements	24,202	22,853	1,349	2,226	-39.43%
19	887 Mains	541,376	133,448	407,928	634,380	-35.70%
20	889 Meas. & Reg. Station Exp.-General	128,575	59,310	69,265	60,570	14.35%
21	890 Meas. & Reg. Station Exp.-Industrial	-	-	-	149	-100.00%
22	891 Meas. & Reg. Station Exp.-City Gate	3,213	749	2,464	4,638	-46.88%
23	892 Services	311,366	47,314	264,052	272,095	-2.96%
24	893 Meters & House Regulators	327,058	73,236	253,822	157,310	61.35%
25	894 Other Equipment	12,275	-	12,275	8,667	41.64%
26	**Total Maintenance-Distribution**	1,751,877	623,350	1,128,527	1,196,970	-5.72%
27	**Total Distribution Expenses**	12,767,967	4,282,316	8,485,651	7,575,860	12.01%
28	**Customer Accounts Expenses**					
29	**Customer Accounts-Operation**					
30	901 Supervision	-	-	-	-	-
31	902 Meter Reading	773,433	457,960	315,473	317,042	-0.49%
32	903 Customer Records & Collection	2,556,694	493,520	2,063,174	2,168,739	-4.87%
33	904 Uncollectible Accounts	757,950	-	757,950	503,543	50.52%
34	905 Miscellaneous Customer Accounts	48,351	47,363	988	493	100.62%
35	**Total Customer Accounts Expenses**	4,136,428	998,843	3,137,585	2,989,817	4.94%
36						
37	**Customer Service & Information Expenses**					
38	**Customer Service-Operation**					
39	907 Supervision	-	-	-	-	-
40	908 Customer Assistance	1,699,930	663,697	1,036,233	953,665	8.66%
41	909 Inform. & Instructional Advertising	353,433	66,137	287,296	233,583	23.00%
42	910 Misc. Customer Service & Inform.	21	-	21	-	-
43	**Total Customer Service & Information Exp.**	2,053,384	729,834	1,323,550	1,187,248	11.48%
44						
45	**Sales Expenses**					
46	**Sales-Operation**					
47	911 Supervision	305,601	-	305,601	381,774	-19.95%
48	912 Demonstrating & Selling	(114)	-	(114)	44,748	-100.26%
49	913 Advertising	3,293	-	3,293	44,884	-92.66%
50	916 Miscellaneous Sales	-	-	-	-	-
51	**Total Sales Expenses**	308,780	-	308,780	471,406	-34.50%

Sch. 10 **MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)**

	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Administrative & General Expenses**					
2	**Admin. & General - Operation**					
3	407 Amortization of Regulatory Asset	(1,517,724)	71,565	(1,589,289)	(18,652,276)	91.48%
4	920 Administrative & General Salaries	10,292,814	2,773,024	7,519,790	6,603,170	13.88%
5	921 Employee Travel	1,036,857	414,133	622,724	297,864	109.06%
6	921 Office Supplies & Expenses	2,198,468	902,055	1,296,413	890,206	45.63%
7	922 Administrative Exp. Transferred-Cr.	(3,340,303)	(770,368)	(2,569,935)	(1,993,398)	-28.92%
8	923 Outside Services Employed	15,930,199	14,051,009	1,879,190	2,077,231	-9.53%
9	924 Property Insurance	367,310	190,929	176,381	170,940	3.18%
10	925 Legal & Claim Department	3,797,170	829,371	2,967,799	1,065,677	178.49%
11	926 Employee Pensions & Benefits	2,343,714	420,115	1,923,599	119,120	>300.00%
12	928 Regulatory Commission Expenses	25,549	-	25,549	20,754	23.10%
13	930 General Advertising	17,072	13,750	3,322	1,419	134.03%
14	930 Miscellaneous General Expenses	469,437	106,750	362,687	136,181	166.33%
15	930 USBC Expenses	1,998,147	-	1,998,147	1,323,511	50.97%
16	931 Rents	662,191	205,122	457,069	334,656	36.58%
17	**Total Operation-Admin. & General**	34,280,901	19,207,455	15,073,446	(7,604,945)	298.21%
18	**Admin. & General - Maintenance**					
19	935 General Plant	1,248,749	99,978	1,148,771	1,131,948	1.49%
20	**Total Admin. & General Expenses**	35,529,650	19,307,433	16,222,217	(6,472,997)	>300.00%
21	**TOTAL OPER. & MAINT. EXPENSES**	$ 304,299,946	$ 101,289,621	$ 203,010,325	$ 124,709,294	62.79%
22						
23						
24						
25						
26						

Sch. 11	MONTANA TAXES OTHER THAN INCOME - NATURAL GAS (INCLUDES CMP)			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	$1,306,747	$1,081,039	20.88%
3	Real Estate & Personal Property	13,064,839	13,965,792	-6.45%
4	Crow Tribe RR and Utility Tax	42,769	31,661	35.08%
5	Blackfoot Possessoray Tax	249,241	303,403	-17.85%
6	Consumer Counsel	168,271	104,378	61.21%
7	Public Service Commission	546,669	313,772	74.22%
8	MT DOR Working Interest Withholding	131,685	117,117	12.44%
9				
10				
11				
12				
13	**Canadian Taxes**			
14	Ad Valorem	7,956	19,940	-60.10%
15				
16				
17				
18				
19	**TOTAL TAXES OTHER THAN INCOME**	$15,518,177	$15,937,102	-2.63%

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	A M Welles Inc	Contractor	379,928
2	Accenture	Strategic Consultant	284,661
3	Alliance Data System	IT Support Services	1,624,835
4	Areva T&D Corporation	Energy Mgmt System Software & Maintenance	311,395
5	Asplundh Tree Experts	Tree Trimming	3,170,751
6	Automotive Rentals	Fleet Management	4,700,443
7	Bill Field Trucking	Equipment Transportation	259,521
8	Central Air Service	Aerial Patrol Services	134,408
9	Computer Associates	Maintenance	155,452
10	COP Construction LLC	Contractor	241,767
11	Dept of Health and Human Services	USBC Services	1,319,379
12	Dolphin IT Project	Consulting	272,369
13	ELM Locating	Locating Services	1,876,772
14	Energy Share of Montana	USBC Services	229,204
15	Express Services Inc	Temporary Employment Services	105,664
16	First Data Integrated Systems	Customer Service	159,381
17	Graves Law Offfices	Legal Services	1,004,744
18	Gregory & Cook Inc	Contractor	3,861,629
19	Heath Consultants	Natural Gas Leakage Surveys	150,765
20	Independent Inspection Company	Electric Line Inspection	645,099
21	Itron, Inc	Hardware/Software Maintenance	893,458
22	Kema, Inc	Energy Audit Programs & Services	1,392,515
23	Lands Energy Consultants	Consulting	176,544
24	Liberty Consulting	Operations Audit Services	191,195
25	Little Bear Construction	Contractor	150,744
26	Mark Thompson	Consultant	157,523
27	Mercer Human Resources	Actuarial & Consulting Services	196,489
28	Merrill Communications	Printing Services	347,770
29	Nat'l Center for Appropriate Technology	Lab Testing	1,011,959
30	Natural Gas Services	Natural Gas Service Work	123,319
31	Northwest Energy Efficiency	Energy Services	525,056
32	Orcom Solutions	Programming & Implementation	1,100,373
33	PAR Electric Contractors	Contractor	2,240,082
34	Power Engineers Inc	Engineering Services	189,087
35	Power Resource Managers	Power Scheduling & Dispatch	312,000
36	Rod Tabbert Construction	Contractor	397,997
37	Russell Reynolds Associates	Legal Services	282,825
38	Special Response Corporation	Security Services	342,005
39	Spherion Corporation	Temporary Employment Services	152,517
40	Spiker Communication	Advertising	154,243
41	State Line Contractors	Contractor	374,925
42	Teamworks USA	Strike Contingency Employment Services	719,493
43	Technology Unlimited	Software Support & Maintenance	164,541
44	Tony Laslovich	Contractor	151,034
45	Trademark Electric	Contractor	146,166
46	Utility Consulting Services	Contractor	146,139
47	Varsity Contractors	Janitorial Services	191,436
48	Zacha Underground	Contractor	144,786
49	**Total of Payments Set Forth Above**		33,264,388
50	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
1	
2	NorthWestern Energy does not make any contributions to Political Action
3	Committees (PACs) or candidates.
4	
5	There are two employee PACs, one called Citizens for Responsible Government / Employees of
6	NorthWestern Energy, and one called NorthWestern Public Service Employee's Political
7	Action Committee. These are organizations of employees and shareholders of NorthWestern
8	Energy. All of the money contributed by members goes to support political candidates. No
9	company funds may be spent in support of a political candidate. Nominal administrative costs
10	for such things as duplicating, postage and meeting expenses are paid by the company. These
11	costs are charged to shareholder expense.

Sch. 14 PENSION COSTS

	Description	Last Year	This Year	% Change
1	Plan Name: Retirement Plan for Employees			
2	of the Montana Power Company			
3	Defined Benefit Plan	Yes	Yes	
4	Defined Contribution Plan (See Schedule 14A)			
5	Is the Plan overfunded?	No - 2/	No - 3/	
6				
7				
8	Actuarial Cost Method			
9	IRS Code			
10	Annual Contribution by Employer	9,700,000	10,000,000	3.09%
11				
12	Accumulated Benefit Obligation	292,261,554	319,159,467	9.20%
13	Projected Benefit Obligation	300,852,204	319,159,467	6.09%
14	Fair Value of Plan Assets	188,693,229	202,894,634	7.53%
15				
16	Discount Rate for Benefit Obligations	6.00%	5.50%	
17	Expected Long-Term Return on Assets	8.50%	8.50%	
18				
19	Net Periodic Pension Cost:			
20	Service Cost	4,325,666	6,519,118	50.71%
21	Interest Cost	17,729,155	16,957,046	-4.36%
22	Return on Plan Assets *(Expected)*	(13,419,317)	(15,574,032)	16.06%
23	Net Amortization	1,919,570	1,919,570	0.00%
24	Recognized net actuarial loss	4,268,343	2,962,566	-30.59%
25	Special Termination Benefit Charge			0.00%
26	Curtailment Charge			0.00%
27	Settlement Charge			0.00%
28	Total Net Periodic Pension Cost	14,823,417	12,784,268	-13.76%
29		0	0	
30	Minimum Required Contribution	0	0	
31	Actual Contribution	5,700,000	10,000,000	75.44%
32	Maximum Amount Deductible	54,597,991	48,227,380	-11.67%
33	Benefit Payments	16,956,612	15,208,268	-10.31%
34				
35	Montana Intrastate Costs:			
36	Pension Costs		NOT AVAILABLE	
37	Pension Costs Capitalized			
38	Accumulated Pension Asset (Liability) at Year End			
39				
40	Number of Company Employees : 1/			
41	Covered by the Plan			
42	Active	1,070	1,043	-2.52%
43	Retired	1,222	1,209	-1.06%
44	Vested Former Employees (Deferred Inactive)	870	893	2.64%
45	Total Covered by the Plan	3,162	3,145	-0.54%
46	Total Not Covered by the Plan			
47				

48 1/ Obtained from The Actuarial Valuation Report of the Retirement Plan for Employees of The
49 Montana Power Company, prepared as of January 1, 2003 and 2004 respectively.
50
51 2/ As of December 31, 2003, the fair value of assets was $188.7 million and the projected benefit obligation
52 was $300.9 million. However, there was an unrecognized net loss of $74.5 million that has not been
53 fully amortized pursuant to SFAS Statement No. 87. There is a pension liability of $12.4 million
54 as of December 31, 2003.
55
56 3/ As of December 31, 2004, the fair value of assets was $202.9 million and the projected benefit obligation
57 was $319.2 million. However, there was an unrecognized net loss of $64.7 million that has not been
58 fully amortized pursuant to SFAS Statement No. 87. There is a pension liability of $125.4 million
59 as of December 31, 2004.
60

Sch. 14A	PENSION COSTS			
	Description	Last Year	This Year	% Change
1	Plan Name: Retirement Savings Plan			
2				
3	Defined Benefit Plan (See Schedule 14)			
4	Defined Contribution Plan	Yes	Yes	
5	Is the Plan overfunded?			
6				
7				
8	Actuarial Cost Method			
9	IRS Code			
10	Annual Contribution by Employer			
11				
12	Accumulated Benefit Obligation			
13	Projected Benefit Obligation			
14	Fair Value of Plan Assets 4/	103,986,249	154,802,831	48.87%
15				
16	Discount Rate for Benefit Obligations			
17	Expected Long-Term Return on Assets			
18				
19	Net Periodic Pension Cost:			
20	Service Cost			
21	Interest Cost	NOT APPLICABLE		
22	Return on Plan Assets (Actual)			
23	Net Amortization			
24	Total Net Periodic Pension Cost			
25				
26	Minimum Required Contribution			
27	Actual Contribution	NOT APPLICABLE		
28	Maximum Amount Deductible			
29	Benefit Payments			
30				
31	Montana Intrastate Costs:			
32	Pension Costs	NOT APPLICABLE		
33	Pension Costs Capitalized			
34	Accumulated Pension Asset (Liability) at Year End			
35			5/	
36	Number of Company Employees :			
37	Covered by the Plan -- Eligible	1,015	1,444	42.27%
38	Not Covered by the Plan	0	0	
39	Active -- Participating	1,005	1,167	16.12%
40	Retired			
41	Vested Former Employees, Retirees and	355	363	2.25%
42	Active-Noncontributing			
43	Total Covered by the Plan	1,015	1,444	42.27%
44	Total Not Covered by the Plan	0	0	
45				
46	4/ On December 31, 2004 the NorthWestern Corporation 401k plan was merged into the NorthWestern Energy			
47	401k plan.			
48				
49	5/ Number of Company Employees reported at December 31, 2004 now include NorthWestern Corporation			
50	401k plan participants.			
51				
52				
53				
54				
55				

Sch 15 OTHER POST EMPLOYMENT BENEFITS (OPEBS)

	Description	Last Year	This Year	% Change
1	**General Information**	1/	2/	
2	Discount Rate for Benefit Obligations	6.50%	5.50%	-15.38%
3	Expected Long-Term Return on Assets	8.50%	8.50%	0.00%
4	Medical Cost Inflation Rate 3/	12.0%,5.0%:9	11.0%,5.0%:9	
5	Actuarial Cost Method	Projected Unit Credit Actuarial		
6		Cost Method allocated from date of hire to		
7		full eligibility date.		
8	List each method used to fund OPEBs (ie: VEBA, 401(h)):			
9	Method - Tax Advantaged (Yes or No) YES			
10	Union Employees - VEBA			
11	Non-Union Employees - 401(h)			
12	Describe Changes to the Benefit Plan: None.			
13				
14	**Total Company**	4/	4/	
15				
16	Accumulated Post Retirement Benefit Obligation (APBO)	46,434,906	43,457,500	-6.41%
17	Fair Value of Plan Assets	5,433,986	8,333,378	53.36%
18				
19	List the amount funded through each funding method:			
20	VEBA - 6/	3,845,324	1,392,282	-63.79%
21	401(h) - 6/	1,394,967	0	-100.00%
22	Other: Cash - 6/	402,710	3,596,134	792.98%
23	Total Amount Funded	5,643,001	4,988,416	-11.60%
24				
25	List amount that was tax deductible for each type of funding:			
26	VEBA - 6/	3,845,324	1,392,282	-63.79%
27	401(h) - 6/	1,394,967	0	-100.00%
28	Other: Cash - 6/	402,710	3,596,134	792.98%
29	Total Amount Tax Deductible	5,643,001	4,988,416	-11.60%
30				
31	Net Periodic Post Retirement Benefit Cost:			
32	Service Cost	814,420	822,705	1.02%
33	Interest Cost	2,827,953	2,428,920	-14.11%
34	Return on Plan Assets *(Expected)*	(261,309)	(369,209)	41.29%
35	Amort. of Transition Oblig. & Regulatory Asset	788,960	788,960	0.00%
36	Amortization of Prior Service Cost	28,211	28,211	0.00%
37	Amortization of Gains or Losses	1,444,766	1,288,829	-10.79%
38	Curtailment charge	0	0	0.00%
39	Special Termination Benefit Charge	0	0	0.00%
40	Total Net Periodic Post Retirement Benefit Cost	5,643,001	4,988,416	-11.60%
41	Benefit Cost Expensed	4,250,228	3,887,356	-81.25%
42	Benefit Cost Capitalized	1,013,615	796,734	-69.98%
43	Benefit Cost Charged to MPC Subs & Colstrip Owners - 5/	379,158	304,326	-19.74%
44	Total Benefit Costs	5,643,001	4,988,416	-11.60%
45	Benefit Payments 6/	402,710	3,596,134	792.98%
46				
47	Number of Company Employees :			
48	Covered by the Plans			
49	Active	1,070	1,043	-2.52%
50	Retired	1,034	977	-5.51%
51	Retired Spouse/Dependents	71	120	69.01%
52	Total Covered by the Plans	2,175	2,140	-1.61%
53	Total Not Covered by the Plans	125	121	-3.20%

54 1/ Obtained from NorthWestern Energy-Montana's 2003 FASB 106 Valuation. Assumptions and data are as of December 31, 2003.

55 2/ Obtained from NorthWestern Energy-Montana's 2004 FASB 106 Valuation. Assumptions and data are as of December 31, 2004.

56 3/ First Year, Ultimate, Years to Reach Ultimate.

Sch 15A OTHER POST EMPLOYMENT BENEFITS (OPEBS)

	Description	Last Year	This Year	% Change
1	**General Information**	4/	4/	
2	Discount Rate for Benefit Obligations			
3	Expected Long-Term Return on Assets			
4	Medical Cost Inflation Rate			
5	Actuarial Cost Method			
6				
7				
8	List each method used to fund OPEBs (ie: VEBA, 401(h)):			
9	Method - Tax Advantaged (Yes or No) YES			
10	Union Employees - VEBA			
11	Non-Union Employees - 401(h)			
12	Describe Changes to the Benefit Plan: None.			
13				
14	**Montana**	4/	4/	
15				
16	Accumulated Post Retirement Benefit Obligation (APBO)			
17	Fair Value of Plan Assets			
18				
19	List the amount funded through each funding method:			
20	VEBA			
21	401(h)			
22	Other: Cash			
23	Total Amount Funded			
24				
25	List amount that was tax deductible for each type of funding:			
26	VEBA			
27	401(h)			
28	Other: Cash			
29	Total Amount Tax Deductible			
30				
31	Net Periodic Post Retirement Benefit Cost:			
32	Service Cost			
33	Interest Cost			
34	Return on Plan Assets - Estimated			
35	Amort. of Transition Oblig. & Regulatory Asset			
36	Amortization of Gains or Losses			
37	Total Net Periodic Post Retirement Benefit Cost			
38	Benefit Cost Expensed			
39	Benefit Cost Capitalized			
40	Benefit Cost Charged to MPC Subs & Colstrip Owners			
41	Total Benefit Costs			
42	Benefit Payments			
43				
44	Number of Company Employees :			
45	Covered by the Plans			
46	Active			
47	Retired			
48	Retired Spouse/Dependents			
49	Total Covered by the Plans			
50	Total Not Covered by the Plans			

51 4/ Substantially all of the amounts are subject to the MPSC jurisdiction. Actual amounts that will be
52 expensed, will reflect reductions for amounts billed to others or allocated to Yellowstone National Park.
53 5/ Due to the sale of our generating assets, there is no longer billing to Colstrip owners from 2000 forward.
54 6/ 2004 Trust funding was made on January 31, 2005 in the amounts of:
55

$0 for 401(h) and $1,392,282 for VEBA. Due to 401(h) deductibility limits, the company was unable to directly fund the 401(h) Trust. All post-retirement benefits for FAS 106 obligation were paid out of company funds during 2004.

CHEDULE 16

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

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary (Wages)	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	John R. Van Camp Former Vice President, Organization & Staffing	103,654	78,933 A	5,654 B 7,803 C 253,800 D 4,500 E 749 I	455,093	287,676	58%
2	Maurice H. Worsfold Former Vice President, Audit & Control	142,423	64,000 A	13,048 B 11,531 C 130,000 D	361,002	N/A	0%
3	Eric R. Jacobsen Former Chief Legal Officer	310,000	302,400 A	17,863 C 350,000 D 749 I	981,012	346,229	183%
4	William M. Austin Former Chief Restructuring Officer	284,615	1,200,000 A	15,385 B 17,341 C 749 I 10,000 J	1,528,090	300,895	408%
5	Dennis Lopach Vice President, Administration	208,000	112,320 A	6,240 A 16,121 C 124,000 D 7,800 E	474,481	229,655	107%
6	Michael J. Young Senior Corporate Counsel	190,000	57,000 A	5,700 A 16,315 C	269,015	N/A	0%
7	Curtis T. Pohl Vice President, Distribution Operations	185,000	44,400 A	5,550 A 16,582 C 2,250 E	253,782	245,196	4%
8	Gregory G. Trandem Vice President, Support Services	182,000	43,680 A	5,460 A 16,445 C 2,748 E	250,333	221,838	13%
9	Bart A. Thielbar Vice President, Information Technology	185,000	44,400 A	5,550 A 17,501 C 2,969 E	255,420	211,360	21%
10	Christian P. Fonss Director, Tax	157,500	33,075 A	4,725 A 11,995 C 7,424 F	214,719	N/A	0%

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	1/ Bonuses consist of the following:						
2							
3	A> Discretionary Bonus & Incentives						
4							
5	2/ All Other Compensation for named employees consists of the following:						
6							
7	A> Merit Cash						
8							
9	B> Vacation Sellbacks / Vacation Payout						
10							
11	C>Employer Contributions to Benefits-Medical, Dental, Vision, EAP/Carewise, Term Life, Group Term Life, 401k						
12							
13	D> Severance Payment						
14							
15	E> Vehicle Payment / Car Allowance						
16							
17	F> Payment for Relocation Expenses						
18							
19	I> Country Club Dues (benefit discontinued effective February 2004)						
20							
21	J> Benefit Offset Payment						
22	**PLEASE NOTE THE FOLLOWING:**						
23	**ERIC JACOBSEN 1/A BONUS INCLUDES A $100,800 INCENTIVE PAYMENT EARNED IN 2004 AND PAID 01/31/2005. IN ITEM 2/D, THE $350,000 SEVERANCE PAYMENT WAS EARNED IN 2004 AND PAID 01/07/2005. BOTH OF THESE PAYMENTS WERE PART OF THE COURT-APPROVED INCENTIVE COMPENSATION AND SEVERANCE PLAN.						
24	**WILLIAM AUSTIN 1/A BONUS INCLUDES A $133,333 INCENTIVE EARNED IN 2004 - TO BE PAID 03/15/2005 - AS PART OF A COURT-APPROVED INCENTIVE AGREEMENT.						
25	** DENNIS LOPACH 1/A BONUS INCLUDES A $56,160 INCENTIVE PAYMENT EARNED IN 2004 AND PAID 01/31/2005. IN ITEM 2/D, THE $124,000 SEVERANCE PAYMENT WAS EARNED IN 2004 AND PAID 01/07/2005. BOTH OF THESE PAYMENTS WERE PART OF THE COURT-APPROVED INCENTIVE COMPENSATION AND SEVERANCE PLAN						
26	** MAURICE WORSFOLD 1/A BONUS INCLUDES A $21,334 INCENTIVE PAYMENT EARNED IN 2004 UNDER THE COURT-APPROVED INCENTIVE COMPENSATION AND SEVERANCE PLAN AND PAID 02/02/2005.						

SCHEDULE 17

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

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

ine No.	Name/Title	Base Salary (Wages)	Bonuses 1/		Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	Gary G. Drook President and Chief Executive Officer	565,000	565,000	A	19,758 C 11,688 E 5,792 F 60,950 H	1,228,188	1,361,098	-10%
2	Michael J. Hanson Chief Operating Officer	350,000	233,334	A	16,028 C 7,978 E 7,533 H	614,873	383,525	60%
3	Brian B. Bird Chief Financial Officer	275,000	350,000	A	12,081 C 31,000 G	668,081	N/A	0%
4	Roger P. Schrum Vice President, HR & Communications	175,000	93,334	A	12,668 C 14,043 F	295,045	N/A	0%
5	Thomas J. Knapp General Counsel	224,038	66,000	A	6,600 A 16,926 C	313,564	N/A	0%

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

ine No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	1/ Bonuses consist of the following:						
2							
3	A> Discretionary Bonus and Incentive Payments earned in the year reported						
4							
5	2/ All Other Compensation for named employees consists of the following:						
6							
7	A> Merit Cash						
8							
9	C> Employer Contributions to Benefits-Medical, Dental, Vision, EAP/Carewise, Term Life, Group Term Life, 401k						
10							
11	E> Vehicle Payment / Car Allowance						
12							
13	F> Payment for Relocation Expenses						
14							
15	G> Imputed Income						
16							
17	H> Personal Airplane Use and Gross-Up						

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	$2,276,328,081	$2,199,781,929	3.48%
5	105	Plant Held for Future Use	4,900	4,900	0.00%
6	107	Construction Work in Progress	13,779,680	18,786,479	-26.65%
7	108	Accumulated Depreciation Reserve	(1,078,749,693)	(1,023,054,596)	5.44%
8	111	Accumulated Amortization & Depletion Reserves	(25,676,187)	(20,677,875)	24.17%
9	114	Electric Plant Acquisition Adjustments	378,735,895	378,904,323	-0.04%
10	115	Accumulated Amortization-Electric Plant Acq. Adj.	(2,631,714)	(2,536,800)	3.74%
11	116	Utility Plant Adjustment - Goodwill	59,445,977	-	-
12	117	Gas Stored Underground-Noncurrent	32,146,287	32,629,132	-1.48%
13	**Total Utility Plant**		1,653,383,226	1,583,837,492	4.39%
14		**Other Property and Investments**			
15	121	Nonutility Property	11,198,240	12,833,284	-12.74%
16	122	Accumulated Depr. & Amort.-Nonutililty Property	(6,085,819)	(5,619,814)	8.29%
17	123.1	Investments in Assoc Companies and Subsidiaries	(91,950,151)	(695,472,793)	-86.78%
18	124	Other Investments	6,195,600	6,515,146	-4.90%
19	128	Miscellaneous Special Funds	830,917	3,822,955	-78.27%
20	**Total Other Property & Investments**		(79,811,213)	(677,921,222)	-88.23%
21		**Current and Accrued Assets**			
22	131	Cash	16,109,544	15,117,132	6.56%
23	134	Other Special Deposits	1,946,151	5,755,423	-66.19%
24	135	Working Funds	40,380	41,220	-2.04%
25	136	Temporary Cash Investments	-	11,361	-100.00%
26	141	Notes Receivable	43,763	11,025,052	-99.60%
27	142	Customer Accounts Receivable	63,230,761	51,768,859	22.14%
28	143	Other Accounts Receivable	9,655,448	17,723,871	-45.52%
29	144	Accumulated Provision for Uncollectible Accounts	(2,093,048)	(1,874,895)	11.64%
30	145	Notes Receivable-Associated Companies	-	-	-
31	146	Accounts Receivable-Associated Companies	306,887,206	946,495,565	-67.58%
32	151	Fuel Stock	2,768,454	2,723,561	1.65%
33	154	Plant Materials and Operating Supplies	13,037,903	12,322,391	5.81%
34	164	Gas Stored - Current	11,773,839	10,898,348	8.03%
35	165	Prepayments	31,154,708	61,009,630	-48.93%
36	171	Interest and Dividends Receivable	-	343,763	-100.00%
38	172	Rents Receivable	81,198	366,662	-77.85%
39	173	Accrued Utility Revenues	58,090,886	40,394,293	43.81%
40	174	Miscellaneous Current & Accrued Assets	1,604,762	945,973	69.64%
41	**Total Current & Accrued Assets**		514,331,955	1,175,068,209	-56.23%
42		**Deferred Debits**			
43	181	Unamortized Debt Expense	13,269,662	52,491,591	-74.72%
44	182	Regulatory Assets	191,936,748	163,173,732	17.63%
45	183	Preliminary Survey and Investigation Charges	-	-	-
46	184	Clearing Accounts	29,084	26,366	10.31%
47	185	Temporary Facilities	78	78	0.00%
48	186	Miscellaneous Deferred Debits	940,038	11,392,664	-91.75%
49	189	Unamortized Loss on Reacquired Debt	2,207,780	3,281,974	-32.73%
50	190	Accumulated Deferred Income Taxes	327,995,937	300,354,317	9.20%
51	191	Unrecovered Purchased Gas Costs	3,102,173	18,490,083	-83.22%
52	**Total Deferred Debits**		539,481,500	549,210,805	-1.77%
53	**TOTAL ASSETS and OTHER DEBITS**		$ 2,627,385,468	$ 2,630,195,284	-0.11%

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	$ 355,000	$ 65,940,167	-99.46%
4	204 Preferred Stock Issued	-	-	-
5	207 Premium on capital stock	-	-	-
6	211 Miscellaneous Paid-In Capital	715,900,934	301,454,875	137.48%
7	213 Discount on Capital Stock	-	-	-
8	214 Capital Stock Expense	-	-	-
9	215 Appropriated Retained Earnings	-	-	-
10	216 Unappropriated Retained Earnings	(6,943,543)	(947,274,476)	-99.27%
12	217 Reacquired capital stock	-	-	-
13	219 Accumulated Other Comprehensive Income	23,006	(6,071,353)	-100.38%
14	**Total Proprietary Capital**	709,335,397	(585,950,787)	-221.06%
15	**Long Term Debt**			
16	221 Bonds	687,306,000	1,288,752,000	-46.67%
17	223 Advances in Associated Companies	-	309,990,784	-100.00%
18	224 Other Long Term Debt	100,000,000	504,100,000	-80.16%
19	226 Unamortized Discount on Long Term Debt-Debit	(2,168,257)	(3,336,258)	-35.01%
20	**Total Long Term Debt**	785,137,743	2,099,506,526	-62.60%
21	**Other Noncurrent Liabilities**			
22	227 Obligations Under Capital Leases-Noncurrent	5,048,631	6,223,761	-18.88%
23	228.1 Accumulated Provision for Property Insurance	227,831	482,612	-52.79%
24	228.2 Accumulated Provision for Injuries and Damages	15,310,625	12,843,728	19.21%
25	228.3 Accumulated Provision for Pensions and Benefits	61,625,542	45,289,697	36.07%
26	228.4 Accumulated Miscellaneous Operating Provisions	177,297,557	186,971,975	-5.17%
27	**Total Other Noncurrent Liabilities**	259,510,186	251,811,773	3.06%
28	**Current and Accrued Liabilities**			
29	231 Notes Payable	-	-	-
30	232 Accounts Payable	87,597,918	73,369,179	19.39%
31	233 Notes Payable to Associated Companies	-	-	-
32	234 Accounts Payable to Associated Companies	12,936,880	9,396,670	37.68%
33	235 Customer Deposits	7,252,925	4,335,422	67.29%
34	236 Taxes Accrued	129,230,181	135,290,206	-4.48%
35	237 Interest Accrued	8,879,509	56,441,937	-84.27%
37	238 Dividends Declared	-	-	-
38	241 Tax Collections Payable	(87,755)	(68,226)	28.62%
39	242 Miscellaneous Current and Accrued Liabilities	19,541,983	19,677,804	-0.69%
40	243 Obligations Under Capital Leases-Current	1,707,791	2,818,994	-39.42%
41	**Total Current and Accrued Liabilities**	267,059,432	301,261,986	-11.35%
42	**Deferred Credits**			
43	252 Customer Advances for Construction	25,269,519	22,840,988	10.63%
44	253 Other Deferred Credits	147,144,511	182,225,840	-19.25%
45	254 Regulatory Liabilities	33,488,677	17,308,100	93.49%
46	255 Accumulated Deferred Investment Tax Credits	5,099,450	5,634,274	-9.49%
47	257 Unamortized Gain on Reacquired Debt	-	-	-
48	281-283 Accumulated Deferred Income Taxes	395,340,553	335,556,584	17.82%
49	**Total Deferred Credits**	606,342,710	563,565,786	7.59%
50	**TOTAL LIABILITIES and OTHER CREDITS**	$ 2,627,385,468	$ 2,630,195,284	-0.11%
51				

52 1/ This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory
53 Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, in accordance with FERC
54 requirements, subsidiaries are presented using the equity method of accounting. The amounts presented are consistent with
55 the presentation in FERC Form 1, plus Canadian Montana Pipeline Corp.
56
57 The financial results reported include income taxes that are based upon NorthWestern's tax basis for plant assets purchased
58 from the Montana Power Company. This tax basis differs from amounts included in the most recently decided rate proceeding and
59 results in a lower deferred tax credit. This change was made in order to prevent any possible violation of the normalization
60 requirements of the federal income tax code. The change results in an increase in the reported rate base.

NOTES TO FINANCIAL STATEMENTS

(1) Management's Statement

The financial statements for the periods included herein have been prepared by NorthWestern Corporation (NorthWestern, we or us), pursuant to the rules and regulations of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts.

In 2002, our financial condition was significantly and negatively affected by the poor performance of our nonenergy businesses, in combination with our significant indebtedness. In early 2003, we unsuccessfully attempted to refinance, reduce and extend the maturities of our debt. 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.

(2) Nature of Operations

We are one of the largest providers of electricity and natural gas in the Upper Midwest and Northwest, serving approximately 617,000 customers in Montana, South Dakota and Nebraska. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have distributed electricity and natural gas in Montana since 2002 under the trade name "NorthWestern Energy."

(3) Emergence from Bankruptcy and Fresh-Start Reporting

Plan of Reorganization

The Bankruptcy Court entered a written order confirming our Plan on October 19, 2004, and the Plan became effective on November 1, 2004. 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 general, the terms of our Plan provided for the following:

- Holders of our senior unsecured notes (Class 7 claimants) received 28.3 million shares of new common stock in exchange for $898.3 million in allowed claims;
- Holders of TOPrS (Class 8a claimants) received 2.3 million shares of new common stock and warrants for an additional 4.4 million shares of common stock in exchange for $321.1 million in allowed claims. The warrants may be exercised for a period of three years from the effective date;
- Holders of QUIPs (Class 8b claimants), were allowed to select either of the following: (i) receive a pro rata share of 0.5 million shares of new common stock, plus warrants with the same terms as the warrants distributed to the TOPrS, in exchange for their claims, including any litigation claims, or (ii) continue the litigation against us generally referred to as the QUIPs Litigation and will receive a distribution based on a Class 9 claim, if any, based only upon final resolution of the QUIPs Litigation;
- 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 (Class 9 claimants) and holders of senior unsecured notes. The shares held in this reserve will be distributed pro rata to holders of allowed trade vendor and general unsecured claims in excess of $20,000, and may be used to resolve various outstanding litigation matters, such as the QUIPs Litigation, certain litigation with PPL Montana and other unliquidated litigation claims;
- Secured debt was not impaired and has been assumed; and
- Common stock existing prior to November 1, 2004 was cancelled and there were no distributions to prior shareholders.

Under Chapter 11, certain claims against us in existence prior to the filing of the petition for relief under the Bankruptcy Code were stayed while we continued operations as a debtor-in-possession. Prior to the application of fresh-start reporting, the Predecessor Company's October 31, 2004 balance sheet included related balances subject to compromise (refer to table below). However, the adoption of fresh-start reporting results in the settlement of such balances based on the estimated payment amounts pursuant to the Plan with the difference recorded as a reorganization gain in the statement of income (loss) for the 10-months ended October 31, 2004. Determination by the Bankruptcy Court (or agreed to by parties in interest) of remaining disputed unsecured prepetition claims as allowed claims for contingencies and other disputed amounts may impact these results. 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 reorganization charges incurred (in thousands):

	2004	2003
Reorganization Items		
Outside services - professional fees (923)	$ 39,271	$ 8,280
Interest earned on accumulated cash (419)	(381)	(14)
Miscellaneous nonoperating income - Effects of the Plan and fresh-start reporting adjustments (421)	(571,953)	—
Total Reorganization Items	$ (533,063)	$ 8,266

Included in Reorganization Items for 2004 was the Predecessor Company's gain recognized from the effects of the Plan and fresh-start reporting. The gain results from the difference between the Predecessor Company's carrying value of unsecured debt and the issuance of new common stock and the discharge of liabilities subject to compromise pursuant to the Plan. The gain from the effects of the Plan and the application of fresh-start reporting is comprised of the following (in thousands):

	Gain
Effects of the Plan and fresh-start reporting	
Issuance of new common stock and warrants	$713,782
Discharge of financing debt subject to compromise	(904,809)
Discharge of company obligated mandatorily redeemable preferred securities subject to compromise	(367,026)
Cancellation of indebtedness income	(558,053)
Discharge of other liabilities subject to compromise	(13,900)
	$(571,953)

Fresh-Start Reporting

In connection with our emergence from Chapter 11, we reflected the terms of the Plan in our December 31, 2004 financial statements, applying fresh-start reporting under SOP 90-7. Fresh-start reporting is required if (1) the reorganization value of the emerging entity's assets immediately before the date of confirmation is less than the total of all postpetition liabilities and allowed claims, and (2) holders of existing voting shares immediately before confirmation receive less than 50% of the voting shares of the emerging entity. Upon applying fresh-start reporting, a new reporting entity (the Successor Company) is deemed to be created and the recorded amounts of assets and liabilities are adjusted to reflect their estimated fair values.

To facilitate the calculation of the enterprise value of the Successor Company as defined in SOP 90-7, we developed a set of financial projections and engaged an independent financial advisor to assist in the determination. The enterprise value was determined using various valuation methods including,

(i) reviewing historical financial information (ii) comparing the company and its projected performance to the market values of comparable companies, (iii) performing industry precedent transaction analysis, and (iv) considering certain economic and industry information relevant to the operating business. The resulting enterprise value was calculated using a 7% discount rate to be within an approximate range of $1.415 billion to $1.585 billion. We selected the midpoint value of the range, $1.5 billion, as the reorganization value. This value is consistent with the Voting Creditors and Bankruptcy Court approval of our Plan.

In applying fresh-start reporting, we followed these principles:

- The reorganization value was allocated to the assets in conformity with the procedures specified by Statement of Financial Accounting Standards (SFAS) No. 141, *Business Combinations*. The enterprise value exceeded the sum of the amounts assigned to assets and liabilities, with the excess allocated to utility plant adjustment.
- Deferred taxes were reported in conformity with applicable income tax accounting standards, principally SFAS No. 109, *Accounting for Income Taxes*. Deferred taxes assets and liabilities have been recognized for differences between the assigned values and the tax basis of the recognized assets and liabilities (see Note 13).
- Adjustment of our qualified pension and other postretirement benefit plans to their projected benefit obligation by recognition of all previously unamortized actuarial gains and losses.
- Reversal of all items included in other comprehensive loss, including recognition of the Predecessor Company's minimum pension liability, recognition of all previously unrecognized cumulative translation adjustments and removal of a hedge gain associated with unsecured debt.
- Changes in existing accounting principles that otherwise would have been required in the financial statements of the emerging entity within the 12 months following the adoption of fresh-start reporting were adopted at the fresh-start reporting date.
- Each liability existing as of the Plan confirmation date, other than deferred taxes, was recorded at the present value of amounts to be paid determined at our computed incremental borrowing rate.

The following table identifies the adjustments made to our balance sheet as a result of implementing the Plan and applying fresh-start reporting on October 31, 2004 (in thousands):

	Effects of Plan and Fresh-Start Reporting	
Notes receivable (141)	$ 4,091	(1)
Utility plant adjustment (116)	59,276	(2)
Unamortized debt expense (181)	(24,252)	(4)
Regulatory assets (182.3)	26,799	(1)(3)
Miscellaneous deferred debits (186)	(7,016)	(1)
Total assets	$ 58,898	
Financing debt (221, 224, 226)	$ (929,114)	(6)
Advances from associated companies (223)	(300,550)	(6)
Accumulated provision for pensions and benefits (228.3)	11,437	(3)
Accumulated provision for injuries and damages (228.2)	2,861	(1)
Accumulated provision for operating expenses (228.4)	(12,373)	(1)
Accrued interest (237)	(46,917)	(1)(4)
Accounts payable (232)	(406)	(1)
Miscellaneous current and accrued liabilities (242)	(27,700)	(1)(3)
Deferred income taxes (283)	45,292	(5)
Other deferred credits (253)	(22,376)	(5)
Total liabilities	(1,279,846)	
Proprietary capital	1,338,744	(6)(7)
Total liabilities and shareholders' equity (deficit)	$ 58,898	

(1) Represents adjustments to assets and liabilities resulting from the fair value provisions of fresh-start reporting.

(2) Reflects the excess reorganization value pursuant to the valuation under our Plan and in accordance with fresh-start reporting. Based on certain regulatory considerations, our property, plant and equipment should be kept at historical book value less adjustments which reduce these assets to the amount included in the utility rate base, therefore management has applied the entire excess reorganization value to goodwill.

(3) Reflects the adjustment of our pension and other postretirement benefit obligations to fair value based on independent actuarial reports.

(4) Reflects the removal of unamortized deferred financing costs and accrued interest related to debt extinguished upon emergence.

(5) Reflects the adjustment of deferred tax assets and liabilities as a result of the impact of the gain related to cancellation of indebtedness and the fair value adjustments in accordance with the Plan.

(6) Reflects the conversion of our unsecured debt and company obligated mandatorily redeemable preferred securities into equity pursuant to the Plan.

(7) Represents the elimination of historical shareholders' deficit and issuance of new common stock pursuant to the Plan.

(4) Significant Accounting Policies

Financial Statement Presentation and Basis of Accounting

The financial statements are 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. 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 $132.9 million and $123.0 million as of December 31, 2004 and 2003, respectively, in accordance with regulatory treatment as compared to regulatory liabilities for GAAP purposes (see Note 7);
- Goodwill resulting from the 2002 acquisition of the Montana operations is reflected in the balance sheets as a plant acquisition adjustment of $375.8 million as of December 31, 2004 and 2003, respectively, and $59.4 million of goodwill resulting from the application of fresh-start reporting is reflected in the December 31, 2004 balance sheet as a utility plant adjustment, as compared to goodwill for GAAP purposes;
- 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 $193.9 and $192.8 million as of December 31, 2004 and 2003, respectively, in accordance with regulatory treatment as compared to plant for GAAP purposes;
- Gas stored underground is reflected in the balance sheets on separate current and non-current lines, whereas the current portion is reflected in materials and supplies and the non-current portion is reflected in plant for GAAP purposes. The following table provides the detail of these items in thousands:

	December 31, 2004	December 31, 2003
Gas stored underground – Current.	$ 11,774	$ 10,898
Gas stored underground – Non-current.	32,146	32,629

- Company Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trusts of $65.0 million as of December 31, 2003, is classified as other long-term debt and the respective dividends are classified as interest expense, whereas SFAS No. 150, Accounting for Certain Instruments with Characteristics of Both Liabilities and Equity, which requires the same classifications, was effective July 1, 2003. Prior to that, for GAAP purposes, the trusts were classified as preferred stock and the respective dividends were classified as preferred dividends. The preferred securities were converted into equity pursuant to the Plan of Reorganization (see Note 3);
- Current and long-term debt is classified in the balance sheets as all long-term debt in accordance with regulatory treatment (see Note 10), while GAAP presentation reflects current and long-term debt on separate lines;
- Accumulated deferred taxes 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; and
- We adopted fresh-start reporting under SOP 90-7 in connection with our emergence from Chapter 11 as of the close of business on October 31, 2004. Upon applying fresh-start reporting, a new reporting entity was deemed to be created and the recorded amounts of assets and liabilities were adjusted to reflect their estimated fair values. While our GAAP financial statement presentation reflects operations from January 1, 2002 through October 31, 2004, representing our "Predecessor Company", and operations from November 1, 2004 through December 31, 2004, representing our "Successor Company" after emergence from bankruptcy, our FERC financial statement presentation reflects the twelve months ended December 31, 2004. See Note 3 for the further information regarding the effects of fresh-start reporting.

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 the 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.

Accrued Utility Revenues

Accrued unbilled utility revenues included in customer accounts receivable totaled $58.1 million and $40.4 million at December 31, 2004 and 2003.

Inventories

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

	December 31, 2004	December 31, 2003
Fuel stock	$ 2,768	$ 2,724
Plant material and operating supplies	13,038	12,322
Gas stored underground	43,920	43,527
	$ 59,726	$ 58,573

Regulation of Utility Operations

Our regulated operations are subject to the provisions of Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulations (SFAS No. 71). 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.

Investments

Investments consisted of life insurance contracts and other investments in the amount of $6.2 million and $6.5 million at December 31, 2004 and 2003, respectively.

Life insurance contracts are carried at their cash surrender value. Investments in life insurance contracts of $3.7 million and $3.6 million are held in trust and restricted for postretirement benefits as of December 31, 2004 and 2003, respectively. In addition, investments in life insurance contracts of $1.5 million and $1.7 million are unrestricted as of December 31, 2004 and 2003, respectively.

Derivative Financial Instruments

In the past, we have managed risk using derivative financial instruments for changes in electric and natural gas supply prices and interest rate fluctuations. We have also periodically used commodity futures contracts to reduce the risk of future price fluctuations for electric and natural gas contracts. Increases or decreases in contract values are reported as gains and losses in our Statements of Income (Loss) unless the commodities are specifically subject to supply tracking mechanisms within the regulatory environment.

In December 2004, we adopted a formal energy risk management policy to govern our electricity and natural gas commodity purchases and sales. Under the language of the policy, we are precluded from using derivative financial instruments to manage our commodity price volatility risk unless specifically authorized by our internal energy supply board. The policy, however, does not preclude the use of derivative financial instruments to mitigate interest rate fluctuations.

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 $10.9 million and $10.5 million as of December 31, 2004 and 2003, 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 9.0% and 8.9% for Montana for 2004 and 2003, and 7.9% and 10.7% for South Dakota for 2004 and 2003, respectively. Interest capitalized totaled $1.2 million and $0.9 million for the years ended December 31, 2004 and 2003, respectively for Montana and South Dakota combined.

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 forty years) determined from engineering studies. As a percentage of the depreciable utility plant at the beginning of the year, our provision for depreciation of utility plant was approximately 3.5% and 3.5% for 2004 and 2003, respectively.

Internal labor and overhead costs capitalized for other property, plant and equipment were $30.6 million and $29.2 million for the years ended December 31, 2004 and 2003, respectively.

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

Stock-based Compensation

The Successor Company prospectively adopted SFAS No. 123-R, *Share-Based Payment,* upon emergence, with no impact to the financial statements or disclosure required as stock-based compensation consists of restricted shares of common stock. The Predecessor Company had a nonqualified stock option plan to provide for the granting of stock-based compensation to certain employees and directors, which was terminated upon our emergence from bankruptcy. The Predecessor Company accounted for this plan in accordance with the intrinsic value based method of Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations in accounting. No compensation cost is recognized as the option exercise price is equal to the market price of the underlying stock on the date of grant.

If compensation costs had been recognized based on the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation*, there would have been no change to our net income (loss) as reported for 2004 and 2003.

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.

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 based on our expectation that we will recover 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 life of the plant, assuming the costs are recoverable in future rates or future cash flow.

We record estimated remediation costs, excluding inflationary increases and probable reductions for insurance coverage and rate recovery. The estimates are based on 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.

New Accounting Standards

In December 2004, the FASB issued a revision to SFAS No. 123, *Accounting for Stock-Based Compensation*, SFAS No. 123-R. SFAS No. 123-R requires companies to record compensation expense for all share-based awards granted subsequent to the adoption of the statement. In addition, SFAS 123-R requires the recording of compensation expense for the unvested portion of previously granted awards that remain outstanding at the date of adoption. In accordance with SOP 90-7 and the provisions of fresh-start reporting, we early adopted the provisions of SFAS 123-R prospectively as of October 31, 2004. As all stock-based compensation of the Predecessor Company was cancelled upon emergence, adoption of the statement did not impact our financial condition or results of operations.

Reclassifications

Certain 2003 amounts have been reclassified to conform to the 2004 presentation. Such reclassifications had no impact on net income (loss) or total proprietary capital as previously reported.

(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, 2004	December 31, 2003
Clark Fork & Blackfoot, L.L.C.	$ (4,963)	$ (1,093)
Natural Gas Funding Trust	785	903
NorthWestern Services Corporation	15,966	15,693
NorthWestern Investments, LLC	(103,738)	(719,892)
NorthWestern Capital Financing I	-	962
NorthWestern Capital Financing II	-	3,288
NorthWestern Capital Financing III	-	3,154
NWPS Capital Financing I	-	1,512
Total Investments in Associated Companies	$ (91,950)	$ (695,473)

(6) Property, Plant and Equipment

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

	December 31, 2004	December 31, 2003
Land and improvements	$ 37,870	$ 37,344
Building and improvements	130,103	131,204
Storage, distribution, transmission and generation	1,976,549	1,903,474
Construction work in process	13,780	18,787
Other equipment	602,139	539,297
	2,761,441	2,630,106
Less accumulated depreciation	(1,107,058)	(1,046,269)
	$1,653,383	$1,583,837

(7) Asset Retirement Obligations

We have identified, but have not recognized, asset retirement obligation, or ARO, liabilities related to our electric and natural gas transmission and distribution assets. Many of these assets are 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 recognize removal costs of transmission and distribution assets as a component of depreciation in accordance with regulatory treatment. These amounts do not represent Statement of Financial Accounting Standards (SFAS) No. 143 legal retirement obligations. As of December 31, 2004 and 2003, we have recognized accrued removal costs of $132.9 million and $123.0 million, respectively, which are classified as accumulated depreciation in the balance sheets.

For our generation properties, we have accrued decommissioning costs since the generating units were first put into service in the amount of $12.3 million and $11.9 million as of December 31, 2004 and 2003, respectively, which is classified as accumulated depreciation. These amounts also do not represent SFAS No. 143 legal retirement obligations.

(8) Acquisition and Utility Plant Adjustments

Effective January 1, 2002, we adopted SFAS No. 142, *Goodwill and Other Intangible Assets*. SFAS No. 142 changed the accounting for goodwill from a model that required amortization of goodwill,

supplemented by impairment tests, to an accounting model that is based solely upon impairment tests. We review goodwill for impairment annually during the fourth quarter, or more frequently if changes in circumstances or the occurrence of events suggest an impairment exists.

We retained a third party to conduct a valuation analysis in connection with our fresh-start reporting. Our consolidated enterprise value was estimated at $1.5 billion, providing for an equity value of $710 million. Upon the adoption of fresh-start reporting on October 31, 2004, we adjusted our assets and liabilities to their fair values and valued our equity to $710 million. Since we are a regulated utility, our regulated property, plant and equipment is kept at values included in utility rate base, and the excess of reorganization value over the fair value of assets and liabilities on the date of our emergence of $435.1 million has been recorded as an acquisition adjustment of $378.7 as of December 31, 2004 and 2003, respectively, with the remaining balance of $59.4 recorded as a utility plant adjustment.

(9) 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,	
	2004	2003
Accounts Receivable from Associated Companies:		
Netexit, Inc.	$ 224,016	$ 224,025
Montana Megawatts I, LLC	77,177	78,884
Natural Gas Funding Trust	40	7
Nekota Resources, Inc.	4,458	3,364
NorthWestern Capital Corporation	—	51,608
NorthWestern Energy Marketing, LLC	1,179	1,767
NorthWestern Investments, LLC	—	586,815
Risk Partners Assurance, Ltd.	18	26
	$ 306,888	$ 946,496
Accounts Payable to Associated Companies:		
Blue Dot Services Inc.	$ 1,273	$ 1,520
Clark Fork & Blackfoot, L.L.C.	1,544	6,625
NorCom Advanced Technologies Inc.	85	—
NorthWestern Services Corporation	10,035	1,252
	$ 12,937	$ 9,397

(10) Long-Term Debt

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

		December 31,	
	Due	2004	2003
Secured Debt:			
Senior Secured Term Loan	2006	$—	$386,100
Senior Secured Term Loan B	2011	100,000	—
Mortgage bonds—			
South Dakota—7.10%	2005	60,000	60,000
South Dakota—7.00%	2023	55,000	55,000
Montana—7.30%	2006	150,000	150,000
Montana—8.25%	2007	365	365
Montana—8.95%	2022	—	1,446
Montana—7.00%	2005	5,386	5,386
South Dakota & Montana—5.875%	2014	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	90,205
Montana—5.90%	2023	80,000	80,000
Secured medium term notes—			
7.25%	2008	—	13,000
Discount on Notes and Bonds	—	(2,168)	(3,180)
Unsecured Debt Subject to Compromise:			
Senior Unsecured Notes—7.875%	2007	$—	$250,000
Senior Unsecured Notes—8.75%	2012	—	470,000
Senior Unsecured debt—6.95%	2028	—	105,000
Unsecured medium term notes—			
7.07%	2006	—	15,000
7.875%	2026	—	20,000
7.96%	2026	—	5,000
Discount on Notes and Bonds	—	—	(156)
		$785,138	$1,789,516

Pre-petition Unsecured Debt

In connection with our emergence from bankruptcy, pre-petition unsecured debt holders were issued shares in satisfaction of their claim, including principal and interest through the petition date, and we have no further obligation. All deferred financing costs and original issue discounts related to unsecured debt were written-off upon emergence in accordance with SOP 90-7 (see Note 3).

Successor Company Long-Term Debt

On November 1, 2004 in connection with our emergence from bankruptcy, we entered into a new $225 million credit facility secured by our utility assets. The credit facility consists of a $125 million, five-year revolving tranche and a $100 million, seven-year term tranche (Senior Secured Term Loan B), which bears interest at a variable rate tied to the London Interbank Offered Rate (approximately 4% as of December 31, 2004). The revolving tranche replaced our DIP Facility and is available to us for general corporate purposes and for the issuance of letters of credit. Concurrently with the establishment of the new credit facility, we issued $225 million of our 5.875% senior secured notes due November 1, 2014. Borrowings under the term portion of the new credit facility, together with the net proceeds of the notes offering and available cash, were used to repay our $390 million senior secured term loan facility. As of December 31, 2004 we had $26.0 million in letters of credit outstanding and no borrowings under the revolving tranche of the facility. Commitment fees for the revolving tranche were approximately $63,000 for the two-months ended December 31, 2004. Commitment fees for the DIP facility were approximately $218,000 for the 10-months ended October 31, 2004 and $102,000 for the year ended December 31, 2003.

The new credit facility includes covenants, which require us to meet certain financial tests, including a minimum interest coverage ratio and a maximum debt to capitalization ratio. The facility 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, enter into transactions with affiliates, engage in business activities other than specified activities, and engage in other matters customarily restricted in such agreements. As of December 31, 2004 we are in compliance with these covenants.

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, Montana Pollution Control Obligations, and Montana Natural Gas Transition Bonds are secured by substantially all of our Montana electric and natural gas assets.

The aggregate minimum principal maturities of long-term debt, during the next five years are $73.4 million in 2005, $157.6 million in 2006, $7.9 million in 2007, $7.4 million in 2008 and $7.0 million in 2009.

(11) 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 as discussed in Note 3. 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,	
	2004	2003
Net income (loss)	$544,433	$(128,670)
Other comprehensive income:		
Net unrealized gain (loss) on available-for-sale securities, net of tax of $(188) and $713 in 2003 and 2002, respectively	—	(352)
Net unrealized gain on derivative instruments qualifying as hedges, net of tax of $(224) and $2,757 in 2003 and 2002, respectively	—	(416)
Minimum pension liability adjustment	—	(1,465)
Foreign currency translation adjustment	23	298
Total other comprehensive income (loss)	23	(1,935)
Total comprehensive income (loss)	$544,456	$(130,605)

The after tax components of accumulated other comprehensive loss as of December 31, 2004 and December 31, 2003, were as follows (in thousands):

	December 31, 2004	December 31, 2003
Balance at end of period,		
Unrealized gain on derivative instruments qualifying as hedges	$—	$3,849
Minimum pension liability adjustment	—	(10,224)
Foreign currency translation adjustment	23	303
Accumulated other comprehensive income (loss)	$23	$(6,072)

(12) Financial Instruments

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

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

- The carrying amounts of cash and working funds, special deposits and other investments approximate fair value due to the short maturity of the instruments. The fair value of life insurance contracts is based on cash surrender value.
- 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 of preferred securities of subsidiary trusts is based on current market prices.
- The fair-value estimates presented herein are based on pertinent information available to us as of December 31, 2004 and December 31, 2003. 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, 2004		December 31, 2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Assets:				
Cash and working funds	$16,110	$16,110	$15,117	$15,117
Special deposits	1,946	1,946	5,755	5,755
Investments	6,196	6,196	6,515	6,515
Liabilities:				
Long-term debt (including current portion)	785,138	791,399	1,789,516	1,682,372

(13) Income Taxes

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

	Year Ended December 31,	
	2004	2003
Federal		
Current	$(787)	$6,730
Deferred	(3,936)	60,795
Investment tax credits	(535)	(535)
State	800	6,619
	$(4,458)	$73,609

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

	Year Ended December 31,	
	2004	2003
Federal statutory rate	35.0%	(35.0)%
State income, net of federal provisions	2.6	(3.9)
Amortization of investment tax credit	(0.1)	(0.8)
Depreciation of flow through items	(0.6)	1.3
Affiliated stock loss on disposition	—	(163.2)
Minority interest preferred stock	—	(7.3)
Dividends received deduction and other investments	—	(0.1)
Prior year tax return refund	(0.2)	(8.5)
Valuation allowance	(31.2)	221.8
Prior year permanent return to accrual adjustments	(8.5)	(7.3)
Prior year permanent IRS examination adjustments	—	2.0
Other, net	1.9	0.9
	(1.1)%	(0.1)%

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,	
	2004	2003
Excess tax depreciation	$(115,219)	$(103,549)
Regulatory assets	169	(6,867)
Regulatory liabilities	(30,191)	4,040
Unbilled revenue	3,971	1,346
Unamortized investment tax credit	2,746	2,751
Compensation accruals	2,654	(3,878)
Reserves and accruals	49,776	16,024
Goodwill impairment/amortization	(24,636)	(11,083)
Net operating loss carryforward (NOL)	257,961	224,934
AMT credit carryforward	3,186	228
Deferred revenue	—	18,811
Reorganization income exclusion	(207,029)	—
Valuation allowance	(10,376)	(181,587)
Other, net	(357)	3,628
	$(67,345)	$(35,202)

The income tax benefit applicable to equity in earnings of subsidiary companies totaled $1.8 million in 2004 and $73.6 million in 2003. A valuation allowance is recorded when a company believes that it will

not generate sufficient taxable income of the appropriate character to realize the value of their deferred tax assets. We have a valuation allowance of $12.8 million as of December 31, 2004 against capital loss carryforwards and certain state NOL carryforwards as we do not believe these assets will be realized. The Predecessor Company recorded a valuation allowance of $181.6 million as of December 31, 2003, because prior to our emergence from bankruptcy it was considered more likely than not that all deferred tax assets would not be realized.

At December 31, 2004 we have a total NOL carryforward of $683.7 million. We expect to utilize approximately $583 million of these NOLs to offset cancellation of indebtedness income. If unused, $87.9 million of the NOL will expire in the year 2022, $490.5 million will expire in the year 2023 and $105.3 million will expire in the year 2024. 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.

An IRS audit of our federal income tax returns for the years 2000 through 2003 is currently in process. Management believes that the final results of these audits will not have a material adverse effect on our financial position or results of operations.

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. Management has established a liability based on our best estimate of future probable adjustments related to these exposures. On a quarterly basis, management evaluates the liability in light of any additional information and adjusts the balance as necessary to reflect the best estimate of the future outcomes. We believe our established liability is 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.

(14) 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 (Loss). 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, 2004			
Ownership percentages	23.4%	8.7%	10.0%
Plant in service	$49,700	$28,106	$42,494
Accumulated depreciation	32,370	17,697	22,479
December 31, 2003			
Ownership percentages	23.4%	8.7%	10.0%
Plant in service	$49,619	$28,037	$42,441
Accumulated depreciation	30,916	16,858	21,354

(15) Operating Leases

We have six years remaining under an operating lease agreement for a generation facility, which requires lease payments of $32.2 million annually. We also lease vehicles, office equipment, an airplane and office and warehouse facilities under various long-term operating leases. At December 31, 2004, future minimum lease payments under non-cancelable lease agreements are as follows (in thousands):

2005	$33,303
2006	32,995
2007	32,638
2008	32,279
2009	32,235

Lease and rental expense incurred was $39.3 million and $40.1 million for the years ended December 31, 2004 and December 31, 2003, 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 remains at $32.2 million through 2010 and decreases to $14.5 million for the remainder of the lease. Beginning in 2005 our lease expense will be reduced to $22.1 million annually based on a straight-line calculation over the full term of the lease.

(16) Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

We sponsor and/or contribute to pension and postretirement health care and life insurance benefit plans for employees. Pension costs in Montana and other postretirement benefit costs in South Dakota are included in rates on a pay as you go basis for regulatory purposes. Pension costs in South Dakota and other postretirement benefit costs in Montana are included in rates on an accrual basis for regulatory purposes. (See Note 18, 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. Gains and losses in excess of 10% of the greater of the benefit obligation or the market-related value of assets are amortized over the average remaining service period of active participants. As a result of fresh-start reporting (see Note 3), 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 upon emergence. The generation of any future amounts subsequent to emergence will be amortized under the same method as discussed above.

Benefit Obligations

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 December 31,		Other Postretirement Benefits December 31,	
	2004	2003	2004	2003
Reconciliation of Benefit Obligation				
Obligation at beginning of period	$356,373	$329,980	$66,948	$103,352
Service cost	7,551	5,165	823	1,350
Interest cost	20,300	21,080	3,325	5,455
Actuarial (gain) loss	14,045	23,446	(2,463)	(387)
Plan amendments	—	—	—	(4,164)
Curtailments	—	—	—	(3,077)
Settlement cost	—	—	—	(16,566)
Special termination benefits	—	785	—	—
Fresh-start reporting adjustments	(4,727)	—	(11,354)	—
Gross benefits paid	(19,563)	(24,083)	(4,888)	(19,015)
Benefit obligation at end of period	$373,979	$356,373	$52,391	$66,948

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 $374.0 million and $244.6 million, respectively, as of December 31, 2004. 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 $371.8 million and $244.6 million, respectively, as of December 31, 2004.

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 $356.4 million and $229.8 million, respectively, as of December 31, 2003. 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 $346.0 million and $229.8 million, respectively, as of December 31, 2003.

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 December 31,		Other Postretirement Benefits December 31,	
	2004	2003	2004	2003
Prepaid benefit cost	$—	$ 2,683	$—	$—
Accrued benefit cost	(140,097)	(66,880)	(44,714)	(43,965)
Additional minimum liability	—	(52,055)	—	—
Intangible asset	—	1,597	—	—
Regulatory asset	—	40,234	—	—
Accumulated other comprehensive income	—	10,224	—	—
Net amount recognized	$(140,097)	$ (64,197)	$(44,714)	$(43,965)

Amounts previously recorded in accumulated other comprehensive income, regulatory assets and intangible assets were reclassified to long-term liabilities to reflect the adoption of fresh-start reporting (see Note 3).

Plan Assets and Funded Status

	Pension Benefits December 31,		Other Postretirement Benefits December 31,	
	2004	2003	2004	2003
Reconciliation of Fair Value of Plan Assets				
Fair value of plan assets at beginning of period	$229,771	$201,202	$5,434	$4,794
Actual return on plan assets	24,221	41,727	576	385
Employer contributions	10,214	10,925	7,211	35,836
Settlements	—	—	—	(16,566)
Gross benefits paid	(19,563)	(24,083)	(4,888)	(19,015)
Fair value of plan assets at end of period	$244,643	$229,771	$8,333	$5,434
Funded Status	$(129,335)	$(126,602)	$(44,058)	$(61,514)
Unrecognized transition amount	—	309	—	—
Unrecognized net actuarial (gain) loss	(10,762)	60,808	(656)	17,549
Unrecognized prior service cost	—	1,288	—	—
Accrued benefit cost	$(140,097)	$(64,197)	$(44,714)	$(43,965)

Our investment goals with respect to managing the pension and other postretirement assets is to achieve and maintain a fully 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.

The company's investment policy for fixed income investments are oriented toward risk adverse, 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) and 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 per the investment policy 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 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, 2004 and 2003, respectively, are as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31.,		December 31.,		December 31.,	
	2004	2003	2004	2003	2004	2003
Cash and cash equivalents	2.0%	1.4%	0.9%	0.6%	—%	2.8%
Debt securities	31.6	28.5	—	11.6	27.5	27.5
Domestic equity securities	55.8	58.9	50.4	38.7	71.9	68.3
International equity securities	10.6	11.2	9.5	4.5	0.6	1.4
Participating group annuity contracts	—	—	39.2	44.6	—	—
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

We review the asset mix of the funds on a quarterly basis. Generally, the fund's asset mix will be rebalanced to the target mix as individual portfolios approach their minimum or maximum levels.

We are still evaluating 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 for the plans each year is December 31. 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.

Annually, we 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, 2004, 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 the potential for lower future returns due to a generally lower interest rate environment, we selected an 8.5% long-term rate of return on assets assumption.

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,	
	2004	2003	2004	2003
Discount rate	5.50%	6.00%	5.50%	6.0-6.75%
Expected rate of return on assets	8.50%	8.50%	8.50%	8.50%
Long-term rate of increase in compensation levels (nonunion)	3.37%	3.97%	3.37%	4.00%
Long-term rate of increase in compensation levels (union)	3.30%	3.50%	3.30%	4.00%

The postretirement benefit obligation is calculated assuming that health care costs increased by 11% in 2004 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 2009.

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,	
	2003	2003	2003	2003
Components of Net Periodic Benefit Cost				
Service cost	$7,551	$5,165	$823	$1,350
Interest cost	20,300	21,080	3,325	5,455
Expected return on plan assets	(18,988)	(16,329)	(369)	(261)
Amortization of transitional obligation	129	155	—	675
Amortization of prior service cost	311	505	—	—
Recognized actuarial (gain) loss	1,068	2,724	467	467
	10,371	13,300	4,246	7,686
Additional (income) or loss recognized:				
Curtailment	—	—	—	13,511
Special termination benefits	—	785	—	—
Settlement cost	—	—	—	(13,586)
Net Periodic Benefit Cost	$10,371	$14,085	$4,246	$7,611

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	$36
on postretirement benefit obligation	2,142
Effect of a one percentage point decrease in assumed health care cost trend	
on total service and interest cost components	$(31)
on postretirement benefit obligation	(1,930)

In May 2004, the FASB issued Staff Position No. 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003*. The impact of

this Medicare prescription legislation has been analyzed and determined to have minimal impact due to the limited post-age 65 liability under the post-retirement benefit plan.

Cash Flows

We anticipate making contributions of approximately $25.7 million to our pension and other benefit plans in 2005. 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 Post-retirement Benefits
2005	$19,961	$4,093
2006	19,770	4,082
2007	19,902	4,055
2008	20,276	3,965
2009	20,426	3,990
2010-2014	116,081	17,996

Predecessor Company

The Predecessor Company sponsored two nonqualified, unfunded defined benefit pension plans, and three other postretirement benefit plans for certain officers and other employees. We have filed motions with the Bankruptcy Court to terminate these plans. Upon the determination of the motions, assuming the Bankruptcy Court permits termination, participants in these plans will receive allowed claims that will be paid in shares from the claims reserve. In accordance with SOP 90-7 and fresh-start reporting, these liabilities were removed from the balance sheet upon emergence and the impact of the termination is reflected in the tables above.

In May 2003, the Predecessor Company terminated or amended various employee benefit plans. The nonqualified supplemental 401(k) plan was terminated effective May 6, 2003. Any investment elections in our common stock were presented as Treasury Stock, other investments as part of Investments, and an offsetting liability for both as part of Other Noncurrent Liabilities in the Balance Sheets. In June 2003, plan assets were distributed to participants and no further liability remains. The Predecessor Company's contributions to the plan were $11,000 in 2003. The Predecessor Company's employee stock purchase plan was also terminated, with no impact to operating results. In addition, two nonqualified postretirement defined benefit plans were amended effective May 6, 2003 to permit vested participants the option of continuing the current benefits level or take a present value lump sum distribution. A third nonqualified postretirement defined benefit plan was terminated effective May 6, 2003. The impact of the amendments and termination are presented in the tables above.

During 2003, the Predecessor Company made an early retirement program available to select employees. The impact of that reduction in participants resulted in the special termination benefits presented in the tables above.

Defined Contribution Plans

Through December 31, 2004 we sponsored two employee savings plans, which permit employees to defer receipt of compensation as provided in Section 401(k) of the Internal Revenue Code. Under the plans, the employees may elect to direct a percentage of their gross compensation to be contributed to the plans. We contribute various percentage amounts of the employee's gross compensation contributed to the plan. Costs incurred under these plans were $3.3 million and $3.1 million in 2004 and 2003, respectively. On December 31, 2004, the NorthWestern Corporation savings plan was merged into the NorthWestern Energy savings plan.

(17) Employee Incentive Plans

Successor Company

In connection with the confirmation of our plan of reorganization, the Bankruptcy Court and Creditors Committee approved a New Incentive Plan to be established and administered by the new Board of Directors. The plan of reorganization reserved 2,265,957 shares of new common stock for the New Incentive Plan. In addition, upon emergence 228,315 restricted shares were issued (Special Recognition Grants) under the New Incentive Plan to certain officers and key employees. The fair value at the date of issuance for these Special Recognition Grants was $4.6 million. Fifty percent, or 114,158 shares of the Special Recognition Grants vested upon emergence. The remaining shares vest on November 1, 2005 for non-officers. For officers, the remaining shares vest 10% on November 1, 2005, 20% on November 1, 2006 and 20% on November 1, 2007. Compensation expense recognized in 2004 for these Special Recognition Grants was $2.5 million.

Predecessor Company Stock Option and Incentive Plan

All common stock options under the NorthWestern Stock Option and Incentive Plan (Option Plan) were cancelled upon emergence from bankruptcy. Under the Option Plan, the Predecessor Company had reserved 3,424,595 shares for issuance to officers, key employees and directors as either incentive-based options or nonqualified options. The Compensation Committee (Committee) of our Board of Directors administered the Option Plan.

Information regarding the Predecessor Company's options granted and outstanding is summarized below:

	Shares	Option Price Per Share	Weighted Average Option Price
Balance December 31, 2001	1,884,492	$21.19-26.13	$23.26
Issued	786,200	15.26-20.70	20.61
Canceled	(1,132,527)	20.30-26.13	22.45
Balance December 31, 2002	1,538,165	15.26-26.13	22.49
Issued	500,623	2.05-4.90	3.97
Canceled	(679,600)	20.30-26.13	22.23
Balance December 31, 2003	1,359,188		15.81
Application of fresh-start reporting (Note 3)	(1,359,188)		
Balance December 31, 2004 (Successor Company)	—		

The Predecessor Company had also issued 283,333 shares of common stock in 2003 under a restricted stock plan with a fair value at date of issuance of $1.2 million. These shares were also cancelled upon emergence. The Predecessor Company had previously issued 33,480 shares of common stock in 2001 under this restricted stock plan with a fair value at date of issuance of $0.7 million. Compensation expense recognized was $0.4 million for the 10-months ended October 31, 2004 and $0.3 million for the year ended December 31, 2003. The Predecessor Company's Employee Stock Ownership Plan (ESOP) was terminated effective July 19, 2003, and the shares were distributed to participants during 2003.

(18) Regulatory Assets and Liabilities

We prepare our financial statements in accordance with the provisions of SFAS No. 71, as discussed in Note 4 to the Financial Statements. Pursuant to this pronouncement, certain expenses and credits, normally reflected in income as incurred, are recognized when included in rates and recovered from or refunded to the customers. 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. We have specific orders to cover approximately 98% of our regulatory assets and approximately 96% of our regulatory liabilities.

	Note Ref.	Remaining Amortization Period	December 31, 2004	2003
Pension	16	Undetermined	$135,358	$95,260
Competitive transition charges		9 Years	(398)	548
SFAS No. 106	16	Undetermined	35,567	27,150
Income taxes	13	Plant Lives	7,642	28,832
Other		Various	13,768	11,384
Total regulatory assets			$191,937	$163,174
Gas storage sales		35 Years	$14,615	$15,036
Supply costs		1 Year	16,621	-
Other		Various	2,253	2,272
Total regulatory liabilities			$ 33,489	$17,308

Through fresh-start reporting 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. See Note 3 for further information regarding the impacts of fresh-start reporting. 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. 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. Competitive transition charges relate to natural gas properties and earn a rate of return sufficient to meet the debt service requirements of the Montana natural gas transition bonds. Tax assets and liabilities 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.

A gas storage sales regulatory liability (cushion gas) was established in 2000 and 2001 based on gains on natural 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 and was fully amortized through rates in 2003. A regulatory liability has been recorded to reflect the future refunding of energy supply costs through the ratemaking process.

(19) Deregulation and Regulatory Matters

Deregulation

The electric and natural gas utility businesses in Montana are operating in a competitive market in which commodity energy products and related services are sold directly to wholesale and retail customers.

Electric

Montana's Electric Utility Industry Restructuring and Customer Choice Act (Electric Act), was passed in 1997. Various energy-related legislation revised and refined the Act during the legislative sessions that followed. The 2003 Legislature established us as the permanent default supplier and set the transition period for all customers to be able to choose their electric supplier to end July 1, 2027. As default supplier, we are obligated to continue to supply electric energy to customers in our service territory who have not chosen, or have not had an opportunity to choose, other power suppliers. The 2003 legislation also requires smaller customers to remain as default supply customers and established a specific set of guidelines, requirements and procedures that guide default supply power procurement and their cost recovery. This provides adequate assurances of recovering our costs of acquiring default supply power.

On January 23, 2003, we filed our first biennial Electric Default Supply Resource Procurement Plan with the MPSC, which fulfills the requirements established by law and describes the planning we are doing on behalf of our electric default supply customers to provide adequate, reliable and efficient annual and long-term electricity supply services at the lowest long-term cost. We have a substantial portion of the portfolio covered by the existing PPL Montana base-load contracts and the QF contracts.

Natural Gas

Montana's Natural Gas Utility Restructuring and Customer Choice Act, also passed in 1997, provides that a natural gas utility may voluntarily offer its customers choice of natural gas suppliers and provide open access. We have opened access on our gas transmission and distribution systems, and all of our natural gas customers have the opportunity of gas supply choice. We are also the default supplier for the remaining natural gas customers.

Regulatory Matters

The MPSC, the SDPUC, and the Nebraska Public Service Commission (NPSC) regulate our bundled transmission and distribution services and approve the rates that we charge for these services, while the FERC regulates our transmission services. There have been no significant regulatory issues in South Dakota or Nebraska during the past three years. Current regulatory issues are discussed below.

On August 12, 2003, the Montana Consumer Counsel (MCC) filed a Petition for Investigation, Adoption of Additional Regulatory Controls and Related Relief with the MPSC. On August 22, 2003, the MPSC issued an order initiating an investigation of us relating to, among others, finances, corporate structure, capital structure, cash management practices, and affiliated transactions. The relief sought includes adoption of new regulatory controls that would specifically apply to us including additional reporting, cost allocation and financing rules and requirements, and examination of affiliate transactions necessary to ensure that we are not operating our energy division, and will not in the future operate, in a manner that would prejudice our ability to furnish reasonably adequate service and facilities at reasonable and just charges as required under Montana law. On July 8, 2004, we reached a Stipulation and Settlement Agreement with the MCC that was approved by the MPSC that led to the resolution of this financial investigation. The investigation is closed with the exception of the ongoing review related to an infrastructure audit.

Electric Rates

On June 16, 2003, we filed our annual electric supply cost tracker request with the MPSC for the 12-month period ended June 30, 2003. On July 15, 2003, an interim order was approved by the MPSC for the projected electric supply cost. On June 1, 2004, we filed our annual electric supply cost tracker request with the MPSC for any unrecovered actual electric supply costs for the 24-month period ended June 30, 2004, and for projected costs for the 12-month period ended June 30, 2005. On July 28, an interim order was approved by the MPSC for the projected electric supply cost.

On November 17, 2004, we filed with the MPSC for an automatic rate adjustment of $0.7 million under a Montana statute allowing the recovery of increased state and local taxes and fees. On December 29, 2004, an interim order was approved by the MPSC however the amount was reduced for the net incremental income tax amount of $0.3 million.

On December 13, 2004, we and our non-regulated power marketing subsidiary, NorthWestern Energy Marketing, LLC, filed with the FERC an updated generation market power study to satisfy our respective triennial rate review compliance filing obligation. This triennial filing obligation arises from our and our subsidiary's FERC authorization to sell power at market-based rates. The filing set forth our arguments as to why our subsidiary and we do not possess generation market power and why there are no affiliate abuse concerns arising from our Montana operations.

Natural Gas Rates

On May 28, 2004, we filed an annual gas cost tracker request with the MPSC for any unrecovered actual gas costs for the 12-month period ended June 30, 2004, and for the projected gas costs for the 12-month period ending June 30, 2005. On July 8, 2004, the MPSC issued an interim order, with respect to our recovery of gas costs.

The MPSC issued a final order relating to the 8-month period ending June 30, 2003, which included a disallowance of $6.2 million of actual natural gas costs. The MPSC also rejected a motion for reconsideration filed by us. We filed suit in district court on July 28, 2003, seeking to overturn the MPSC's decision to disallow recovery of these costs. $6.2 million was written off during June 2003 to comply with

the final order. We filed a motion for reconsideration regarding the disallowance of purchased gas cost with the MPSC on July 14, 2003, which was denied. We filed suit in Montana state court on July 28, 2003, seeking to overturn the MPSC's decision to disallow recovery of these costs. At this time, this matter has been suspended pending settlement discussion.

On June 2, 2003, we filed an annual gas cost tracker request with the MPSC for the projected gas costs for the 12-month period ending June 30, 2004. The MPSC granted an interim order on July 3, 2003, for the projected gas cost adjusted for 4,200 MDKT at a fixed price of $3.50 as opposed to the market price submitted in the original filing, which was at a higher price. The disallowance on 4,200 MDKT at market price resulted in the Company under collecting $4.6 million for the period July 1, 2003 through June 30, 2004.

On December 6, 2004, MCC and we filed a stipulation for approval by the MPSC. This stipulation settled recovery of gas costs for the 2003 and 2004 annual gas costs trackers. The MPSC approved this stipulation on April 14, 2005. However, approval is contingent upon settlement of the lawsuit discussed above regarding the disallowance of purchased gas costs between us and the MPSC.

On November 17, 2004, we filed with the MPSC for an automatic rate adjustment of $.2 million under a Montana statute allowing the recovery of increased state and local taxes and fees. On December 29, 2004, an interim order was approved by the MPSC however the amount was reduced for the net incremental income tax amount of $0.1 million.

In Nebraska, where natural gas companies have been regulated by the municipalities in which they serve, the 2003 Nebraska Unicameral Legislature enacted a new law during the second quarter of 2003, shifting the regulation to the NPSC. Under the new law, the NPSC regulates rates and terms and conditions of service for natural gas companies, however, the law provides that a natural gas company and the cities in which it serves have the ability to negotiate rates for natural gas service when the natural gas company files an application for increased rates. If the cities and the company choose not to negotiate or they are unable to reach an agreement, then the NPSC will review the rate filing. Our initial tariffs, including our rates, terms and conditions for service consistent with those formerly filed with the municipalities, were filed with and accepted by the NPSC.

(20) Guarantees, 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 $1.7 billion through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $1.3 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. At December 31, 2004, the liability was $143.4 million.

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

	Gross obligation	Recoverable amounts	Net
2005	$54,347	$ (52,061)	$2,286
2006	56,175	(52,061)	4,114
2007	58,284	(52,567)	5,717
2008	60,537	(53,060)	7,477
2009	62,656	(53,583)	9,073
Thereafter	1,406,260	(1,067,032)	339,228
Total	$1,698,259	$(1,330,364)	$367,895

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 30 years. Costs incurred under these contracts were approximately $331.5 million and $281.6 million for the years ended December 31, 2004 and 2003, respectively. As of December 31, 2004 our commitments under these contracts are $341.2 million in 2005, $228.7 million in 2006, $154.7 million in 2007, $96.2 million in 2008, $89.0 million in 2009 and $271.1 million thereafter. These commitments are not reflected in our Financial Statements.

Employment Contracts

We have an Employment Agreement with Chief Financial Officer Brian B. Bird, which, as amended and approved by the Bankruptcy Court in its Order dated January 13, 2004, provides for him to serve as Chief Financial Officer, commencing December 1, 2003, and extends until the earlier of his termination of employment or December 1, 2005. For the first year of Mr. Bird's compensation package, he received a sign-on bonus, a base salary, performance-based incentive of up to 100% of his annual salary and a housing and commuting allowance. Mr. Bird's future incentive compensation is to be determined by the Board. Mr. Bird is also entitled to participate in our benefit plans available to executives, including, among other things, health, retirement, disability and life insurance benefits. The agreement also provides for severance if Mr. Bird is terminated for any reason other than Cause.

Environmental Liabilities

We are subject to numerous state and federal environmental regulations. Because laws and regulations applicable to our businesses are continually developing and are subject to amendment, reinterpretation and varying degrees of enforcement, we may be subject to, but can not predict with certainty the nature and amount of future environmental liabilities. The Clean Air Act Amendments of 1990 (the Act) stipulate limitations on sulfur dioxide and nitrogen oxide emissions from coal-fired power plants. We believe we can comply with such sulfur dioxide emission requirements at the generating plants serving our South Dakota operations and that we are in compliance with all presently applicable environmental protection requirements and regulations with respect to these plants. We also are subject to other environmental statutes and regulations including those that relate to former manufactured gas plant sites and other past and present operations and facilities. In addition, we may be subject to financial liabilities related to the investigation and remediation from activities of previous owners or operators of our industrial and generating facilities. The range of exposure for environmental remediation obligations at present is estimated to range between $45.3 million to $84.1 million. Our environmental reserve accrual is $45.3 million as of December 31, 2004.

Our subsidiary, CFB owns the Milltown Dam hydroelectric facility, a two 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 announcement, we commenced negotiations with the Atlantic Richfield Company or Atlantic Richfield, to prevent a challenge from Atlantic Richfield to our statutorily exempt status under the Comprehensive Environmental Response Compensation and Liability Act (CERCLA) as a potentially responsible party. On September 10, 2003, we executed a confidential settlement agreement with Atlantic Richfield which, among other things, capped our maximum contribution towards remediation of the Milltown Reservoir superfund site. A motion to approve the settlement agreement with Atlantic Richfield was filed with the Bankruptcy Court on October 17, 2003. On April 7, 2004 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 is intended to resolve both our liability with Atlantic Richfield in general accordance with the previously negotiated settlement agreement and establish a framework to resolve our liability with the Government Parties for their claims, including natural resource restoration claims, against NorthWestern as they relate to

remediation of the Milltown Site. The Stipulation caps NorthWestern's and CFB's collective liability to Atlantic Richfield and the Government Parties at $11.4 million. On June 22, 2004 the Bankruptcy Court approved the Stipulation and the funding of the Atlantic Richfield settlement, as modified by the Stipulation. The amount of the stipulated liability has been fully accrued in the accompanying financial statements. Pursuant to the Stipulation, commencing in August 2004 and each month thereafter, we pay $500,000 alternately into two escrow accounts, one for the State of Montana and one for Atlantic Richfield, until the total agreed amount is funded. No interest will accrue on the unpaid balance due, and the escrow accounts will remain funded until a final, nonappealable consent decree is entered by the United States District Court. If, however, a consent decree (i) is not executed by the relevant parties, (ii) is not approved by the United States District Court, or (iii) does not become fully effective, then all funds in the escrow accounts will continue to be held in trust pending further court order. The Stipulation incorporates appropriate releases and indemnifications from Atlantic Richfield under the previously negotiated settlement agreement. There can be no assurance that the settlement set forth in the Stipulation will become effective, as the parties to this matter continue to negotiate the terms and conditions of the consent decree.

In anticipation of completion of the consent decree negotiations, CFB filed an application to amend its FERC operating license to allow for the commencement of Stage 1 of the EPA's proposed plan for the remediation of the Milltown Reservoir superfund site. Stage 1 activities anticipated the permanent drawdown of the Milltown Reservoir and the construction of: (i) the Clark Fork River bypass channel, (ii) a railroad spur to facilitate loading of contaminated sediments to be removed from the reservoir, and (iii) certain equipment access roads. All such construction activity was to take place within FERC jurisdictional areas. On January 19, 2005, the FERC issued an order dismissing CFB's application, and issuing a notice of intent to accept surrender of CFB's operating license. Based on certain incorrect assumptions made by the FERC (particularly with respect to the existence of a completed and executed consent decree for the Milltown Reservoir superfund site as of the date of the order), the FERC transferred its complete jurisdiction over the Milltown facility to the EPA and concluded that, based on certain actions to take place during the Stage 1 activities, that such actions demonstrate CFB's intent to surrender its operating license. Moreover, based upon the operation of Section 121(e) of CERCLA, the FERC concluded that CFB need not file a formal license surrender application. Due to the FERC's reliance upon certain incorrect assumptions, all relevant parties to the Milltown superfund consent decree negotiations concluded that the order created certain unacceptable risks due, in large part, to the fact that a consent decree addressing the rights and obligations of the various parties with respect to implementation of the Milltown remedial action and restoration plan has not been fully negotiated and approved by the federal district court in Montana. As a result, EPA, the State of Montana, the Atlantic Richfield Company and CFB all filed comments with the FERC on February 18, 2005, requesting that the FERC modify its order to continue jurisdiction over the Milltown facility until entry of a final consent decree.

Legal Proceedings

As a result of the Chapter 11 filing for the period from September 14, 2003 through November 1, 2004, attempts by third parties to collect, secure or enforce remedies with respect to most prepetition claims against us were subject to the automatic stay provisions of Section 362(a) of Chapter 11.

On October 19, 2004 the Bankruptcy Court entered a written order confirming our plan of reorganization. On October 25, 2004 Magten Asset Management Corporation (Magten) filed a notice of appeal of such order seeking, among other things, a reversal of the confirmation order. In connection with this appeal, Magten filed motions with the Bankruptcy Court and the United States District Court for the District of Delaware seeking a stay of the enforcement of the confirmation order to prevent our plan of reorganization from becoming effective. On October 25, 2004 the Bankruptcy Court denied Magten's motion for a stay, and on October 29, 2004, the Delaware District Court denied Magten's motion for a stay. With no stay imposed, our plan of reorganization became effective November 1, 2004. On December 31, 2004 a notice was filed that our plan of reorganization has been substantially consummated. In March 2005, we filed a motion to dismiss the appeal on equitable mootness grounds. While we cannot currently predict the impact or resolution of Magten's appeal of the confirmation order, we intend to vigorously defend against the appeal.

On May 4, 2004, Netexit and its subsidiaries filed for bankruptcy protection under chapter 11 of the U.S. Bankruptcy Code. A creditors committee has been formed which is composed of creditors who had

pending lawsuits and claims against Netexit at the time of filing for bankruptcy. Netexit and its subsidiaries filed a liquidating plan of reorganization on February 28, 2005 and a hearing on the disclosure statement is scheduled for April 5, 2005. The creditors committee has sent NorthWestern and Netexit a notice that it will be seeking bankruptcy court approval to file an avoidance or subordination claim against NorthWestern if Netexit and its subsidiaries do not. We intend to vigorously defend against the creditors committee claim if filed in Netexit's bankruptcy case, but we cannot currently predict the impact or resolution of such creditors committee action on NorthWestern's claim in Netexit's bankruptcy case.

We, and certain of our present and former officers and directors, were named as defendants in numerous complaints purporting to be class actions which were filed in the United States District Court for the District of South Dakota, Southern Division, alleging violations of Sections 11, 12 and 15 of the Securities Act of 1933 and Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 and Rule 10b-5 promulgated thereunder. In June 2003, the complaints were consolidated in the United States District Court for the District of South Dakota and given the caption *In Re NorthWestern Corporation Securities Litigation*, Case No. 03-4049, and Carpenters Pension Trust for Southern California, Oppenheim Investment Management, LLC, and Richard C. Slump were named as co-lead plaintiffs (the "Lead Plaintiffs"). In July 2003, the Lead Plaintiffs filed a consolidated amended class action complaint naming NorthWestern, NorthWestern Capital Financing II and III, Blue Dot, Expanets, certain of our present and former officers and directors, along with a number of investment banks that participated in the securities offerings. The amended complaint alleges that the defendants misrepresented and omitted material facts concerning the business operations and financial performance of NorthWestern, Expanets, Blue Dot and CornerStone, overstated NorthWestern's revenues and earnings by, among other things, maintaining insufficient reserves for accounts receivable at Expanets, failing to disclose billing problems and lapses and data conversion problems, failing to make full disclosures of problems (including the billing and data conversion issues) arising from the implementation of Expanets' EXPERT system, concealing losses at Expanets and Blue Dot by improperly allocating losses to minority interest shareholders, maintaining insufficient internal controls, and profiting from improper related-party transactions. We, and certain of our present and former officers and directors, were also named as defendants in two complaints purporting to be class actions which were filed in the United States District Court for the Southern District of New York, entitled Sanford & Beatrice Golman Family Trust, et al. v. NorthWestern Corp., et al., Case No. 03CV3223, and Arthur Laufer v. Merle Lewis, et al., Case No. 03CV3716, which were brought on behalf of the purchasers of our 7.20%, 8.25%, and 8.10% trust preferred securities which were offered and sold pursuant to our registration statement on Form S-3 filed on July 12, 1999. The plaintiffs' claims are based on similar allegations of material misrepresentations and omissions of fact relating to the registration statement in violation of Sections 11 and 12 of the Securities Act of 1933, and they seek unspecified compensatory damages, rescission and attorneys', accountants' and experts' fees. In July 2003, Arthur Laufer v. Merle Lewis, et al. was transferred to the District of South Dakota and consolidated with the consolidated actions pending in that court. In September 2003, Sanford & Beatrice Golman Family Trust, et al. v. NorthWestern Corp., et al. was also transferred to the District of South Dakota and consolidated with the consolidated actions. In February 2004, the Golman Family Trust action was also consolidated with the actions pending in that court. The actions have been stayed as to NorthWestern Corporation due to its bankruptcy filing. In October 2003, Expanets, Blue Dot, and certain of NorthWestern's present and former officers and directors filed motions to dismiss the consolidated amended class action complaint for failure to state a claim, which are currently pending in the District of South Dakota.

Certain of our present and former officers, former directors and NorthWestern, as a nominal defendant, have been named in two shareholder derivative actions commenced in the United States District Court for the District of South Dakota, Southern Division, entitled Deryl Lusty, et al. v. Richard R. Hylland, et al., Case No. CIV034091 and Jerald and Betty Stewart, et al. v. Richard R. Hylland, et al., Case No. CIV034114. These shareholder derivative lawsuits allege that the defendants breached various fiduciary duties based upon the same general set of alleged facts and circumstances as the federal shareholder suits. The plaintiffs seek unspecified compensatory damages, restitution of improper salaries, insider trading profits and payments from NorthWestern, and disgorgement under the Sarbanes-Oxley Act of 2002. In July 2003, the complaints were consolidated in the United States District Court for the District of South Dakota and given the caption In re NorthWestern Corporation Derivative Litigation, Case No. 03-4091. In October 2003, the action was stayed pending a ruling on defendants' motions to dismiss in the related securities class action, *In re NorthWestern Corporation Securities Litigation*. On November 6,

2003, the Bankruptcy Court entered an order preliminarily enjoining the plaintiffs in *In re NorthWestern Corporation Derivative Litigation* from prosecuting the litigation against NorthWestern, its subsidiaries and its current and former officers and directors until further order of the Bankruptcy Court. On February 15, 2005, the Bankruptcy Court vacated its preliminary injunction order. The federal court has been advised of the Bankruptcy Court's order.

On February 7, 2004, the parties to the above consolidated securities class actions and consolidated derivative litigation, together with certain other affected persons and parties, reached a tentative settlement of the litigation. On April 19, 2004, the parties and other affected persons signed a memorandum of understanding (MOU) which memorialized the tentative settlement. On June 16, 2004, the parties and other affected persons signed a settlement agreement memorializing the tentative settlement and addressing various issues necessary for federal court approval. We obtained approval of the MOU in the NorthWestern and Netexit bankruptcy cases on October 7, 2004 and September 15, 2004, respectively. Prior to those approvals from the Bankruptcy Court in both the NorthWestern and Netexit bankruptcy cases, the federal court in Sioux Falls granted preliminary approval of the settlement agreement pending a fairness hearing on December 13, 2004. On January 14, 2004 the federal court finally approved the settlement *In Re NorthWestern Securities Litigation* and no timely appeals have been filed. The federal court delayed its final approval on *In Re NorthWestern Derivative Litigation* pending bankruptcy court dismissal of its stay of the derivative litigation. Among the terms of the settlement, we, Expanets, Blue Dot and other parties and persons are released from all claims to these cases, a settlement fund in the amount of $41 million (of which approximately $37 million would be contributed by our directors and officers liability insurance carriers, and $4 million would be contributed from other persons and parties) is established, and the plaintiffs have a $20 million liquidated securities claim against Netexit. Claims by our current and former officers and directors for indemnification for these proceedings will be channeled into the Directors and Officers Trust under the Plan.

On October 26, 2004 Magten filed a notice of appeal of the Bankruptcy Court's approval of the MOU. Magten's appeal of the confirmation order and the order approving the MOU have been consolidated. In March 2005 we moved to dismiss both appeals on equitable mootness grounds. While we cannot currently predict the impact or resolution of the appeals and our motion to dismiss, we intend to vigorously prosecute our dismissal motion and defend against the appeals as noted.

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. This development followed the SEC's requests for information made in connection with the previously disclosed SEC informal inquiry into questions regarding the restatements and other accounting and financial reporting matters. Since December 2003, we have periodically received and continue to receive subpoenas from the SEC requesting documents and testimony from employees regarding these matters. The SEC investigation will continue and any claims alleging violations of federal securities laws made by the SEC will not be extinguished pursuant to our plan of reorganization. In addition, certain of our directors and several employees of NorthWestern and our subsidiary affiliates have been interviewed by representatives of the Federal Bureau of Investigation (FBI) concerning certain of the allegations made in the class action securities and derivative litigation matters. We have not been advised that NorthWestern is the subject of any FBI investigation. We understand that the FBI and the Internal Revenue Service (IRS) have contacted former employees of ours or our subsidiaries. As of the date hereof, we are not aware of any other governmental inquiry or investigation related to these matters. We are cooperating with the SEC's investigation and intend to cooperate with the FBI and IRS if we are contacted in connection with any investigation. We cannot predict whether or not any other governmental inquiry or investigation will be commenced. We cannot predict when the SEC investigation will be completed or its outcome. If the SEC determines that we have violated federal securities laws and institutes civil enforcement proceedings against us, for which we can provide no assurance, we may face sanctions, including, but not limited to, monetary penalties and injunctive relief and any monetary liability incurred by us may be material to our financial position or results of operations.

In January 2004, two of the QFs—Colstrip Electric Limited Partnership (CELP) and Yellowstone Electric Limited Partnership (YELP)—initiated adversary proceedings against NorthWestern in our Chapter 11 proceedings. In the CELP adversary proceeding, CELP seeks additional payment for capacity contracted to be provided to NorthWestern under its existing power purchase agreement. In addition, we

intervened in a FERC proceeding, which places at issue the QF status of CELP. A FERC judge initially has ruled that CELP is a QF; we filed an appeal with the FERC on October 12, 2004 and the FERC's response is pending. In the YELP adversary proceeding, YELP seeks a determination of when and who has the right to determine the scheduling of maintenance on the power facility. We have obtained approval in our bankruptcy case for assumption of an amended agreement with YELP and a settlement with YELP which resolves prepetition claims, lowers the overall energy cost and eliminates the distinction in the previous agreement between summer and winter pricing. We intend to vigorously defend against the CELP adversary proceedings. In the opinion of management, the amount of ultimate liability with respect to the CELP adversary proceedings will not materially affect our financial position or results of operations.

On April 16, 2004 Magten and Law Debenture Trust Company of New York (Law Debenture) initiated an adversary proceeding, the QUIPs Litigation, against NorthWestern seeking among other things, to void the transfer of certain assets 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 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. By its adversary proceeding, the 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. In August 2004, the Bankruptcy Court granted in part, but denied in part our motion to dismiss the QUIPs Litigation. (In addition to the adversary proceeding filed by Magten and Law Debenture, the plaintiffs in the class action lawsuit entitled McGreevey, et al v. Montana Power Company, et al received approval in our bankruptcy case to initiate similar adversary proceedings. Under the terms of the settlement with the plaintiffs in the McGreevey case discussed below, they would not file such proceeding.) 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 breaches of fiduciary duties by such officers. 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. On February 9, 2005 we agreed to settlement terms with Magten and Law Debenture to release all claims, including Magten and Law Debenture's fraudulent conveyance action pending against each other for Magten and Law Debenture receiving the distribution of new common stock and warrants from Class 8(b) in the same amounts as if they had voted to accept the Plan and a distribution from Class 9 of new common stock in the amount of approximately $17.4 million. Prior to seeking approval from the Bankruptcy Court, certain major shareholders and the Plan Committee objected to the settlement on both its economic terms and asserting that the structure of the settlement violated the Plan. After reviewing the objections and undertaking our own analysis of the potential Plan violation, we informed Magten and Law Debenture as well as the Plan Committee and the objecting major shareholders that we would not proceed with the settlement. Magten and Law Debenture have filed a motion with our Bankruptcy Court seeking approval of the settlement. A hearing was held on such motion on March 8, 2005. The Bankruptcy Court took this matter under advisement and entered an order denying the motion filed by Magten and Law Debenture on March 10, 2005. At this time, we cannot predict the impact of the resolution of any of these lawsuits or reasonably estimate a range of possible loss, which could be material. The resolution of these lawsuits could harm our business and have a material adverse impact on our financial condition. We intend to vigorously defend against the adversary proceeding and any subsequently filed similar 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 share reserve that we established with respect to the Class 9 disputed claims reserve under the plan of reorganization.

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 Montana Power LLC, which plaintiffs claim is a successor to the Montana Power Company.

On November 6, 2003, the Bankruptcy Court approved a stipulation between NorthWestern and the plaintiffs in McGreevey, et al. v. The Montana Power Company, et al. The stipulation provides that litigation, as against NorthWestern, CFB, The Montana Power Company, Montana Power LLC and Jack Haffey, shall be temporarily stayed for 180 days from the date of the stipulation. The stay has been extended. Pursuant to the stipulation and after providing notice to NorthWestern, the plaintiffs may move the Bankruptcy Court for termination of the temporary stay. On July 10, 2004, we and the other insureds under the applicable directors and officers liability insurance policies along with the plaintiffs in the McGreevey case, plaintiffs in the *In Re Touch America Holdings, Inc. Securities Litigation* and the Touch America Creditors Committee reached a tentative settlement through mediation. Among the terms of the tentative settlement, we, CFB and other parties will be released from all claims in this case, the plaintiffs in McGreevey will dismiss their claims against the third party purchasers of the generation assets and non-regulated energy assets of Montana Power Company including PPL Montana, and a settlement fund in the amount of $67 million (all of which will be contributed by the former Montana Power Company directors and officers liability insurance carriers) will be established. The settlement is subject to the occurrence of several conditions, including approval of the proposed settlement by the Bankruptcy Court in our bankruptcy proceeding, and approval of the proposed settlement by the Federal District Court for the District of Montana, where the class actions are pending. We cannot predict the ultimate outcome of this litigation in the event that the settlement is not approved, or does not take effect for any other reason. If for any reason the settlement is not approved, then we intend to vigorously defend against this lawsuit. If we are unsuccessful in defending against this class action lawsuit, the plaintiffs' litigation claims would be subordinated to our other debt under our Plan, and such claims would be treated as securities, or Class 14, claims under our plan of reorganization, and would be entitled to no recovery against NorthWestern under our Plan. Claims by our current and former officers and directors (and the former officers and directors of The Montana Power Company) for indemnification for these proceedings would be channeled into the Directors and Officers Trust established by the Plan. The plaintiffs could elect to proceed directly against CFB and the assets owned by such entity, which as of December 31, 2004 were not material to our operations or financial position. We cannot currently predict the impact or resolution of this litigation or reasonably estimate a range of possible loss, which could be material, and the resolution of this lawsuit may harm our business and have a material adverse impact on our financial condition.

In NorthWestern Corporation vs. PPL Montana, LLC vs. NorthWestern Corporation and Clark Fork and Blackfoot, LLC, No. CV-02-94-BU-SHE, (D. MT), we are pursuing claims against PPL Montana, LLC (PPL) due to its refusal to purchase the Colstrip transmission assets under the Asset Purchase Agreement (APA) executed by and between The Montana Power Company (MPC) and PP&L Global, Inc. (PPL Global). NorthWestern claims PPL (PPL Global's successor-in-interest under the APA) is required to purchase the Colstrip transmission assets for $97.1 million. PPL has also asserted a number of counterclaims against NorthWestern and CFB based in large part upon PPL's claim that MPC and/or NorthWestern Energy breached two Wholesale Transition Service Agreements and certain indemnification obligations under the APA in the approximate amount of $120 million. PPL also filed a proof of claim and an amended proof of claim against NorthWestern's bankruptcy estate which asserts substantially the same claims as the PPL counterclaim. PPL moved the Bankruptcy Court for relief from the automatic stay to pursue its counterclaims. NorthWestern objected to PPL's motion to lift the automatic stay and has also filed a motion to transfer the venue of the entire litigation to the United States District Court for the District of Delaware. On March 19, 2004 the federal court in Montana denied our motion to transfer the entire case. Thereafter, our Bankruptcy Court transferred all the claims for resolution to the federal court in Montana. We intend to vigorously defend against the PPL claims in federal court as well as vigorously prosecute our claims against PPL. We cannot currently predict the impact or resolution of the claims or this litigation or reasonably estimate a range of possible loss on the counterclaims, which could be material to the disputed claims reserve. PPL's counterclaims with respect to this litigation will be treated as general unsecured, or Class 9, claims and will be satisfied out of the share reserve that we established with respect to the Class 9 disputed claims reserve under the plan of reorganization.

We are also one of several defendants in a class action lawsuit entitled *In Re Touch America ERISA Litigation*, which is currently pending in U.S. District Court in Montana. The lawsuit was filed by participants in the former Montana Power Company retirement savings plan and alleges that there was a breach of fiduciary duty in connection with the employee stock ownership aspects of the plan. The court has recently entered orders indefinitely staying the ERISA litigation because of Touch America

Holdings Inc.'s bankruptcy filing. We intend to vigorously defend against these lawsuits. We cannot currently predict the impact or resolution of this litigation or reasonably estimate a range of possible loss, which could be material, and the resolution of this lawsuit may harm our business and have a material adverse impact on our financial condition. We believe that in the event of a judgment against us in this litigation, we will be able to make claims against The Montana Power Company's fiduciary insurance policy. Any judgment against us in excess of policy limits would be treated as unsecured general, or Class 9, claims and would be satisfied out of the share reserve that we have established.

We, and certain of our former officers and directors, were named as defendants in certain complaints filed against CornerStone Propane Partners, LP and other defendants purporting to be class actions filed in the United States District Court for the Northern District of California by purchasers of units of CornerStone Propane Partners alleging violations of Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 and Rule 10b-5 promulgated thereunder. Through November 1, 2002, we held an economic equity interest in a subsidiary that serves as the managing general partner of CornerStone Propane Partners, LP. Certain former officers and directors of NorthWestern who are named as defendants in certain of these actions have also been sued in their capacities as directors of the managing general partner. These complaints allege that defendants sold units of CornerStone Propane Partners based upon false and misleading statements and failed to disclose material information about CornerStone Propane Partners' financial condition and future prospects, including overpayment for acquisitions, overstating earnings and net income, and that it lacked adequate internal controls. All of the lawsuits have now been consolidated and Gilbert H. Lamphere has been named as lead plaintiff. The actions have been stayed as to NorthWestern due to its bankruptcy filing. On October 27, 2003, the plaintiffs filed an amended consolidated class action complaint. The new complaint does not name NorthWestern as a defendant, although it alleges facts relating to NorthWestern's conduct. Certain of our former officers and directors are named as defendants in the amended consolidated complaint. The plaintiffs seek compensatory damages, prejudgment and postjudgment interest and costs, injunctive relief, and other relief. On November 6, 2003, the Bankruptcy Court entered an order approving a stipulation between NorthWestern and plaintiffs in this litigation. The stipulation provides that litigation as against NorthWestern shall be temporarily stayed for 180 days from the date of the stipulation. The stay has been extended. Pursuant to the stipulation and after providing notice to NorthWestern, the plaintiffs may move the Bankruptcy Court for termination of the temporary stay. On March 2, 2004, the plaintiffs filed a corrected consolidated amended complaint against CornerStone and the individual defendants, which also did not name NorthWestern. In June 2004, CornerStone Propane Partners, LP along with its subsidiaries and affiliates filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. As a result of that filing this case is now stayed against CornerStone Propane Partners and other named subsidiaries and affiliates. If we are named in the lawsuit, we intend to vigorously defend any claims asserted against us by these lawsuits. To the extent such claims are prepetition claims, such claims would be extinguished under the confirmation order. If the claims are not extinguished, the plaintiffs' claims with respect to this litigation would be treated as securities, or Class 14, claims and would be entitled to no recovery under the plan of reorganization. Any claims in this litigation for indemnification from our officers and directors, would be channeled into the Directors and Officers Trust to the extent that they are indemnification claims.

We were named in a complaint filed against us, CornerStone Propane GP, Inc., CornerStone Propane Partners LP and other defendants in a lawsuit entitled Leonard S. Mewhinney, Jr. v. NorthWestern Corporation, et al. in the circuit court of the city of St. Louis, state of Missouri. The complaint alleges that the plaintiff purchased units of Cornerstone Propane Partners, LP between March 13, 1998 and November 29, 2001 and that NorthWestern owned and controlled all or the majority of stock or other indicia of ownership of Cornerstone Propane, GP, Inc. and all other entities that were the general partners of Cornerstone Propane Partners, LP. According to the plaintiff, NorthWestern, Cornerstone Propane GP, Inc., Coast Gas, Inc. and Cornerstone Propane Partners, LP breached fiduciary duties to the plaintiff by engaging in certain misconduct, including mismanaging Cornerstone Propane Partners, LP and transferring its assets for less than market value and other activities. The complaint further alleges that the defendants fraudulently failed to disclose material information regarding the value of units of Cornerstone Propane Partners, LP and violated the Florida Securities Act in connection with the sale of such units. The plaintiff seeks compensatory damages, punitive damages and costs. The complaint was amended to add a state class action claim. All defendants filed a petition to remove the case to the federal court in St. Louis, Missouri,

but the federal court granted plaintiff's motion to remand. The case has now been stayed against NorthWestern and CornerStone due to their bankruptcy filings. Any claim arising from this lawsuit has been channeled to the Directors and Officers Trust under the confirmation order.

Certain of our present and former officers and directors, and CornerStone Propane Partners, LP, as a nominal defendant, are among other defendants named in two derivative actions commenced in the Superior Court for the State of California, County of Santa Cruz, entitled Adelaide Andrews v. Keith G. Baxter, et al., Case No. CV146662 and Ralph Tyndall v. Keith G. Baxter, et al., Case No. CV146661. These derivative lawsuits allege that the defendants breached various fiduciary duties based upon the same general set of alleged facts and circumstances as the federal unitholder suits. The plaintiffs seek unspecified compensatory damages, treble damages pursuant to the California Corporations Code, injunctive relief, restitution, disgorgement, costs, and other relief. The case has now been stayed against CornerStone due to its bankruptcy filing. Claims by our current and former officers and directors for indemnification with respect to these proceedings would be channeled into the Directors and Officers Trust under the terms of the Plan.

On April 30, 2003, Mr. Richard Hylland, our former President and Chief Operating Officer, filed a demand for arbitration of contract claims under his employment agreement, as well as tort claims for defamation, infliction of emotional distress and tortious interference and a claim for punitive damages. Mr. Hylland is seeking relief in the amount of $25 million, plus interest, attorney's fees, costs, and punitive damages. Mr. Hylland has also filed claims in our bankruptcy case similar to the claims in his arbitration demand. We dispute Mr. Hylland's claims and intend to vigorously defend the arbitration and object to Mr. Hylland's claims in our bankruptcy case. On May 6, 2003, based on the recommendations of the Special Committee of the NorthWestern Board of Directors formed to evaluate Mr. Hylland's performance and conduct in connection with the management of NorthWestern and its subsidiaries, the Board determined that Mr. Hylland's performance and conduct as President and Chief Operating Officer warranted termination under his employment contract. This arbitration will proceed under the terms of the order confirming the Plan, and we have obtained a timetable from the arbitrator. Mr. Hylland's claims with respect to this proceeding would be treated as unsecured general, or Class 9, claims and would be satisfied out of the share reserve that we have established.

On August 12, 2003, the Montana Consumer Counsel (MCC) filed a Petition for Investigation, Adoption of Additional Regulatory Controls and Related Relief with the Montana Public Service Commission (MPSC). On August 22, 2003, the MPSC issued an order initiating an investigation of NorthWestern Energy relating to, among others, finances, corporate structure, capital structure, cash management practices and affiliated transactions. The relief sought includes adoption of new regulatory controls that would specifically apply to NorthWestern, including additional reporting, cost allocation and financing rules and requirements, and examination of affiliate transactions necessary to ensure that we are not operating our energy division, and will not in the future operate, in a manner that would prejudice our ability to furnish reasonably adequate service and facilities at reasonable and just charges as required under Montana law. We have entered into a settlement of this matter with the MPSC and MCC, which was approved by the Bankruptcy Court on July 15, 2004, and thereafter by the MPSC, and this proceeding will be closed except for the ongoing review and consideration of recommendations related to an infrastructure audit conducted by a consultant. We are currently reviewing these recommendations and have not yet determined the estimated financial impact they may have on our results of operations. As part of the settlement, we agreed to pay approximately $2.8 million of professional fees incurred by the MPSC, the MCC and the Montana Attorney General in connection with our bankruptcy filing. These fees were paid upon emergence from bankruptcy.

Expanets and NorthWestern have been named defendants in two complaints filed with the Supreme Court of the State of New York, County of Bronx, alleging violations of New York's prevailing wage laws, breach of contract, unjust enrichment, willful failure to pay wages, race, ethnicity, national origin and/or age discrimination and retaliation. In the complaint entitled Felix Adames et al. v. Avaya, Expanets, NorthWestern et al., Supreme Court of the State of New York, Bronx County, Index No. 8664-04, which has not yet been served upon Expanets, 14 former employees of Expanets seek damages in the amount of $27,750,000, plus interest, penalties, punitive damages, costs, and attorney's fees. In the complaint entitled Wayne Belnavis and David Daniels v. Avaya, Expanets, NorthWestern et al., Supreme Court of the State of New York, Bronx County, Index No. 8729-04, two former employees of Expanets seek damages in the

amount of $12,500,000, plus interest, penalties, punitive damages, costs, and attorney's fees. Avaya Inc. has sent NorthWestern and subsidiaries a notice seeking indemnification and defense for these lawsuits under the asset purchase agreement. We have responded by accepting in part and rejecting in part the indemnification request. As a result of the Netexit bankruptcy, the cases were removed to federal court in New York and Netexit was dismissed from the lawsuit. NorthWestern and Avaya were dismissed as defendants by the plaintiffs. These claims against Netexit will be subject to the claims process of the Netexit bankruptcy proceeding. We intend to vigorously defend against the allegations made in these claims. We cannot currently predict the impact or resolution of these claims or reasonably estimate a range of possible loss.

Netexit is also subject to an investigation by the New York City Comptroller's Office over the same prevailing wage allegations set forth in the Adames and Belnavis lawsuits. The Comptroller's Office scheduled a hearing before the Office of Administrative Trials and Hearings, which hearing is now stayed pending the Bankruptcy Court's decision on its rule to show cause why the Comptroller's Office should not be held in contempt of court. The Comptroller's Office also filed claims in the Netexit bankruptcy and will be subject to the claims process in the bankruptcy case. Avaya Inc. has sent NorthWestern and subsidiaries a notice seeking indemnification and defense for these lawsuits under the asset purchase agreement. We have responded by accepting in part and rejecting in part the indemnification request. We intend to vigorously defend against the allegations made in these claims. We cannot currently predict the impact or resolution of these claims or reasonably estimate a range of possible loss.

On March 17, 2004, certain minority shareholders of Expanets filed a lawsuit against Avaya Inc., Expanets, NorthWestern Growth Corporation, and Merle Lewis, Dick Hylland and Dan Newell entitled Cohen et al. v Avaya Inc., et al. in U.S. District Court in Sioux Falls, South Dakota contending that (i) the defendants fraudulently induced the shareholders to sell their businesses to Expanets during 1998 and 1999 in exchange for Expanets stock which would have value only if Expanets went public, when in fact no IPO was intended, and (ii) the defendants and NorthWestern (a) hid the true financial condition of NorthWestern, NorthWestern Growth and Expanets, (b) permitted internal controls to lapse, (c) failed to document loans by NorthWestern to Expanets, and (d) allowed the individual defendants to realize millions of dollars in bonus payments at the expense of Expanets and its minority shareholders. The lawsuit alleges federal and state securities laws violations and breaches for fiduciary duties. The plaintiffs have recently filed an amended complaint that reflects one less plaintiff and a clarification on the damages that they seek. In addition, Avaya Inc. has sent NorthWestern a notice seeking indemnification and defense for this lawsuit under the terms of the asset purchase agreement. We have responded by accepting in part and rejecting in part the indemnification request. The case has now been stayed against Expanets due to its bankruptcy filing. The defendants, including NorthWestern Growth Corporation, have filed motions to dismiss, which are pending and we have filed a formal objection to the claim the defendants filed in the bankruptcy case. Claims by our former officers and directors for indemnification for these proceedings would be channeled in to the Directors and Officers Trust established pursuant to NorthWestern's Plan. The plaintiff's litigation claims against Netexit would be subordinated to NorthWestern's debt and claims of general unsecured creditors in the Netexit bankruptcy, and therefore such claims would not be entitled to recovery. NorthWestern Growth Corporation intends to vigorously defend against this lawsuit. We cannot currently predict the impact or resolution of this litigation or reasonably estimate a range of possible loss, which could be material.

Relative to Colstrip Unit 4's long-term coal supply contract with Western Energy Company, Mineral Management Service of the United States Department of Interior issued orders to Western Energy Company (WECO) in 2002 and 2003 to pay additional royalties concerning coal sold to Colstrip Units 3 and 4. The orders assert that additional royalties are owed as a result of WECO not paying royalties under a coal transportation agreement from 1991 through 2001. WECO has appealed these orders and we are monitoring the process. WECO has asserted that any potential judgment would be considered a pass-through cost under the coal supply agreement. Based on our review, we do not believe any potential judgment would qualify as a pass-through cost under the terms of the coal supply agreement. Neither the outcome of this matter nor the associated costs can be predicted at this time.

Each year we submit a natural gas tracker filing for recovery of natural gas costs. The MPSC reviews such filings and makes a determination as to whether or not our natural gas procurement activities were prudent. If the MPSC finds that we have not exercised prudence, it can disallow such costs. For the tracker

period ending June 30, 2003, the MPSC issued a final order relating to that period, which included a disallowance of $6.2 million of natural gas costs. We filed a motion for reconsideration regarding the disallowance of purchased natural gas cost with the MPSC on July 14, 2003, which was denied. Since we believe that the natural gas procurement activities in question were not imprudent we filed suit in district court on July 28, 2003, seeking to overturn the MPSC's decision to disallow recovery of these costs. At this time, this matter has been suspended pending settlement discussions with the MPSC.

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 or results of operations.

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 of reorganization. If these claims ultimately exceed the reserve, then such claimants could request the bankruptcy court to amend our plan of reorganization to allow for payment of the claims in excess of the reserve. 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.

(21) Capital Stock

The Predecessor Company's Plan became effective and the Predecessor Company emerged from bankruptcy on November 1, 2004. The Predecessor Company applied fresh-start reporting effective October 31, 2004 and, as a result, reflected all shares of NorthWestern Corporation common stock as cancelled in accordance with the Plan.

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 issued for Special Recognition Grants (see Note 17).

In addition, 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 strike price of $28.48. We recognized $3.8 million of expense associated with these warrants as a reduction of cancellation of indebtedness income.

Sch. 19	MONTANA PLANT IN SERVICE - NATURAL GAS (INCLUDES CMP)			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1	**Intangible Plant**			
2	2301 Organization	$12,873	$12,876	-0.02%
3	2302 Franchises and Consents	114,169	114,169	0.00%
4	2303 Miscellaneous Intangible Plant	507,254	521,586	-2.75%
5	**Total Intangible Plant**	634,296	648,631	-2.21%
6	2004			
7	**Underground Storage Plant**			
8	2350 Land and Land Rights	4,140,119	3,995,388	3.62%
9	2351 Structures and Improvements	2,905,632	2,845,364	2.12%
10	2352 Wells	7,801,650	7,782,699	0.24%
11	2353 Lines	7,088,914	6,525,844	8.63%
12	2354 Compressor Station Equipment	7,306,416	7,279,989	0.36%
13	2355 Measuring & Regulating Equip.	1,998,228	1,995,005	0.16%
14	2356 Purification Equipment	223,171	223,171	0.00%
15	2357 Other Equipment	831,994	831,994	0.00%
16	**Total Underground Storage Plant**	32,296,124	31,479,454	2.59%
17				
18	**Transmission Plant**			
19	2365 Rights of Way	5,810,431	5,527,200	5.12%
20	2366 Structures and Improvements	8,820,235	8,807,540	0.14%
21	2367 Mains	141,414,933	133,635,438	5.82%
22	2368 Compressor Station Equipment	17,782,880	17,720,360	0.35%
23	2369 Meas. & Reg. Station Equipment	11,160,912	10,574,293	5.55%
24	2370 Communication Equipment	-	21,616	-100.00%
24	2371 Other Equipment	83,701	82,052	2.01%
25	**Total Transmission Plant**	185,073,092	176,368,499	4.94%
26				
27	**Distribution Plant**			
28	2374 Land and Land Rights	874,556	874,556	0.00%
29	2375 Structures and Improvements	89,106	89,106	0.00%
30	2376 Mains	81,912,860	77,530,920	5.65%
31	2377 Compressor Station Equipment		-	-
32	2378 M&R Station Equip.-General	2,055,115	2,015,705	1.96%
33	2379 M&R Station Equip.-City Gate		-	-
34	2380 Services	53,791,734	52,916,670	1.65%
35	2381 Customers Meters and Regulators	28,836,651	26,772,261	7.71%
36	2382 Meter Installations	11,231,162	10,201,753	10.09%
37	2383 House Regulators		-	-
38	2384 House Regulator Installations		-	-
39	2385 M&R Station Equip.-Industrial	56,334	56,334	0.00%
40	2386 Other Prop. on Customers' Premises		-	-
41	2387 Other Equipment	2,903	-	-
42	**Total Distribution Plant**	178,850,421	170,457,305	4.92%

Sch. 19 cont. **MONTANA PLANT IN SERVICE - NATURAL GAS (INCLUDES CMP)**

	Account Number & Title	This Year Montana	Last Year Montana	% Change
1				
2	**General Plant**			
3	2389 Land and Land Rights	101,675	101,675	-
4	2390 Structures and Improvements	679,257	684,305	-0.74%
5	2391 Office Furniture and Equipment	1,151,854	1,164,688	-1.10%
6	2392 Transportation Equipment	4,725,206	4,389,480	7.65%
7	2393 Stores Equipment	11,131	12,037	-7.53%
8	2394 Tools, Shop & Garage Equipment	3,934,983	3,990,380	-1.39%
9	2395 Laboratory Equipment	775,651	786,655	-1.40%
10	2396 Power Operated Equipment	1,532,195	1,531,113	0.07%
11	2397 Communication Equipment	1,353,740	1,314,423	2.99%
12	2398 Miscellaneous Equipment	92,775	96,119	-3.48%
13	2399 Other Tangible Property			-
14	**Total General Plant**	14,358,467	14,070,875	2.04%
15	**Total Gas Plant in Service**	411,212,400	393,024,764	4.63%
16				
17	4101 Gas Plant Allocated from Common	27,975,885	27,218,466	2.78%
18	2105 Gas Plant Held for Future Use	4,900	4,990	-1.80%
19	2107 Gas Construction Work in Progress	1,441,178	3,043,347	-52.64%
20	2117 Gas in Underground Storage	40,439,354	39,706,740	1.85%
21				
22				
23	**Total Gas Plant**	$481,073,717	$462,998,307	3.90%

Sch. 20	MONTANA DEPRECIATION SUMMARY - NATURAL GAS (INCLUDES CMP)				
	Functional Plant Class	Montana Plant Cost	This Year Montana	Last Year Montana	Current Avg. Rate
1	**Accumulated Depreciation**				
2					
3	Production and Gathering	$ -	$ -	$ -	
4					
5					
6	Underground Storage	31,479,455	16,231,901	15,382,306	2.68%
7					
8	Other Storage				
9					
10	Transmission	176,161,312	65,742,756	62,626,128	1.78%
11					
12	Distribution	170,457,306	69,735,583	64,439,206	3.02%
13					
14	General and Intangible	14,515,249	9,138,449	8,173,016	8.34%
15					
16	Common	26,238,772	8,649,070	7,266,566	6.60%
17					
18	**TOTAL DEPRECIATION**	$418,852,094	$169,497,759	$157,887,222	2.63%
19					
20					
21					
22					
23					

Sch. 21	MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED) - NATURAL GAS			
	Account Number & Title	This Year Cons. Utility	Last Year Montana	%Change
1				
2	151 Fuel Stock			
3				
4	152 Fuel Stock Expenses Undistributed			
5				
6	153 Residuals			
7				
8	154 Plant Materials & Operating Supplies			
9	Assigned and Allocated to:			
10	Operation & Maintenance			
11	Construction			
12	Storage Plant	$ 127,013	$ 126,127	0.70%
13	Transmission Plant	727,847	706,648	3.00%
14	Distribution Plant	703,374	682,964	2.99%
15				
16	155 Merchandise			
17				
18	156 Other Materials & Supplies			
19				
20	157 Nuclear Materials Held for Sale			
21				
22	163 Stores Expense Undistributed			
23				
24	**TOTAL MATERIALS & SUPPLIES**	$1,558,234	$1,515,739	2.80%
25				
26				
27				
28				
29				

Sch. 22

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - GAS

	% Capital Structure	% Cost Rate	Weighted Cost
Commission Accepted - Most Recent 1/			
Docket Number: 2000.8.113			
Order Number : 6271c			
Common Equity	45.00%	10.75%	4.84%
Preferred Stock	6.97%	6.40%	0.45%
QUIPs Preferred	7.86%	8.54%	0.67%
Long Term Debt	40.17%	7.13%	2.86%
TOTAL	100.00%		8.82%

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

	% Capital Structure	% Cost Rate	Weighted Cost
Actual Corporate Consolidated 2/			
Common Equity	48.16%	10.75%	5.18%
Long Term Debt	51.84%	6.32%	3.28%
TOTAL	100.00%		8.46%

2/ This information reflects the capital structure of the consolidated NorthWestern Energy Corporation. The capital structure reflects the outcome of the company's recent bankruptcy filing. A method to allocate capital between Montana, South Dakota, Nebraska, and other operations has not been determined.

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	$ 544,432,692	$ (128,670,080)	>300.00%
4	Depreciation	71,845,113	69,917,276	2.76%
5	Amortization, net	(831,823)	(1,555,150)	46.51%
6	Deferred Income Taxes - Net	(13,150,181)	60,794,580	-121.63%
7	Investment Tax Credit Adjustments - Net	534,824	534,725	0.02%
8	Other Non-cash charges to net income-net	(580,569,066)	14,582,994	>-300.00%
9	Change in Receivables - Net	23,049,987	(26,401,203)	187.31%
10	Change in Materials, Supplies & Inventories - Net	(1,635,896)	(648,663)	-152.20%
11	Change in Payables & Accrued Expenses - Net	54,721,511	73,765,862	-25.82%
12	Allowance for Funds Used During Construction (AFUDC)	(454,548)	(475,960)	4.50%
13	Change in Other Current Assets & Liabilities - Net	44,748,607	(93,881,217)	147.67%
14	Other Operating Activities:			
15	Undistributed Earnings from Subsidiary Companies	9,855,962	(12,471,008)	179.03%
16	Other (net)	(14,893,440)	4,424,860	>-300.00%
17	Change in Regulatory Assets	(1,963,851)	5,442,175	-136.09%
18	Change in Regulatory Liabilities	16,180,577	(38,445,538)	142.09%
19	**Net Cash Provided by/(Used in) Operating Activities**	151,870,468	(73,086,348)	>300.00%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(79,371,496)	(65,844,359)	-20.54%
22	(net of AFUDC)			
23	Contributions In and Advances to Affiliates	-	121,169	-100.00%
24	Other Investing Activities:			
25	Proceeds from sales of Assets and Investments	15,579,037	31,943,769	-51.23%
26	Additional Investments		(1,084,073)	100.00%
27	**Net Cash Provided by/(Used in) Investing Activities**	(63,792,459)	(34,863,493)	-82.98%
28	**Cash Flows from Financing Activities:**			
29	Proceeds from Issuance of:			
30	Long-Term Debt	325,000,000	390,000,000	-16.67%
31	Credit Facilities Borrowings, net	-	(255,000,000)	100.00%
32	Debt Financing Costs	(11,551,798)	(27,944,351)	58.66%
33	Payment for Retirement of:			
34	Long-Term Debt	(400,546,000)	(23,600,000)	>-300.00%
35	Capital Lease Obligations	-	(2,760,547)	100.00%
36	**Net Cash Provided by (Used in) Financing Activities**	(87,097,798)	80,695,102	-207.93%
37	**Net Increase/(Decrease) in Cash and Cash Equivalents**	980,211	(27,254,739)	103.60%
38	**Cash and Cash Equivalents at Beginning of Year**	15,169,713	27,914,771	-45.66%
39	**Cash and Cash Equivalents at End of Year**	$ 16,149,924	$ 15,169,713	6.46%
40				
41	This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory			
42	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, in accordance with FERC			
43	requirements, subsidiaries are presented using the equity method of accounting. The amounts presented are consistent with			
44	the presentation in FERC Form 1, plus Canadian Montana Pipeline Corp.			
45				
46	The financial results reported include income taxes that are based upon NorthWestern's tax basis for plant assets purchased from			
47	the Montana Power Company. This tax basis differs from amounts included in the most recently decided rate proceeding and			
48	results in a lower deferred tax credit. This change was made in order to prevent any possible violation of the normalization			
49	requirements of the federal income tax code. The change results in an increase in the reported rate base.			

Sch. 24

MONTANA LONG TERM DEBT 1/

	Description	Issue Date	Maturity Date	Principal Amount	Net Proceeds	Outstanding	Yield to Maturity	Annual Net Cost Inc. Prem./Disc.	Total Cost %
1									
2	**First Mortgage Bonds**								
3	8.25% Series, Due 2007	12/05/91	02/01/07	55,000,000	54,550,100	364,985	8.260%	30,167	8.27%
4	7.30% Series, Due 2006	11/27/01	12/01/06	150,000,000	148,670,240	149,674,065	7.426%	11,289,296	7.54%
5	5.875% Series, Due 2014	11/01/04	11/01/14	161,000,000	161,000,000	161,000,000	5.875%	9,786,582	6.08%
6	**Total First Mortgage Bonds**			$366,000,000	$364,220,340	$311,039,050		$21,106,045	6.79%
7									
8	**Pollution Control Bonds**								
9	6-1/8% Series, Due 2023	06/30/93	05/01/23	$90,205,000	$88,199,743	$88,972,719	6.428%	$5,604,531	6.30%
10	5.90% Series, Due 2023	12/30/93	12/01/23	80,000,000	79,040,800	79,390,797	5.841%	4,763,619	6.00%
11	**Total Pollution Control Bonds**			$170,205,000	$167,240,543	$168,363,516		$10,368,150	6.16%
12									
13	**Other Long Term Debt**								
14	Variable Rate Credit Facility, Due 2011	11/01/04	11/01/11	72,000,000	72,000,000	71,280,000	n/a	3,190,953	4.43%
15	Revolver, Due 2006	11/01/04	11/01/09	90,000,000		-		253,500	N/A
16	Cost Associated with Prior Debt Retirements	N/A	N/A					184,978	N/A
17	**Total Other Long Term Debt**			$162,000,000	$72,000,000	$71,280,000		$3,629,431	N/A
18	**TOTAL LONG TERM DEBT**			$698,205,000	$603,460,883	$550,682,566		$35,103,626	6.37%

19
20 1/ Total Long-Term Debt does not include amounts due within 1 year - $5,385,177 on March 31, 2005 and $720,000 (quarterly payments) due in 2005.
21
22
23
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33

SCHEDULE 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										
3										
4										
5										
6										
7	NOT APPLICABLE									
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 2/	Dividends Per Share (Declared)	Retention Ratio	Market Price		Price/ Earnings Ratio
							High	Low	
1									
2									
3	January								
4									
5	February								
6									
7	March								
8									
9	April								
10									
11	May								
12									
13	June								
14									
15	July								
16									
17	August								
18									
19	September								
20									
21	October								
22									
23	November	35,614,158	19.87				26.62	24.80	
24									
25	December	35,614,158	19.92	(0.19)			28.19	25.01	
26									
27	**TOTAL Year End**	35,614,158	$19.92	($0.19)	$0.00	100.00%	$28.00		n/a
28									

29 In connection with the consummation of our Plan of Reorganization from bankruptcy on November 1, 2004,
30 all shares of our old common stock were canceled. Due to this cancellation, per share results have not
31 been presented for the months prior to November.
32
33 1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average
34 shares for the two months ended December 31, 2004.
35
36 2/ For the two month period ending December 31, 2004.

Sch. 27

MONTANA EARNED RATE OF RETURN - GAS

	Description	This Year	Last Year	% Change
1	**Rate Base**			
2	101 Plant in Service	$426,409,429	$409,699,639	4.08%
3	108 Accumulated Depreciation	(164,027,831)	(153,892,234)	-6.59%
4				
5	**Net Plant in Service**	$262,381,598	$255,807,405	2.57%
6	Additions:			
7	154, 156 Materials & Supplies	$2,776,577	$2,653,293	4.65%
8	165 Prepayments			
9	Other Additions 1/	34,060,174	35,828,802	-4.94%
10				
11	**Total Additions**	$36,836,751	$38,482,095	-4.28%
12	Deductions:			
13	190 Accumulated Deferred Income Taxes 2/	$9,880,400	$6,632,546	48.97%
14	252 Customer Advances for Construction	4,654,333	4,466,293	4.21%
15	255 Accumulated Def. Investment Tax Credits			
16	Other Deductions	26,380,774	31,038,898	-15.01%
17				
18	**Total Deductions**	$40,915,507	$42,137,737	-2.90%
19	**Total Rate Base**	$258,302,842	$252,151,763	2.44%
20	**Net Earnings**	$18,642,730	$20,749,897	-10.16%
21	**Rate of Return on Average Rate Base**	7.217%	8.229%	-12.29%
22	**Rate of Return on Average Equity 3/**	6.633%	7.462%	-11.11%
23				
24	**Major Normalizing and**			
25	**Commission Ratemaking Adjustments**			
26	Rate Schedule Revenues	$1,809,739	$1,975,873	-8.41%
27	Gas Cost Disallowance	2,822,981	7,812,372	-63.87%
28	Inventory Receipts Adjustment	0	114,932	-100.00%
29	CIS Project Write-Off	0	160,413	-100.00%
30	Funding Trust Regulatory Liability	(117,238)	(430,040)	72.74%
31	Restricted Stock Expense	562,466	0	100.00%
32	A & G Not Previously Allocated 4/	0	(3,713,657)	100.00%
33				
34	Non-Allowables:			
35	Advertising	20,365	44,884	-54.63%
36	Benefit Restoration Plan	53,670	(315,621)	117.00%
37	Dues, Contributions, Other	19,152	12,400	54.45%
38				
39	Associated Income Taxes 5/	(2,643,874)	(4,286,644)	38.32%
40	**Total Adjustments**	$2,527,261	$1,374,912	83.81%
41	**Revised Net Earnings**	$21,169,991	$22,124,809	-4.32%
42	**Adjusted Rate of Return on Average Rate Base**	8.196%	8.774%	-6.59%
43	**Adjusted Rate of Return on Average Equity 3/**	8.968%	10.081%	-11.04%

44 1/ Other additions includes a FAS 109 Regulatory Asset that is based on NWE tax basis. This
45 provides an offset to the accumulated deferred taxes.
46
47 2/ The financial results reported include income taxes that are based upon NorthWestern's tax basis for
48 plant assets purchased from the Montana Power Company. This tax basis differs from amounts included
49 in the most recently decided rate proceeding and results in a lower deferred tax credit. This change was
50 made in order to prevent any possible violation of the normalization requirements of the federal income
51 tax code. The change results in an increase in the reported rate base. 2003 has been revised to
52 reflect a true up to actuals.
53
54 3/ Return on Equity calculated using the capital structure approved in Docket D2000.8.113.
55
56 4/ A & G expenses adjusted do not include any restructuring costs or amounts attributable
57 to Non-Utility operations.
58
59 5/ Associated Income taxes include an interest synchronization adjustment based upon the approved
60 capital structure in Docket D2000.8.113.

Sch. 27 cont.

MONTANA EARNED RATE OF RETURN - GAS

	Description	This Year	Last Year	% Change
1				
2	**Detail - Other Additions**			
3	FAS 109 Regulatory Asset	$173,538	$178,093	-2.56%
4	Gas Stored Underground	32,170,919	33,279,559	-3.33%
5	Cost of Refinancing Debt	342,338	435,069	-21.31%
6	1997 and 1998 Severance Plans	41,884	41,884	0.00%
7	1999 Severance Plan	0	59,151	-100.00%
8	ORCOM Development Costs	0	298,706	-100.00%
9	SAP Development Costs	1,331,495	1,536,340	-13.33%
10				
11				
12	**Total Other Additions**	$34,060,174	$35,828,802	-4.94%
13				
14	**Detail - Other Deductions**			
15	Personal Injury and Property Damage	($3,381,124)	($2,720,334)	-24.29%
16	Storage Gas Sales 2000 & 2001	8,640,920	9,061,672	-4.64%
17	Gross Cash Requirements	3,194,678	6,441,435	-50.40%
18	Met Life Refund	0	68,106	-100.00%
19	Bond Refinancing CTC - GP	4,298,064	4,298,064	0.00%
20	Bond Refinancing CTC - RA	13,689,232	13,689,232	0.00%
21	USBC Gas	(60,996)	200,723	-130.39%
22				
23	**Total Other Deductions**	$26,380,774	$31,038,898	-15.01%
24				
25				
26				
27				
28				
29				
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Sch. 28	MONTANA COMPOSITE STATISTICS - NATURAL GAS (INCLUDES CMP)		
		Description	Amount
1			
2		**Plant (Intrastate Only)**	
3			
4	101	Plant in Service (Includes Allocation from Common)	$ 439,188,285
5	105	Plant Held for Future Use	4,900
6	107	Construction Work in Progress	1,441,178
7	117	Gas in Underground Storage	40,439,354
8	151-163	Materials & Supplies	1,558,234
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	169,497,759
11	252	Contributions in Aid of Construction	4,963,399
12	**NET BOOK COSTS**		$ 308,170,793
13			
14		**Revenues & Expenses**	
15			
16	400	Operating Revenues	$ 254,514,015
17			
18	**Total Operating Revenues**		$ 254,514,015
19			
20	401-402	Other Operating Expenses	$ 203,010,325
21	403-407	Depreciation & Amortization Expenses	12,048,792
22	408.1	Taxes Other than Income Taxes	15,518,177
23	409-411	Federal & State Income Taxes	5,293,991
24			
25	**Total Operating Expenses**		$ 235,871,285
26	**Net Operating Income**		$ 18,642,730
27			
28	415-421.1	Other Income	1,741,326
29	421.2-426.5	Other Deductions	6,084,121
30	**NET INCOME BEFORE INTEREST EXPENSE**		$14,299,935
31			
32		**Average Customers (Intrastate Only)**	
33		Residential	143,100
34		Commercial	19,989
35		Industrial	348
36		Other	83
37	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		163,520
38			
39		**Other Statistics (Intrastate Only)**	
40		Average Annual Residential Use (Dkt)	86.4
41		Average Annual Residential Cost per (Dkt)	$9.34
42		Average Residential Monthly Bill	$67.29
43			
44		Plant in Service (Gross) per Customer	$2,686

Sch. 29

Montana Customer Information- Natural Gas, 1/

	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,234	457	77	2	536
2	Amsterdam		41	7		48
3	Anaconda	9,417	3,351	335	5	3,691
4	Augusta	284	187	41	1	229
5	Belfry	219	5	-	-	5
6	Belgrade	5,728	4,051	518	2	4,571
7	Big Mountain		133	29	-	162
8	Big Sandy	703	299	73	-	372
9	Big Timber	1,650	900	176	9	1,085
10	Bigfork	1,421	956	156	-	1,112
11	Billings	89,847	12	2	3	17
12	Bonner	1,693	78	5	-	83
13	Boulder	1,300	475	80	1	556
14	Bozeman	27,509	15,838	2,425	12	18,275
15	Browning	3,877	1,089	168	2	1,259
16	Buffalo		5	-	-	5
17	Butte	33,892	12,320	1,304	46	13,670
18	Cardwell	40	17	5	-	22
19	Carter	62	29	10	-	39
20	Chester	871	374	114	3	491
21	Chinook	1,386	723	138	7	868
22	Choteau	1,802	845	174	3	1,022
23	Churchill		291	34	-	325
24	Clancy	1,406	744	38	1	783
25	Clinton		362	16	1	379
26	Columbia Falls	3,645	2,976	318	4	3,298
27	Columbus	1,748	994	153	5	1,152
28	Conrad	2,753	1,128	200	15	1,343
29	Coram	337	113	22	-	135
30	Corvallis	443	968	90	1	1,059
31	Cut Bank	3,105	46	12	3	61
32	Deer Lodge	3,421	1,587	201	7	1,795
33	Dillon	3,752	1,961	331	6	2,298
34	Drummond	318	210	56	2	268
35	East Glacier Park	396	123	44	1	168
36	East Helena	1,642	1,858	104	4	1,966
37	Elliston	225	95	13	-	108
38	Essex		72	14	1	87
39	Fairfield	659	405	84	4	493
40	Florence	901	1,067	69	1	1,137
41	Floweree		46	8	-	54
42	Fort Belnap	1,262	350	55		405
43	Fort Benton	1,594	625	156	1	782
44	Fort Harrison			2	59	61
45	Fort Shaw	274	105	13	-	118
46	Galata		3	-	-	3
47	Gallatin Gateway		154	32	-	186
48	Garneill		9	1	-	10
49	Garrison	112	23	4	-	27
50	Gildford	185	80	29	1	110
51	Gransdale		22	2	-	24
52	Great Falls	56,690	949	44	4	997

Sch. 29

Montana Customer Information- Natural Gas, 1/

	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Greycliff	56	41	4	-	45
2	Hall		61	12	-	73
3	Hamilton	3,705	3,583	622	9	4,214
4	Harlem	848	328	72	2	402
5	Harlowton	1,062	538	98	2	638
6	Havre	9,621	4,517	616	9	5,142
7	Helena	45,819	15,562	2,190	46	17,798
8	Hingham	157	85	26	-	111
9	Hungry Horse	934	256	34	-	290
10	Iverness	103	37	14	-	51
11	Jefferson City	295	126	11	2	139
12	Joplin	210	97	27	-	124
13	Judith Gap	164	65	15	-	80
14	Kalispell	14,223	10,105	1,799	18	11,922
15	Kremlin	126	49	16	-	65
16	Laurel	6,255	11	-	-	11
17	Ledger		6	-	-	6
18	Lewistown	6,178	2,865	463	14	3,342
19	Livingston	7,348	3,738	520	17	4,275
20	Logan		40	2	-	42
21	Lohman		2	1	-	3
22	Lolo	3,388	1,340	86	-	1,426
23	Loma	92	40	18	-	58
24	Manhattan	1,396	793	100	1	894
25	Martin City	331	115	16	-	131
26	Milltown		74	8	-	82
27	Missoula	57,053	27,063	3,430	57	30,550
28	Montana City		523	46	-	569
29	Moore	186	2	1	-	3
30	Philipsburg	914	429	77	-	506
31	Ramsay		38	7	-	45
32	Red Lodge	2,177	1,606	258	7	1,871
33	Reedpoint	185	107	15	1	123
34	Roberts		149	20	-	169
35	Rocker		13	7	-	20
36	Rudyard	275	132	29	-	161
37	Ryegate		3	-	-	3
38	Shawmut		24	4	-	28
39	Shelby	3,216	9	3	-	12
40	Sheridan	659	381	66	-	447
41	Silver Star		22	5	-	27
42	Silverbow		4	-	2	6
43	Simms	373	156	17	-	173
44	Somers	556	252	22	-	274
45	Springdale		1	-	-	1
46	Stevensville	1,553	1,442	223	6	1,671
47	Sun River	131	108	20	-	128
48	Three Forks	1,728	784	121	1	906
49	Trident		1	-	-	1
50	Turah		89	1	-	90

Sch. 29

Montana Customer Information- Natural Gas, 1/

	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Twin Bridges	400	207	51	-	258
2	Valier	498	306	67	4	377
3	Vaughn	701	329	25	1	355
4	Victor	859	461	68	1	530
5	Walkerville		238	11	-	249
6	West Glacier		105	39	3	147
7	Whitefish	5,032	3,277	454	4	3,735
8	Whitehall	1,044	666	111	3	780
9	Whitlash		2	-	-	2
10	Williamsburg		1	-	-	1
11	Willow Creek	209	94	12	-	106
12	Wolf Creek		51	27	1	79
13	**Total**	447,863	143,100	19,989	428	163,517

1/ Customer populations represent an average of the 12 month period from 01/01/04 through 12/31/04.

Sch. 30

MONTANA EMPLOYEE COUNTS 1/

	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
3	Executive	1	1	1
4	Financial, Risk Mgmt. & Information Services	120	112	116
5	Human Resources & Administration	33	31	32
6	Utility Services & Division Administration	620	635	627
7	Business Development & Regulatory Affairs	24	25	24
8	Transmission	150	160	155
9	Legal	5	5	5
10				
11				
12				
13				
14				
15				
16				
17	**TOTAL EMPLOYEES**	953	969	960
18				
19	1/ Part time employees have been converted to full time equivalents.			
20				
21				
22				
23				
24				

Sch. 31	MONTANA CONSTRUCTION BUDGET 2005 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3			
4	Three Rivers Substation 230kV Auto yr 2 of 2	$4,417,299	$4,417,299
5	Three Rivers Jackrabbit 161kV Line yr 3 of 3	5,278,177	5,278,177
6	Bozeman Sourdough Substation Rebuil	1,229,571	1,229,571
7	Restoration of Path 18 capacity Dillon Salmon	1,174,319	1,174,319
8	Helena Golf Course Bank #2	1,079,870	1,079,870
9			
10	All Other Projects < $1 Million Each	30,593,689	30,593,689
11			
12	**Total Electric Utility Construction Budget**	43,772,925	43,772,925
13			
14	**Natural Gas Operations**		
15	Basin Creek Generation	967,844	967,844
16	Gas Transmission Pipeline Integrity Management	882,216	882,216
17			
18			
19	All Other Projects < $1 Million Each	8,534,397	8,534,397
20			
21	**Total Natural Gas Utility Construction Budget**	10,384,457	10,384,457
22			
23	**Common**		
24	Customer Care ADS/Orcom ECIS replacement	2,000,000	2,000,000
25			
26	All Other Projects < $1 Million Each	3,833,879	3,833,879
27	(Includes IS, Communications, Facillities, Cust Serv, Fleet)		
28			
29			
30	**Total Common Utility Construction Budget**	5,833,879	5,833,879
31			
32	Feedwater Heater 3-7	832,500	832,500
33			
34	All Other Projects < $1 Million Each	1,550,550	1,550,550
35			
36			
37			
38	**Total Colstrip Unit 4 Construction Budget**	2,383,050	2,383,050
39	**TOTAL CONSTRUCTION BUDGET**	$62,374,311	$62,374,311

Sch. 32

MONTANA TRANSMISSION, DISTRIBUTION and STORAGE SYSTEMS -NATURAL GAS

Transmission System-Sales and Transportation

	Month	Peak Day of Month		Peak Day Volume (MMBTU's)		Monthly Volumes (MMBTU's)	
		Total Company	Montana	Total Company	Montana	Total Company, 2/	Montana, 3/
1	January					6,053,563	5,052,859
2	February					5,236,385	4,577,330
3	March					4,337,503	3,904,665
4	April		NOT AVAILABLE 1/			3,068,134	2,943,549
5	May					2,472,062	2,046,051
6	June					1,827,407	1,840,240
7	July					1,406,865	1,046,049
8	August					1,530,392	2,167,287
9	September					2,052,554	1,992,165
10	October					3,161,699	3,241,711
11	November					3,927,034	4,137,883
12	December					5,469,663	3,532,690
13	TOTAL					40,543,261	36,482,479

14
15
16

Distribution System-Sales and Transportation

17		Sales Volumes		Transportation Volumes		Monthly Volumes (MMBTU's)	
18	Month	Total Company	Montana	Total Company	Montana	Total Company, 4/	Montana, 5/
19	January	3,599,664		238,599		3,838,263	3,599,664
20	February	2,907,109		166,930		3,074,039	2,907,109
21	March	2,277,440		183,389		2,460,829	2,277,440
22	April	1,435,044		224,294		1,659,338	1,435,044
23	May	1,042,698		122,758		1,165,456	1,042,698
24	June	926,231		149,841		1,076,072	926,231
25	July	571,753		102,010		673,763	571,753
26	August	401,614		134,097		535,711	401,614
27	September	478,262		158,589		636,851	478,262
28	October	887,225		243,123		1,130,348	887,225
29	November	1,660,065		175,316		1,835,381	1,660,065
30	December	2,566,148		198,523		2,764,671	2,566,148
31	TOTAL	18,753,253		2,097,469		20,850,722	18,753,253

32
33
34

Storage System-Sales and Transportation

35		Peak Day & Peak Day Vol.		Total Monthly Volumes (MMBTU's)			
36		Total Company	Montana	Total Company 4/		Montana 5/	
37	Month	1/	1/	Injection	Withdrawal	Injection	Withdrawal
38	January			1,767	2,803,252		635,580
39	February			293	2,183,831	245,794	
40	March			50,235	1,185,531	584,437	
41	April			617,398	182,394	233,960	
42	May			1,415,218	64,815		226,119
43	June			1,644,534	32,624	131,517	
44	July			2,101,031	35,406		293,889
45	August			2,041,663	31,058	707,008	
46	September			2,096,502	53,510	42,249	
47	October			1,531,272	128,730	48,245	
48	November			484,982	319,208	157,280	
49	December			25,874	2,833,661		844,579
50	TOTAL			12,010,769	9,854,020	2,150,490	2,000,167

51 1/ Data is not accumulated on a daily basis, therefore the peak day and peak day volumes are not available.
52 2/ Includes intrastate and interstate deliveries.
53 3/ Includes intrastate deliveries only.
54 4/ Includes sales and transportation volumes. Losses of gas are not available.
55 5/ Includes sales volumes only. Losses of gas are not available.

Sch. 33

SOURCES OF CORE NATURAL GAS SUPPLY

	Name of Supplier	Last Year Volumes MMBTU	This Year Volumes MMBTU	Last Year Avg. Commodity Cost	This Year Avg. Commodity Cost
1					
2	Canadian Pipeline	(3,569,868)		($4.3590)	
3	Havre Pipeline	5,440,529		4.8710	
4	Pan Canadian Pipeline	6,072,960		4.8250	
5	Colorado Interstate Pipeline	1,412,472		4.3680	
6	Intra Montana Purchase	8,946,592		4.4680	
7	**TOTAL CORE SUPPLY LAST YEAR**	18,302,685	0	$4.7180	
8					
9	Canadian Pipeline		(250,000)		($4.2180)
10	Havre Pipeline		5,036,279		5.1340
11	Pan Canadian Pipeline		7,149,911		5.1660
12	Colorado Interstate Pipeline		(525,174)		(5.2650)
13	Intra Montana Purchase		7,473,181		4.6920
14	**TOTAL CORE SUPPLY THIS YEAR**		18,884,197		$5.0200
15					
16	Note: This year's volumes reflect the net amount of volumes procured from the named supplier less				
17	volumes sold to that supplier.				
18					

	A	B	C	D
1	**Sch. 34**	**MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS**		
2–4				**NorthWestern Energy Natural Gas Utility 2004 USBC Revenues**
5–7		**USBC DKT (Load)**	**USBC Revenue By Class**	**% of USB Revenue By Class**
8	**Residential**			
9	Residential	12,450,418	$ 757,679	46%
10	**General Service**			
11	Commercial	6,379,891	$ 387,999	24%
12	**On-System Transportation**			
13	Core/Tier 2	2,134,238	$ 129,038	8%
14	Tier 1	11,051,774	$ 357,581	22%
15	**Total DKT**	**32,016,321**	**$ 1,632,297**	**100%**
16–17				
18				**2004 Universal System Benefits Program Results**
19–21	**USB Categories**	**2004 Natural Gas Revenue Allocation**	**Spent in 2004**	**Allocation less Expenses**
22	**Local Conservation**	**327,000**	**327,000**	**0**
23	E+ Residential Audit		312,892	
24	NWE Promotion		-	
25	NWE Labor		14,492	
26	NWE Admin. Non-labor		-	
27	USB Interest & Svc Chg		(383)	
28	Local Conservation Summary		327,000	
30	**Low Income**	**1,305,297**	**1,469,229**	**(163,932)**
31	Bill Assistance		871,046	
32	Free Weatherization		585,000	
33	NWE Promotion		-	
34	NWE Labor		14,331	
35	NWE Admin. Non-labor		572	
36	USB Interest & Svc Chg		(1,720)	
37	Low Income Summary		1,469,229	
39	**Totals**	**1,632,297**	**1,796,229**	**(163,932)**
40	**2004 USB Revenues less Expenses***			**(163,932)**

41–44 * In 2004, low-income bill assistance expense increased due to higher natural gas supply costs and more customers signing up for energy assistance. Upward pressure on the discount, combined with other low-income program commitments, caused gas USB expenses to exceed revenues. NWE filed for a natural gas USB rate increase mid-year, which MPSC granted on an interim basis, however, the increase was not sufficient to cover all of the escalating discount costs. In late 2004, NWE filed a projection of the shortfall with MPSC, and proposed that it be recovered through a tracking mechanism in 2005. MPSC will issue an order on the combined filings in 2005.

45–46 **2004 USB Expenditure Summary and Savings Estimate**

47–48 USB Category	Allocation of 2004 Natural Gas USB	Percentage by Category	Estimated Savings (DKT)
49 Local Conservation	327,000	18%	14,808
50 Low Income**	1,469,229	82%	10,946
51	**1,796,230**	**100%**	**25,754**

52–53 ** ARM 38.5.7021 sets the minimum allocation of gas USB funds to low-income activities at .42% of annual revenue. In 2004, NWE's allocation to low-income natural gas programs was .80% of annual revenue, or 1.9 times the minimum required by ARM 38.5.7021.

54

55 **2004 Gas USB Customer/Project Summary**	**Quantity**	**Units**
56 Residential Onsite Audits	629	Homes
57 Bill Assistance	7,683	Customers
58 Free Weatherization	434	Homes

59

Sch. 35

MONTANA CONSUMPTION AND REVENUES - NATURAL GAS

	Description	Operating Revenues 1/		Dkt Sold		Average Customers	
		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	Sales of Natural Gas						
2							
3	Residential	$ 115,544,919	$ 86,467,860	12,366,881	12,981,395	143,100	140,286
4	Commercial	56,904,414	42,599,960	6,028,552	6,314,806	19,929	19,570
5	Industrial Firm	1,798,428	1,463,246	195,742	222,004	348	359
6	Public Authorities	436,789	284,199	48,487	42,976	80	76
7	Interdepartmental	442,228	331,872	50,259	52,967	60	60
8	CNG Station	3,346	2,971	-	-	-	-
9	Sales to Other Utilities 2/	61,028,066	31,652,646	197,714	200,922	3	3
10	TOTAL SALES	236,158,190	162,802,754	18,887,635	19,815,070	163,520	160,354
11		Operating Revenues		Dkt Transported		Average Customers	
12		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
13							
14	Transportation of Gas						
15							
16	On System Transportation	$ 14,379,744	$ 11,530,713	17,938,722	19,632,758	234	237
17	Off System Transportation	866,850	1,273,490	2,526,852	6,739,590	15	13
18	Canadian Montana Pipeline	57,779	52,329				
19	TOTAL TRANSPORTATION	15,304,373	12,856,532	20,465,574	26,372,348	249	250
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							

32 1/ Revenue and Dkts for 2003 were adjusted to include unbilled and Canadian Montana Pipeline, consistent with the 2004
33 presentation.
34
35 2/ In 2003, NorthWestern entered into approximately 3.3 bcf of fixed price natural gas contracts to hedge customer price risk during
36 the 2003-2004 winter season. These fixed price contracts at the AECO hub systematically offset medium-term on-system supply,
37 which are purchased from a third party on NorthWestern's system at a floating daily index price. For the 2004-2005 winter season,
38 the 3.3 bcf of hedging was accomplished by putting additional gas in underground storage during the spring and summer at
39 prices below the winter market price. Other sales for both periods were conducted due to excess supply on system or exchanges
40 for in-ground storage from customers. All purchases and sales were conducted as regulated activity for the Montana
41 customers and such net cost will be recovered in rates.