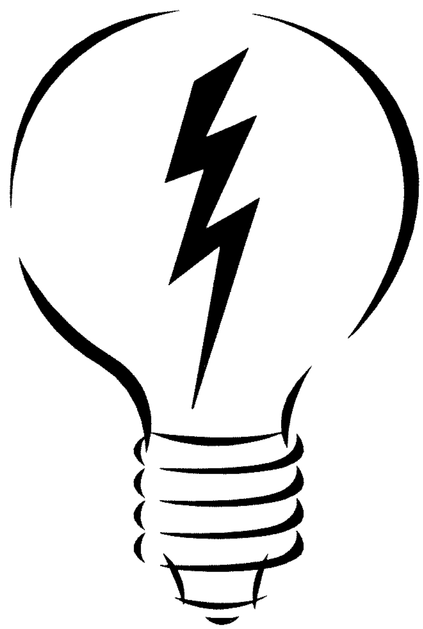
YEAR 2003

ANNUAL REPORT
OF

NorthWestern Energy

ELECTRIC UTILITY



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

REVISED JULY 28, 1998

ELECTRIC ANNUAL REPORT

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Sch. 1

IDENTIFICATION

Legal Name of Respondent:	NorthWestern Corporation (formerly The Montana Power Company)
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.

NorthWestern Energy is a 100% controlled division of:

NorthWestern Corporation
125 South Dakota Avenue
Sioux Falls, SD 57104-6403

Sch. 2	BOARD OF DIRECTORS	
	Director's Name & Address (City, State)	Remuneration
1		
2	NOT APPLICABLE	
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Sch. 3

OFFICERS

Title	Department Supervised	Name
President & Chief Executive Officer	Executive	Gary G. Drook
Chief Operating Officer	Operations	Michael J. Hansen
Vice President, Human Resources & Communications	Human Resources Communications Benefits & Compensation	Roger Schrum
Chief Financial Officer	Tax, Accounting Operations, Financial Planning & Analysis	Brian Bird
Vice President Information Technology	IT Applications & Infastructure Systems Continuity Licensing & Leasing Telecommunications	Bart Thielbar
Vice President Administration	Government Relations State, Local & Community Relations	Dennis Lopach
Vice President, Distribution Operations	Distribution Services Distribution Engineering & Performance SD Construction & Maintenance	Curt Pohl
Vice President, Transmission Operations	Transmission Contracts & Scheduling Electric & Gas Transmission & Storage General Production & Generation Transmission Operations & Regional Issues	David G. Gates
Vice President, Regulatory Affairs & Support Services	Regulatory Affairs Electric & Natural Gas Supply	Patrick R. Corcoran
Vice President, Asset Management	Asset Management Safety/Health/Environmental Process Improvement	Greg Trandem
Vice President, Customer Care	Revenue Collections Customer Strategies Call Center Systems Infastructure & Support Customer/Supplier Relations	Bobbi Schroeppel
Vice President, Legal Administration	Legal	Alan Dietrich
Vice President, Deputy General Counsel	Legal	Thomas J. Knapp
Vice President, General Counsel & CLO	Legal	Eric Jacobsen
Vice President, Audit & Controls	Internal Audit Project Office	Maurice Worsfold
Chief Restructuring Officer		William M. Austin
Chief Accountant	Financial Reporting	Kendall Kliewer

Sch. 4	CORPORATE STRUCTURE - 1/			
	Subsidiary/Company Name	Line of Business	Earnings (000)	% of Total
2	**NORTHWESTERN ENERGY**			
3	**Utility Operations**		37,657	110.74%
4	Electric Utility	Electric utility		
5	Natural Gas Utility	Natural gas utility		
6	Propane Utility	Propane utility		
7	Canadian-Montana Pipe Line Corporation	Natural gas transmission		
8	Montana Power Capital 1	Financing		
9	MPC Natural Gas Funding Trust	Bond transition financing		
11	**Nonutility Operations**		(3,651)	-10.74%
12	Montana Power Services Company	Inactive		
13	Northwestern Energy Marketing	Supply energy to schools and public lighting		
14	One Call Locators, Ltd. 1/	Underground facility locating		
15	Colstrip Unit 4 Lease Mgmt Division	Wholesale sales of electric power *		
16	Clark Fork and Blackfoot L.L.C.	Milltown Dam		
54	**TOTAL**		34,005	100.00%
55	1/ One Call Locators, Ltd was sold in June 2003.			
58	* Colstrip Unit 4 Lease Management Division is an operating division of Northwestern Energy.			

Sch. 5

CORPORATE ALLOCATIONS

	Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
1-2	Corporate - 1/	Includes all of the Corporate Departments in NOR including Chariman; Vice Chairman; CFO; HR; Flight Services & Investor Services.	Direct Charge of a Fixed Monthly Amount from corporate	$3,742,796	45.28%	$4,523,200
3	Utility Administration - 2/					
4-12	Executive Department	Includes the following departments: CEO; T&D Executives; Asset Mgmt; Market Analysis & Planning.	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	$1,606,958	69.08%	$719,112
13-19	Human Resources	Includes the following departments: Human Resources; Benefits Admin.; Compensation & Labor Relations; Employment; Organizational Development; Technology Training;	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	1,613,173	68.94%	726,795
20-28	Finance / Accounting	Includes the following departments: Audit Services; Risk Management; Treasury Services; Accounting; Tax & Financial Reporting Credit & Cash Management	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	6,545,705	64.05%	3,673,618
29-35	MT Facilities	Includes the following departments: Facilities; Mailing Services & Printing Services	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	2,035,980	62.65%	1,213,819

Sch. 5 cont.

CORPORATE ALLOCATIONS

Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
Information Services	Includes the following departments: IT Sr; VP/CIO; IT Applications; Administrative Systems; Special Purpose Systems; Client Services; Infrastructure; Technical Services; Architecture and Key Accounts Rep	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on %'s developed using formulas based on net plant, revenues and gross payroll.	6,854,591	68.94%	3,088,245
Administrative Services	Sr. VP of Administrative Service; Legal; Government Affairs; Records Control	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on %'s developed using formulas based on net plant, revenues and gross payroll.	3,663,420	84.09%	693,323
Customer Service	Customer Service; Promotional Advertising	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	12,791,894	72.35%	4,889,082
Communications	Communications; Advertising; Community Relations; Web Development; Video/Photo Services.	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	851,971	68.77%	386,832
TOTAL			$39,706,488	66.60%	$19,914,026

1/ -Corporate Departments are located in Sioux Falls and a set amount was charged to the utility companies for the year.

2/ - Utility administration departments are in transition with many areas within N.W.E being combined.
Cost were charged direct to MT & SD/NE utilities and then allocated to the segments during most of the year.

Company Name: **SCHEDULE 6**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

Year:

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	One Call Locators *	Line location services	Market Rates	655,513	0.83%	655,513
4						
5						
6	Colstrip Unit 4 - Lease Management Division	Purchased Power	Market Rates	159,571	0.20%	159,571
7						
8						
31						
32	**TOTAL Nonutility Subs**			815,084		815,084
33	**Total Nonutility Subs Revenues**			79,286,081		
34						
35	**Utility Subsidiaries**					
36	**Total Utility Subsidiaries**					
37	**Total Utility Sub Revenues**			3,757,415		
38	**TOTAL AFFILIATE TRANSACTIONS**			815,084		815,084

*** The sale of One Call Locators by the company was completed in June 2003.**

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	One Call Locators *	Sales of Gas & Electricity	Tariff Schedules	$4,016	0.03%	$4,016
4						
5						
6						0
7						0
8						0
9	**Total Nonutility Subsidiaries**			4,016	0.03%	4,016
10	**Total Nonutility Subsidiaries Expenses**			13,761,836		
11						
12						
13	**Utility Subsidiaries**					
14						-
15	**Total Utility Subsidiaries**			-	0.00%	-
16	**Total Utility Subsidiaries Expenses**			72,466,962		
17	**TOTAL AFFILIATE TRANSACTIONS**			$4,016		$4,016

* The sale of One Call Locators by the company was completed during June 2003

Sch. 8	MONTANA UTILITY INCOME STATEMENT - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana 1/	% Change
1						
2	400 Operating Revenues	$501,771,266	$2,848,102	$498,923,164	$404,102,536	23.46%
3						
4	**Total Operating Revenues**	501,771,266	2,848,102	498,923,164	404,102,536	23.46%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expenses	297,058,140	(16,303,499)	313,361,639	338,757,275	-7.50%
9	402 Maintenance Expense	13,770,030	184,172	13,585,858	16,215,315	-16.22%
10	403 Depreciation Expense	42,180,398	375,499	41,804,899	40,490,946	3.25%
11	404-405 Amort. of Electric Plant	2,544,573	-	2,544,573	2,140,057	18.90%
12	406 Amort. of Plant Acquisition Adj.	(4,998,960)	(5,093,874)	94,914	94,914	0.00%
13	408.1 Taxes Other Than Income Taxes	44,634,392	19,816	44,614,576	38,058,554	17.23%
14	409.1 Income Taxes - Federal	(4,471,758)	3,691,090	(8,162,848)	(21,382,790)	61.83%
15	- Other	(122,882)	751,308	(874,190)	(3,447,299)	74.64%
16	410.1 Deferred Income Taxes-Dr.	25,373,700	631,418	24,742,282	6,278,820	294.06%
17	411.1 Deferred Income Taxes-Cr.	(247,200)	(4,193)	(243,007)	(8,505,551)	97.14%
18	411.4 Investment Tax Credit Adj.	2	(3,487)	3,489	3,713	-6.02%
19	411.6 Gain from Disposition of Property					
20	411.7 Loss from Disposition of Property					
21	411.8 SO2 Allowances	(671,427)	(671,427)	-	-	-
22						
23	**Total Operating Expenses**	415,049,008	(16,423,177)	431,472,185	408,703,954	5.57%
24	**NET OPERATING INCOME**	86,722,258	19,271,279	67,450,979	($4,601,418)	>300.00%

1/ Amounts for 2002 have been adjusted to reflect the removal of the non-jurisdictional Qualifying Facility (QF) income.

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 - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	**Sales to Ultimate Consumers**					
3						
4	440 Residential	$ 161,748,549	$115,753	$161,632,796	$142,912,629	13.10%
5	442 Commercial	188,601,189	358,603	188,242,586	159,362,874	18.12%
6	Industrial	31,133,628	-	31,133,628	28,196,646	10.42%
7	444 Public Street, Highway Lighting					
8	& Other Sales to Public Authorities	11,878,591	2,373,746	9,504,845	8,518,719	11.58%
9	448 Interdepartmental Sales	899,134	-	899,134	813,731	10.50%
10						
11	**Total Sales to Ultimate Consumers**	394,261,091	2,848,102	391,412,989	339,804,599	15.19%
12	447 Sales for Resale	60,947,720		60,947,720	15,288,680	298.65%
13						
14	**Total Sales of Electricity**	455,208,811	2,848,102	452,360,709	355,093,279	27.39%
15	449.1 Provision for Rate Refunds			-	-	-
16						
17	**Total Revenue Net of Rate Refunds**	455,208,811	2,848,102	452,360,709	355,093,279	27.39%
18						
19	**Other Operating Revenues**					
20						
21	451 Miscellaneous Service Revenue	1,971	-	1,971	107,734	-98.17%
22	453 Sales of Water & Water Power	-	-	-	-	-
23	454 Rent From Electric Property	2,128,957	-	2,128,957	2,421,521	-12.08%
24	456 Other Electric Revenues	44,431,527	-	44,431,527	46,480,002	-4.41%
25						
26	**Total Other Operating Revenue**	46,562,455	-	46,562,455	49,009,257	-4.99%
27	**TOTAL OPERATING REVENUE**	$501,771,266	$2,848,102	$498,923,164	$404,102,536	23.46%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana 1/	% Change
1	**Power Production Expenses**					
2	**Steam Power Generation-Operation**					
3	500 Supervision & Engineering	$ -	$ -	$ -	$ -	-
4	501 Fuel	-	-	-	-	-
5	502 Steam Expenses	-	-	-	-	-
6	503 Steam from Other Sources	-	-	-	-	-
7	505 Electric Plant	-	-	-	-	-
8	506 Miscellaneous Steam Power	-	-	-	-	-
9	507 Rents	-	-	-	-	-
10	**Total Operation-Steam Power Gen.**	-	-	-	-	-
11	**Steam Power Generation-Maintenance**					
12	510 Supervision & Engineering	-	-	-	-	-
13	511 Structures	-	-	-	-	-
14	512 Steam Boiler Plant	-	-	-	-	-
15	513 Electric Plant	-	-	-	-	-
16	514 Miscellaneous Steam Plant	-	-	-	-	-
17	**Total Maintenance-Steam Power Gen.**	-	-	-	-	-
18	**Total Steam Power Generation**	-	-	-	-	-
19	**Hydro Power Generation-Operation**					
20	535 Supervision & Engineering	-	-	-	-	-
21	536 Water for Power	-	-	-	-	-
22	537 Hydraulic Expenses	-	-	-	-	-
23	538 Electric Expenses	-	-	-	-	-
24	539 Miscellaneous Hydraulic Power	-	-	-	-	-
25	540 Rents	-	-	-	-	-
26	**Total Operation-Hydro Power Gen.**	-	-	-	-	-
27	**Hydro Power Generation-Maintenance**					
28	541 Supervision & Engineering	-	-	-	213,667	-100.00%
29	542 Structures	-	-	-	-	-
30	543 Reservoirs, Dams & Waterways	-	-	-	44,129	-100.00%
31	544 Electric Plant	-	-	-	-	-
32	545 Miscellaneous Hydro Plant	-	-	-	-	-
33	**Total Maintenance-Hydro Power Gen.**	-	-	-	257,796	-100.00%
34	**Total Hydraulic Power Generation**	-	-	-	257,796	-100.00%
35	**Other Power Generation-Operation**					
36	546 Supervision & Engineering	-	-	-	-	-
37	547 Fuel	88,094	88,094	-	-	-
38	548 Generation Expenses	4,402	4,402	-	-	-
39	549 Miscellaneous Other Power	4,217	4,217	-	-	-
40	**Total Operation-Other Power Gen.**	96,713	96,713	-	-	-
41	**Other Power Generation-Maintenance**					
42	551 Supervision & Engineering	-	-	-	-	-
43	552 Structures	-	-	-	-	-
44	553 Generating & Electric Plant	18,805	18,805	-	-	-
45	554 Miscellaneous Other Power Plant	44,950	44,950	-	-	-
46	**Total Maintenance-Other Power Gen.**	63,755	63,755	-	-	-
47	**Total Other Power Generation**	160,468	160,468	-	-	-
48	**Other Power Supply Expenses**					
49	555 Purchased Power	263,633,780	(7,782,279)	271,416,059	182,954,140	48.35%
50	556 System Control & Load Dispatch	-	-	-	-	-
51	557 Other Expenses	650,079	-	650,079	(270,921)	>300.00%
52	**Total Other Power Supply Expenses**	264,283,859	(7,782,279)	272,066,138	182,683,219	48.93%
53	**Total Power Production Expenses**	264,444,327	(7,621,811)	272,066,138	182,941,014	48.72%

1/ Amounts for 2002 have been adjusted to reflect the removal of the non-jurisdictional Qualifying Facility (QF) income.

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	**Transmission Expenses**					
3						
4	**Transmission-Operation**					
5	560 Supervision & Engineering	1,883,097	-	1,883,097	995,043	89.25%
6	561 Load Dispatching	1,484,590	-	1,484,590	1,116,961	32.91%
7	562 Station Expenses	460,804	-	460,804	170,272	170.63%
8	563 Overhead Lines	546,651	102,637	444,014	506,359	-12.31%
9	564 Underground Lines	-	-	-	-	-
10	565 Transmission of Elec. by Others	4,447,475	-	4,447,475	5,653,822	-21.34%
11	566 Miscellaneous Transmission	(2,344,583)	-	(2,344,583)	(1,135,406)	-106.50%
12	567 Rents	2,783,961	-	2,783,961	2,747,835	1.31%
13	**Total Operation-Transmission**	9,261,995	102,637	9,159,358	10,054,886	-8.91%
14	**Transmission-Maintenance**					
15	568 Supervision & Engineering	218,755	-	218,755	653,994	-66.55%
16	569 Structures	14,180	-	14,180	29,519	-51.96%
17	570 Station Equipment	2,142,112	9,788	2,132,324	1,985,615	7.39%
18	571 Overhead Lines	1,316,778	31,780	1,284,998	1,057,609	21.50%
19	572 Underground Lines	-	-	-	-	-
20	573 Miscellaneous Transmission Plant	-	-	-	-	-
21	**Total Maintenance-Transmission**	3,691,825	41,568	3,650,257	3,726,737	-2.05%
22	**Total Transmission Expenses**	12,953,820	144,205	12,809,615	13,781,623	-7.05%
23						
24	**Distribution Expenses**					
25						
26	**Distribution-Operation**					
27	580 Supervision & Engineering	1,334,469	6,593	1,327,876	1,165,470	13.93%
28	581 Load Dispatching	-	-	-	-	-
29	582 Station Expenses	563,800	20,087	543,713	625,933	-13.14%
30	583 Overhead Lines	1,710,480	46,440	1,664,040	1,371,339	21.34%
31	584 Underground Lines	2,693,658	30,307	2,663,351	1,845,628	44.31%
32	585 Street Lighting & Signal Systems	558,728	-	558,728	631,493	-11.52%
33	586 Meters	1,910,320	4,376	1,905,944	1,358,757	40.27%
34	587 Customer Installations	697,820	2,294	695,526	707,544	-1.70%
35	588 Miscellaneous Distribution	5,045,883	21,947	5,023,936	3,819,663	31.53%
36	589 Rents	37,122	-	37,122	69,666	-46.71%
37	**Total Operation-Distribution**	14,552,280	132,044	14,420,236	11,595,493	24.36%
38	**Distribution-Maintenance**					
39	590 Supervision & Engineering	368,076	-	368,076	578,208	-36.34%
40	591 Structures	111,431	812	110,619	104,020	6.34%
41	592 Station Equipment	812,194	38,763	773,431	670,700	15.32%
42	593 Overhead Lines	3,822,193	15,164	3,807,029	3,526,079	7.97%
43	594 Underground Lines	639,907	2,131	637,776	597,352	6.77%
44	595 Line Transformers	595,387	1,375	594,012	726,748	-18.26%
45	596 Street Lighting, Signal Systems	403,756	-	403,756	374,897	7.70%
46	597 Meters	610,119	133	609,986	640,239	-4.73%
47	598 Miscellaneous Distribution Plant	-	-	-	-	-
48	**Total Maintenance-Distribution**	7,363,063	58,378	7,304,685	7,218,243	1.20%
49	**Total Distribution Expenses**	21,915,343	190,422	21,724,921	18,813,736	15.47%

Sch. 10 **MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC (EXCLUDES UNIT 4)**

	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	**Customer Accounts Expenses**					
3						
4	**Customer Accounts-Operation**					
5	901 Supervision	-		-	-	-
6	902 Meter Reading	942,342	8,709	933,633	993,703	-6.05%
7	903 Customer Records & Collection	4,789,133	-	4,789,133	4,658,101	2.81%
8	904 Uncollectible Accounts	1,016,312	-	1,016,312	1,174,225	-13.45%
9	905 Miscellaneous Customer Accts.	1,375	-	1,375	86	>300.00%
10	**Total Customer Accounts Expenses**	6,749,162	8,709	6,740,453	6,826,115	-1.25%
11						
12	**Customer Service & Information**					
13						
14	**Customer Service-Operation**					
15	907 Supervision	-		-	-	-
16	908 Customer Assistance	2,235,931		2,235,931	1,916,518	16.67%
17	909 Inform. & Instruct. Advertising	513,243		513,243	394,393	30.13%
18	910 Misc. Customer Service & Info.	605,505		605,505	2,556	>300.00%
19	**Total Customer Service & Info. Expense**	3,354,679	-	3,354,679	2,313,467	45.01%
20						
21	**Sales Expenses**					
22						
23	**Sales-Operation**					
24	911 Supervision	720,743		720,743	183,311	293.18%
25	912 Demonstrating & Selling	290,308		290,308	1,012,757	-71.33%
26	913 Advertising	99,911		99,911	334,143	-70.10%
27	916 Miscellaneous Sales	-		-	27	-100.00%
28	**Total Sales Expenses**	1,110,962	-	1,110,962	1,530,238	-27.40%
29						
30	**Administrative & General Expenses**					
31						
32	**Admin. & General-Operation**					
33	920 Admin. & General Salaries	14,239,215	110,468	14,128,747	17,593,234	-19.69%
34	921 Office Supplies & Expenses	2,623,160	20,427	2,602,733	4,073,119	-36.10%
35	922 Admin. Expense Transferred-Cr.	(5,922,448)	(45,946)	(5,876,502)	(6,867,466)	14.43%
36	923 Outside Services Employed	4,514,971	35,027	4,479,944	4,452,527	0.62%
37	924 Property Insurance	380,404	2,951	377,453	607,338	-37.85%
38	925 Injuries & Damages	(6,593,850)	(9,078,246)	2,484,396	3,086,157	-19.50%
39	926 Employee Pensions & Benefits	(971,810)	19,640	(991,450)	3,226,279	-130.73%
40	927 Franchise Requirements	-	-	-	-	-
41	928 Regulatory Commission Expenses	635,675	-	635,675	649,893	-2.19%
42	407 Amortization of Property Losses	(20,841,229)	-	(20,841,229)	86,921,561	-123.98%
43	929 Duplicate Charges-Cr.	-	-	-	-	-
44	930 Miscellaneous General Expenses	8,825,298	68,467	8,756,831	8,549,108	2.43%
45	931 Rents	759,104	5,889	753,215	1,462,109	-48.48%
46	**Total Operation-Admin. & General**	(2,351,510)	(8,861,323)	6,509,813	123,753,859	-94.74%
47	**Admin. & General-Maintenance**					
48	935 General Plant	2,651,387	20,471	2,630,916	5,012,538	-47.51%
49	**Total Maintenance-Admin. & General**	2,651,387	20,471	2,630,916	5,012,538	-47.51%
50	**Total Admin. & General Expenses**	299,877	(8,840,852)	9,140,729	128,766,397	-92.90%
51	**TOTAL OPER. & MAINT. EXPENSES**	310,828,170	(16,119,327)	326,947,497	354,972,590	-7.90%

Sch.11	MONTANA TAXES OTHER THAN INCOME - ELECTRIC (EXCLUDES UNIT 4)				
		Description	This Year	Last Year	% Change
1					
2		**Federal Taxes**			
3	2521xx	Social Security, Medicare and Unemployment	2,272,036	$2,808,971	-19.11%
4					
5		**Montana Taxes**			
6	252410	Real Estate & Personal Property	39,401,060	33,104,687	19.02%
7	252212	Montana Beneficial Use Tax	193,331	189,807	1.86%
8	252213	Crow Tribe Railroad & Utility Tax	34,416	8,161	>300.00%
9	252450	Electric Energy Producer's License	1,639	2,447	-33.03%
10	252450	Consumer Counsel	307,767	283,395	8.60%
11	252450	Public Service Commission	905,598	791,304	14.44%
12	252460	Wholesale Energy Transaction	1,498,729	859,634	74.35%
13		Various	-	10,148	-100.00%
14					
15					
16					
17					
18					
19					
20					
21	**TOTAL TAXES OTHER THAN INCOME**		$44,614,576	$38,058,554	17.23%
22					
23					

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	Asphlundh Tree Expert	Tree Trimming	1,406,688
2	Automotive Rentals	Fleet Management	4,056,619
3	Bill Field Trucking	Equipment Transportation	318,869
4	Browning, Kaleczyc, Berry & Hovan	Legal Services	549,471
5	Computer Associates	Maintenance	115,063
6	Davenport, Evans, Hurwitz & Smith	Legal Services	1,561,167
7	Express Services	Temporary Employment Services	241,688
8	Filenet Corporation	Maintenance	107,779
9	First Data Integrated Systems	Customer Service	157,838
10	Gibson, Dunn & Crutcher	Legal Services	845,384
11	Graves Law Offices	Legal Services	2,081,569
12	Independent Inspection Company	Electric Line Inspection	102,101
13	Itron, Inc.	Hardware/Software Maintenance	429,203
14	Kema-Xenergy	Energy Audit Programs & Services	1,419,372
15	Lands Energy consultants	Consulting	115,339
16	Lazard Freres & Co	Advisory Fees	1,078,978
17	Leonard, Street & Deinard	Professional Services	520,722
18	Lockton Companies	Insurance Brokerage & Claims Adminstration	588,820
19	March Engineering	Contractor	109,848
20	Morrison & Foerster	Legal Services	190,626
21	Nat'l Center for Appropriate Technology	Lab Testing	1,034,797
22	Northwest Energy Efficiency	Energy Services	532,403
23	Orcom Solutions	Programming & Implementation	2,653,286
24	PAR Electric Contractors	Contractor	1,287,768
25	Paul J. Evans	Consulting Services	344,960
26	Paul, Hastings, Janofsky & Wal	Legal Services	6,086,819
27	Paul, Weiss, Rifkind, & Wharton	Legal Services	150,000
28	Power Resource Managers	Power Scheduling & Dispatch	363,815
29	Risk Administration	Risk Administration Services	191,663
30	River Network	Consultants	101,417
31	Rod Tabbert Construction, Inc.	Contractor	213,932
32	Skadden, Arps, Slate, Meagh & Flom	Legal Services	434,952
33	Spiker Communication	Advertising	148,432
34	State Line Contractors	Contractor	245,456
35	Tony Laslovich	Contractor	106,536
36	Towers Perrin	Consulting/Actuary	283,058
37	Utilities Underground	Locator Services	101,766
38	Utility Consulting Services	Contractor	171,218
39	Varsity Contractors	Janitorial Services	197,477
40	Washington Group International	Consulting & Engineering	143,892
42	**Total of Payments Set Forth Above**		30,790,791

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

NorthWestern Energy does not make any contributions to Political Action Committees (PACs) or candidates.

There are two employee PACs, one called Citizens for Responsible Government / Employees of NorthWestern Energy, and one called NorthWestern Public Service Employee's Political Action Committee. These are organizations of employees and shareholders of NorthWestern Energy. All of the money contributed by members goes to support political candidates. No company funds may be spent in support of a political candidate. Nominal administrative costs for such things as duplicating and postage are paid by the company. These costs are charged to shareholder expense.

Sch. 14 PENSION COSTS

Description	Last Year	This Year	% Change
Plan Name: Retirement Plan for Employees			
of the Montana Power Company			
Defined Benefit Plan	Yes	Yes	
Defined Contribution Plan (See Schedule 14A)			
Is the Plan overfunded?	No - 3/	No - 3/	
Actuarial Cost Method			
IRS Code			
Annual Contribution by Employer	30,466	9,700,000	
	-		
Accumulated Benefit Obligation	268,318,815	292,261,554	8.92%
Projected Benefit Obligation	275,899,175	300,852,204	9.04%
Fair Value of Plan Assets	163,468,246	188,693,229	15.43%
Discount Rate for Benefit Obligations	6.50%	6.00%	
Expected Long-Term Return on Assets	8.50%	8.50%	
Net Periodic Pension Cost:			
Service Cost	4,143,675	4,325,666	4.39%
Interest Cost	17,344,669	17,729,155	2.22%
Return on Plan Assets *(Expected)*	(16,474,650)	(13,419,317)	-18.55%
Net Amortization	1,919,570	1,919,570	0.00%
Recognized net actuarial loss	-	4,268,343	> 300.00%
Special Termination Benefit Charge	4,191,451		100.00%
Curtailment Charge	910,439		100.00%
Settlement Charge	3,744,292		100.00%
Total Net Periodic Pension Cost	15,779,446	14,823,417	-6.06%
Minimum Required Contribution			
Actual Contribution	4,000,000	5,700,000	0.00%
Maximum Amount Deductible	20,535,023	54,597,991	0.00%
Benefit Payments	14,453,492	16,956,612	17.32%
Montana Intrastate Costs:			
Pension Costs		NOT AVAILABLE	
Pension Costs Capitalized			
Accumulated Pension Asset (Liability) at Year End			
Number of Company Employees : 1/			
Covered by the Plan			
Active	1,147	1,070	-6.71%
Retired	1,179	1,222	3.65%
Vested Former Employees (Deferred Inactive)	867	870	0.35%
Total Covered by the Plan	3,193	3,162	-0.97%
Total Not Covered by the Plan			

1/ Obtained from The Actuarial Valuation Report of the Retirement Plan for Employees of The Montana Power Company, prepared as of January 1, 2002 and 2003 respectively.

2/ As of December 31, 2002, the fair value of assets was $163.5 million and the projected benefit obligation was $275.9 million. However, there was an unrecognized net loss of $77.9 million that has not been fully amortized pursuant to SFAS Statement No. 87. There is a pension liability of $7.3 million as of December 31, 2002.

3/ As of December 31, 2003, the fair value of assets was $188.7 million and the projected benefit obligation was $300.9 million. However, there was an unrecognized net loss of $74.5 million that has not been fully amortized pursuant to SFAS Statement No. 87. There is a pension liability of $12.4 million as of December 31, 2003.

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	85,938,422	103,986,249	21.00%
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				
36	Number of Company Employees :			
37	Covered by the Plan -- Eligible	1,048	1,015	-3.15%
38	Not Covered by the Plan	0	0	
39	Active -- Participating	1,029	1,005	-2.33%
40	Retired	0		
41	Vested Former Employees, Retirees and	377	355	-5.84%
42	Active-Noncontributing	0		
43	Total Covered by the Plan	1,141	1,015	-3.15%
44	Total Not Covered by the Plan	0	0	
45				
46				
47				
48				
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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%	6.50%	0.00%
3	Expected Long-Term Return on Assets	8.50%	8.50%	0.00%
4	Medical Cost Inflation Rate 3/	12.0%,5.0%:9	12.0%,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**			
15				
16	Accumulated Post Retirement Benefit Obligation (APBO)	36,196,701	46,434,906	28.28%
17	Fair Value of Plan Assets	4,869,343	5,433,986	11.60%
18				
19	List the amount funded through each funding method:			
20	VEBA - 6/	1,073,647	3,845,324	258.16%
21	401(h) - 6/	3,436,840	1,394,967	-59.41%
22	Other: Cash	1,071,468	402,710	-62.42%
23	Total Amount Funded	5,581,955	5,643,001	1.09%
24				
25	List amount that was tax deductible for each type of funding:			
26	VEBA	1,073,647	3,845,324	258.16%
27	401(h)	3,436,840	1,394,967	-59.41%
28	Other: Cash	1,071,468	402,710	-62.42%
29	Total Amount Tax Deductible	5,581,955	5,643,001	1.09%
30				
31	Net Periodic Post Retirement Benefit Cost:			
32	Service Cost	549,846	814,420	48.12%
33	Interest Cost	2,196,959	2,827,953	28.72%
34	Return on Plan Assets *(Expected)*	(399,122)	(261,309)	-34.53%
35	Amort. of Transition Oblig. & Regulatory Asset	788,960	788,960	0.00%
36	Amortization of Prior Service Cost	28,210	28,211	-96.42%
37	Amortization of Gains or Losses	471,952	1,444,766	0.00%
38	Curtailment charge	804,397	-	100.00%
39	Special Termination Benefit Charge	167,837	-	100.00%
40	Total Net Periodic Post Retirement Benefit Cost	4,609,039	5,643,001	22.43%
41	Benefit Cost Expensed	3,650,359	4,250,228	-72.23%
42	Benefit Cost Capitalized	691,356	1,013,615	-45.16%
43	Benefit Cost Charged to MPC Subs & Colstrip Owners - 5/	267,324	379,158	41.83%
44	Total Benefit Costs	4,609,039	5,643,001	22.43%
45	Benefit Payments	1,071,468	402,710	-62.42%
46				
47	Number of Company Employees :			
48	Covered by the Plans			
49	Active	1,147	1,070	-6.71%
50	Retired	986	1,034	4.87%
51	Retired Spouse/Dependents	68	71	4.41%
52	Total Covered by the Plans	2,201	2,175	-1.18%
53	Total Not Covered by the Plans	217	125	-42.40%
54	1/ Obtained from MPC's 2002 FASB 106 Valuation. Assumptions and data are as of December 31, 2002.			
55	2/ Obtained from MPC's 2003 FASB 106 Valuation. Assumptions and data are as of December 31, 2003.			
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 3/			
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/ 2003 Trust funding was made on March 31, 2004 in the amounts of:
55 ($440,873) for 401(h) and $2,764,664 for VEBA.

SCHEDULE 16

Note: This schedule includes the ten most highly compensated officers 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	William Pascoe Vice President, Chief Operating Officer of Transmission (retired 2003)	44,615		4,624 B 478,731 C 5,748 D	533,718	182,729	192%
2	Ernie Kindt Vice President-Chief Accounting Officer (resigned 2003)	65,385		22,987 B 278,000 C 8,318 D	374,690	154,273	143%
3	Michael Manion Vice President-Legal Services (retired 2003)	26,615		1,538 A 7,701 B 296,098 C 3,303 D	335,255	187,594	79%
4	John Van Camp Vice President Organization and Staffing	248,926		15,226 D 14,000 F 3,745 I 5,779 J	287,676	276,270	4%
5	Richard Hylland President and Chief Operating Officer (resigned 2003)	209,656		53,942 B 10,892 D 2,595 H	277,085	747,968	-63%
6	Curtis Pohl Vice President-Distribution Operations	169,022		4,030 A 14,761 D 2,162 F 55,221 G	245,196	183,562	34%
7	Dennis Lopach Chief Administrative Officer	211,000		2,000 A 8,855 D 7,800 F	229,655	290,144	-21%
8	Gregory Trandem Vice President-Asset Management	184,917		5,460 A 15,603 D 3,892 F 11,966 H	221,838	340,387	-35%
9	Bart Thielbar Senior Vice President, Information Technology and Chief Information Officer	187,965		4,810 A 15,629 D 2,956 F	211,360	253,218	-17%
10	Kurt Whitesel Vice President-Controller and Treasurer (resigned 2003)	145,451		12,548 B 10,193 D 33,501 E	201,693	304,975	-34%

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 paid in 2003 but earned in 2002 are not listed above due to the change in how we are reporting						
2	include the following: Curtis Pohl $116,294, Dennis Lopach $226,130, Gregory Trandem $164,993, and Bart						
3	Thielbar $146,569.						
4							
5	2/ All Other Compensation for named employees consists of the following:						
6	A> Merit Cash						
7							
8	B> Vacation Sellbacks / Vacation Payout						
9							
10	C> Change in Control Payments						
11							
12	D>Employer Contributions to Benefits-Medical, Dental, Vision, EAP/Carewise, Term Life, Group Term Life, 401k						
13							
14	E> Severance Payment						
15							
16	F> Vehicle Payment / Car Allowance						
17							
18	G> Payment for Relocation Expenses						
19							
20	H> Imputed Income						
21							
22	I> Country Club Dues						
23							
24	J> Tax for Gross-up Pmts-SVIP Stk						
25							
26							
27							
28							
29	**BONUSES ARE REPORTED IN THE YEAR THEY WERE EARNED NOT COMPENSATED, HOWEVER 2003 BONUSES EARNED HAVE NOT BEEN APPROVED						
30	BY THE COURT AND WON'T BE UNTIL 5/17/2004 SO ARE NOT DISCLOSED AT THIS TIME						
31	**REPORTING IN PRIOR YEARS WAS BASED ON W-2. NOTE THIS YEAR(2003) WE ARE REPORTING DIFFERENTLY.						
32	**Bonus/Incentives are reported in the year they are earned not paid.						
33	**Benefits reflect the amounts the Employer Contributes to all Benefits noted in G > above						
34	Note that the change in reporting makes the variance skewed from 2003 to 2002.						

SCHEDULE 17

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

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary (Wages)	Bonuses 1/		Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	Gary Drook President and Chief Executive Officer	544,355	600,000	A	13,566 C 11,334 E 99,806 F 92,037 H	1,361,098	N/A (employment began 1/3/03)	0%
2	Kipp Orme Vice President, Finance and Chief Financial Officer (resigned 2003)	184,215			21,154 B 12,438 C 263,000 D 4,400 E 1,873 I	487,080	326,949	49%
3	William Austin Chief Restructuring Officer	284,615			13,236 C 797 G 2,247 I	300,895	N/A (employment began 4/7/03)	0%
4	Michael Hanson Chief Operating Officer	355,609			14,856 C 5,035 E 8,025 J	383,525	1,057,605	-64%
5	Eric Jacobsen Vice President, General Counsel & Chief Legal Officer	314,968			15,833 C 4,778 E 3,745 I 6,905 J	346,229	566,999	-39%

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation

1/ Bonuses consist of the following:

A> Discretionary & NOR Bonus

1/ Bonuses shown were earned in the year shown and paid in the following year with the exception of a employment bonus to Gary Drook $600,000.

1/ Bonuses paid in 2003 but earned in 2002 are not listed above due to the change in how we are reporting include the following: Michael Hanson $440,000, Eric Jacobsen $250,000

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

B> Vacation Sellbacks / Vacation Payout

C>Employer Contributions to Benefits-Medical, Dental, Vision, EAP/Carewise, Term Life, Group Term Life, 401k

D> Severance Payment

E> Vehicle Payment / Car Allowance

F> Payment for Relocation Expenses

G> Imputed Income

H> Fringe Airplane Gross-Up

I> Country Club Dues

J> Tax for Gross-up Pmts-SVIP Stk

**BONUSES ARE REPORTED IN THE YEAR THEY WERE EARNED NOT COMPENSATED, HOWEVER 2003 BONUSES EARNED HAVE NOT BEEN APPROVED BY THE COURT AND WON'T BE UNTIL 5/17/2004 SO ARE NOT DISCLOSED AT THIS TIME

**REPORTING IN PRIOR YEARS WAS BASED ON W-2. NOTE THIS YEAR(2003) WE ARE REPORTING DIFFERENTLY.

**Bonus/Incentives are reported in the year they are earned not paid.

**Benefits reflect the amounts the Employer Contributes to all Benefits noted in C > above

Note that the change in reporting makes the variance skewed from 2003 to 2002.

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	$1,622,304,365	$1,587,393,652	2.20%
4	105 Plant Held for Future Use	4,901	8,984	-45.45%
5	107 Construction Work in Progress	12,888,897	13,265,884	-2.84%
6	108 Accumulated Depreciation Reserve	(746,535,248)	(713,142,815)	4.68%
7	111 Accumulated Amortization & Depletion Reserves	(12,976,399)	(9,116,109)	42.35%
8	114 Electric Plant Acquisition Adjustments	399,030,704	399,030,704	0.00%
9	115 Accumulated Amortization-Electric Plant Acq. Adj.	(2,536,800)	(2,441,885)	3.89%
10	117 Gas Stored Underground-Noncurrent	32,599,489	33,414,607	-2.44%
11	**Total Utility Plant**	1,304,779,909	1,308,413,021	-0.28%
12	**Other Property and Investments**			
13	121 Nonutility Property	3,475,012	3,646,390	-4.70%
14	122 Accumulated Depr. & Amort.-Nonutililty Property	(54,552)	(24,641)	121.39%
15	123.1 Investments in Subsidiary Companies	(190,751)	12,402,929	-101.54%
16	123 Investments in Colstrip Unit 4 & YNP	38,492,491	42,480,052	-9.39%
17	124 Other Investments	4,529,363	22,974,086	-80.28%
18	128 Miscellaneous Special Funds	2,322,955	1,497,098	55.16%
19	**Total Other Property & Investments**	48,574,517	82,975,914	-41.46%
20	**Current and Accrued Assets**			
21	131 Cash	18,450,362	27,914,771	-33.90%
22	135 Working Funds	36,705	47,780	-23.18%
23	136 Temporary Cash Investments	-	-	-
24	141 Notes Receivable	39,321	-	-
25	142 Customer Accounts Receivable	42,001,390	30,506,362	37.68%
26	143 Other Accounts Receivable	7,082,397	7,597,704	-6.78%
27	144 Accumulated Provision for Uncollectible Accounts	(1,570,429)	(1,283,900)	22.32%
28	145 Notes Receivable-Associated Companies	-	-	-
29	146 Accounts Receivable-Associated Companies	452,285,517	71,434,340	>300.00%
30	151 Fuel Stock	-	-	-
31	154 Plant Materials and Operating Supplies	7,597,097	7,928,691	-4.18%
32	164 Gas Stored - Current	7,120,719	6,954,010	
33	165 Prepayments	34,974,471	8,032,735	>300.00%
34	171 Interest and Dividends Receivable	-	-	-
36	172 Rents Receivable	325,610	214,063	52.11%
37	173 Accrued Utility Revenues	40,394,293	30,537,915	32.28%
38	174 Miscellaneous Current & Accrued Assets	708,316	217,395	225.82%
39	**Total Current & Accrued Assets**	609,445,769	190,101,866	220.50%
40	**Deferred Debits**			
41	181 Unamortized Debt Expense	19,971,998	3,467,877	>300.00%
42	182 Regulatory Assets	161,631,465	160,907,518	0.45%
43	183 Preliminary Survey and Investigation Charges	-	-	-
44	184 Clearing Accounts	(78)	(78)	0.00%
45	185 Temporary Facilities	78	78	0.00%
46	186 Miscellaneous Deferred Debits	4,222,870	3,503,600	20.53%
47	189 Unamortized Loss on Reacquired Debt	2,993,902	3,300,790	-9.30%
48	190 Accumulated Deferred Income Taxes	106,190,840	112,240,970	-5.39%
49	191 Unrecovered Purchased Gas Costs	8,659,475	2,459,019	252.15%
50	**Total Deferred Debits**	303,670,550	285,879,774	6.22%
51	**TOTAL ASSETS and OTHER DEBITS**	$ 2,266,470,745	1,867,370,574	21.36%

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	$ -	$ -	-
4	204 Preferred Stock Issued	-	-	-
5	207 Premium on capital stock	-	-	-
6	211 Miscellaneous Paid-In Capital	578,633,741	578,633,741	0.00%
7	213 Discount on Capital Stock	-	-	-
8	214 Capital Stock Expense	-	-	-
9	215 Appropriated Retained Earnings	-	-	-
10	216 Unappropriated Retained Earnings	98,422,947	63,824,632	54.21%
11	217 Reacquired capital stock	-	-	-
12	**Total Proprietary Capital**	677,056,688	642,458,373	5.39%
13	**Long Term Debt**			
14	221 Bonds	327,402,000	327,402,000	0.00%
15	224 Other Long Term Debt	395,200,000	133,000,000	197.14%
16	226 Unamortized Discount on Long Term Debt-Debit	(2,606,300)	(2,886,070)	-9.69%
17	**Total Long Term Debt**	719,995,700	457,515,930	57.37%
18	**Other Noncurrent Liabilities**			
19	227 Obligations Under Capital Leases-Noncurrent	3,081,181	6,022,866	-48.84%
20	228.1 Accumulated Provision for Property Insurance	482,612	(117,388)	>-300.00%
21	228.2 Accumulated Provision for Injuries and Damages	12,188,458	13,465,656	-9.48%
22	228.3 Accumulated Provision for Pensions and Benefits	39,554,182	52,521,282	-24.69%
23	228.4 Accumulated Miscellaneous Operating Provisions	149,529,369	163,671,391	-8.64%
24	**Total Other Noncurrent Liabilities**	204,835,801	235,563,807	-13.04%
25	**Current and Accrued Liabilities**			
25	231 Notes Payable	-	-	-
26	232 Accounts Payable	48,023,604	32,698,245	46.87%
27	233 Notes Payable to Associated Companies	-	-	-
28	234 Accounts Payable to Associated Companies	251,251,424	121,387,163	106.98%
29	235 Customer Deposits	3,821,680	2,472,985	54.54%
30	236 Taxes Accrued	23,693,007	27,662,203	-14.35%
31	237 Interest Accrued	8,347,304	4,438,793	88.05%
32	238 Dividends Declared	-	-	-
33	241 Tax Collections Payable	(68,273)	(118,384)	-42.33%
34	242 Miscellaneous Current and Accrued Liabilities	7,447,256	17,374,652	-57.14%
35	243 Obligations Under Capital Leases-Current	4,072,181	3,533,688	15.24%
36	**Total Current and Accrued Liabilities**	346,588,183	209,449,345	65.48%
37	**Deferred Credits**			
38	252 Customer Advances for Construction	22,840,988	21,993,098	3.86%
39	253 Other Deferred Credits	107,645,512	117,443,222	-8.34%
40	254 Regulatory Liabilities	17,308,100	48,833,050	-64.56%
41	255 Accumulated Deferred Investment Tax Credits	(1)	(1)	0.00%
42	257 Unamortized Gain on Reacquired Debt	-	3,867	-100.00%
43	281-283 Accumulated Deferred Income Taxes	170,199,773	134,109,883	26.91%
44	**Total Deferred Credits**	317,994,372	322,383,119	-1.36%
45	**TOTAL LIABILITIES and OTHER CREDITS**	$ 2,266,470,745	1,867,370,574	21.37%
46	1/ Includes CMP and Montana Power Capital I; excludes Colstrip Unit 4 and Yellowstone National Park.			
47				
48		(0)	(0)	
49	The financial results reported include income taxes that are based upon NorthWestern's tax basis for plant assets purchased from			
50	the Montana Power Company. This tax basis differs from amounts included in the most recently decided rate proceeding and			
51	results in a lower deferred tax credit. This change was made in order to prevent any possible violation of the normalization			
52	requirements of the federal income tax code. The change results in an increase in the reported rate base.			
53				

NOTES TO FINANCIAL STATEMENTS

(1) Management's Statement

The financial statements for the periods included herein have been prepared by NorthWestern Corporation (the "Corporation", "Debtor" or "we"), a debtor-in-possession, pursuant to the rules and regulations Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. These financial statements represent the Montana operations of NorthWestern Energy.

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). Pursuant to Chapter 11 (as discussed further in Note 3), we retain control of our assets and are authorized to operate our business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court. We have investments in subsidiaries that are not party to the Chapter 11 case and are not debtors.

(2) Nature of Operations and Basis of Consolidation

We are one of the largest providers of electricity and natural gas in the Upper Midwest and Northwest, serving approximately 608,000 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 through our energy division, NorthWestern Energy. On February 15, 2002, we completed the acquisition of the electric and natural gas transmission and distribution business of The Montana Power Company, or Montana Power. As a result of the acquisition, from February 15, 2002 through November 15, 2002, we distributed electricity and natural gas in Montana through our wholly owned subsidiary, NorthWestern Energy, LLC. Effective November 15, 2002, we transferred the electric and natural gas transmission and distribution operations of NorthWestern Energy, LLC to NorthWestern Corporation, and since that date, we have operated its business as part of our NorthWestern Energy division. We are operating our utility business under the common name "NorthWestern Energy" in all our service territories. The former NorthWestern Energy, LLC has been renamed "Clark Fork and Blackfoot, LLC."

(3) Chapter 11 Filing

As a result of our Chapter 11 filing, we operate our business as a "debtor-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code, the Federal Rules of Bankruptcy Procedure and applicable court orders. All vendors are being paid for all goods furnished and services provided after the Petition Date while under the supervision of the bankruptcy court. As a debtor-in-possession, we are authorized to continue to operate as an ongoing business, but may not engage in transactions outside the ordinary course of business without the approval of the Court, after notice and an opportunity for a hearing.

On September 16, 2003, following first day hearings held on September 15, 2003, the Bankruptcy Court entered orders granting us authority to, among other things, pay prepetition and postpetition employee wages, salaries, benefits and other employee obligations, pay selected vendors and other providers for the postpetition delivery of goods and services, continue bank accounts and existing cash management system, and continue existing forward power contracts and enter into additional similar contracts in the ordinary course of business. On November 7, 2003, the Bankruptcy Court entered a final order to approve access of up to $85 million of the $100 million debtor-in-possession financing facility arranged by the company with Bank One, N.A. In December 2003, we reduced the commitment to $85 million and in April 2004, we further reduced the commitment to $75 million under this facility. The DIP Facility expires on September 12, 2004, and bears interest at a variable rate tied to the Eurodollar rate plus a spread of 3.00% or at the prime rate plus a spread of 1.00%. The DIP Facility will provide a source of liquidity during the course of our bankruptcy, but requires that we maintain certain other financial covenants and restricts liens, indebtedness, capital expenditures, dividend payments and sales of assets. As of December 31, 2003, there were $15.2 million in letters of credit outstanding and no borrowings under the DIP Facility.

In January 2004, the Bankruptcy Court extended our exclusive period to file a plan of reorganization through and including March 12, 2004, and extended the time to solicit votes on our plan of reorganization through and including May 11, 2004. We filed our initial plan of reorganization on March 12, 2004.

The financial statements have been prepared on a "going concern" basis in accordance with GAAP. The "going concern" basis of presentation assumes that we will continue in operation for the foreseeable future and will be able to realize our assets and discharge our liabilities in the normal course of business. Because of the Chapter 11 case and the circumstances leading to the filing thereof, our ability to continue as a "going concern" is subject to substantial doubt and is dependent upon, among other things, confirmation of a plan of reorganization, our ability to comply with the terms of the DIP Facility, and our ability to generate sufficient cash flows from operations, asset sales and financing arrangements to meet our obligations. There can be no assurance that this can be accomplished and if it were not, our ability to realize the carrying value of our assets and discharge our liabilities would be subject to substantial uncertainty. Therefore, if the "going concern" basis were not used for the Financial Statements, then significant adjustments could be necessary to the carrying value of assets and liabilities, the revenues and expenses reported, and the balance sheet classifications used.

The Chapter 11 filing triggered defaults, or termination events, on substantially all of our debt and lease obligations, and certain contractual obligations. Subject to certain exceptions under the Bankruptcy Code, our Chapter 11 filing automatically enjoined, or stayed, the continuation of any judicial or administrative proceedings or other actions against us or our property to recover on, collect or secure a claim arising prior to the Petition Date. Thus, for example, creditor actions to obtain possession of our property, or to create, perfect or enforce any lien against our property, or to collect on or otherwise exercise rights or remedies with respect to a prepetition claim are enjoined unless and until the Bankruptcy Court lifts the automatic stay.

(4) Significant Accounting Policies

Basis of Accounting

Our accounting policies conform with generally accepted accounting principles. With respect to our utility operations, these policies are in accordance with the accounting requirements and ratemaking practices of applicable regulatory authorities.

Financial Statement Presentation

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 generally accepted accounting principles due to FERC requiring the reflection 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. The other significant differences are comparative statements of retained earnings and cash flows and net income per share are not presented.

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 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.

Cash Equivalents

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

Accounts Receivable

Accounts receivable includes accrued unbilled revenues of $40.7 million and $30.6 million at December 31, 2003 and 2002.

Inventories

Inventories are stated at the lower of cost or market, with cost determined using the average cost method.

Regulatory Assets and Liabilities

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). Regulatory assets represent probable future revenue associated with certain costs, which will be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are to be credited to customers through the ratemaking process.

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 $4.5 million and $23 million at December 31, 2003 and 2002, respectively.

Life insurance contracts are carried at their cash surrender value. We also have investments in various money market accounts and other items. Investments in life insurance contracts of $3.6 million and $22.2 million are held in trust and restricted for postretirement benefits as of December 31, 2003 and 2002, respectively. Investments in money market accounts of $3.6 million and $3.8 million are restricted to satisfy certain debt requirements as of December 31, 2003 and 2002, respectively.

Derivative Financial Instruments

We manage risk using derivative financial instruments for changes in electric and natural gas supply prices and interest rate fluctuations.

We periodically use 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.

The fair value of fixed-price commodity contracts is estimated based on market prices of commodities covered by the contracts. As of December 31, 2003, we have outstanding call obligations for physical delivery of 3.3 million MMBTU of natural gas during February and March of 2004. We have recorded a liability related to these obligations of $1.8 million based on the market value of natural gas as of December 31, 2003. We settled these calls during January and February 2004, resulting in a gain of approximately $526,000.

Property, Plant and Equipment

Property, plant and equipment are stated at cost. Depreciation is computed using the straight-line method based on the estimated useful lives of the various classes of property, ranging from 3 to 40 years.

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.

Property, plant and equipment at December 31 consisted of the following (in thousands):

	2003	2002
Land and improvements	$ 33,255	$ 29,344
Building and improvements	59,928	62,870
Storage, distribution, transmission and generation	1,415,459	1,374,965
Construction work in process	12,889	13,266
Electric plant acquisition adjustments	399,031	399,031
Other equipment	146,266	153,638
	2,066,828	2,033,114
Less accumulated depreciation	(762,048)	(724,701)
	$ 1,304,780	$ 1,308,413

We capitalize the cost of plant additions and replacements, including an allowance for funds used during construction (AFUDC) of utility plant. We determine the rate used to compute AFUDC in accordance with a formula established by the FERC. This rate averaged 8.9% and 8.7% for Montana for 2003 and 2002, respectively. Interest capitalized totaled $0.9 million and $1.0 million in 2003 and 2002, respectively, for Montana.

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%, 3.4% and 3.3% for 2003, 2002 and 2001, respectively.

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, 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, 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 June 2001, the Financial Accounting Standards Board issued SFAS No. 143, *Accounting for Asset Retirement Obligations*, which was effective January 1, 2003. The statement provides accounting and disclosure requirements for retirement obligations associated with long-lived assets. The statement requires the present value of future asset retirement costs for which the Corporation has a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over the asset life.

We have completed an assessment of the specific applicability and implications of SFAS No. 143. 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 SFAS No. 143 legal retirement obligations. As of December 31, 2003 and 2002, we have estimated accrued removal costs of $124.9 million and $115.5 million, respectively.

SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections*, was issued in April 2002. SFAS No. 145 eliminates the requirement that gains and losses from the extinguishments of debt be aggregated and classified as extraordinary items, net of the related income tax. It also requires sale-leaseback treatment for certain modifications of a capital lease that result in the lease being classified as an operating lease. We adopted SFAS No. 145 on January 1, 2003 and our loss on debt extinguishment is reflected as miscellaneous non-operating on the Statement of Income (Loss). The related tax benefit of $7.2 million is reflected as a benefit for income taxes on the Statement of Income (Loss).

SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*, was issued in June 2002. SFAS No. 146 requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan, including lease termination costs and certain employee termination benefits that are associated with a restructuring, discontinued operation, plant closing or other exit or disposal activity. SFAS No. 146 is being applied prospectively and is effective for exit or disposal activities that are initiated after December 31, 2002. We adopted SFAS No. 146 on January 1, 2003. The adoption of SFAS No. 146 did not have a material impact on our results of operations, financial position, or cash flows.

FASB Interpretation No. 46, *Consolidation of Variable Interest Entities* (FIN 46), was issued in January 2003 and was revised in December 2003. This interpretation changes the method of determining whether certain entities, including securitization entities, should be included in a company's financial statements. An entity that is subject to FIN 46 is called a variable interest entity, or VIE, if it has equity that is insufficient to permit the entity to finance its activities without additional subordinated financial support from other parties, or equity investors that cannot make significant decisions about the entity's operations, or that do not absorb the expected losses or receive the expected returns of the entity. All other entities are evaluated for consolidation in accordance with SFAS No. 94, *Consolidation of All Majority-Owned Subsidiaries*. A VIE is by its primary beneficiary, which is the party involved with the VIE that has a majority of the expected losses or a majority of the expected residual returns or both. The requirements of FIN 46 are applicable to NorthWestern Corporation in the fourth quarter of 2003. Had we not filed for bankruptcy, we would have been required to deconsolidate our Subsidiary Trusts, which hold our Company Obligated Mandatorily Redeemable Preferred Securities (TPS), upon adoption of FIN 46. However, upon filing for bankruptcy, the Subsidiary Trusts were terminated and the TPS became direct obligations of NorthWestern Corporation. In February 2004, we became aware that certain long-term purchase power and tolling contracts may be considered variable interests under FIN No. 46R. We have various long-term purchase power contracts with other utilities and certain qualifying facility plants. We believe the counterparties to these contracts are not special-purpose entities and, therefore, FIN No. 46R would not apply to these contracts until March 31, 2004. We have not yet completed our evaluation of these contracts to determine if we need to consolidate these counterparties under FIN No. 46R and will continue to monitor developing practice in this area.

In April 2003, the FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*, which amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. SFAS No. 149 is effective prospectively for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. The exception to these requirements are the provisions of SFAS No. 149 related to SFAS No. 133 implementation issues that have been effective for fiscal quarters that began prior to June 15, 2003, should continue to be applied in accordance with their respective effective dates. In addition, paragraphs 7(a) and 23(a), which relate to forward purchases or sales of when-issued securities or other securities that do not yet exist, should be applied to both existing contracts and new contracts entered into after June 30, 2003. The adoption of SFAS No. 149 did not have a material impact on our results of operations, financial condition or cash flows.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Instruments with Characteristics of Both Liabilities and Equity*, which establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. SFAS No. 150 requires that an issuer classify a financial instrument that is within its scope, which may have previously been reported as equity, as a liability or an asset in some circumstances. SFAS No. 150 is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. In accordance with SFAS No. 150, we have presented our Company Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trusts as liabilities and the respective dividends have been reflected as interest expense.

Reclassifications

Certain 2002 amounts have been reclassified to conform to the 2003 presentation. Such reclassifications had no impact on net income (loss) or shareholders' equity (deficit) as previously reported.

(5) Acquisitions

On February 15, 2002, we completed the asset acquisition of Montana Power's energy transmission and distribution business for $478.0 million in cash and the assumption of $511.1 million in existing debt and mandatorily redeemable preferred securities of subsidiary trusts (net of cash received). Acquisition costs were approximately $24.8 million. We completed this acquisition to expand our presence in the energy market. As a result of the acquisition, we are now a provider of natural gas and electricity to approximately 608,000 customers in Montana, South Dakota and Nebraska. Results of our Montana operations have been included in the accompanying financial statements since the effective date of the acquisition.

(6) Goodwill

We adopted the provisions of SFAS No. 142 effective January 1, 2002, and goodwill is no longer amortized. According to the guidance set forth in SFAS No. 142, we are required to evaluate our goodwill and indefinite-lived intangible assets for impairment at least annually (October 1) and more frequently when indications of impairment exist. Accounting standards require that if the fair value of a reporting unit is less than its carrying value including goodwill, an impairment charge for goodwill must be recognized in the financial statements. To measure the amount of the impairment loss to recognize, we compare the implied fair value of the reporting unit's goodwill with its carrying value. This methodology differs from our previous policy, as permitted under previous accounting standards, of using undiscounted cash flows on an enterprise wide basis to determine if goodwill is recoverable.

We determined that our Chapter 11 bankruptcy filing constitutes an event that may reduce the fair value of our reporting unit below its carrying value. Therefore we retained a third party to assist us in completing a goodwill impairment test as required by SFAS No. 142. Fair value was determined using a discounted cash flow approach and a guideline company market approach. Completion of the testing indicated that no impairment charge was required.

There were no changes in our goodwill during the 12 months ended December 31, 2003. Goodwill relates entirely to the Montana operations acquired in 2002 and is reflected in the Balance Sheets as a plant acquisition adjustment of $375.8 million as of December 31, 2003 and 2002.

(7) (This Footnote was Intentionally Left Blank)

(8) (This Footnote was Intentionally Left Blank)

(9) Long-Term Debt

Long-term debt at December 31 consisted of the following (in thousands):

	Due	2003	2002
Senior Secured Term Loan	2006	277,200	—
Mortgage bonds—			
Montana—7.30%	2006	150,000	150,000
Montana—8.25%	2007	365	365
Montana—8.95%	2022	1,446	1,446
Montana—7.00%	2005	5,386	5,386
Pollution control obligations—			
Montana—6.125%	2023	90,205	90,205
Montana—5.90%	2023	80,000	80,000
Secured medium term notes—			

7.23%	2003	—	15,000
7.25%	2008	13,000	13,000
Unsecured medium term notes—			
7.07%	2006	15,000	15,000
7.875%	2026	20,000	20,000
7.96%	2026	5,000	5,000
Quips — 8.45%		65,000	65,000
Discount on Notes and Bonds	—	(2,606)	(2,886)
		$ 719,996	$ 457,516

On September 14, 2003, the Bankruptcy Court gave interim approval for access of up to $50 million of our $100 million DIP Facility. On November 7, 2003, the Bankruptcy Court entered a final order to approve the DIP Facility and, in doing so, increased our access under this facility to $85 million. In December 2003, we reduced the commitment to $85 million and in April 2004, we further reduced the commitment to $75 million under this facility. The DIP Facility expires on September 12, 2004, and bears interest at a variable rate tied to the Eurodollar rate plus a spread of 3.00% or at the prime rate plus a spread of 1.00%. The DIP Facility requires that we maintain certain other financial covenants and restricts liens, indebtedness, capital expenditures, dividend payments and sales of assets. As of December 31, 2003, we had $15.2 million in letters of credit outstanding and no borrowings under the DIP facility.

We have reached an agreement with the lenders holding claims under our senior credit facility agented by CSFB to amend the terms of our $390 million prepetition credit facility. In January 2004, the Bankruptcy Court entered a final order authorizing the amendment of the credit facility and granting protection in connection therewith. The amended credit facility provides advantages to NorthWestern, including lower interest expense allowing reinstatement upon NorthWestern's emergence from Chapter 11. At NorthWestern's option, the amended credit facility bears interest at a variable rate tied to the Eurodollar rate, plus a spread of 5.50%, or at an alternate base rate, as defined by the amended credit facility, plus a spread of 3.50%. There is no longer a minimum floor for the Eurodollar rate or the alternate base rate. As a result of this amendment, we estimate annualized interest expense will be reduced by approximately $6 million to $8 million.

Our senior secured term loan expires on December 1, 2006, and requires quarterly amortization payments equal to $975,000. The credit agreement contains financial covenants related to minimum EBITDAR(1), maximum capital expenditures and a number of other representations and warranties. We are in compliance with these debt covenants at December 31, 2003.

In January 2003, in connection with executing the new senior secured term loan facility, we applied to the MPSC for authorization to issue up to $280 million aggregate principal amount of First Mortgage Bonds secured by Montana utility assets as security for our new senior secured term loan facility. In granting its approval, the MPSC placed the following conditions on the approval of the First Mortgage Bonds:

- We must apply all proceeds from the sale of nonutility assets, specifically including Blue Dot and Expanets, to debt reduction;
- We must commit to fully funding the operation, maintenance, repair and replacement of our public utility infrastructure in Montana, and we were required to file a maintenance plan and budget with the MPSC by March 13, 2003;
- We may not provide more than an additional $10 million in aggregate in capital to any nonutility entity without the prior approval of the MPSC;
- We must report all advances to nonutility companies to the MPSC within 5 business days of such advance; and
- if the existing credit agreements for Blue Dot or Expanets are terminated, we may file an application with the MPSC seeking approval to provide secured loans of up to $20 million to Blue Dot and up to $30 million to Expanets.

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 are four series of bonds that The Montana Power Company issued. The Montana Pollution Control Obligations, and the Secured Medium Term Notes are obligations that The Montana Power Company issued. The Montana Natural Gas Transition Bonds were issued by The Montana Power Company. All of these obligations are secured by substantially all of our Montana electric and natural gas assets.

The Senior Notes are two series of unsecured notes that we issued in 2002 in connection with our acquisition of NorthWestern Energy LLC. Proceeds were used for the acquisition and for general corporate purposes.

The Senior Unsecured Debt is a general obligation that we issued in November 1998. The proceeds were used to repay short-term indebtedness and for general corporate purposes.

The Unsecured Medium Term Notes are general obligations issued by The Montana Power Company.

The aggregate minimum principal maturities of long-term debt, absent accelerations due to default, during the next five years are $2.8 million in 2004, $8.2 million in 2005, $436.6 million in 2006, $0.4 million in 2007 and $13.0 million in 2008.

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(1) EBITDAR is earnings before interest, taxes, depreciation, amortization and non-recurring restructuring expenses. EBITDAR is a non-GAAP financial measure and as such, we have not used it in describing our results of operations. We have used EBITDAR in this section specifically to show compliance with our debt covenants, and we do not refer to EBITDAR for any other purpose herein.

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(10) Comprehensive Income (Loss)

Comprehensive income is the sum of net income as reported and other comprehensive income. Our other comprehensive income primarily resulted from our foreign currency translation adjustment.

The after tax components of accumulated other comprehensive income for the years ended December 31, 2003 and 2002, were as follows (in thousands):

	2003	2002
Balance at December 31,		
Other Comprehensive Income:		
Foreign currency translation adjustment	158	122
Accumulated other comprehensive loss	$ 158	$ 122

The accumulated balance of other comprehensive income at December 31, 2003 and 2002 was $2.4 million and $2.2 million, respectively.

(11) Financial Instruments

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

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 cash equivalents, restricted cash and 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, 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 at December 31 is summarized as follows (in thousands):

	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Assets:				

Cash and cash equivalents	$	18,487 $	18,487 $	27,963 $	27,963
Investments		4,529	4,529	22,974	22,974
Liabilities:					
Long-term debt (including current portion)		719,996	695,516	457,516	426,553

(12) Income Taxes

Income tax benefit applicable to continuing operations before minority interests for the years ended December 31 is comprised of the following (in thousands):

	2003	2002
Federal		
Current	$ (9,906)	$ 5,900
Deferred	37,717	4,594
Investment tax credits		
State	317	2,586
	$ 28,128	$ 13,080

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

	2003	2002
Federal statutory rate	35.00%	35.00%
State income, net of federal provisions	4.24%	5.02%
Amortization of investment tax credit	0.00%	0.00%
Reversal of Utility book/tax depreciation	5.33%	-11.10%
Other, net	0.48%	-3.52%
	45.06%	25.39%

The components of the net deferred income tax liability recognized in our Consolidated Balance Sheets are related to the following temporary differences at December 31 (in thousands):

	2003	2002
Amortization of gain on sale/leaseback	$ 2,957	$ 3,379
Other	103,234	108,862
	106,191	112,241
Plant Related	(147,139)	(94,173)
Other, net	(23,061)	(39,937)
	(170,200)	(134,110)
	$ (64,009)	$ (21,869)

(13) (This Footnote was Intentionally Left Blank)

(14) (This Footnote was Intentionally Left Blank)

(15) Employee Benefit Plan

We sponsor and/or contribute to pension and postretirement health care and life insurance benefit plans for employees of the corporation and regulated utility division. In addition, we also sponsor nonqualified, unfunded defined benefit pension plans for certain officers and other employees. With the acquisition of Montana Power, we assumed their pension and postretirement health care plans. These plans are reflected in the 2003 and 2002 columns of the tables below.

Net periodic cost for our pension and other postretirement plans consists of the following for the year ended December 31 (in thousands):

	Pension Benefits			Other Postretirement Benefits	
	2003	2002	2001	2003	2002
Components of Net Periodic Benefit Cost					

(Income)					
Service cost	$ 4,326	$ 4,144	$ 4,731	$ 814	$ 550
Interest cost	17,729	17,345	18,028	3,573	3,555
Expected return on plan assets	(13,419)	(16,475)	(20,547)	(261)	(399)
Amortization of transitional obligation.	—	(41)	(20)		789
Amortization of prior service cost	—	1,960	2,094	—	28
Recognized actuarial (gain) loss	1,934	—	—	692	633
	10,570	6,933	4,286	4,818	5,156
Additional (income) or loss recognized:					
Curtailment	—	910	(2,315)	—	804
Special termination benefits	—	4,191	—	—	168
Settlement cost	—	3,744	(770)	(1,798)	—
Net Periodic Benefit Cost	$ 10,570	$ 15,778	$ 1,201	$ 3,020	$ 978

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.

Following is a reconciliation of the changes in plan benefit obligations and fair value and a statement of the funded status as of December 31 (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	2003	2002
Reconciliation of Benefit Obligation				
Obligation at January 1	$ 275,899	$ 259,971	$ 58,291	$ 46,537
Service cost	4,326	4,144	814	550
Interest cost	17,729	17,345	3,573	3,555
Actuarial loss	19,855	16,537	8,040	17,422
Plan amendments	—	—	)	(983)
Acquisitions/Divestitures		(11,835)		(1,201)
Curtailments	—	—	)	—
Settlement cost	—	—	(16,566)	—
Special termination benefits		4,191	—	168
Gross benefits paid	(16,957)	(14,454)	(4,354)	(7,757)
Benefit obligation at end of year	$ 300,852	$ 275,899	$ 49,798	$ 58,291
Reconciliation of Fair Value of Plan Assets				
Fair value of plan assets at January 1	$ 163,468	$ 215,144	$ 4,869	$ 5,872
Actual return on plan assets	32,482	(21,290)	309	(767)
Acquisitions/Divestitures	—	(15,932)	—	—
Employer contributions	9,700	—	21,176	7,521
Settlements	—	—	(16,566)	—
Gross benefits paid	(16,957)	(14,454)	(4,354)	(7,757)
Fair value of plan assets at end of year	$ 188,693	$ 163,468	$ 5,434	$ 4,869

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 $300.9 million and $188.7 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 $292.3 million and $188.7 million, respectively, as of December 31, 2003. 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 $275.9 million and $163.9 million, respectively, as of December 31, 2002. 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 $268.3 million and $163.9 million, respectively, as of December 31, 2002.

In January 2004, the Financial Accounting Standards Board issued FASB Staff Position No. FAS 106-1, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003* (FSP 106-1). While we have elected to defer recognition of the effects of FSP 106-1 until guidance on the accounting for the federal subsidy is issued, we do not expect the effects of FSP 106-1 to be material to the measurement of our APBO or our net periodic postretirement benefit cost.

The accrued pension and other postretirement benefit obligations recognized in the accompanying Balance Sheets are computed as follows for the years ended December 31 (in thousands):

	Pension Benefits 2003	Pension Benefits 2002	Other Postretirement Benefits 2003	Other Postretirement Benefits 2002
Funded Status	$ (112,159)	$ (112,431)	$ (44,364)	$ (53,422)
Unrecognized transition amount	—	(82)	—	7,932
Unrecognized net actuarial loss	48,824	77,976	15,622	17,822
Unrecognized prior service cost	—	18,499	—	237
Accrued benefit cost	$ (63,335)	$ (16,038)	$ (28,742)	$ (27,431)
Prepaid benefit cost	$ —	$ —	$ —	$ —
Accrued benefit cost	(63,335)	(16,038)	(28,742)	(27,431)
Additional minimum liability	(40,233)	88,813	—	—
Intangible asset	—	(18,499)	—	—
Regulatory asset	—	—	—	—
Accumulated other comprehensive income	40,233	(70,314)	—	—
Net amount recognized	$ (63,335)	$ (16,038)	$ (28,742)	$ (27,431)

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

	Pension Benefits 2003	Pension Benefits 2002	Pension Benefits 2001	Other Postretirement Benefits 2003	Other Postretirement Benefits 2002
Discount rate	6.00%	7.00%	7.00%	6.0-6.5%	6.0-6.5%
Expected rate of return on assets	8.50%	8.50%	9.00%	8.5%	8.5%
Long-term rate of increase in compensation levels (nonunion)	3.97%	3.97%	4.40%	—	—

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, 2002, 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 10.1%. 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.

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.

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.

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 target asset allocation percentages are as follows, within an allowable range of plus or minus 5%:

	Pension Benefits	Other Benefits
Cash and cash equivalents	—	—
Debt securities	30.0%	30.0%
Domestic equity securities	60.0%	60.0%
International equity securities	10.0%	10.0%
Other	—	—

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, 2003 and 2002, are as follows:

	NorthWestern Energy Pension		NorthWestern Energy Health and Welfare	
	2003	2002	2003	2002
Cash and cash equivalents	1.4%	7.2%	2.8%	4.0%
Debt securities	28.5%	33.4%	27.5%	30.4%
Domestic equity securities	58.9%	54.2%	68.3%	64.7%
International equity securities	11.2%	5.2%	1.4%	0.9%
Participating group annuity contracts	—	—	—	—
	100.0%	100.0%	100.0%	100.0%

At December 31, 2002, the NorthWestern Energy pension plan investment portfolio was undergoing a change in investment managers, Domestic equity investments were liquidated and pending reinvestment by the new investment manager. This was completed and the portfolio was again rebalanced to bring it within the target asset allocation during 2003. We also began the process of transitioning NorthWestern Corporation's pension plan assets over to comply with the new investment policy asset target guidelines adopted in 2002. At December 31, 2003, this process was partially completed with the liquidation and diversified reinvestment of part of the plan assets. We are 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.

We estimate contributions to our pension and other benefit plans in 2004 to be approximately $16.0 million in total.

The rate of increase in per capita costs of covered health care benefits is assumed to be 11% in 2004, decreasing gradually to 5% by the year 2009. 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	$	239
on postretirement benefit obligation		2,488
Effect of a one percentage point decrease in assumed health care cost trend		
on total service and interest cost components	$	(191)
on postretirement benefit obligation		(1,943)

Pension costs in Montana are included in rates on a pay as you go basis for regulatory purposes. Other postretirement benefit costs in Montana are included in rates on an accrual basis for regulatory purposes. (See Note 17, Regulatory Assets and Liabilities, for the regulatory assets related to our pension and other postretirement benefit plans.)

During 2003 and 2002, we made available to select employees an early retirement program. The impact of that reduction in participants resulted in the special termination benefits presented in the above table.

We provide various 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 up to a maximum of 4.0% of the employee's gross compensation contributed to the Plan. Costs incurred under these plans were $2.5 million and $2.7 million in 2003, and 2002, respectively.

(16) (This Footnote was Intentionally Left Blank)

(17) 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 98% of our regulatory liabilities.

	Note Ref.	Remaining Amortization Period	2003	2002
Pension	15	Undetermined	$ 43,818	$ 42,696
SFAS No. 106 purchase obligation	15	Undetermined	4,020	4,174
Income taxes	12	Plant lives	63,841	62,908
Other		Various	11,009	11,950
Total regulatory assets			$ 122,688	$ 121,728
Gas storage sales		36 Years	$ 15,036	$ 15,456
Proceeds from oil and gas sale		—	—	15,982
Utility sale stipulation agreement		—	—	16,254
Other		Various	2,272	6,794
Total regulatory liabilities			$ 17,308	$ 54,486

A pension regulatory asset has been recognized upon the purchase of Montana Power for the obligation that will be included in future cost of service. Pension costs in Montana are recovered in rates on a cash 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. A regulatory asset has been recognized for the SFAS No. 106 purchase obligation upon the purchase of Montana Power. The MPSC allows recovery of SFAS No. 106 costs on an accrual basis. A regulatory asset has been recorded to reflect the future recovery of energy supply costs through the ratemaking process. 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.

During 2001, Montana Power made sales of natural gas from its storage field at prices in excess of its original cost, creating a regulatory liability. 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. Montana Power also has a regulatory liability related to oil and gas proceeds that was credited to customer bills on a monthly basis. In connection with the acquisition of Montana Power, a stipulation agreement was signed that required a contribution by the previous owner and us to fund credits to Montana electric distribution customers. The account was applied on a kilowatt hour basis beginning July 1, 2002 for one year.

(18) 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 requirements and procedures that guide power supply procurements and their cost recovery. This provides adequate assurances of recovering our costs of acquiring electric supply.

On January 23, 2003, we filed our first biannual Electric Default Supply Resource Procurement Plan with the PSC, which fulfills the requirements established by law and describes the planning we are doing on behalf of our electric default supply customers to acquire a balanced and well designed resource portfolio. 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 MPSCregulates our bundled transmission and distribution, services and approves the rates that we charge for these services, while the FERC regulates our transmission services. Current regulatory issues are discussed below.

On August 12, 2003, the 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. A procedural schedule was set in January 2004 with a hearing tentatively scheduled for June 2004. We cannot determine the impact or resolution of this petition, however, any action taken by the MPSC to increase the regulatory controls under which we operate may have a material affect on our liquidity, operations and financial condition. If we are unable to comply with any MPSC orders in a timely manner, we may become subject to material monetary penalties and fines. We are cooperating with the MCC in the discovery process, but have retained the right to argue that the investigation is stayed as a result of our Chapter 11 filing.

Electric Rates

On June 12, 2003, the MPSC approved the next annual tracking period for the stipulated competitive transition charges Qualifying Facilities Contracts, or CTC-QFs in the amount of $17.4 million to be effective July 1, 2003. On June 16, 2003, we filed our annual electric supply cost tracker request with the MPSC for any unrecovered actual electric supply costs for the 12-month period ended June 30, 2003, and for projected costs for the 12-month period ended June 30, 2004. On July 15, an interim order was approved by MPSC for the projected electric supply cost.

Natural Gas Rates

On June 2, 2003, we filed an annual gas cost tracker request with the MPSC for any unrecovered actual gas costs for the eight-month period ended June 30, 2003, and for the projected gas costs for the 12-month period ending June 30, 2004. On July 3, 2003, the MPSC issued two separate orders, a final order and an interim order, with respect to our recovery of gas costs.

The final order issued by the MPSC disallowed recovery of $6.2 million of actual natural gas costs we incurred during the past eight months. 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. Included in other current assets was $6.2 million, which was written off during June 2003 to comply with the final order. In the event the MPSC's decision is overturned, we will reinstate the asset.

The MPSC also granted an interim order on July 3, 2003, for the projected gas cost adjusted for a portion of the gas portfolio at a fixed price of $3.50 per MMBTU as opposed to the market price submitted in the original filing, which was higher. Assuming our average forecast price over the next six months occurs, the impact of this disallowance on the volumes at the imputed price compared to market price would be approximately $4.5 million for the period July 1, 2003 through June 30, 2004.

FERC

Through a filing with FERC in April 2000, we sought recovery of transition costs associated with serving two wholesale electric cooperatives. On July 15, 2002, a FERC administrative judge issued a summary judgment dismissing the company's claim primarily on the grounds that the filing did not use FERC methodology. On December 2, 2002, we filed a "Brief on Exceptions to the Initial Decision" aimed at reversing the initial decision. A decision by FERC was received on January 28, 2004, which affirmed the original summary judgment decision.

(19) (This Footnote was Intentionally Left Blank)

(20) (This Footnote was Intentionally Left Blank)

(21) Guarantees, Commitments and Contingencies

Qualifying Facilities Liability

With the acquisition of our Montana operations, we assumed a liability for expenses associated with certain Qualifying Facilities Contracts, 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 $1.8 billion through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates and payments from the MPSC, totaling approximately $1.4 billion through 2029. Upon completion of the purchase price allocation related to our acquisition of the electric and natural gas transmission and distribution business of The Montana Power Company, we established a liability of $134.3 million, based on the net present value (using an 8.75% discount factor) of the difference between our obligations under the QFs and the related amount recoverable. At December 31, 2003, the liability was $142.8 million.

... less amounts recoverable through rates (in thousands):

	Gross obligation	Recoverable amounts	Net
2004	$ 54,823	($44,652)	$ 10,171
2005	56,579	(52,647)	3,932
2006	58,468	(52,681)	5,787
2007	60,634	(53,222)	7,412
2008	62,931	(53,750)	9,181
Thereafter	1,525,238	(1,138,340)	386,898
Total	$ 1,818,673	($1,395,292)	$ 423,381

Long Term Power Purchase Obligations

We have entered into various commitments, largely purchased power, coal and natural gas supply, electric generation construction and natural gas transportation contracts. These commitments range from one to 30 years. The commitments under these contracts as of December 31, 2003, were $251.0 million in 2004, $227.7 million in 2005, $165.0 million in 2006, $98.4 million in 2007, $45.3 million in 2008 and $448.5 million thereafter. These commitments are not reflected in our Financial Statements.

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 our generating plants and that we are in compliance with all presently applicable environmental protection requirements and regulations. We also are subject to other environmental statutes and regulations including those that related 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 $43.9 million to $82.7 million.

During the third quarter of 2003, we engaged the services of an environmental consulting firm to perform a comprehensive evaluation of our historical and current utility operations and facilities. Based upon the results of the evaluation, we decreased our environmental reserve by $0.3 million. Our environmental reserve accrual is $4.9 million as of December 31, 2003. This reserve was established and adjusted during the current year in anticipation of future remediation activities at our Montana environmental sites and does not factor in any exposure arising from private tort actions or government claims for damages allegedly associated with specific environmental conditions.

Legal Proceedings

On September 14, 2003, we filed a voluntary petition for relief under the provisions of Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware under case number 03-12872 (CGC). We will continue to manage our properties and operate our business as a "debtor-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with Sections 1107(a) and 1108 of Chapter 11. As a result of the Chapter 11 filing, attempts to collect, secure or enforce remedies with respect to most prepetition claims against us are subject to the automatic stay provisions of Section 362(a) of Chapter 11. The description of our bankruptcy proceedings is summarized in Note 3, Chapter 11.

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 federal court in Montana. The lawsuit, which was filed by the 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 Corporation 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. We intend to vigorously defend against this lawsuit. 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, Clark Fork & Blackfoot LLC, the Montana Power Company, Montana Power LLC and Jack Haffey, shall be temporarily stayed for 180 days from the date of the stipulation. Pursuant to the stipulation and after providing notice to Northwestern, the plaintiffs may move the Bankruptcy Court for termination of the temporary stay. 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 or ability to timely confirm a plan of reorganization.

In NorthWestern Corporation vs. PPL Montana, LLC vs. NorthWestern Corporation and Clark Fork and Blackfoot, LLC, No. CV 02-94-BU-SHE (D. MT), the Company is pursuing claims against PPL Montana, LLC due to its refusal to purchase the

Colstrip transmission assets which 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 Montana, LLC ("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 Clark Fork 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 $40 million. PPL also filed a proof of claim against NorthWestern's bankruptcy estate which assert 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 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. We intend to vigorously defend against the PPL claims in the bankruptcy court and the counterclaims 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.

We are also one of several defendants in a class action lawsuit entitled *In Re Touch America ERISA Litigation*, which is currently pending in federal 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 federal 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 or ability to timely confirm a plan of reorganization.

On August 12, 2003, the 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 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. A procedural schedule was set in January 2004 with a hearing tentatively scheduled for June 2004. We cannot determine the impact or resolution of this petition, however, any action taken by the MPSC to increase the regulatory controls under which we operate may have a material affect on our liquidity, operations and financial condition. If we are unable to comply with any MPSC orders in a timely manner, then we may become subject to material monetary penalties and fines. We are working with the MCC to provide requested information in a timely manner, but we have reserved the right to contest whether this proceeding is stayed as a result of our bankruptcy filing.

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 or ability to timely confirm a plan of reorganization.

Sch.19	MONTANA PLANT IN SERVICE - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	**Intangible Plant**					
3	301 Organization	$19,995	$ -	$19,995	$19,995	0.00%
4	302 Franchises and Consents	2,004	-	2,004	2,004	0.00%
5	303 Miscellaneous Intangible Plant	1,659,191	-	1,659,191	1,786,472	-7.12%
6	**Total Intangible Plant**	1,681,190	-	1,681,190	1,808,471	-7.04%
7						
8	**Production Plant**					
9						
10	**Steam Production**					
11	310 Land and Land Rights	-	-	-	-	-
12	311 Structures and Improvements	-	-	-	-	-
13	312 Boiler Plant Equipment	-	-	-	-	-
14	313 Engines, Engine Driven Generator	-	-	-	-	-
15	314 Turbogenerator Units	-	-	-	-	-
16	315 Accessory Electric Equipment	-	-	-	-	-
17	316 Misc. Power Plant Equipment	-	-	-	-	-
18	**Total Steam Production Plant**	-	-	-	-	-
19						
20	**Nuclear Production**					
21	320 - 325 Not Applicable	-	-	-	-	-
22	**Total Nuclear Production Plant**	-	-	-	-	-
23						
24	**Hydraulic Production**					
25	330 Land and Land Rights	2,082	-	2,082	2,082	0.00%
26	331 Structures and Improvements	-	-	-	-	-
27	332 Reservoirs, Dams and Waterways	-	-	-	-	-
28	333 Water Wheel, Turbine, Generators	-	-	-	-	-
29	334 Accessory Electric Equipment	-	-	-	-	-
30	335 Misc. Power Plant Equipment	-	-	-	-	-
31	336 Roads, Railroads and Bridges	-	-	-	-	-
32	**Total Hydraulic Production Plant**	2,082	-	2,082	2,082	0.00%
33						
34	**Other Production**					
35	340 Land and Land Rights					
36	341 Structures and Improvements	30,746	30,746	-	-	-
37	342 Reservoirs, Dams and Waterways	112,084	112,084	-	-	-
38	343 Water Wheel, Turbine, Generators	-	-	-	-	-
39	344 Accessory Electric Equipment	2,255,293	2,255,293	-	-	-
40	345 Misc. Power Plant Equipment	261,038	261,038	-	-	-
41	346 Roads, Railroads and Bridges	7,554	7,554	-	-	-
42	**Total Other Production Plant**	2,666,715	2,666,715	-	-	-
43	**Total Production Plant**	2,668,797	2,666,715	2,082	2,082	0.00%

Sch. 19 cont.	MONTANA PLANT IN SERVICE - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	**Transmission Plant**					
3	350 Land and Land Rights	15,505,900	-	15,505,900	15,490,115	0.10%
4	352 Structures and Improvements	4,623,541	-	4,623,541	4,350,717	6.27%
5	353 Station Equipment	127,538,305	-	127,538,305	126,356,792	0.94%
6	354 Towers and Fixtures	23,243,555	-	23,243,555	23,229,676	0.06%
7	355 Poles and Fixtures	123,938,295	710,150	123,228,145	120,638,778	2.15%
8	356 Overhead Conductors & Devices	109,755,692	594,293	109,161,399	107,684,502	1.37%
9	357 Underground Conduit	137,878	102,286	35,592	35,592	0.00%
10	358 Undergrnd Conductors & Devices	1,410,535	554,036	856,499	856,499	0.00%
11	359 Roads and Trails	2,454,768	44,906	2,409,862	2,405,873	0.17%
12	**Total Transmission Plant**	408,608,469	2,005,671	406,602,798	401,048,544	1.38%
13						
14	**Distribution Plant**					
15	360 Land and Land Rights	3,846,732	601	3,846,131	3,803,707	1.12%
16	361 Structures and Improvements	5,142,610	141,867	5,000,743	4,906,452	1.92%
17	362 Station Equipment	96,190,501	1,975,474	94,215,027	92,816,589	1.51%
18	363 Storage Battery Equipment	-	-	-	-	-
19	364 Poles, Towers, and Fixtures	117,578,143	253,226	117,324,917	115,289,537	1.77%
20	365 Overhead Conductors & Devices	71,755,814	344,943	71,410,871	69,683,627	2.48%
21	366 Underground Conduit	28,045,600	130,057	27,915,543	24,198,954	15.36%
22	367 Undergrnd Conductors & Devices	79,713,135	2,557,407	77,155,728	74,527,153	3.53%
23	368 Line Transformers	134,116,945	715,091	133,401,854	128,543,107	3.78%
24	369 Services	65,448,847	179,727	65,269,120	63,725,025	2.42%
25	370 Meters	44,418,624	67,145	44,351,479	30,554,564	45.16%
26	371 Installations on Cust. Premises	-	-	-	-	-
27	372 Leased Property on Cust. Premises	-	-	-	-	-
28	373 Street Lighting and Signal Systems	40,474,296	19,362	40,454,934	38,885,576	4.04%
29	**Total Distribution Plant**	686,731,247	6,384,900	680,346,347	646,934,291	5.16%
30						
31	**General Plant**					
32	389 Land and Land Rights	407,767	-	407,767	414,102	-1.53%
33	390 Structures and Improvements	7,523,402	84,207	7,439,195	7,362,892	1.04%
34	391 Office Furniture and Equipment	933,996	-	933,996	981,120	-4.80%
35	392 Transportation Equipment	21,034,561	87,696	20,946,865	21,413,942	-2.18%
36	393 Stores Equipment	424,954	-	424,954	440,639	-3.56%
37	394 Tools, Shop & Garage Equipment	4,161,315	33,017	4,128,298	4,185,662	-1.37%
38	395 Laboratory Equipment	3,948,376	6,081	3,942,295	4,124,672	-4.42%
39	396 Power Operated Equipment	2,153,450	-	2,153,450	2,265,713	-4.95%
40	397 Communication Equipment	17,131,775	74,172	17,057,603	17,034,548	0.14%
41	398 Miscellaneous Equipment	209,970	59,305	150,665	152,124	-0.96%
42	399 Other Tangible Equipment	-	-	-	-	-
43	**Total General Plant**	57,929,566	344,478	57,585,088	58,375,414	-1.35%
44	**Total Plant in Service**	1,157,619,269	11,401,764	1,146,217,505	1,108,168,802	3.43%
45						
46	4101 El Plant Allocated from Common	54,458,817	-	54,458,817	52,758,144	3.22%
47	105 El Plant Held for Future Use	-	-	-	-	-
48	107 El Construction Work in Progress	9,841,703	-	9,841,703	9,781,905	0.61%
49	114.2 El Plant Acquisition Adjustment	3,106,285	-	3,106,285	3,106,285	-
50						
51	**TOTAL ELECTRIC PLANT**	$1,225,026,074	$11,401,764	$1,213,624,310	$1,173,815,136	3.39%

Sch. 20	MONTANA DEPRECIATION SUMMARY - ELECTRIC (EXCLUDES UNIT 4)						
	Functional Plant Class	Montana Plant Cost	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	Current Avg. Rate
1	**Accumulated Depreciation**						
2							
3	Steam Production	$ -	$ -	$ -	$ -	$ -	
4							
5	Nuclear Production	-	-	-	-	-	
6							
7	Hydraulic Production	-	-	-	-	-	
8							
9	Other Production	-	1,640,709	1,640,709	-	-	
10							
11	Transmission	400,081,869	146,432,093	1,312,742	145,119,351	136,345,569	2.94%
12							
13	Distribution	645,158,741	282,604,235	2,866,768	279,737,467	259,108,533	3.91%
14							
15	General and Intangible	59,747,784	28,335,440	217,624	28,117,816	25,001,004	7.07%
16							
17	Common	50,754,646	15,120,460	-	15,120,460	12,591,580	6.20%
18							
19	**TOTAL DEPRECIATION**	$1,155,743,040	$474,132,937	$6,037,843	$468,095,094	$433,046,686	3.73%
20							
21							
22							
23							

Sch. 21	MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)- ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	151 Fuel Stock	$ -		$ -	$ -	-
3						
4	154 Plant Materials & Operating Supplies					
5	Assigned and Allocated to:					
6	Operation & Maintenance	-		-	-	-
7	Construction	-		-	-	-
8	Production Plant	12		12	13	-7.69%
9	Transmission Plant	2,274,893		2,274,893	2,425,748	-6.22%
10	Distribution Plant	3,806,454		3,806,454	3,950,004	-3.63%
11						
12						
13	**TOTAL MATERIALS & SUPPLIES**	$6,081,359		$6,081,359	$6,375,765	-4.62%

Sch. 22

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - ELECTRIC

Commission Accepted - Most Recent 1/	% Capital Structure	% Cost Rate	Weighted Cost
Docket Number: 2000.8.113			
Order Number : 6271c			
Common Equity	43.00%	10.75%	4.62%
Preferred Stock	6.97%	6.40%	0.45%
QUIPS Preferred	7.86%	8.54%	0.67%
Long Term Debt	42.17%	6.46%	2.72%
Other			
TOTAL	100.00%		8.46%

1/ Docket 2000.8.113, Order 627c specifies the authorized capital structure and associated costs for the regulated electric utility effective May 8, 2001.

Sch. 23

STATEMENT OF CASH FLOWS - 1/

	Description	This year	Last year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2	**Cash Flows from Operating Activities:**			
3	Net Income	$34,301,745	$32,959,449	4.07%
4	Depreciation	52,444,146	50,433,581	3.99%
5	Amortization	3,737,096	3,129,978	19.40%
6	Amortization of Discount on LT Debt	279,770	324,433	-13.77%
7	Deferred Income Taxes - Net	42,140,019	(37,371,972)	212.76%
8	Investment Tax Credit Adjustments - Net	-	(12,717,931)	100.00%
9	Writedown for Utility Stipulation Agreement - Net	-	99,881,116	-100.00%
10	Writedown of Investments	-	412,500	-100.00%
11	Change in Operating Receivables - Net	(20,708,279)	2,776,114	>-300.00%
12	Change in Intercompany Receivables - Net	(125,843,337)	31,510,337	>-300.00%
13	Change in Materials, Supplies & Inventories - Net	164,886	3,214,845	-94.87%
14	Change in Operating Payables & Accrued Liabilities - Net	136,600,346	104,114,970	31.20%
15	Allowance for Funds Used During Construction (AFUDC)	(281,311)	(509,119)	44.75%
16	Change in Other Current Assets & Liabilities - Net	(24,271,232)	6,144,537	>-300.00%
17	Other Operating Activities:			
18	Undistributed Earnings from Subsidiary Companies	5,187,050	5,471,549	-5.20%
19	Other (net)	(62,241,794)	98,116,324	-163.44%
20	Change in Regulatory Assets	(723,947)	(93,050,012)	99.22%
21	Change in Regulatory Liabilities	(31,524,950)	(33,778,887)	6.67%
22	**Net Cash Provided by/(Used in) Operating Activities**	$9,260,208	$261,061,811	-96.45%
23	**Cash Inflows/Outflows From Investment Activities:**			
24	Construction/Acquisition of Property, Plant and Equipment	(44,744,506)	(52,472,205)	14.73%
25	(net of AFUDC & Capital Lease Related Acquisitions)			
26	Proceeds from Sale of Property, Plant and Equipment	-	8,312,695	-100.00%
27	Premium Paid by NorthWestern, Corp. for Utility Acquisition	-	(105,776,771)	
28	Contributions In and Advances to Affiliates	3,416,395	317,613	>300.00%
29	Other Investing Activities:			
30	Proceeds from Investments	19,132,574	145,676	>300.00%
31	Additional Investments	(532,358)	(884,185)	39.79%
32	Miscellaneous Special Funds	(825,857)	(67,197)	>-300.00%
33	**Net Cash Provided by/(Used in) Investing Activities**	(23,553,750)	(150,424,375)	84.34%
34	**Cash Flows from Financing Activities:**			
35	Proceeds from Issuance of:			
36	Long-Term Debt			
37	Members Capital Contribution in MP LLC	$0	500	-100.00%
38	Credit Facilities Borrowings, net	277,200,000		-
39	Dividends from Subsidiaries	-	-	-
40	Capital Financing	389,680	1,970,000	-80.22%
41	Net Increase in Short-Term Debt	-	-	-
42	Advance to Parent Company	(255,000,000)	(65,684,699)	-288.22%
43	Payment for Retirement of:			
44	Long-Term Debt	(15,000,000)	(13,003,479)	-15.35%
45	Preferred Stock	-	-	-
46	Capital Lease Obligations	(2,760,547)	(1,285,821)	-114.69%
47	Net Decrease in Short-Term Debt			
48	Dividends on Preferred Stock	-	(922,508)	100.00%
49	Dividends on Common Stock	-	-	-
50	Other Financing Activities	-	-	-
51	**Net Cash Provided by (Used in) Financing Activities**	4,829,133	(78,926,007)	106.12%
52	**Net Increase/(Decrease) in Cash and Cash Equivalents**	(9,464,409)	$31,711,430	-129.85%
53	**Cash and Cash Equivalents at Beginning of Year**	$27,914,771	(3,796,659)	>300.00%
54	**Cash and Cash Equivalents at End of Year**	18,450,362	$27,914,771	-33.90%

56 1/ There were significant non-cash changes in the 2002 balance sheet related to our corporate reorganization and subsequent
57 divestiture and acquisition resetting equity under new ownership by NorthWestern Corporation. Additionally,
58 there were significant non-cash changes in regulatory asset and liability and other accounts for compliance with terms
59 in the stipulation agreement/TierII settlement. The cash flow presentation for 2002 is net of these non-cash changes.
60

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

LONG TERM DEBT 1/

Description	Issue Date	Maturity Date	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem./Disc.	Total Cost %
First Mortgage Bonds								
8.25% Series, Due 2007	12/05/91	02/01/07	55,000,000	54,550,100	364,979	8.260%	30,168	8.27%
8.95% Series, Due 2022	12/05/91	02/01/22	50,000,000	49,536,500	1,438,042	8.957%	129,981	9.04%
7.00% Series, Due 2005	03/01/93	03/01/05	50,000,000	49,375,000	5,380,236	7.075%	383,032	7.12%
7.30% Series, Due 2006	11/27/01	12/01/06	150,000,000	148,670,240	149,504,012	7.426%	11,289,296	7.55%
6.75% Credit Facility, Due 2006	12/17/02	12/01/06	280,000,000	258,103,495	274,400,000	6.750%	27,802,541	10.13%
Total First Mortgage Bonds			$585,000,000	$560,235,335	$431,087,269		$39,635,018	9.19%
Pollution Control Bonds								
6-1/8% Series, Due 2023	06/30/93	05/01/23	$90,205,000	$88,199,743	$88,905,504	5.841%	$5,604,532	6.30%
5.90% Series, Due 2023	12/30/93	12/01/23	80,000,000	79,040,800	79,358,592	6.428%	4,763,618	6.00%
Total Pollution Control Bonds			$170,205,000	$167,240,543	$168,264,096		$10,368,150	6.16%
Other Long Term Debt								
Quarterly Income Preferred Securities,								
8.45%, Series A (QUIPS) 2/	11/96	12/36	$ 65,000,000	$ 62,567,385	$ 65,000,000		$ 3,943,588	6.07%
Medium Term Notes-Secured Series	Various	Various	128,000,000	126,807,269	13,000,000		955,555	7.35%
Medium Term Notes-Unsecured Series B	Various	Various	115,000,000	113,851,197	39,844,335		3,058,306	7.68%
Cost Associated with Prior Debt Retirements	N/A	N/A	0	0	0		306,888	N/A
Total Other Long Term Debt			$308,000,000	$303,225,851	$117,844,335		$8,264,337	7.01%
TOTAL LONG TERM DEBT			$1,063,205,000	$1,030,701,729	$717,195,700		$58,267,505	8.12%

1/ Total Long-Term Debt does not include amounts due within 1 year - $2,800,000 at December 31, 2003.

2/ The Company believes and intends to take the position that the securities associated with the QUIPS issue will constitute indebtedness for United States federal income tax purposes. As such, the cost of QUIPS are deemed to be tax deductible. Since November 6, 2001, the Company has the right to wholly redeem the securities at any time, or partially redeem them from time to time.

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										
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17										
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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 2/	Earnings Per Share 3/	Dividends Per Share (Declared)	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio
January	37,396,762	($12.90)				$6.18	$5.02	
February	37,630,095	(13.24)				5.28	2.50	
March	37,630,095	(11.87)	$0.26			2.79	1.41	
April	37,680,095	(14.54)				2.62	1.65	
May	37,680,095	(15.26)				3.09	2.10	
June	37,680,095	(13.38)	(1.55)			2.85	1.96	
July	37,680,095	(13.55)				2.12	1.05	
August	37,680,095	(13.69)				1.23	0.51	
September	37,680,095	(14.78)	(1.41)			0.91	0.15	
October	37,680,095	(14.79)				0.32	0.15	
November	37,680,095	(14.93)				0.23	0.11	
December	37,680,095	(15.32)	(0.41)			0.16	0.08	
TOTAL Year End	37,648,151	($15.32)	($3.20)	$0.00	100.00%	$0.08		(0.0)

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for 2003.

2/ All Book Value Per Share amounts are based on actual shares and include unallocated stock held by Trustee for the Deferred Savings and Employee Ownership Plans.

3/ Quarterly Per Share amounts do not total to the annual Per Share amounts due to the effect of common stock issuances during the year.

As was stated in NorthWestern Corporation's 2003 Form 10-K, under anyplan of reorganization in the Chapter 11 proceedings, management of NorthWestern expects that there will be no value available for distribution to its common shareholders.

Sch. 27

MONTANA EARNED RATE OF RETURN - ELECTRIC

	Description	This Year	Last Year 3/	% Change
	Rate Base			
101	Plant in Service	$1,175,715,732	$1,152,823,872	1.99%
108	Accumulated Depreciation	(456,119,496)	(432,979,505)	-5.34%
Net Plant in Service		$719,596,236	$719,844,367	-0.03%
	Additions:			
154, 156	Materials & Supplies	$5,347,611	$6,108,363	-12.45%
165	Prepayments			-
	Other Additions	7,082,034	7,540,070	-6.07%
Total Additions		$12,429,645	$13,648,433	-8.93%
	Deductions:			
190	Accumulated Deferred Income Taxes 1/	$6,072,666	($5,367,973)	213.13%
252	Customer Advances for Construction	18,271,047	16,592,948	10.11%
255	Accumulated Def. Investment Tax Credits		0	-
	Other Deductions	11,377,428	3,274,644	247.44%
Total Deductions		$35,721,141	$14,499,619	146.36%
Total Rate Base		$696,304,740	$718,993,181	-3.16%
Net Earnings		$67,450,979	($4,601,418)	>300.00%
Rate of Return on Average Rate Base		9.687%	-0.640%	>300.00%
Rate of Return on Average Equity 2/		10.237%	-7.814%	231.01%
	Major Normalizing and Commission Ratemaking Adjustments			
	Rate Schedule Revenues	$1,276,760	($1,721,400)	174.17%
	Inventory Receipts Adjustment	185,244	0	-
	CIS Project Write-Off	357,049	0	-
	Sale Credit	0	20,000,000	-100.00%
	CTC QF Write-off	0	60,000,000	-100.00%
	Industrial CTC QF/RA Write-off	0	20,976,125	-100.00%
	Generation Related Tier II Stranded Cost Adj.	0	(1,025,780)	100.00%
	A & G Not Previously Allocated 4/	(8,265,882)	0	-
	Non-Allowables:			
	Advertising	165,471	447,899	-63.06%
	Benefit Restoration Plan	(702,512)	883,593	-179.51%
	Dues, Contributions, Other	66,432	49,414	34.44%
	Divestiture Related Expense	0	150,551	-100.00%
	Associated Income Taxes 5/	($5,465,676)	($38,352,546)	85.75%
Total Adjustments		($12,383,114)	$61,407,856	-120.17%
Revised Net Earnings		$55,067,865	$56,806,438	-3.06%
Adjusted Rate of Return on Average Rate Base		7.909%	7.901%	0.10%
Adjusted Rate of Return on Average Equity 2/		9.032%	9.016%	0.18%

1/ Includes adjustments related to FAS 109.

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

3/ Amounts for 2002 have been adjusted to reflect the removal of non-jursdictional Qualifying Facilities (QF) income.

4/ A & G expenses adjusted do not include any restructuring costs or amounts attributable to Non-Utility operations.

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

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. 27 cont.

MONTANA EARNED RATE OF RETURN - ELECTRIC

	Description	This Year	Last Year	% Change
1				
2	**Detail - Other Additions 3/**			
3	FAS 109 Regulatory Asset	$0	$0	-
4	Cost of Refinancing Debt	2,712,277	2,735,017	-0.83%
5	ORCOM Development Costs	853,687	853,687	0.00%
6	SAP Development Costs	3,264,721	3,700,017	-11.76%
7	1999 Severance Plan	125,696	125,696	0.00%
8	1997 &1998 Severance Plan	125,653	125,653	0.00%
9	**Total Other Additions**	$7,082,034	$7,540,070	-6.07%
10				-
11	**Detail - Other Deductions 4/**			-
12	Personal Injury and Property Damage	($6,054,936)	($2,731,303)	-121.69%
13	Unamortized Gain on Reacquired Debt	892	8,508	-89.52%
14	Gross Cash Requirements	12,749,809	794,884	>300.00%
15	Storm Damage Reserve	182,612	202,666	-9.90%
16	Met Life Refund	144,724	144,724	0.00%
17	USBC Expenses	4,354,327	4,855,165	-10.32%
18				-
19	**Total Other Deductions**	$11,377,428	$3,274,644	247.44%

Sch. 28	MONTANA COMPOSITE STATISTICS - ELECTRIC (EXCLUDES UNIT 4 & YNP)		
		Description	Amount
1			
2		**Plant (Intrastate Only)**	
3			
4	101	Plant in Service (Includes Allocation from Common)	$ 1,200,676,322
5	105	Plant Held for Future Use	-
6	107	Construction Work in Progress	9,841,703
7	114	Plant Acquisition Adjustments	3,106,285
8	151-163	Materials & Supplies	$6,081,359
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	$468,095,094
11	252	Contributions in Aid of Construction	18,555,540
12	**NET BOOK COSTS**		733,055,035
13			
14		**Revenues & Expenses**	
15			
16	400	Operating Revenues	498,923,164
17			
18	**Total Operating Revenues**		498,923,164
19			
20	401-402	Other Operating Expenses	326,947,497
21	403-407	Depreciation & Amortization Expenses	44,444,386
22	408.1	Taxes Other than Income Taxes	44,614,576
23	409-411	Federal & State Income Taxes	15,465,726
24			
25	**Total Operating Expenses**		431,472,185
26	**Net Operating Income**		67,450,979
27			
28	415-421.1	Other Income	2,835,684
29	421.2-426.5	Other Deductions	2,710,102
30	**NET INCOME BEFORE INTEREST EXPENSE**		67,576,562
31			
32		**Average Customers (Intrastate Only)**	
33		Residential	246,888
34		Commercial & Industrial	53,678
35		Other	3,840
36			
37	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		304,406
38			
39		**Other Statistics (Intrastate Only)**	
40		Average Annual Residential Use (Kwh)	8,458
41		Average Annual Residential Cost per (Kwh)	$0.077
42		Average Residential Monthly Bill	$54.27
43			
44		Plant in Service (Gross) per Customer	$3,944

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,234	455	117	2	574
2	Alberton	374	357	79	8	444
3	Alder	116	186	70	6	262
4	Amsterdam	727				-
5	Anaconda	9,417	4,145	740	42	4,927
6	Armington		1			1
7	Arrow Creek		4	3		7
8	Augusta	284	232	88	1	321
9	Austin					-
10	Avon	124	88	54	1	143
11	Barber		50	9		59
12	Basin	255	155	64	1	220
13	Bearcreek-Washoe	83	70	18	4	92
14	Belfry	219	197	62	4	263
15	Belgrade	5,728	5,616	1,126	53	6,795
16	Belt	633	619	218	16	853
17	Benchland		7	7		14
18	Big Sandy	703	343	136	4	483
19	Big Sky	1,221	1,997	404	10	2,411
20	Big Timber	1,650	1,169	351	25	1,545
21	Bigfork	1,421				-
22	Billings	89,847	40,439	6,782	635	47,856
23	Black Eagle		442	135	14	591
24	Bonner	1,693	81	22	3	106
25	Boulder	1,300	739	215	12	966
26	Box Elder	794	120	69	6	195
27	Bozeman	27,509	19,750	3,850	218	23,818
28	Brady		93	37	4	134
29	Bridger	745	389	130	9	528
30	Broadview	150	208	145	3	356
31	Buffalo			3		3
32	Butte - Walkerville	33,892	14,070	2,178	301	16,549
33	Cameron		225	87	1	313
34	Canyon Creek		162	29	3	194
35	Carter	62	120	69	3	192
36	Cascade	819	1,005	253	17	1,275
37	Centerville		13	12		25
38	Checkerboard		55	12	1	68
39	Chester	871	481	259	13	753
40	Chinook	1,386	823	300	10	1,133
41	Choteau	1,781	960	344	9	1,313
42	Churchill		25	2		27
43	Clancy	1,406	1,536	244	11	1,791
44	Clinton	549	96	36	2	134
45	Coffee Creek		55	23	1	79
46	Colstrip	2,346	942	193	24	1,159
47	Columbus	1,748	919	290	15	1,224
48	Conrad	2,753	1,252	476	14	1,742
49	Corbin-Jefferson			1		1
50	Corvallis	443	672	149	9	830

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Craig					-
2	Custer	145		3		3
3	Darby	710	731	219	5	955
4	Deer Lodge	3,421	1,997	491	35	2,523
5	Denton	301	188	76	1	265
6	Dillon	3,752	1,822	492	32	2,346
7	Divide		55	10	2	67
8	Dodson	122	117	56	7	180
9	Drummond	318	361	194	5	560
10	Dutton	389	254	122	3	379
11	East Helena	1,642	2,475	325	15	2,815
12	Edgar		241	75	6	322
13	Elliston	225	196	62	2	260
14	Ennis	840	1,458	451	8	1,917
15	Fairfield	659	402	145	10	557
16	Florence	901	333	115	7	455
17	Floweree		111	55	1	167
18	Fort Belknap	1,262	449	96	25	570
19	Fort Benton	1,594	797	326	27	1,150
20	Fort Harrison		1	87	1	89
21	Fromberg	486	300	68	6	374
22	Gallatin Gateway		953	257	7	1,217
23	Gardiner	851	717	265	9	991
24	Garrison	112	109	50	8	167
25	Geraldine	284	275	147	2	424
26	Geyser		67	32	2	101
27	Gildford	185	93	66	2	161
28	Glasgow	3,253	1,695	589	71	2,355
29	Glen		2			2
30	Gold Creek		56	30	1	87
31	Gransdale		26	4	1	31
32	Great Falls	56,690	26,722	4,706	372	31,800
33	Greycliff	56	50	29	2	81
34	Hall		195	60	2	257
35	Hamilton	3,705	4,731	1,204	77	6,012
36	Hardin	3,384	1,412	425	23	1,860
37	Harlem	848	457	183	11	651
38	Harlowtown	1,062	663	258	5	926
39	Harrison	162	164	53	2	219
40	Haugan-Deborgia	69	209	64	3	276
41	Havre	10,594	4,863	1,054	182	6,099
42	Helena	45,819	20,171	4,095	252	24,518
43	Hingham	157	106	65	1	172
44	Hinsdale		141	48	6	195
45	Hobson	244	155	50	4	209
46	Huson		110	30	2	142
47	Inverness	103	44	26	1	71
48	Jardine			2		2
49	Jeffers		2	1		3
50	Jefferson City	295	230	39	4	273

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Joliet	575	358	94	9	461
2	Joplin	210	99	53	2	154
3	Judith Gap	164	89	45	2	136
4	Kremlin	126	68	36	1	105
5	Lake		5			5
6	Laurel	6,255	2,888	425	19	3,332
7	Lavina	209	181	93	4	278
8	Lennep-Ringling		62	42	3	107
9	Lewistown	5,813	3,231	856	47	4,134
10	Lincoln	1,100	999	210	20	1,229
11	Livingston	6,851	4,240	978	40	5,258
12	Logan		3	9	1	13
13	Lohman		20	15	1	36
14	Lolo	3,388	1,201	162	15	1,378
15	Loma	92	70	43	2	115
16	Lothair		15	10		25
17	Malta	2,120	1,317	440	41	1,798
18	Mammoth		164	68	2	234
19	Manhattan	1,396	1,572	342	15	1,929
20	Martinsdale		112	67	3	182
21	Marysville		56	29	2	87
22	Maxville		1			1
23	McAllister		140	31	2	173
24	Melrose		1			1
25	Melstone	136	160	282	3	445
26	Melville		80	51	2	133
27	Milltown		79	24	5	108
28	Missoula	57,053	30,389	5,449	585	36,423
29	Moccasin		47	28	1	76
30	Molt		23	20		43
31	Monarch		329	49	5	383
32	Moore	186	103	36	2	141
33	Musselshell	60	67	28		95
34	Nashua	325	205	57	3	265
35	Neihart	91	182	28	2	212
36	Nevada City		1	3		4
37	Norris		58	29	1	88
38	Nye		40	5		45
39	Old Faithful		2	3		5
40	Paradise	184	153	55	4	212
41	Park City	870	384	57	5	446
42	Philipsburg	914	1,568	262	21	1,851
43	Plains	1,126	1,360	389	10	1,759
44	Pony		123	24	2	149
45	Power	171	83	42	4	129
46	Pray		18	1		19
47	Radersburg	70	60	6	1	67
48	Ramsay		53	24		77
49	Raynesford		65	34	1	100
50	Red Lodge	2,177	1,676	349	11	2,036
51	Reedpoint	185	150	58	2	210

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Rocker		18	13	2	33
2	Rocvale		2			2
3	Roscoe		76	10		86
4	Roundup	1,931	1,098	390	14	1,502
5	Rudyard	275	157	66	2	225
6	Ryegate	268	143	62	4	209
7	Saco	224	161	91	3	255
8	Saint Marie	183	170	52	4	226
9	Saltese		33	22	1	56
10	Sand Coulee		142	42	6	190
11	Sapphire Village		61	4		65
12	Shawmut		44	25	1	70
13	Sheridan	659	790	200	4	994
14	Silesia		31	7		38
15	Silverbow		14	4		18
16	Springdale		37	16	1	54
17	Square Butte		44	25	2	71
18	St. Regis	315	397	139	14	550
19	Stanford	454	334	185	5	524
20	Stevensville	1,553	1,722	487	35	2,244
21	Stockett		164	45	3	212
22	Sumatra			3		3
23	Superior	893	782	263	28	1,073
24	Taft			1		1
25	Tampico		13	7		20
26	Thompson Falls	1,321	957	314	26	1,297
27	Three Forks	1,728	1,224	419	21	1,664
28	Toston	105	48	51	1	100
29	Townsend	1,867	1,087	274	9	1,370
30	Tracy		92	13	4	109
31	Trident		2			2
32	Twin Bridges	400	307	138	11	456
33	Twodot		49	42	2	93
34	Ulm	750	375	113	5	493
35	Utica		2	5		7
36	Valier	498	362	181	5	548
37	Vaughn	701	226	34	6	266
38	Victor	859	748	225	11	984
39	Virginia City	130	143	82	4	229
40	Wagner		45	18	1	64
41	Warm Springs			2		2
42	White Sulphur Springs	984	765	319	36	1,120
43	Whitehall	1,044	921	251	14	1,186
44	Wickes		1			1
45	Williamsburg		1	1		2
46	Willow Creek	209	134	52	4	190
47	Windham		51	29	1	81
48	Winston	73	95	27	1	123
49	Wolf Creek		468	158	7	633
50	Yellowstone Park		1	5		6
51	Zurich		97	64	3	164
52	**Total**	448,194	247,053	53,608	3,967	304,628
53	1/ Customer populations represent an average of the 12 month period from 01/01/03 through 12/31/03.					

Sch. 30	MONTANA EMPLOYEE COUNTS			
	Department	Year Beginning 1/	Year End 1/	Average
2	**Utility Operations**			
3	Executive	2	1	2
4	Financial, Risk Mgmt. & Information Services	113	120	117
5	Human Resources & Administration	36	33	34
6	Utility Services & Division Administration	655	620	637
7	Business Development & Regulatory Affairs	25	24	24
8	Transmission	168	150	159
9	Legal	5	5	5
17	**TOTAL EMPLOYEES**	1,004	953	978
19	1/ Part time employees have been converted to full time equivalents.			

Sch. 31	MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3			
4	Rainbow-Canyon Ferry Taps Line Reconductoring	$1,030,000	$1,030,000
5	Electric Transmission Circuit Upgrades	1,130,000	1,130,000
6			
7			
8			
9	All Other Projects < $1 Million Each	29,686,227	29,686,227
10			
11	**Total Electric Utility Construction Budget**	31,846,227	31,846,227
12			
13	**Natural Gas Operations**		
14			
15			
16			
17			
18	All Other Projects < $1 Million Each	7,805,557	7,805,557
19			
20	**Total Natural Gas Utility Construction Budget**	7,805,557	7,805,557
21			
22	**Common**		
23			
24	All Other Projects < $1 Million Each	5,089,868	5,089,868
25	(Includes IS, Communications, Facillities, Cust Serv)		
26			
27			
28	**Total Common Utility Construction Budget**	5,089,868	5,089,868
29			
30	CU4 Saddle Dam Repair	1,012,000	1,012,000
31			
32	All Other Projects < $1 Million Each	3,128,276	3,128,276
33			
34			
35			
36	**Total Colstrip Unit 4 Construction Budget**	4,140,276	4,140,276
37	**TOTAL CONSTRUCTION BUDGET**	$48,881,928	$48,881,928

Sch. 32	TOTAL SYSTEM & MONTANA PEAK AND ENERGY					
		System Peak and Energy				
		Peak Day	Peak Hour	Peak Day Volume Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	January	22	1900	1,297	729,398	249,343
2	February	24	2000	1,297	678,923	217,824
3	March	6	2000	1,231	710,479	243,364
4	April	2	2000	1,094	711,970	261,607
5	May	29	1700	1,233	710,091	377,849
6	June	30	1700	1,312	766,298	358,800
7	July	23	1600	1,442	809,350	319,222
8	August	1	1700	1,346	808,076	308,117
9	September	4	1700	1,224	821,471	277,664
10	October	30	1900	1,244	719,902	293,652
11	November	4	600	1,277	614,827	181,165
12	December	29	1900	1,307	792,189	139,047
13	**TOTALS**				8,872,974	3,227,654
14		**Montana Peak and Energy**				
15		Peak	Peak	Peak Day Volume	Total Monthly Volumes	Non-Requirements
16		Day	Hour	Megawatts	Energy (Mwh)	Sales For Resale (Mwh)
17	January					
18	February					
19	March					
20	April					
21	May					
22	June					
23	July			NOT AVAILABLE		
24	August					
25	September					
26	October					
27	November					
28	December					
29	**TOTALS**				-	-

Sch. 33	TOTAL SYSTEM SOURCES & DISPOSITION OF ENERGY			
	Sources	Megawatthours	Dispositions	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	1,592,043		
3	Nuclear	-	**Sales to Ultimate Consumers**	5,177,892
4	Hydro - Conventional		(Include Interdepartmental) 1/	
5	Hydro - Pumped Storage	-		
6	Other	-	Sales for Resale	
7	(Less) Energy for Pumping	-	Requirement Sales	1,579,399
8	**Net Generation**	1,592,043	Non-Requirement Sales	1,648,255
9	**Purchases**	7,073,569	**Sales for Resale**	3,227,654
10	Power Exchanges		Energy Furnished w/o Charge	
11	Received	1,145,320		
12	Delivered	1,116,164		-
13	**Net Power Exchanges**	29,156	**Energy Furnished**	-
14	Transmission Wheeling for Others		Energy Used Within Utility	
15	Received	7,261,894	Electric Department	
16	Delivered	7,083,688	(Less) Station Use	-
17	**Net Transmission Wheeling**	178,206	**Net Energy Used Within Util.**	-
18	**Transmission by Others Losses**	-	**Energy Losses**	467,428
19	**TOTAL SOURCES**	8,872,974	**TOTAL DISPOSITIONS**	8,872,974

1/ The megawatts hours listed above does not include sales to choice customers of 2,505,052 megawatt hours, consistent with the presentation used in the corresponding schedule on FERC Form 1, and does include Colstrip Unit 4 in the Generation section.

Sch. 34	SOURCES OF ELECTRIC SUPPLY /1				
	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Hydro	Milltown	Missoula, MT		
2	Subtotal			2.5	6,429.3
3	Internal Combustion	Lake	Yellowstone Nat'l Park	0.0	291.2
4	Internal Combustion	Old Faithful	Yellowstone Nat'l Park	0.0	306.8
5	Internal Combustion	Tower Falls	Yellowstone Nat'l Park	0.0	6.4
6	Internal Combustion	Grant Village	Yellowstone Nat'l Park	0.0	300.6
7	Subtotal			0.0	905.0
8	Purchases	Small Power Producers	Colstrip Energy, Ltd.	0.0	302,419.0
9	Purchases	Small Power Producers	Billings Generation, Inc.	0.0	378,015.0
10	Purchases	Small Power Producers	State of Montana - DNRC	0.0	43,837.0
11	Purchases	Small Power Producers	Others	0.0	6,914.0
12	Subtotal			0.0	731,185.0
13	Purchases	Nonassociated Utilities	PPL Montana	0.0	3,576,431.0
14	Subtotal			0.0	3,576,431.0
15	Default Supply Purch Power		City of Seattle	0.0	154,367.0
16	Default Supply Purch Power		PG & E	0.0	23,600.0
17	Default Supply Purch Power		Tacoma Power	0.0	5,860.0
18	Default Supply Purch Power		Avista Energy	0.0	698,155.0
19	Default Supply Purch Power		Benton County PUD	0.0	19,151.0
20	Default Supply Purch Power		Snohomish County PUD	0.0	3,627.0
21	Default Supply Purch Power		Franklin County PUD	0.0	13,024.0
22	Default Supply Purch Power		PPL Montana	0.0	
23	Default Supply Purch Power		Puget Sound Energy	0.0	49,913.0
24	Default Supply Purch Power		Avista Utility	0.0	39,905.0
25	Default Supply Purch Power		Grays Harbor PUD	0.0	7,191.0
26	Default Supply Purch Power		Duke Energy	0.0	644,595.0
27	Default Supply Purch Power		Idaho Power	0.0	3,304.0
28	Default Supply Purch Power		BPA	0.0	61,271.0
29	Default Supply Purch Power		Energy West	0.0	29,040.0
30	Default Supply Purch Power		Portland General Electric	0.0	602,525.0
31	Default Supply Purch Power		Powerex	0.0	73,762.0
32	Default Supply Purch Power		EWEB	0.0	5,130.0
33	Default Supply Purch Power		WAPA	0.0	29,158.0
34	Default Supply Purch Power		Hinson Power	0.0	35,880.0
35	Default Supply Purch Power		Pinnacle West	0.0	17,680.0
36	Default Supply Purch Power		Grant	0.0	2,910.0
37	Default Supply Purch Power		Morgan Stanley	0.0	17,010.0
38	Default Supply Purch Power		Arizona Public Service	0.0	2,375.0
39	Default Supply Purch Power		Pacific Northwestern Generating	0.0	2,800.0
40	Default Supply Purch Power		Conoco	0.0	7,152.0
41	Default Supply Purch Power		Rainbow Energy	0.0	42,799.0
38	Subtotal			0.0	2,592,184.0
39	Imbalance Transactions	Investor Owned	Avista	0.0	124,190.0
40	Imbalance Transactions	Investor Owned	Idaho Power	0.0	46,661.0
41	Subtotal			0.0	170,851.0
42	Reserve Sharing				2,918.0
39	Total				7,080,903.3
40					
41	\1 An outage report does not accompany Schedule 34 because of the sale of almost all of our generation assets				
42	in December 1999.				

Sch. 35 MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

2003 Electric USB Program Expenditures and Contractual Commitments

USB Categories	Revenue Allocation: PSC Guidelines Order 5986i	Revenue Allocation: Reallocation Order 6514 *	2003 Spent in 2003	Contracted - 2003 Complete - 2004	Allocation & Expenses
Local Conservation	**1,748,496**	**(605,972)**	718,079	424,445	**1,142,524**
E+ Residential Audit/Sm. Com. Pilot			223,319	146,318	369,637
E+ Business Partners			52,918	278,127	331,045
Vendor Miser			225,222	-	225,222
NWE Promotion			125,162	-	125,162
NWE Labor			69,239	-	69,239
NWE Admin. Non-labor			22,219	-	22,219
Local Conservation Summary			718,079	424,445	1,142,524
Market Transformation	**1,097,315**	**(20,195)**	949,205	127,916	**1,077,120**
E+ Commercial Lighting			160,512	127,916	288,428
NW Energy Efficiency Alliance			532,403	-	532,403
Energy Star Rebates			163,078	-	163,078
NWE Promotion			25,467	-	25,467
NWE Labor			60,739	-	60,739
NWE Admin. Non-labor			7,006	-	7,006
Market Transformation Summary			949,205	127,916	1,077,120
Renewable Resources	**1,078,674**	**(161,971)**	385,802	530,901	**916,703**
Generation/Education			310,382	530,901	841,283
Green Power Product Offering			23,275	-	23,275
NWE Promotion			3,452	-	3,452
NWE Labor			46,068	-	46,068
NWE Admin. Non-labor			2,625	-	2,625
Renewable Resources Summary			385,802	530,901	916,703
Research & Development	**217,889**	**(103,040)**	114,849	-	**114,849**
R&D/ Infrastructure			90,834	-	90,834
NWE Promotion			13,415	-	13,415
NWE Labor			8,474	-	8,474
NWE Admin. Non-labor			2,126	-	2,126
Research & Development Summary			114,849	-	114,849
Low Income	**1,789,817**	**922,487**	1,986,700	725,604	**2,712,304**
Bill Assistance			1,032,007	-	1,032,007
Free Weatherization			610,528	-	610,528
Energy Share			225,000	-	225,000
Low-Income Security Deposit Pilot			12,500	-	12,500
Supplemental Bill Assistance			-	489,354	489,354
Supplemental Weatherization			-	236,250	236,250
NWE Promotion			66,527	-	66,527
NWE Labor			34,585	-	34,585
NWE Admin. Non-labor			5,553	-	5,553
Low Income Summary			1,986,700	725,604	2,712,304
Irrigation	**16,274**	**-**	16,274	-	**16,274**
Irrigation Conservation			-	-	-
NWE Promotion			5,409	-	5,409
NWE Labor			9,669	-	9,669
NWE Admin. Non-labor			1,196	-	1,196
Renewable Resources Summary			16,274	-	16,274
Large Customer	**2,574,474**	**(31,309)**	2,033,303	509,862	**2,543,165**
Self-Directed Energy Reduction			1,907,362	497,879	2,405,241
Self-Directed to Low Income			108,767	11,983	120,749
Unspent $ Reallocated by NWE					
-NWE Labor			17,166	-	17,166
-NWE Admin. Non-labor			8	-	8
-2003 Low Income Activities		(31,309)	-	-	-
Large Customer Summary			2,033,303	509,862	2,543,165
Totals	**8,522,939**	**-**	6,204,211	2,318,728	**8,522,939**
2003 USB Revenues less Expenses*					**-**

**** $922,487 of 2003 Electric USB funds were reallocated to the Low-Income USB Category from other USB Categories in 2003. $725,604 was reallocated as a result of recommendations of the Governor's Energy Consumer Protection Taskforce, and MPSC Order 6514. An additional Low-Income budget shortfall of $196,883 required the reallocation of $165,574 more from other categories, and the reassignment of $31,309 of unclaimed Large Customer USB credits.***

Sch. 35a MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

2003 Electric USB Funding Summary,
Savings Estimates and Participation Summary

2003 USB FUNDING AND EXPENDITURE SUMMARY

USB Category	Allocation of 2003 funds based on Order 5986i	Percentage by Category	Reallocation of 2003 funds based on Order 6514 *(a)*	Percentage by Category	Order 6514 Allocation w/Lrg Cust funds self-directed to LI *(b)*	Percentage by Category	Total Electric USB Funds Spent in 2003	2003 Electric USB Funds Contracted to Spend in 2004
Local Conservation	$ 1,748,496	21%	$ 1,142,524	13%	$ 1,142,524	13%	$ 718,079	$ 424,445
Market Transformation	$ 1,097,315	13%	$ 1,077,120	13%	$ 1,077,120	13%	$ 949,205	$ 127,916
Renewables	$ 1,078,674	13%	$ 916,703	11%	$ 916,703	11%	$ 385,802	$ 530,901
Research & Development	$ 217,889	3%	$ 114,849	1%	$ 114,849	1%	$ 114,849	$ -
Low Income	$ 1,789,817	21%	$ 2,712,304	32%	$ 2,833,053	33%	$ 1,986,700	$ 725,604
Irrigation	$ 16,274	0%	$ 16,274	0%	$ 16,274	0%	$ 16,274	$ -
Large Customer	$ 2,574,474	30%	$ 2,543,165	30%	$ 2,422,416	28%	$ 2,033,303	$ 509,862
	$ 8,522,939	**100%**	**$ 8,522,939**	**100%**	**$ 8,522,939**	**100%**	**$ 6,204,211**	**$ 2,318,728**

2003 LOW-INCOME FUNDING SUMMARY

Low-Income Category	
Bill Assistance	$ 1,032,007
Free Weatherization	$ 610,528
Energy Share	$ 225,000
Low-Income Security Deposit Pilot	$ 12,500
Supplemental Bill Assistance	$ 489,354
Supplemental Free Weatherization	$ 236,250
NWE Promotion	$ 66,527
NWE Labor	$ 34,585
NWE Admin. Non-labor	$ 5,553
Self-Directed Large Customer	$ 120,749
2003 Low-Income USB Funding from all sources :	**$ 2,833,053**
Low-Income share of 2003 Electric USB revenues :	**33.2%**

2003 ENERGY SAVINGS & RENEWABLE RESOURCES ESTIMATES

Savings & Resources acquired in 2003 w/ 2003 $

	aMW	MWH	MW
Local Conservation	0.2408	2,109	0.170
Market Transformation *(c)*	1.5674	13,730	1.013
Renewables	0.0198	174	0.081
Research & Development	NA	NA	NA
Low Income	0.0648	568	0.142
Large Cust - Low Income	NA	NA	NA
Large Customer	NA	NA	NA
	1.8928	**16,581**	**1.406**

Projected Savings & Resources to acquire in 2004 w/ 2003 $ *(f)*

	aMW	MWH	MW
Local Conservation	0.1789	1,567	0.175
Market Transformation	0.2179	1,909	1.070
Renewables	0.3673	3,217	1.237
Research & Development	NA	NA	NA
Low Income	0.0146	128	0.032
Large Cust - Low Income	NA	NA	NA
Large Customer *(d)*	NA	NA	NA
	0.7787	**6,821**	**2.513**
Total Savings & Resources	**2.6715**	**23,402**	**3.919**

2003 ELECTRIC USB PARTICIPATION SUMMARY

Electric USB Activity by Category	Quantity	Units
Conservation		
Residential Onsite Audits	438	homes
Residential Mailout Audits	829	homes
Business Appraisals	75	businesses
Business Partners	8	projects
Vendor Miser	375	vending machines
Market Transformation		
Commercial Lighting	69	projects
Energy Star Washer Rebates *(e)*	2,238	washers
NW Energy Efficiency Alliance		
- Energy Star Windows	9,176	sqft
- Energy Star Residential Lighting	140,628	CFL's
- Super Good Cents/Natural Choice	23	homes
- Energy Star Washers (e)	2,421	washers
- Energy Star Dishwashers	828	dishwashers
- Energy Star Refrigerators	4,131	refrigerators
- Energy Star Room A/C	625	air conditioners
- Building Operator Certification	16	people
- Commission Public Buildings	1	buildings
- MagnaDrive Coupling	98	hp
Renewables		
Generation / Education	32	projects
Research & Development		
R&D / Infrastructure	2	projects
Customer & Electrician Education	906	attendees
Low-Income		
Bill Assistance	10,121	households
Free Weatherization	526	homes
Energy Share	972	households
Low-Income Security Deposit Pilot	374	households

(a) $922,487 of 2003 Electric USB funds were reallocated to the Low-Income USB Category from other USB Categories in 2003. $725,604 was reallocated as a result of recommendations of the Governor's Energy Consumer Protection Taskforce, and MPSC Order 6514. An additional Low-Income budget shortfall of $196,883 required the reallocation of $165,163 more from other categories, the reassignment of $31,309 of unclaimed 2003 Large Customer USB credits, and $411 of unclaimed 2002 Large Customer credits. The monies self-directed to low-income by the Large Customers are in addition to this amount - see (b).

(b) Large Customers may self-direct their USB dollars to energy saving and renewable activities in their own facilities, or to Low-Income activities. In 2003, Large Customers self-directed a total of $120,749 to Low-Income, $108,767 of which was spent in 2003, and $11,983 of which will be spent in 2004.

(c) Market Transformation includes energy savings estimates provided by the Northwest Energy Efficiency Alliance. NWE adjusted the savings estimates provided by the Alliance to account for the prevalence natural gas space and water heating in the Company's service territory.

(d) Large Customer energy savings estimates are reported by individual large customers and are not available in this report.

(e) NWE offered an Energy Star washer rebate to customers purchasing Energy Star-qualified washers in 2003. 2238 rebates were issued under NWE's program. The Alliance reported the sale of an additional 2421 washers outside of NWE's rebate program.

(f) Projected Savings & Resources are based on contracts that were in place at the end of 2003. Actual results will be reported in 2004.

Sch. 36	MONTANA CONSUMPTION AND REVENUES - ELECTRIC (EXCLUDES UNIT 4 & YNP)						
		Operating Revenues		MWH Sold		Average Customers	
		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	**Sales of Electricity**						
2							
3	Residential	$161,632,796	$142,912,629	2,088,299	2,029,696	246,888	240,739
4	Commercial & Industrial	219,376,214	187,559,520	5,553,105	5,311,367	53,678	51,533
5	Public Street, Highway Lighting						
6	& Other Sales to Public Authorities 1/	9,504,845	8,518,719	41,740	39,415	3,824	3,630
7	Sales to Cooperatives	-	-	-	-	-	-
8	Sales to Other Utilities	60,947,720	15,288,680	3,227,654	628,733	16	18
9	Interdepartmental	899,134	813,731	-	-	-	-
10	**TOTAL SALES**	$452,360,709	$355,093,279	10,910,798	8,009,211	304,406	295,920
11							
12	1/ The customer classes "Public Street" and "Highway Lighting" are combined with "Other Sales to Public Authorities" in our customer						
13	accounting system.						
14							
15							
16							
17							