YEAR 2000

ANNUAL REPORT

OF

The Montana Power Company

ELECTRIC UTILITY

The Montana Power Company

TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 20261
HELENA, MT 59620-2601

Revised June 5, 2000

ELECTRIC ANNUAL REPORT

TABLE OF CONTENTS

Sch. 1

IDENTIFICATION

Legal Name of Respondent:	The Montana Power Company
Name Under Which Respondent Does Business:	The Montana Power Company
Date Utility Service First Offered in Montana:	Electricity - Dec 12, 1912 Natural Gas - Jan 01, 1933 Propane - Oct 13, 1995
Person Responsible for Report:	Ernest J. Kindt
Telephone Number for Report Inquiries:	(406) 497-2233
Address for Correspondence Concerning Report:	40 East Broadway Butte, Montana 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.

NOT APPLICABLE

Sch. 2	BOARD OF DIRECTORS	
	Director's Name & Address (City, State)	Remuneration
1/	Alan F. Cain	$25,950
	P. O. Box 1589	
	Big Fork, MT 59911	
1/	R. D. Corette	26,800
	Corette, Pohlman & Kebe Law Firm	
	P. O. Box 509	
	Butte, MT 59703	
1/	Kay Foster	26,800
	Planteriors Unlimited	
	P. O. Box 628	
	Billings, MT 59103	
1/	Carl Lehrkind, III	27,950
	Lehrkind's, Inc.	
	P. O. Box 10580	
	Bozeman, MT 59715	
1/	N. E. Vosburg	26,800
	Pacific Steel & Recycling	
	P. O. Box 1549	
	Great Falls, MT 59403	
1/	John R. Jester	27,800
	Bargain Street, LLC	
	3610 S. Pine St	
	Tacoma, WA 98409	
1/	Tucker Hart Adams	27,300
	US Bank	
	918 17th St, 6th Floor	
	Denver, CO 80202	
1/	John G. Connors	23,800
	Microsoft Corporation	
	1 Microsoft Way, Building 11/2017	
	Redmond, WA 98052-6399	
1/	Deborah D. McWhinney	27,800
	Charles Schwab & Company	
	425 Market Place, 14th Fl.	
	San Francisco, CA 94105	

Sch. 2 cont.	**BOARD OF DIRECTORS**	
	Director's Name & Address (City, State)	Remuneration
2/	Robert P. Gannon The Montana Power Company 40 East Broadway Butte, MT 59701	-
2/	Jerrold P. Pederson The Montana Power Company 40 East Broadway Butte, MT 59701	-

1/ Remuneration:

Non-employee Directors are paid $19,600 per year, effective 12/1/96, plus $500 for each meeting of a Committee of the Board attended, except those held in conjunction with regular Board meetings.

They also receive $850 per special meeting of the Board, when such special meetings are held in addition to the regularly scheduled Board meeting in any one month.

The Company has a Deferred Compensation Plan for non-employee Directors.
Directors may elect to defer their payments as Directors until retirement from the Board.
No compensation was deferred in 2000.
Deferred payments earn interest based on Moody's average Baa Corporate Bond Rates.

The Company has a Stock Compensation Plan for non-employee Directors.
The Plan provides annual grants of 960 shares of the Company's common stock.
The Plan also allows Directors to elect to receive any portion of their annual retainer in the Company's common stock.
Directors may elect to defer receipt of the stock payment until they cease to be a Director of the Company or until such other date the Director elects.
At the end of the deferral period, the Director will be paid for the stock units in Company common stock or the equivalent value in cash based upon the market value of the Company's common stock at that time.

All Company Directors elected prior to 12/31/97participated in a non-qualified retirement plan (the Benefit Restoration Plan for Directors).
The Plan was implemented in 1986 for all eligible Directors.
This Plan provides for annual benefit payments to vested participants upon retirement.
It is intended to allow for supplemental income to the Director at the time of retirement or to beneficiaries in the event of the Director's death.
Trust owned life insurance is carried on Plan participants.
The Company and participants in the Plan contribute to the cost of the life insurance.
All death proceeds are specifically directed to the Plan Trust for the sole purpose of paying for Plan benefits and premium costs.
The board curtailed the Plan, effective 12/31/97, by closing it to additional participants and by capping the maximum annual benefits to eliminate further increases to benefits as the annual retainer increases.

2/ Employee Directors do not receive compensation for board and/or committee meetings.

Sch. 3	OFFICERS	
Title	**Department Supervised**	**Name**
Chairman of the Board, President and Chief Executive Officer	Executive - Shared Administrative Services (Corporate Communications) (Governmental Affairs) (Corporate Community Relations)	Robert P. Gannon
Vice Chairman and Chief Financial Officer	Executive - Shared Administrative Services (Audit Services) (Controller Services) (Information Services) (Strategic Planning) (Treasury Services) (Financial Reporting) (EVA Planning)	Jerrold P. Pederson
Vice President, Human Resources and Secretary	Executive - Shared Administrative Services (Shareholder Services) (Human Resources)	Pamela K. Merrell
Vice President and General Counsel	Executive - Shared Administrative Services (Legal) (Land & Enviromental Services)	Michael E. Zimmerman
Executive Vice President and Chief Operating Officer	Energy Services Division (Regulatory Affairs)	John D. Haffey
Vice President	Distribution Services	David A. Johnson, 1 /
Vice President	Transmission Services	William A. Pascoe, 2 /
President and Chief Operating Officer	TOUCHAMERICA	Michael J. Meldahl
Chief Information Officer	Shared Administrative Services	Daniel J. Sullivan

Sch. 3 cont.	OFFICERS	
Title	Department Supervised	Name
Treasurer	Treasury Services	Ellen M. Senechal
Treasurer	TOUCHAMERICA	Harry Freebourn
Controller	Controller Services	David S. Smith
Controller	TOUCHAMERICA	John Burke
Assistant Controller	Controller Services	Ernest J. Kindt
Assistant Secretary	Executive - Shared Administrative Services	Susan D. Breining
Assistant Secretary	Shareholder Services	Rose Marie Ralph

1 / Vice President of Energy Supply Division after January 1, 2001.

2 / Vice President of Transmission and Distribution Services after January 1, 2001.

Sch. 4	CORPORATE STRUCTURE			
	Subsidiary/Company Name	Line of Business	Earnings (000)	% of Total
1				
2	**THE MONTANA POWER COMPANY**			
3	**Continuing Operations**			
3	**Utility Operations**		$8,588	4.39%
4	Electric Utility	Electric utility		
5	Natural Gas Utility	Natural gas utility		
6	Canadian-Montana Pipe Line Corporation	Natural gas transmission		
6	Glacier Gas Company	Production and transmission of natural gas*		
7	Colstrip Community Services Company	Water and refuse services		
8	Montana Power Capital 1	Financing		
9	MPC Natural Gas Funding Trust	Bond transition financing		
10	**Nonutility Operations**		63,915	32.64%
11	Montana Power Services Company	Service provider for the company		
12	Discovery Energy Solutions, Inc.	Energy services consulting		
13	One Call Locators, Ltd.	Underground facility locating		
14	Colstrip Unit 4 Lease Mgmt Division	Wholesale sales of electric power **		
15	Continental Energy Services, Inc.	Independent power & cogen. dev. & invest.		
16	EMPECO, Inc.	Independent power & cogen. dev. & invest.		
17	EMPECO IV, Inc.	Independent power & cogen. dev. & invest.		
18	Montana Energy , Inc.	Independent power & cogen. dev. & invest.		
19	ECI Energy, Ltd.	Investment in British partnership in a		
20		natural gas-fired cogeneration project ***		
21	Enserch Development Corp. One, Inc.	Generate electricity		
22	Montana Grimes County, Inc.	Ownership in electric power generating facility		
23	Montana Grimes Frontier, Inc.	Ownership in electric power generating facility		
24	CES International	Independent power & cogen. dev. & invest.		
25	PAK Energy LLC	Holding co. for power plant investment		
26	Entech, Inc.	Admin. & mgmt. of nonutility services, excluding		
27		Colstrip 4 Lease & Continental Energy Services		
27	Tetragenics Company	Process control systems		
28	New Horizon Technologies Energy	Energy information systems & integration & value-		
28	Services, LLC	added services		
29	Touch America, Inc.	Telecommunications systems & equipment		
30	Touch America Holdings, Inc.	Holding company		
31	Touch America Intangible Holding			
32	Company, LLC	Manage TA's intangible assets		
33	Touch America Purchasing Company,			
34	LLC	Sales and lease of telecommunications equipment		
35	Touch America Services Group, Inc.	Holding company/operations		
36	Touch America Services, Inc.	Telecommunications services		
37	The Montana Power, L.L.C.	Electric and natural gas business		
38	**Discontinued Nonutility Operations**			
39	Coal		31,897	16.29%
40	Western Energy Company	Coal & minerals mining		
41	Western SynCoal Company			
42	SynCoal, Inc.	Develop coal drying technology		
43	Northwestern Resources Company	Lignite & minerals mining		
44	Basin Resources, Inc.	Underground coal mining		
45	Horizon Coal Services, Inc.	Coal sales & development		
46	North Central Energy Company	Exploration, develop. & production of coal		
47	Income from discontinued oil & natural gas			
48	operations, net of income taxes ****		29,395	15.01%
49	Gain on sale of discontinued oil & natural gas			
50	operations, net of income taxes		62,006	31.67%
51	**TOTAL**		195,801	100.00%
52	* Glacier Gas Co. was included in the October 31, 2000 sale of the oil & natural gas companies.			
53	** Colstrip Unit 4 Lease Management Division is an operating division of The Montana Power Company.			
54	*** Continental Energy Services owns 47.5 % of the value and 50% of the voting power of this corporation.			
55	****Because the sale of the oil & natural gas companies was completed on October 31, 2000, they are not listed here.			

Sch. 5

CORPORATE ALLOCATIONS

Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
Shared Administrative Services - 1/					
Executive Management & Office of the Corporation Secretary	Includes the following departments: CEO & Chairman; Vice Chairman & CFO Vice Pres. & Secretary; Vice Pres. & CLC; Corporate Communications; Governmental and Legislative Affairs; Environmental Compliance Flight Services; Investor Services; Community Relations; MPC Foundation; Vice-Pres. - Marketing; Market Research and Planning Strategic 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.	$7,393,359	46.66%	$8,452,901
Human Resources	Includes the following departments: Human Resources; Benefits; Compensation & Labor Relations; Employment; Organizational Development; Technology Training; HR Liaison to Energy Supply; HR Liaison to Energy 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.	(180,775)	61.20%	(114,597)
Financial Accounting	Includes the following departments: Audit Services; Commodity Risk; Controller Administration; Corporate Accounting; Property Records; Corporate Tax; Disbursements; Financial Reporting; CS Liaison to Energy Supply; CS Liaison to Energy Services; G&T Admin. Services; Gas Oper. Admin. 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.	3,566,847	45.10%	4,341,632
Treasury Services & Facilities	Includes the following departments: Treasury Services; Facilities; Mailing Services; Financial Services; Financial Systems; Investor Relations; Risk Mgmt.; Credit and Cash	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.	2,224,670	46.93%	2,515,237

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: Information Services; IS Customer Services; Admin. & User Support; Applications; Text Services; Information Tech Services; Data Administration; Data Center Operations; Network Services; Security & Disaster Recovery; IS Liaison to Energy Supply; IS Liaison to Energy Services; IS Liaison to SAS; Internet Communications	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.	5,268,375	50.91%	5,080,681
Legal Services	Legal Services Department	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.	762,015	46.63%	872,231
Land & Environmental	Land & Environmental Department	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.	802,320	91.74%	72,237
TOTAL			$19,836,811	48.32%	$21,220,322

1/ - Shared Administrative Services (SAS) became effective August 1, 1996. The purpose of SAS is to centralize overhead functions that are shared by all business units. Prior to August 1, 1996, only corporate costs were allocated. However, with the development of SAS, several departments that were separately maintained within MPC and Entech, Inc. have been combined and are now being allocated to the business segments.

Sch. 6	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Utility	% of Total Affil. Revs.	Charges to MT Utility
1						
2	**Nonutility Subsidiaries**					
3	Western Energy Company	Coal sales & transportation	Contract Rates	$ -	0.00%	$ -
4		Misc. Services	Actual Costs Incurred	1,643,216	0.16%	1,643,216
5	North American Resources	By-product sales	Market Rates	32,424	0.00%	32,424
6	Tetragenics	Engineering Services	Market Rates	97,535	0.01%	97,535
7	Touch America, Inc.	Communication Services	Market Rates	921,556	0.09%	921,556
8	Entech, Inc.	Interest on notes	Interest rate used is average of MPC's	58,390	0.01%	58,390
9			short term borrowing rate & Colstrip			
10			Unit 4's portfolio investment rate.			
11			2000 Annual Average Rate = 6.2600%			
12	North American Energy Services	Power plant O & M Services	Market Rates	17,736	0.00%	17,736
13	Continental Energy Services, Inc.	Interest on loans	Interest rate used is average of MPC's	3,082,403	0.31%	3,082,403
14			short term borrowing rate & Colstrip			
15			Unit 4's portfolio investment rate.			
16			2000 Annual Average Rate = 6.2600%			
17	Colstrip Unit 4 -	Interest on loans	Interest rate used is average of MPC's	5,128,126	0.51%	5,128,126
18	Lease Management Division		short term borrowing rate & Colstrip			
19			Unit 4's portfolio investment rate.			
20			2000 Annual Average Rate = 6.2600%			
21	**Total Nonutility Subsidiaries**			10,981,386	1.09%	10,981,386
22	**Total Nonutility Subsidiaries Revenues**			1,002,883,000		
23	**Utility Subsidiaries**					
24	Glacier Gas Company	Gas sales	Based Upon Rate Base	-	0.00%	-
25	**Total Utility Subsidiaries**			-	0.00%	-
26	**Total Utility Subsidiaries Revenues**			599,405		
27	**TOTAL AFFILIATE TRANSACTIONS**			$10,981,386		$10,981,386

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	Western Energy Company	Sales of Electricity	Tariff Schedules	$4,109,499	1.01%	$4,109,499
4						
5	North American Resources	Sales of Electricity	Monthly Bid Rate(FERC Tariff)			
6			& Fixed Rate (NEB)	951	0.00%	951
7	Touch America, Inc.	Sales of Gas & Electricity	Tariff Schedules	4,178,763	1.03%	4,178,763
8	Rosebud SynCoal	Sale of Coal	Actual Costs Incurred	not available	0.00%	not available
9	**Total Nonutility Subsidiaries**			8,289,213	2.04%	8,289,213
10	**Total Nonutility Subsidiaries Expenses**			407,018,000		
11						
12						
13	**Utility Subsidiaries**					
14	Colstrip Community Services	Project Services	Actual Costs Incurred	-	0.00%	-
15	**Total Utility Subsidiaries**			-	0.00%	-
16	**Total Utility Subsidiaries Expenses**			518,259,000		
17	**TOTAL AFFILIATE TRANSACTIONS**			$8,289,213		$8,289,213

Sch. 8	MONTANA UTILITY INCOME STATEMENT - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	400 Operating Revenues	$473,166,695	$2,829,194	$470,337,501	$485,926,640	-3.21%
3						
4	**Total Operating Revenues**	473,166,695	2,829,194	470,337,501	485,926,640	-3.21%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expenses	347,661,287	1,460,778	346,200,509	241,080,831	43.60%
9	402 Maintenance Expense	17,853,841	139,027	17,714,814	30,771,784	-42.43%
10	403 Depreciation Expense	36,446,114	367,796	36,078,318	50,855,904	-29.06%
11	404-405 Amort. of Electric Plant	653,785		653,785	2,186,484	-70.10%
12	406 Amort. of Plant Acquisition Adj.	94,939		94,939	94,914	0.03%
13	408.1 Taxes Other Than Income Taxes	38,443,641	0	38,443,641	50,857,524	-24.41%
14	409.1 Income Taxes - Federal	4,011,393	201,266	3,810,127	21,359,103	-82.16%
15	- Other	1,409,547	13,235	1,396,312	4,598,342	-69.63%
16	410.1 Deferred Income Taxes-Dr.	10,879,978	32,402	10,847,576	6,212,903	74.60%
17	411.1 Deferred Income Taxes-Cr.	(9,641,781)		(9,641,781)		
18	411.4 Investment Tax Credit Adj.	(43,057)	(3,576)	(39,481)	(2,035,257)	98.06%
19	411.6 Gain from Disposition of Property					
20	411.7 Loss from Disposition of Property					
21						
22	**Total Operating Expenses**	$447,769,687	$2,210,927	$445,558,760	$405,982,532	9.75%
23	**NET OPERATING INCOME**	$25,397,008	$618,267	$24,778,741	$79,944,108	-69.00%

Sch. 9	MONTANA REVENUES - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	**Sales to Ultimate Consumers**					
3						
4	440 Residential	$128,392,655	$104,180	$128,288,475	$129,891,846	-1.23%
5	442 Commercial	155,896,524	287,544	155,608,980	144,635,363	7.59%
6	Industrial	51,201,933		51,201,933	72,835,312	-29.70%
7	444 Public Street, Highway Lighting					
8	& Other Sales to Public Authorities	9,344,647	2,437,469	6,907,178	7,035,492	-1.82%
9	448 Interdepartmental Sales	771,982		771,982	613,054	25.92%
10						
11	**Total Sales to Ultimate Consumers**	345,607,741	2,829,194	342,778,547	355,011,066	-3.45%
12	447 Sales for Resale	74,874,651		74,874,651	108,916,562	-31.26%
13						
14	**Total Sales of Electricity**	420,482,392	2,829,194	417,653,198	463,927,628	-9.97%
15	449.1 Provision for Rate Refunds			-	-	-
16						
17	**Total Revenue Net of Rate Refunds**	420,482,392	2,829,194	417,653,198	463,927,628	-9.97%
18						
19	**Other Operating Revenues**					
20						
21	451 Miscellaneous Service Revenue	41,728		41,728	31,192	33.78%
22	453 Sales of Water & Water Power	(52,905)		(52,905)	2,708,554	-101.95%
23	454 Rent From Electric Property	6,845,479		6,845,479	2,276,168	200.75%
24	456 Other Electric Revenues	45,850,001		45,850,001	16,983,098	169.97%
25						
26	**Total Other Operating Revenue**	52,684,303	-	52,684,303	21,999,012	139.48%
27	**TOTAL OPERATING REVENUE**	$473,166,695	$2,829,194	$470,337,501	$485,926,640	-3.21%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1	**Power Production Expenses**					
2	**Steam Power Generation-Operation**					
3	500 Supervision & Engineering	$ -		$ -	$1,282,881	-100.00%
4	501 Fuel	108,090		108,090	32,644,628	-99.67%
5	502 Steam Expenses	(15,930)		(15,930)	2,834,514	-100.56%
6	503 Steam from Other Sources	40,257		40,257	(2,828)	1523.53%
7	505 Electric Plant	-		-	2,124,704	-100.00%
8	506 Miscellaneous Steam Power	8,274		8,274	2,936,558	-99.72%
9	507 Rents	4,513		4,513	-	-
10	**Total Operation-Steam Power Gen.**	145,204	-	145,204	41,820,457	-99.65%
11	**Steam Power Generation-Maintenance**					
12	510 Supervision & Engineering	-		-	520,358	-100.00%
13	511 Structures	-		-	1,011,327	-100.00%
14	512 Steam Boiler Plant	(508)		(508)	8,179,735	-100.01%
15	513 Electric Plant	(426)		(426)	2,048,200	-100.02%
16	514 Miscellaneous Steam Plant	-		-	1,353,573	-100.00%
17	**Total Maintenance-Steam Power Gen.**	(934)	-	(934)	13,113,193	-100.01%
18	**Total Steam Power Generation**	144,270	-	144,270	54,933,650	-99.74%
19	**Hydro Power Generation-Operation**					
20	535 Supervision & Engineering	217,220		217,220	1,776,868	-87.78%
21	536 Water for Power	(11,344)		(11,344)	665,041	-101.71%
22	537 Hydraulic Expenses	18,032		18,032	658,841	-97.26%
23	538 Electric Expenses	10,527		10,527	1,794,685	-99.41%
24	539 Miscellaneous Hydraulic Power	62,960		62,960	755,949	-91.67%
25	540 Rents	-		-	13,808,133	-100.00%
26	**Total Operation-Hydro Power Gen.**	297,395	-	297,395	19,459,517	-98.47%
27	**Hydro Power Generation-Maintenance**					
28	541 Supervision & Engineering	-		-	179,727	-100.00%
29	542 Structures	31,680		31,680	136,883	-76.86%
30	543 Reservoirs, Dams & Waterways	36,745		36,745	860,723	-95.73%
31	544 Electric Plant	4,092		4,092	676,608	-99.40%
32	545 Miscellaneous Hydro Plant	3,024		3,024	297,982	-98.99%
33	**Total Maintenance-Hydro Power Gen.**	75,541	-	75,540	2,151,923	-96.49%
34	**Total Hydraulic Power Generation**	372,936	-	372,935	21,611,440	-98.27%
35	**Other Power Generation-Operation**					
36	546 Supervision & Engineering	559	652	(93)		
37	547 Fuel	57,904	57,904	-	-	-
38	548 Generation Expenses	7,018	5,339	1,679	-	-
39	549 Miscellaneous Other Power	4,016	3,951	65	-	-
40	**Total Operation-Other Power Gen.**	69,497	67,846	1,651	-	-
41	**Other Power Generation-Maintenance**					
42	551 Supervision & Engineering	-	-	-	-	-
43	552 Structures	-	-	-	-	-
44	553 Generating & Electric Plant	19,902	19,960	(58)	-	-
45	554 Miscellaneous Other Power Plant	32,915	32,623	292	-	-
46	**Total Maintenance-Other Power Gen.**	52,817	52,583	234	-	-
47	**Total Other Power Generation**	122,314	120,429	1,886	-	-
48	**Other Power Supply Expenses**					
49	555 Purchased Power	271,808,412	880,432	270,927,980	89,672,527	202.13%
50	556 System Control & Load Dispatch	4,943	-	4,943	1,536	221.81%
51	557 Other Expenses	1,033,327	-	1,033,327	-	-
52	**Total Other Power Supply Expenses**	272,846,682	880,432	271,966,251	89,674,063	203.28%
53	**Total Power Production Expenses**	273,486,202	1,000,861	272,485,342	166,219,153	63.93%

Sch. 10 cont'd.	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	**Transmission Expenses**					
3						
4	**Transmission-Operation**					
5	560 Supervision & Engineering	1,940,962	-	1,940,962	2,619,753	-25.91%
6	561 Load Dispatching	1,368,722	-	1,368,722	1,235,078	10.82%
7	562 Station Expenses	123,649	-	123,649	161,831	-23.59%
8	563 Overhead Lines	752,202	46,383	705,819	715,538	-1.36%
9	564 Underground Lines	5,235	-	5,235	-	-
10	565 Transmission of Elec. by Others	1,865,847	-	1,865,847	4,140,820	-54.94%
11	566 Miscellaneous Transmission	456,329	-	456,329	272,333	67.56%
12	567 Rents	2,550,779	-	2,550,779	1,398,769	82.36%
13	**Total Operation-Transmission**	9,063,725	46,383	9,017,343	10,544,122	-14.48%
14	**Transmission-Maintenance**					
15	568 Supervision & Engineering	884,377	-	884,377	604,930	46.19%
16	569 Structures	32,396	4,587	27,809	919	2926.04%
17	570 Station Equipment	3,076,509	6,909	3,069,600	1,389,458	120.92%
18	571 Overhead Lines	1,928,197	35,717	1,892,479	1,924,224	-1.65%
19	572 Underground Lines	549	-	549	(2,269)	124.19%
20	573 Miscellaneous Transmission Plant	1,608	-	1,608	4,824	-66.67%
21	**Total Maintenance-Transmission**	5,923,636	47,213	5,876,423	3,922,086	49.83%
22	**Total Transmission Expenses**	14,987,361	93,596	14,893,766	14,466,208	2.96%
23						
24	**Distribution Expenses**					
25						
26	**Distribution-Operation**					
27	580 Supervision & Engineering	1,271,482	794	1,270,688	1,678,734	-24.31%
28	581 Load Dispatching	-	-	-	30	-100.00%
29	582 Station Expenses	547,038	2,504	544,534	573,585	-5.06%
30	583 Overhead Lines	4,550,006	90,138	4,459,867	2,785,129	60.13%
31	584 Underground Lines	2,505,005	33,481	2,471,524	980,149	152.16%
32	585 Street Lighting & Signal Systems	664,106	-	664,106	838,546	-20.80%
33	586 Meters	1,770,163	9,907	1,760,255	2,066,943	-14.84%
34	587 Customer Installations	812,059	322	811,737	1,289,938	-37.07%
35	588 Miscellaneous Distribution	982,911	47,070	935,841	2,031,190	-53.93%
36	589 Rents	83,594	-	83,594	88,503	-5.55%
37	**Total Operation-Distribution**	13,186,364	184,216	13,002,146	12,332,747	5.43%
38	**Distribution-Maintenance**					
39	590 Supervision & Engineering	798,844	-	798,844	654,801	22.00%
40	591 Structures	67,644	-	67,644	20,908	223.53%
41	592 Station Equipment	1,037,374	8,484	1,028,890	1,601,999	-35.77%
42	593 Overhead Lines	6,026,622	11,094	6,015,528	6,583,786	-8.63%
43	594 Underground Lines	740,470	4,775	735,695	1,308,585	-43.78%
44	595 Line Transformers	614,972	156	614,816	684,876	-10.23%
45	596 Street Lighting, Signal Systems	410,134	-	410,134	452,789	-9.42%
46	597 Meters	460,442	-	460,442	454,645	1.28%
47	598 Miscellaneous Distribution Plant	-	-	-	-	-
48	**Total Maintenance-Distribution**	10,156,502	24,509	10,131,992	11,762,389	-13.86%
49	**Total Distribution Expenses**	23,342,866	208,725	23,134,137	24,095,136	-3.99%

Sch. 10	cont'd. MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	**Customer Accounts Expenses**					
3						
4	**Customer Accounts-Operation**					
5	901 Supervision			-	-	-
6	902 Meter Reading	936,639	3,505	933,134	1,508,957	-38.16%
7	903 Customer Records & Collection	4,063,301	-	4,063,301	7,245,941	-43.92%
8	904 Uncollectible Accounts	1,324,172	-	1,324,172	1,024,780	29.22%
9	905 Miscellaneous Customer Accts.	170	-	170	230	-26.27%
10	**Total Customer Accounts Expenses**	6,324,282	3,505	6,320,777	9,779,908	-35.37%
11						
12	**Customer Service & Information**					
13						
14	**Customer Service-Operation**					
15	907 Supervision	20,047		20,047	61,464	-67.38%
16	908 Customer Assistance	1,790,021		1,790,021	2,193,117	-18.38%
17	909 Inform. & Instruct. Advertising	269,131		269,131	323,379	-16.78%
18	910 Misc. Customer Service & Info.	400		400	552	-27.61%
19	**Total Customer Service & Info. Expense**	2,079,599	-	2,079,599	2,578,512	-19.35%
20						
21	**Sales Expenses**					
22						
23	**Sales-Operation**					
24	911 Supervision	261,614		261,614	207,356	26.17%
25	912 Demonstrating & Selling	875,768		875,768	501,375	74.67%
26	913 Advertising	389,119		389,119	92,887	318.92%
27	916 Miscellaneous Sales	13,699		13,699	1,842	643.70%
28	**Total Sales Expenses**	1,540,200	-	1,540,201	803,460	91.70%
29						
30	**Administrative & General Expenses**					
31						
32	**Admin. & General-Operation**					
33	920 Admin. & General Salaries	13,644,145	93,361	13,550,784	20,212,908	-32.96%
34	921 Office Supplies & Expenses	3,530,730	24,213	3,506,517	5,404,680	-35.12%
35	922 Admin. Expense Transferred-Cr.	(2,196,995)	(15,033)	(2,181,962)	(4,088,854)	46.64%
36	923 Outside Services Employed	5,467,856	37,414	5,430,442	5,299,330	2.47%
37	924 Property Insurance	156,921	1,074	155,848	502,413	-68.98%
38	925 Injuries & Damages	3,209,630	21,962	3,187,668	3,108,711	2.54%
39	926 Employee Pensions & Benefits	309,183	1,877	307,306	(3,042,682)	110.10%
40	927 Franchise Requirements					
41	928 Regulatory Commission Expenses	300,290		300,290	1,332,575	-77.47%
42	407 Amortization of Property Losses	1,095,015		1,095,015	6,927,517	-84.19%
43	929 Duplicate Charges-Cr.					
44	930 Miscellaneous General Expenses	11,378,346	77,857	11,300,489	10,466,400	7.97%
45	931 Rents	5,213,218	35,672	5,177,546	4,989,104	3.78%
46	**Total Operation-Admin. & General**	42,108,339	278,396	41,829,944	51,112,102	-18.16%
47	**Admin. & General-Maintenance**					
48	935 General Plant	1,646,279	14,721	1,631,557	2,798,137	-41.69%
49	**Total Maintenance-Admin. & General**	1,646,279	14,721	1,631,557	2,798,137	-41.69%
50	**Total Admin. & General Expenses**	43,754,618	293,117	43,461,501	53,910,239	-19.38%
51	**TOTAL OPER. & MAINT. EXPENSES**	$365,515,128	$1,599,805	363,915,323	$271,852,615	33.86%

Sch.11	MONTANA TAXES OTHER THAN INCOME - ELECTRIC (EXCLUDES UNIT 4)			
	Description	This Year	Last Year	% Change
1				
2	**Federal Taxes**			
3	Social Security Old Age, Unemployment, and			
4	Medicare	$1,265,898	$4,350,999	-70.91%
5				
6	**Montana Taxes**			
7	Real Estate & Personal Property	30,811,662	46,290,117	-33.44%
6	Montana Beneficial Use Tax	244,192	170,339	43.36%
7	Crow Tribe Railroad & Utility Tax	44,393	45,621	-2.69%
8	Social Security Unemployment	-	(9,585)	100.00%
8	Old Fund Liability	-	(1,624)	100.00%
9	Units 3 & 4 Transmission Property	4,406,370	1,238,110	255.89%
10	Electric Energy Producer's License	76,888	1,653,071	-95.35%
11	Consumer Counsel	263,757	347,761	-24.16%
12	Public Service Commission	852,369	918,736	-7.22%
13	City Licenses	3,474	9,841	-64.70%
14	Wholesale Energy Transaction	1,308,028	-	0.00%
15	Accrued Other Taxes	18,792	-	0.00%
16				
17	**District of Columbia Taxes**			
18	Social Security Unemployment	216	216	0.00%
19	Personal Property	-	139	-100.00%
20				
21	**Other**			
22	Payroll Tax Credit	(852,398)	(4,156,217)	79.49%
23				
24	**TOTAL TAXES OTHER THAN INCOME**	$38,443,641	$50,857,524	-24.41%

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES, 1/		
	Name of Recipient	Nature of Service	Total
1	ACSIS Inc.	Computer maintenance	$127,122
2	Allen & Company, Inc.	Financial advisory services	100,000
3	Alme Construction, Inc.	Gas Pipeline Construction	537,229
4	Alstom Esca Corp	Maintenance	251,400
5	Asplundh	Tree trimming	1,624,377
6	ATS, Anderson Tree Service	Tree trimming	481,171
7	Bill Field Trucking, LLC	Equipment transportation	326,019
8	Blue Cross/Blue Shield of MT	Administration-welfare plan	8,662,314
9	Burns International Security	Security service	168,161
10	Community Health Options	Health services	133,346
11	Computer Associates	Maintenance	133,251
12	Computerland of West. MT	Maintenance & equipment	115,850
13	Crowley, Haughey,Hanson	Legal services	421,537
14	D J & A P.C. Consulting	Consulting	111,448
15	Delta Consulting Group	Consulting	131,185
16	Dennis J Woods	Consulting	100,000
17	EPRI	Research	344,823
18	Express Services, Inc.	Temporary service	143,367
19	F X Drilling Company, Inc.	Contractor	230,630
20	Goldman Sachs	Consulting	600,000
21	Harp Line Constructors Co.	Line construction & maintenance	2,755,227
22	Heath Consultants, Inc.	Gas leak detection	140,042
23	Howrey & Simon	Environmental consulting	260,476
24	IBEX Construction	Tree trimming	138,711
25	IBM Corp	Computer maintenance	2,833,689
26	Independent Inspection Co	Electric line inspection	739,039
27	Interim Personnel/Spherion Corp	Temporary service	140,810
28	Itron, Inc.	Hardware/software maintenance	588,795
29	Jensen's Tree Service, Inc.	Tree trimming	106,435
30	Lehman Bros.	Financial services	3,857,802
31	Lewis Mfg. & Construction, Inc.	Contractor	490,157
32	Morgan Stanley Dean Witter	Consulting	254,798
33	Mtn.Utility Constr.& Design	Contractor	4,401,540
34	Nat'l Ctr. For Appropriate Technology	Lab Testing	664,832
35	Northern Trust	Consulting 401(k)/pension	14,860,158
36	Northwest Energy Efficiency	Energy serices	693,142
37	Orcom Solutions	Programming & implementation	4,577,989
38	PricewaterhouseCoopers	Auditing/ Consulting	521,649
39	Professional Access	Consulting	179,442
40	Rod Tabbert Construction, Inc.	Contractor	234,395
41	SAP American Inc.	Maintenance	189,709
42	Schweitzer Engineering Labs	Lab contract	254,730
43	Spiker Communications, Inc.	Advertising	341,128
44	Thelen Reid & Priest, LLC	Legal services	277,024
45	Towers Perrin	Consulting/Actuary	156,121
46	Tri-County Mechanical & Eng	Miscellaneous Plumbing	433,092
47	Williams Construction Co Inc.	Electric line maintenance	706,319
48	Wolfer Printing Co	Printing services	173,100
49	XENERGY, Inc.	Contract services	933,603
50	Zacha Construction, Inc.	Construction & maintenance	160,014
51			
52	**Total Payments for Services**		$56,807,198
54	1/ Due to the multiple % allocations, it is not practical to separately identify amounts charged to the electric or gas utility.		

Sch. 13

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS

The Montana Power Company does not make any contributions to Political Action Committees (PACs) or candidates.

There is an employee PAC - Citizens for Responsible Government / Employees of The Montana Power Company (CRG). CRG is an organization of employees and shareholders of Montana Power and its subsidiaries. All of the money contributed by members goes to support political candidates. No company funds may be spent in support of a political candidate. Officers and local representatives of CRG donate their time. 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	This Year	Last Year	% Change
1	**Plan Name: Retirement Plan for Employees**			
2	**of The Montana Power Company**			
3	Defined Benefit Plan	Yes	Yes	
4	Defined Contribution Plan (See Schedule 14A)			
5	Is the Plan overfunded?	Yes - 3/	Yes - 2/	
6				
7	Actuarial Cost Method		Projected Unit Credit Method	
8	IRS Code			
9	Annual Contribution by Employer	0	0	
10	Accumulated Benefit Obligation	233,928,474	202,668,644	15.42%
11	Projected Benefit Obligation	185,807,217	154,225,053	20.48%
12	Fair Value of Plan Assets	199,126,255	204,921,941	-2.83%
13				
14	Discount Rate for Benefit Obligations	7.50%	7.75%	
15	Expected Long-Term Return on Assets	9.00%	9.00%	
16				
17	Net Periodic Pension Cost:			
18	Service Cost	2,964,375	5,038,661	-41.17%
19	Interest Cost	12,628,371	13,023,645	-3.04%
20	Return on Plan Assets (Expected)	(17,825,360)	(19,597,988)	-9.04%
21	Net Amortization	(1,212,247)	(112,893)	973.80%
22	Special Termination Benefit Charge	6,443,178	-	
23	Curtailment Charge	-	(3,750,922)	-100.00%
24	Settlement Charge	-	(7,844,276)	-100.00%
25	Total Net Periodic Pension Cost	2,998,317	(13,243,773)	-122.64%
26				
27	Minimum Required Contribution			
28	Actual Contribution	-	-	
29	Maximum Amount Deductible	-	-	
30	Benefit Payments	9,942,351	9,416,644	5.58%
31				
32	Montana Intrastate Costs:			
33	Pension Costs		NOT APPLICABLE	
34	Pension Costs Capitalized			
35	Accumulated Pension Asset (Liability) at Year End			
36				
37	Number of Company Employees : 1/			
38	Covered by the Plan			
39	Active	1,023	1,557	-34.30%
40	Retired	870	825	5.45%
41	Vested Former Employees (Deferred Inactive)	558	556	0.36%
42	Total Covered by the Plan	2,451	2,938	-16.58%
43	Total Not Covered by the Plan			
44				
45	1/ Obtained from The Actuarial Valuation Report of the Retirement Plan for Employees of The			
46	Montana Power Company, prepared as of January 1, 1999 and 2000 respectively.			
47				
48	2/ As of December 31, 1999, the fair value of assets was $204.9 million and the projected benefit obligation			
49	was $154.2 million. However, there was an unrecognized net gain of $45.7 million that has not been			
50	fully amortized pursuant to SFAS Statement No. 87. There is a prepaid pension cost of $5.9 million			
51	as of December 31,1999.			
52				
53	3/ As of December 31, 2000, the fair value of assets was $199.1 million and the projected benefit obligation			
54	was 185.8 million. However, there was an unrecognized net gain of $21.0 million that has not been			
55	fully amortized pursuant to SFAS Statement No. 87. There is a prepaid pension cost of $10.8 million			
56	as of December 31, 2000.			

Sch. 14A	PENSION COSTS			
	Description	This Year	Last Year - 3/	
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	138,602,820	217,103,334	-36.16%
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 -4/	1,032	1,208	-14.57%
38	Not Covered by the Plan	-	-	
39	Active -- Participating	1,013	885	14.46%
40	Retired			
41	Vested Former Employees, Retirees and -4/	19	323	-94.12%
42	Active-Noncontributing			
43	Total Covered by the Plan -4/	1,032	1,208	-14.57%
44	Total Not Covered by the Plan	0	0	
45				
46				
47				
48	4/ Employee count number for 1999 were restated. An error was found in the count data for eligilbe employees.			

Sch 15	OTHER POST EMPLOYMENT BENEFITS (OPEBS)			
	Description	This Year, 1/	Last Year , 2/	% Change
1	**General Information**			
2	Discount Rate for Benefit Obligations	7.50%	6.75%	11.11%
3	Expected Long-Term Return on Assets	9.00%	9.00%	0.00%
4	Medical Cost Inflation Rate 3/	10.0%,5.50%:7	7.50%,5.00%: 5	
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)	$20,294,406	$16,706,651	21.48%
17	Fair Value of Plan Assets	8,316,657	8,709,459	-4.51%
18				
19	List the amount funded through each funding method:			
20	VEBA	726,947	1,070,467	-32.09%
21	401(h)	756,619	1,114,160	-32.09%
22	Other: Cash	639,256	632,133	1.13%
23	Total Amount Funded	2,122,822	2,816,760	-24.64%
24				
25	List amount that was tax deductible for each type of funding:			
26	VEBA	726,947	1,070,467	-32.09%
27	401(h)	756,619	1,114,160	-32.09%
28	Other: Cash	639,256	632,133	1.13%
29	Total Amount Tax Deductible	2,122,822	2,816,760	-24.64%
30				
31	Net Periodic Post Retirement Benefit Cost:			
32	Service Cost	323,697	548,259	-40.96%
33	Interest Cost	1,375,300	1,429,031	-3.76%
34	Return on Plan Assets (Expected)	(712,005)	(645,008)	10.39%
35	Amort. Of Transition Oblig. & Regulatory Asset	756,214	954,713	-20.79%
36	Amortization of Prior Service Cost	123,309	134,876	-8.58%
37	Amortization of Gains or Losses	(110,447)	(100,336)	10.08%
38	Total Net Periodic Post Retirement Benefit Cost	1,756,068	2,321,535	-24.36%
39	Benefit Cost Expensed	1,350,416	1,412,886	-4.42%
40	Benefit Cost Capitalized	368,774	390,250	-5.50%
41	Benefit Cost Charged to MPC Subs & Colstrip Owners -5/	36,877	518,399	-92.89%
42	Total Benefit Costs	1,756,068	2,321,535	-24.36%
43	Benefit Payments	639,256	632,133	1.13%
44				
45	Number of Company Employees :			
46	Covered by the Plans			
47	Active	1,026	1,551	-33.85%
48	Retired	748	650	15.08%
49	Retired Spouse/Dependents	28	68	-58.82%
50	Total Covered by the Plans	1,802	2,269	-20.58%
51	Total Not Covered by the Plans	264	251	5.18%
52	1/ Obtained from MPC's 2000 FASB 106 Valuation. Assumptions and data are as of December 31, 2000.			
53	2/ Obtained from MPC's 1999 FASB 106 Valuation. Assumptions and data are as of December 31, 1999.			
54	3/ First Year, Ultimate, Years to Reach Ultimate.			

Sch. 16	TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)				
Name/Title	Base Salary 1/	Other Comp. 2/	Total Comp.	Total Comp. Last Year	% Change
R. P. Gannon	$484,119	$5,463 <B			
Chairman of the Board		271,650 <C			
President and Chief Executive		2,136 <G			
Officer		406 <H			
		566 <I			
			$764,340	$891,093	-14%
R.F. Cromer, 3/	210,129	6,800 <B			
Executive Vice President &		133,299 <C			
Chief Operating Officer, Energy		782 <G			
Supply Division		796 <H			
			351,806	407,449	-14%
M.J. Meldahl	231,563	13,221 <A			
Executive Vice President &		6,800 <B			
Chief Operating Officer,		177,131 <C			
Technology Division [Touch		182,652 <F			
America, Inc.]		621 <H			
			611,988	484,310	26%
J. P. Pederson	213,616	21,635 <A			
Vice Chairman & Chief Financial		6,800 <B			
Officer		116,884 <C			
		538 <G			
			359,473	866,288	-59%
P.K. Merrell	144,729	12,927 <A			
Vice President,		6,292 <B			
Human Resources		46,329 <C			
		219,190 <E			
		17 <G			
			$429,484	$244,738	75%
P.J. Cole					
Vice President, Corporate					
Business Development					
P.T. Fleming					
Corporate Secretary					

CONFIDENTIAL INFORMATION

NOT REQUIRED FOR GENERAL DISTRIBUTION

Sch. 16A	TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)					
	Name/Title	Base Salary 1/	Other Comp. 2/	Total Comp.	Total Comp. Last Year	% Change
	M. E. Zimmerman Vice President & General Counsel	CONFIDENTIAL INFORMATION NOT REQUIRED FOR GENERAL DISTRIBUTION				
	J.D. Haffey Executive Vice President & Chief Operating Officer, Energy Services Division					
	D.A. Johnson Vice President, Distribution Services					

1/ Salary includes the employees' annual base federally taxable earnings, pretax contributions to the Company's Deferred Savings and Employee Stock Ownership (401(K)) Plan, pretax Section 125 flexible spending account contributions, pretax medical premium contributions, and, in some cases, tax deferred Executive Benefit Restoration Plan contributions.

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

A> Vacation time sold back to the Company. The vacation sellback program is available to all employees.

B> The value of the Company's matching contribution of stock made to the employee's accounts under the Deferred Savings and Employee Stock Ownership (401(K)) Plan sponsored by the Company.

C> Incentive Compensation Plan which were earned under the 1997 and 1998 EVA Bonus Plan.

D> Dividend equivalents on stock options awarded under the Long-Term Incentive Plan in 1994. These awards, approved by the Personnel Committee, were based on certain performance criteria.

E> Gains on exercised stock options.

F> Payout of stock under the Restricted Stock Plan. The Plan was based on certain 1994 performance criteria.

G> Imputed taxable income on Company-paid life insurance premiums.

H> Company-paid physical examinations.

I> Personal use of company vehicles.

J> Spot cash bonus awards.

K> Severance pay.

3/ Mr. Cromer resigned as an executive officer on December 8, 2000.

Sch. 17

COMPENSATION OF TOP FIVE CORPORATE EMPLOYEES - SEC INFORMATION

Name/Title	Base Salary 1/	Other Comp. 2/	Total Comp.	Total Comp. Last Year	% Change
R. P. Gannon	$484,119	$5,463 <B			
Chairman of the Board		271,650 <C			
President and Chief Executive		2,136 <G			
Officer		406 <H			
		566 <I	$764,340	$891,093	-14%
R.F. Cromer, 3/	210,129	6,800 <B			
Executive Vice President &		133,299 <C			
Chief Operating Officer, Energy		782 <G			
Supply Division		796 <H	351,806	407,449	-14%
M.J. Meldahl	231,563	13,221 <A			
Executive Vice President &		6,800 <B			
Chief Operating Officer,		177,131 <C			
Technology Division [Touch		182,652 <F			
America, Inc.]		621 <H	611,988	484,310	26%
J. P. Pederson	213,616	21,635 <A			
Vice Chairman & Chief Financial		6,800 <B			
Officer		116,884 <C			
		538 <G	359,473	866,288	-59%
P.K. Merrell	144,729	12,927 <A			
Vice President,		6,292 <B			
Human Resources		46,329 <C			
		219,190 <E			
		17 <G	$429,484	$244,738	75%

1/ Salary includes the employees' annual base federally taxable earnings, pretax contributions to the Company's Deferred Savings and Employee Stock Ownership (401(K)) Plan, pretax Section 125 flexible spending account contributions, pretax medical premium contributions, and, in some cases, tax deferred Executive Benefit Restoration Plan contributions.

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

A> Vacation time sold back to the Company. The vacation sellback program is available to all employees.

B> The value of the Company's matching contribution of stock made to the employee's accounts under the Deferred Savings and Employee Stock Ownership (401(K)) Plan sponsored by the Company.

C> Incentive Compensation Plan which were earned under the 1997 and 1998 EVA Bonus Plan.

D> Dividend equivalents on stock options awarded under the Long-Term Incentive Plan in 1994. These awards, approved by the Personnel Committee, were based on certain performance criteria.

E> Gains on exercised stock options.

F> Payout of stock under the Restricted Stock Plan. The Plan was based on certain 1994 performance criteria.

G> Imputed taxable income on Company-paid life insurance premiums.

H> Company-paid physical examinations.

I> Personal use of company vehicles.

J> Spot cash bonus awards.

K> Severance pay.

3/ Mr. Cromer resigned as an executive officer on December 8, 2000.

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	$1,221,842,478	$1,151,900,735	6.07%
4	105 Plant Held for Future Use	8,984	8,983	0.01%
5	107 Construction Work in Progress	1,805,954	3,781,637	-52.24%
6	108 Accumulated Depreciation Reserve	(493,655,655)	(446,763,168)	-10.50%
7	111 Accumulated Amortization & Depletion Reserves	(9,683,037)	(8,765,640)	-10.47%
8	114 Electric Plant Acquisition Adjustments	3,106,285	3,106,285	0.00%
9	115 Accumulated Amortization-Electric Plant Acq. Adj.	(2,252,057)	(2,157,142)	-4.40%
10	117 Gas Stored Underground-Noncurrent	40,710,265	44,881,517	-9.29%
11	**Total Utility Plant**	761,883,217	745,993,206	2.13%
12	**Other Property and Investments**			
13	121 Nonutility Property	2,780,825	2,749,633	1.13%
14	122 Accumulated Depr. & Amort.-Nonutililty Property	(69,747)	2,384	-3026.08%
15	123.1 Investments in Subsidiary Companies	759,190,205	444,772,792	70.69%
16	123 Investments in Colstrip Unit 4 & YNP	46,158,027	55,120,653	-16.26%
17	124 Other Investments	21,162,587	19,545,284	8.27%
18	128 Miscellaneous Special Funds	1,393,095	474,630,855	-99.71%
19	**Total Other Property & Investments**	830,614,992	996,821,601	-16.67%
20	**Current and Accrued Assets**			
21	131 Cash	(4,330,121)	(7,087,137)	38.90%
22	135 Working Funds	89,047	120,259	-25.95%
23	136 Temporary Cash Investments	-	15,500,000	-100.00%
24	141 Notes Receivable	254,123	111,754	127.40%
25	142 Customer Accounts Receivable	75,778,151	53,519,077	41.59%
26	143 Other Accounts Receivable	22,238,445	4,721,959	370.96%
27	144 Accumulated Provision for Uncollectible Accounts	(1,163,900)	(1,103,926)	-5.43%
28	145 Notes Receivable-Associated Companies	60,980,872	17,316,970	252.15%
29	146 Accounts Receivable-Associated Companies	125,321,575	137,430,243	-8.81%
30	151 Fuel Stock	151,070	29,919	404.92%
31	154 Plant Materials and Operating Supplies	10,238,825	9,066,025	12.94%
32	165 Prepayments	11,574,145	7,282,083	58.94%
33	171 Interest and Dividends Receivable	2,380,228	2,870,880	-17.09%
34	172 Rents Receivable	266,113	102,309	160.11%
35	173 Accrued Utility Revenues	27,744,975	28,881,980	-3.94%
36	174 Miscellaneous Current & Accrued Assets	64,019	-	
36	**Total Current & Accrued Assets**	331,587,567	268,762,395	23.38%
37	**Deferred Debits**			
38	181 Unamortized Debt Expense	3,353,218	4,236,556	-20.85%
39	182 Regulatory Assets	206,288,584	191,198,312	7.89%
40	183 Preliminary Survey and Investigation Charges	625,340	625,340	-
41	184 Clearing Accounts	(27,020)	39,911	-167.70%
42	185 Temporary Facilities	(12,238)	(9,288)	-31.76%
43	186 Miscellaneous Deferred Debits	14,500,996	15,018,157	-3.44%
44	189 Unamortized Loss on Reacquired Debt	3,914,566	7,787,554	-49.73%
45	190 Accumulated Deferred Income Taxes	170,007,486	150,657,017	12.84%
46	191 Unrecovered Purchased Gas Costs	14,414,108	4,021,066	258.46%
47	**Total Deferred Debits**	413,065,040	373,574,625	10.57%
48	**TOTAL ASSETS and OTHER DEBITS**	2,337,150,816	2,385,151,827	-2.01%

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	705,656,783	703,367,615	0.33%
4	204 Preferred Stock Issued	58,063,500	58,063,500	-
5	207 Premium on capital stock	-	(95,082)	100.00%
6	211 Miscellaneous Paid-In Capital	2,391,602	2,311,971	3.44%
7	213 Discount on Capital Stock	(815,700)	(815,700)	-
8	214 Capital Stock Expense	(93,889)	(93,888)	(0)
9	215 Appropriated Retained Earnings	6,238,312	6,238,312	0
10	216 Unappropriated Retained Earnings	595,587,557	442,365,355	34.64%
11	217 Reacquired capital stock	(205,656,384)	(144,871,974)	-41.96%
12	**Total Proprietary Capital**	1,161,371,781	1,066,470,109	8.90%
13	**Long Term Debt**			
14	221 Bonds	177,402,000	350,205,000	-49.34%
15	224 Other Long Term Debt	209,197,000	299,609,179	-30.18%
16	226 Unamortized Discount on Long Term Debt-Debit	(2,443,514)	(3,346,377)	26.98%
17	**Total Long Term Debt**	384,155,486	646,467,802	-40.58%
18	**Other Noncurrent Liabilities**			
19	227 Obligations Under Capital Leases-Noncurrent	4,166	112,682	-96.30%
20	228.1 Accumulated Provision for Property Insurance	939,516	747,760	25.64%
21	228.2 Accumulated Provision for Injuries and Damages	2,790,548	3,068,351	-9.05%
22	228.3 Accumulated Provision for Pensions and Benefits	6,736,462	13,578,729	-50.39%
23	228.4 Accumulated Miscellaneous Operating Provisions	7,350,000	125,687	5747.85%
24	**Total Other Noncurrent Liabilities**	17,820,692	17,633,209	1.06%
25	**Current and Accrued Liabilities**			
25	231 Notes Payable	75,000,000	-	
26	232 Accounts Payable	70,843,169	23,313,868	203.87%
27	233 Notes Payable to Associated Companies	49,372,117	59,476,916	-16.99%
28	234 Accounts Payable to Associated Companies	157,968,250	92,096,994	71.52%
29	235 Customer Deposits	849,654	356,122	138.59%
30	236 Taxes Accrued	27,568,964	106,844,968	-74.20%
31	237 Interest Accrued	4,821,957	10,784,797	-55.29%
32	238 Dividends Declared	1,456,066	19,990,697	-92.72%
33	241 Tax Collections Payable	(304,174)	254,204	-219.66%
34	242 Miscellaneous Current and Accrued Liabilities	30,465,232	11,467,797	165.66%
35	243 Obligations Under Capital Leases-Current	22,542	910,595	-97.52%
36	**Total Current and Accrued Liabilities**	418,063,777	325,496,958	28.44%
37	**Deferred Credits**			
38	252 Customer Advances for Construction	20,944,582	17,532,701	19.46%
39	253 Other Deferred Credits	6,685,685	29,918,061	-77.65%
40	254 Regulatory Liabilities	60,280,578	12,178,384	394.98%
41	255 Accumulated Deferred Investment Tax Credits	13,162,867	13,329,637	-1.25%
42	257 Unamortized Gain on Reacquired Debt	22,360	31,613	-29.27%
43	281-283 Accumulated Deferred Income Taxes	254,643,008	256,093,352	-0.57%
44	**Total Deferred Credits**	355,739,080	329,083,748	8.10%
45	**TOTAL LIABILITIES and OTHER CREDITS**	$2,337,150,816	$2,385,151,827	-2.01%
46				
47	1/ Includes CMP and Montana Power Capital I; excludes Colstrip Unit 4, Yellowstone National Park and			
48	nonregulated propane.			

NOTES TO THE FINANCIAL STATEMENTS

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

❑ BASIS OF ACCOUNTING

Our accounting policies conform to 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.

❑ USE OF ESTIMATES

Preparing financial statements requires the use of estimates based on information available. Actual results may differ from our accounting estimates as new events occur or we obtain additional information.

❑ RECLASSIFICATIONS

We have made reclassifications to certain prior-year amounts to make them comparable to the 2000 presentation. These reclassifications had no material effect on our previously reported consolidated financial position, results of operations, or cash flows.

❑ 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 (SFAS) No. 94 "Consolidation of All Majority-Owned Subsidiaries." SFAS No. 94 requires that all majority-owned subsidiaries be consolidated. The other differences are comparative statements of retained earnings and cash flows and net income per share are not presented.

❑ CASH AND CASH EQUIVALENTS AND TEMPORARY INVESTMENTS

We consider all liquid investments with original maturities of three months or less to be cash equivalents, and investments with original maturities over three months and up to one year as temporary investments. At December 31, 1999, all of our investments were available for sale, and their fair value approximates the value reported on the Consolidated Balance Sheet. We had no temporary investments at December 31, 2000.

PROPERTY, PLANT, AND EQUIPMENT

The following table provides year-end balances of the major classifications of our property, plant, and equipment, which we record at cost:

	December 31 2000	December 31 1999
	(Thousands of Dollars)	
UTILITY PLANT:		
Electric:		
Generation (including our share of jointly owned)	$ (238,431)	$ (239,961)
Transmission	395,218	370,166
Distribution	597,871	567,333
Other	95,625	92,292
Natural Gas:		
Production and storage	71,659	71,424
Transmission	167,416	163,968
Distribution	151,039	147,764
Other	27,077	30,693
Total plant	$1,267,474	$1,203,679

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 Federal Energy Regulatory Commission (FERC). This rate averaged 8.6 percent for 2000 and 7.1 percent for 1999.

We charge costs of utility depreciable units of property retired plus costs of removal less salvage, to accumulated depreciation and recognize no gain or loss. We charge maintenance and repairs of plant and property, as well as replacements and renewals of items determined to be less than established units of plant, to operating expenses.

Included in the plant classifications are utility plant under construction in the amounts of $1,806,000 and $3,782,000 for 2000 and 1999, respectively.

We record provisions for depreciation and depletion at amounts substantially equivalent to calculations made on straight-line and unit-of-production methods by applying various rates based on useful lives of properties determined from engineering studies. As a percentage of the depreciable and depletable utility plant at the beginning of the year, our provisions for depreciation and depletion of utility plant were approximately 3.5 percent for 2000 and 3.0 percent for 1999.

REVENUE AND EXPENSE RECOGNITION

We record operating revenues monthly on the basis of consumption or service rendered. To match revenues with associated expenses, we accrue unbilled revenues for electric and natural gas services delivered to customers but not yet billed at month-end.

❑ REGULATORY ASSETS AND LIABILITIES

For our regulated operations, we follow SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." 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. The significant regulatory assets and liabilities we have recorded are discussed below.

With the sale of the electric generating assets, it is our position that any of the following amounts related to electric supply should be recovered from sale proceeds in excess of book value. Amortization of these items stopped in February 2000 when the expenses were removed from rates. For further information on the effects of the sale of our electric generating assets, see Note 4, "Deregulation, Regulatory Matters, and 1999 Sale of Electric Generating Assets."

In the ratemaking process, tax costs and benefits related to certain temporary differences are recovered in rates on an as paid or "flow-through" basis. SFAS No. 109, "Accounting for Income Taxes," requires that tax assets and liabilities be reflected on the balance sheet on an accrual basis. This timing difference requires that we recognize a regulatory asset for taxes accrued but not yet recovered in rates. That regulatory asset was $88,822,000 and $87,222,000 as of December 31, 2000 and 1999, respectively.

In August 1985, the Montana Public Service Commission (PSC) issued an order allowing us to recover deferred carrying charges and depreciation expenses over the remaining life of Colstrip Unit 3. These recoveries compensated us for unrecovered costs of our investment for the period from January 10, 1984, to August 29, 1985, when we placed the plant in service. We were amortizing this asset to expense, and recovering in rates, $1,831,000 per year. At December 31, 2000 and 1999, the unamortized amounts were $38,337,000 and $38,494,000, respectively.

We also include costs related to our Demand Side Management (DSM) programs in other regulatory assets. These amounts were $27,956,000 and $28,378,000 for 2000 and 1999, respectively. These costs are in rate base and we were amortizing them to income over a 10-year period.

We recorded a regulatory liability of $32,549,000 in connection with the sale of our unregulated oil and natural gas operations on October 31, 2000. The liability represents the portion of the proceeds from the sale attributable to properties previously in the natural gas utility's rate base. Based on gas stipulation agreements addressing the removal of natural gas production properties from regulation, we have agreed to share this amount with our natural gas utility ratepayers. For more information on the sale of oil and natural gas operations see Note 2, "Decision to Sell Energy Businesses."

Certain other amounts represent items that we are amortizing currently or are subject to future regulatory confirmation.

Changes in regulation or changes in the competitive environment could result in our not meeting the criteria of SFAS No. 71. If we were to discontinue application of SFAS No. 71 for some or all of our regulated operations, we would have to eliminate the related regulatory assets and liabilities from the balance sheet. We would include the associated expenses and credits in income in the period when the discontinuation occurred, unless recovery of those costs was provided through rates charged to those customers in portions of the business that were to remain regulated.

❑ STORM DAMAGE AND ENVIRONMENTAL REMEDIATION COSTS

When losses from costs of storm damage and environmental remediation obligations for our utility operations are probable and reasonably estimable, we charge these costs against established, approved operating reserves.

❑ INCOME TAXES

We defer income taxes to provide for the temporary differences between the financial reporting basis and the tax basis of our assets and liabilities. For further information on income taxes, see "Regulatory Assets and Liabilities" in this Note 1 and Note 5, "Income Tax Expense."

❑ ASSET IMPAIRMENT

In accordance with SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of," we periodically review long-lived assets for impairment whenever events or changes in circumstances indicate that we may not recover the carrying amount of an asset.

❑ COMPREHENSIVE INCOME

Comprehensive income consists of net income and other comprehensive income (loss). For the years ended December 31, 2000 and 1999, our only item of other comprehensive income was foreign currency translation adjustments of the assets and liabilities of our foreign subsidiaries. These adjustments resulted in increases to retained earnings of $17,625,000 and $3,058,000 in 2000 and 1999, respectively.

Nearly all of the 2000 increase resulted from the sale of the Canadian subsidiaries of our former oil and natural gas businesses. In accordance with SFAS Nos. 52, "Foreign Currency Translation," and 130, "Reporting Comprehensive Income," we recognized the cumulative translation loss associated with those subsidiaries by including it in the computation of the gain on the October 31, 2000 sale of the oil and natural gas businesses. Including it reduced our gain by approximately $21,200,000. Because the translation adjustment was not part of the tax basis of the foreign subsidiaries' properties, it did not affect the calculation of taxes on the sale. For more information on the sale of oil and natural gas operations see Note 2, "Decision to Sell Energy Businesses."

❑ DERIVATIVE FINANCIAL INSTRUMENTS

Electric Swap Agreements

Long-term power supply agreements, primarily one with a large industrial customer, expose us to commodity price risk, to the extent that a portion of the electric energy we are required to sell to our industrial customers at fixed rates is purchased at prices indexed to the Mid-Columbia (Mid-C) wholesale electric market, which can be higher than the fixed sales rate. We mitigate our exposure to losses on these agreements with financial derivative instruments called "price swaps" and offsetting electric energy purchase and sales agreements.

Since June 1998, we have had a price swap agreement with one of our industrial customers that converts 43 MWs of the Mid-Columbia (Mid-C) index price of our supply agreement with that customer to a fixed price through May 2001. In fiscal year 2000, we also entered into another price swap with a counterparty that effectively hedges 35 MWs of the anticipated market-based purchases to supply that agreement through March 2001.

In accordance with the provisions of SFAS No. 80, "Accounting for Futures Contracts," we recognized gains and losses from the financial swaps in the same period in which the sales and related purchases under that agreement occurred. For fiscal year 2000, we recognized a net gain of approximately $16,000,000 from these financial swaps and losses of approximately $32,200,000 from supplying large industrial customers. For more specific information about the commodity price risk that we face as a result of our long-term power supply agreements, see Note 12, "Contingencies," in the "Long-Term Power Supply Agreements" section.

An estimate of the fair market value of the swaps based on the Mid-C forward prices of December 29, 2000 aggregated approximately $21,800,000 as of December 31, 2000, which would offset approximately 40 percent of the expected losses on the above power supply agreements. For information on SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and how we expect it to affect us, see Note 14, "New Accounting Pronouncements."

Natural Gas Utility Swaps

By drilling wells and adding compression at our Cobb storage reservoir, we are able to sell natural gas that had been held in reserve to provide firm storage deliverability to our customers. We therefore contracted to sell, from October 2000 through March 2001, 1,760,000 dekatherms from that reservoir at a monthly price based on the Alberta Energy Company "C" Hub (AECO-C) index. To reduce our exposure to fluctuations of the market index price, we entered into a swap agreement with a counterparty that effectively converts that index price to a fixed price for 903,000 dekatherms associated with these sales from December 2000 through February 2001.

For December 2000, we recognized a loss of approximately $300,000 on the swap and a profit of approximately $1,200,000 on the sale of the Cobb storage natural gas. Based on the AECO-C forward prices at December 29, 2000, we estimate a loss of approximately $3,000,000 on the swap to offset profits of $4,900,000 on the sale through February 2001. We are deferring the expected net profit of these transactions in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," until the PSC approves its inclusion in future rate schedules.

❑ FAIR VALUE OF FINANCIAL INSTRUMENTS

	2000		1999	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Thousands of Dollars)			
ASSETS:				
Other significant investments ..	$ 21,127	$ 21,127	$ 19,509	$ 19,509
LIABILITIES:				
Long-term debt (including due within one year)	$ 384,155	$ 381,654	$ 646,468	$ 628,313

The following methods and assumptions were used to estimate fair value:

- Other significant investments - The carrying value of most of the investments approximates fair value as they have short maturities or the carrying value equals their cash surrender value. The investments consist mainly of the cash value of insurance policies associated with an unfunded, nonqualified benefit plan for senior management, executives, and directors.

- Long-term debt - The fair value was estimated using quoted market rates for the same or similar instruments. Where quotes were not available, fair value was estimated by discounting expected future cash flows using year-end incremental borrowing rates.

NOTE 2 - DECISION TO SELL ENERGY BUSINESSES

On March 28, 2000, after a careful review of options and strategies, our Board of Directors announced that we would begin the process of divesting our multiple energy businesses, separating them from Touch America. Following the merger and the sale of the utility business to NorthWestern, Touch America expects to use the cash proceeds from the sale of the oil and natural gas businesses, the coal businesses, the independent power production business, and the utility business to take advantage of opportunities in the telecommunications business. We expect these gross cash proceeds, before income taxes and transaction costs, to total approximately $1,300,000,000.

❑ SALE OF OIL AND NATURAL GAS OPERATIONS

On August 25, 2000, our wholly owned subsidiary, Entech, and Altana Exploration Company, Entech's wholly owned subsidiary, entered into a Stock and Asset Purchase Agreement with PanCanadian Petroleum Limited (PanCanadian Petroleum) and one of PanCanadian Petroleum's wholly owned subsidiaries, PanCanadian Energy, Inc. (PanCanadian Energy). Pursuant to the Stock and Asset Purchase Agreement, PanCanadian Petroleum agreed to purchase from us all of the stock and assets of our Canadian oil and natural gas businesses, and PanCanadian Energy agreed to purchase from us all of the stock of our United States oil and natural gas businesses. (We collectively refer to PanCanadian Petroleum and PanCanadian Energy as PanCanadian.) The transaction closed on October 31, 2000, with a purchase price of US$475,000,000, subject to post-closing adjustments.

As a result of the transaction, we recorded a gain in the fourth quarter 2000 of approximately $62,000,000, net of income taxes and a regulatory liability of approximately $32,500,000. The $32,500,000 liability represents the portion of the proceeds from the sale of oil and natural gas businesses to PanCanadian attributable to properties previously in the natural gas utility's rate base. Based on gas stipulation agreements addressing the removal of natural gas production properties from regulation, we have agreed to share this amount with our natural gas utility ratepayers.

❑ SALE OF CONTINENTAL ENERGY

On September 19, 2000, Entech entered into a Stock Purchase Agreement with BBI pursuant to which BBI agreed to purchase the stock of Continental Energy, our remaining independent power production business. In January 2001, BBI assigned its right to purchase Continental Energy to BBI's wholly owned subsidiary, CES Acquisition Corp. The transaction closed on February 21, 2001, with a purchase price of $84,500,000, subject to post-closing adjustments. Based on the net book value of Continental Energy, we expect to record a gain in the first quarter 2001 of approximately $33,000,000, net of income taxes. For information on the first quarter 2001 closing of the sale of Continental Energy, see Note 13 "Subsequent Events."

❑ STATUS OF SALES OF REMAINING ENERGY BUSINESSES

Pending Sale of Coal Operations

On September 15, 2000, Entech entered into a Stock Purchase Agreement with Westmoreland pursuant to which Westmoreland agreed to purchase the companies comprising our coal businesses. The purchase price is $138,000,000, subject to customary closing adjustments. We expect this transaction to close at approximately the beginning of the second quarter 2001 and, based on the net book value of our coal operations, we expect to record a gain on the sale. For information on the April 30, 2001 closure of the sale, see Note 13, "Subsequent Events."

The Montana Power L.L.C./Utility Business

On September 29, 2000, we entered into a Unit Purchase Agreement with NorthWestern Corporation, a South Dakota-based energy company, pursuant to which NorthWestern agreed, as discussed below, to purchase our affiliate, The Montana Power L.L.C., a Montana limited liability company (MPLLC). MPLLC will hold - among other assets, liabilities, commitments, and contingencies - our electric (including Colstrip Unit 4) and natural gas utility business. The consideration for MPLLC is approximately $1,090,000,000, and is comprised of cash of $602,000,000 and NorthWestern's assumption of up to $488,000,000 of our debt.

The transaction is targeted to close approximately three months after the proxy statement/prospectus is filed and becomes effective. The closing is subject to the approval of our shareholders, regulatory approvals from the PSC, and other customary conditions. We received approval for the sale from FERC in February 2001. We can provide no assurance that the transaction will close or, if it does, that the terms and conditions will remain unchanged. For additional information on the special meeting of our shareholders to consider and vote on the sale and other matters, see Note 3, "Upcoming Special Meeting of Shareholders."

NOTE 3 - UPCOMING SPECIAL MEETING OF SHAREHOLDERS

Our Board of Directors has approved a merger that will create a new company, Touch America Holdings, Inc., to own what is today our telecommunications business. Immediately following this merger, our remaining energy business - consisting of our electric and natural gas utility - will be sold to NorthWestern. On completion of this merger and the sale of the utility business to NorthWestern, Touch America Holdings will own Touch America, Inc. and Tetragenics Company, which together will constitute its telecommunications operating business.

On completion of the merger, our shareholders will be deemed to receive one share of Touch America Holdings' common stock for each common share of The Montana Power Company, and one share of Touch America Holdings' Preferred Stock, $6.875 Series, for each share of The Montana Power Company's outstanding Preferred Stock, $6.875 Series.

We will hold a special meeting of our shareholders to consider and vote on the merger and the sale of the utility business to NorthWestern. In addition, shareholders of our common stock will be asked to vote in favor of the redemption of The Montana Power Company's outstanding Preferred Stock, $4.20 Series, and Preferred Stock, $6.00 Series. If the redemption of the preferred stock is not approved by at least a majority of all of our common shareholders, each shareholder of The Montana Power Company's Preferred Stock, $4.20 Series, and Preferred Stock, $6.00 Series, will be deemed to receive in the merger one share of Touch America Holdings' Preferred Stock, $4.20 Series, and Preferred Stock, $6.00 Series, for each outstanding share of The Montana Power Company's Preferred Stock, $4.20 Series, and Preferred Stock, $6.00 Series, respectively. We plan to schedule this special meeting of our shareholders for the second or third quarter 2001.

NOTE 4 - DEREGULATION, REGULATORY MATTERS, AND 1999 SALE OF ELECTRIC GENERATING ASSETS

- **DEREGULATION**

The electric and natural gas utility businesses in Montana are transitioning to a competitive market in which commodity energy products and related services are sold directly to wholesale and retail customers. Montana's Electric Act, passed in 1997, provides that all customers will be able to choose their electric supplier by July 1, 2002. In October 2000, the PSC issued a Request for Comments on Extension of Transition Period. In December 2000, due to the lack of a competitive market for the supply of electric energy in Montana, the PSC extended the transition period two years, until July 1, 2004. Pursuant to the Electric Act, the electric utility is required to supply electric energy for the additional two-year period, and we are working with the Montana Legislature and the PSC to fully recover the default supply costs.

Montana's Natural Gas Act, also passed in 1997, provides that a 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.

Electric

Residential accounts previously in the competitive market largely returned to regulated supply in the fourth quarter 2000. Some industrial loads have curtailed operations due to high supply costs in the competitive market, reducing our electric load.

As required by the Electric Act, we filed a comprehensive transition plan with the PSC in July 1997. On July 1, 1999, we filed a case with the PSC to resolve the remaining Tier II issues under the filing. Tier II issues address the recovery and treatment of the Qualifying Facility (QF) power-purchase contract costs; regulatory assets associated with the electric generating business; and a review of our electric generating assets sale, including the treatment of sale proceeds above the book value of the assets.

In implementing our comprehensive transition plan, we initiated litigation in Montana District Court in Butte to address our ability to use tracking mechanisms to ensure fair and accurate recovery of above-market QF costs and certain other transition costs. We also sought court clarification on whether the Electric Act authorized a rate freeze, which means that rates cannot change, or a rate cap, which means that rates cannot increase more than a certain level, during the initial transition period that ends July 1, 2002.

In May 2000, the district court ruled that the PSC must allow us to incorporate tracking mechanisms in our transition plan proposal and that the Electric Act authorized a rate cap. The PSC and the Large Customer Group appealed to the Montana Supreme Court the court's decision regarding tracking mechanisms, and we did not appeal its decision regarding the rate cap. The parties completed briefing of the tracking-mechanisms issue in October 2000 and are awaiting a decision from the Montana Supreme Court, which has requested amicus briefs and will schedule oral argument.

After the district court case, we updated our Tier II filing to reflect the closing of the sale of our electric generating assets. The PSC has suspended the procedural schedule pending a resolution from the Montana Supreme Court and, therefore, we do not expect an order from the PSC until the third or fourth quarter 2001.

Natural Gas

Through December 31, 2000, approximately 240 natural gas customers with annual consumption of 5,000 dekatherms or more - 52 percent of our pre-choice natural gas-supply load - have chosen alternate suppliers since the transition to a competitive natural gas environment began in 1991.

❑ REGULATORY MATTERS

Milltown Dam and our electric transmission operations remain subject to FERC and PSC regulation, and the PSC regulates our electric distribution operations.

Our natural gas transportation pipelines are generally not subject to FERC jurisdiction. We conduct limited interstate transportation subject to FERC jurisdiction, but FERC has allowed the PSC to set the rates for this interstate service. Our natural gas storage and distribution services, as well as our intrastate transportation services, are subject to PSC jurisdiction.

As a public utility, we also are subject to PSC jurisdiction when we issue, assume, or guarantee securities, or when we create liens on our properties.

Electric

FERC

On March 30, 1998, we submitted a cost-of-service filing with FERC to increase our open access transmission rates and the rates for bundled wholesale electric service to two rural electric cooperatives. Effective November 1, 1998, FERC approved an interim increase in rates charged for transmission service. In May 2000, we received final approval from FERC.

Through a stranded-costs filing with FERC in April 2000, we are seeking recovery of approximately $23,800,000 in transition costs associated with serving both of the wholesale electric cooperatives. We do not expect a FERC decision on this filing, which corresponds with our transition-costs recovery proceedings with the PSC in Montana, until after the PSC issues its order.

PSC

In January 2000, as a result of the sale proceeds from the sale of our electric generating assets exceeding the book value of the assets sold, we filed a voluntary rate reduction with the PSC for approximately $16,700,000 annually. This reduction became effective February 2, 2000.

The Electric Act established a rate cap for all electric customers pursuant to which transmission and distribution rates could not be increased until July 1, 2000. On August 11, 2000, with the expiration of the Electric Act's cap, we filed a combined rate case with the PSC, seeking increased electric and natural gas rates. We requested increased annual electric transmission and distribution revenues of approximately $38,500,000, with a proposed interim annual increase of approximately $24,900,000. On November 28, 2000, the PSC granted us an interim electric rate increase of approximately $14,500,000, with hearings on this submission held in late January and early February 2001. We expect a decision from the PSC during the second quarter 2001.

On August 25, 2000, we filed a request for increased rates to recover approximately $9,200,000 of higher power-supply costs relating to certain QF costs on an interim basis, pending final determination of QF transition costs. In a PSC work session in October 2000, the PSC denied our request. We sought reconsideration of the PSC's order, but the PSC also denied this request in January 2001. We have decided not to appeal this decision.

In accordance with our October 31, 1998 Asset Purchase Agreement with PPL Montana, as amended June 29, 1999 and October 29, 1999, we expect to sell our portion of the 500-kilovolt transmission system associated with Colstrip

Units 1, 2, and 3 for $97,100,000. We expect this transaction to close in 2001. The after-tax proceeds that we expect to receive as a result of this transaction will remain with The Montana Power L.L.C.

Natural Gas/PSC

On January 19, 2001, we submitted with the PSC an Annual Gas Cost Tracker for an increase of approximately $51,000,000 and a Compliance Filing resulting from the sale of gathering and production properties previously in the natural gas utility's rate base for a credit of approximately $32,500,000. This resulted in a net increase of approximately $18,500,000 in revenues effective February 1, 2001. See Note 2, "Decision to Sell Energy Businesses," under the "Sale of Oil and Natural Gas Operations" section, for further information on the $32,500,000 credit to our natural gas utility ratepayers.

As discussed above, we submitted a combined filing with the PSC on August 11, 2000, seeking increased natural gas and electric rates. We requested increased annual natural gas revenues of approximately $12,000,000, with a proposed interim annual increase of approximately $6,000,000. On November 28, 2000, the PSC granted us an interim natural gas rate increase of approximately $5,300,000, with hearings on this submission held in late January and early February 2001. We expect a decision from the PSC during the second quarter 2001.

On August 12, 1999, we filed a natural gas rate case with the PSC requesting increased annual revenues of $15,400,000, with a proposed interim increase of $11,500,000. An interim increase of $7,600,000 became effective on December 10, 1999, and a final PSC order that became effective on April 1, 2000 approved an additional increase of $2,800,000.

❑ 1999 SALE OF ELECTRIC GENERATING ASSETS

Assets Sold

On December 17, 1999, in accordance with the Asset Purchase Agreement entered into with PPL Montana, we sold substantially all of our electric generating assets and related contracts. We also sold an immaterial amount of associated transmission assets, totaling less than 40 miles. The asset sale did not include the Milltown Dam near Missoula, Montana (gross capacity of approximately 3 MWs) or any of our QF purchase-power contracts. It also did not include our leased share of the Colstrip Unit 4 generation or transmission assets.

As expected, the sale of our electric generating assets in December 1999 reduced the utility's net income for 2000. Utility revenues decreased because of discontinued off-system revenues that related to the electric generating assets sold. In addition, we no longer earn a return on our shareholders' investment in the electric generating assets. Before the sale, revenues covered the costs of operating the generating plants, taxes and interest, and earned a return on our shareholders' investment. Since the sale, we continue to bill our core customers for energy supply, but now these revenues recover the costs of the power that we purchase to serve these customers. The energy that we formerly generated and sold to core customers is now purchased pursuant to buyback contracts. The maximum price that we pay for power in the buyback contracts, $22.25/MWh, represents our net fully allocated supply costs of service in current rates, replacing operations and maintenance expense, property tax expense, depreciation expense, and return on investment associated with the electric generating assets.

In the sale of these assets, we generally retained all pre-closing obligations, and the purchaser generally assumed all post-closing obligations. However, with respect to environmental liabilities, the purchaser assumed all pre-closing (with certain limited exceptions) and post-closing environmental liabilities associated with the purchased assets.

While the purchaser assumed pre-closing environmental liabilities, we agreed to indemnify the purchaser from these pre-closing environmental liabilities, including a limited indemnity obligation for losses arising from required remediation of pre-closing environmental conditions, whether known or unknown at the closing, limited to:

- 50 percent of the loss. (Our share of this indemnity obligation at the Colstrip Project is limited to our pro-rata share of this 50 percent based on our pre-sale ownership share.)

- A two-year period after closing for unknown conditions. The indemnity for required remediation of pre-closing conditions known at the time of the closing continues indefinitely.

- An aggregate amount no greater than 10 percent of the purchase price paid for the assets.

In December 2000, we received a claim notice related to this indemnity obligation. Based on available information, we do not expect this indemnity claim on the indemnity obligation to have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

Cash Proceeds

At December 31, 1999, we recorded a regulatory liability and related deferred income tax to reflect the generation sale proceeds in excess of book value. Our current estimate of this liability, which will ultimately be determined in the Tier II docket, is approximately $215,000,000 before income taxes. This liability represents a deferral of the gain on the generation sale and nothing has been reflected in the Consolidated Statement of Income.

As part of our Tier II filing, we plan to deduct from the regulatory liabilities approximately $22,000,000 of other generation-related transition costs and approximately $65,600,000 of regulatory asset transition costs. The other generation-related transition costs consist mainly of SG&A costs and costs to retire debt. The regulatory asset transition costs consist mainly of capitalized conservation costs and carrying charges associated with Colstrip Unit 3.
We have used a portion of the net cash proceeds received (excluding the proceeds in excess of book value) to purchase shares of our common stock, to reduce debt, and to fund projects involving expansion of Touch America. For additional information on the purchase of shares of common stock and the reduction of debt, see Note 7, "Common Stock," and Note 10, "Long-Term Debt." For additional information on Touch America's projects, see Note 14, "Commitments," in the "Telecommunications" section.

Effect on 1999 Earnings

The asset sale affected positively our electric utility's 1999 earnings through the reversal of approximately $3,000,000 (after taxes) in interest expense recorded in prior years relating to Kerr Project liabilities and through recognition of approximately $10,000,000 in ITCs.

NOTE 6 - INCOME TAX EXPENSE

Income before income taxes was as follows:

	Year Ended December 31	
	2000	**1999**
	(Thousands of Dollars)	
Income from continuing operations:		
United States	$ (4,173)	$ 76,861
Canada	237	104
	$ (3,936)	$ 76,965

The provision for income taxes differs from the amount of income tax that would result by applying the applicable United States statutory federal income tax rate to pretax income because of the following differences:

	Year Ended December 31	
	2000	**1999**
	(Thousands of Dollars)	
Computed "expected" income tax expense	$ (1,378)	$ 26,938
Adjustments for tax effects of:		
General business credits	(167)	(20,489)
State income tax, net	(4,734)	1,219
Reversal of excess of utility book/tax depreciation	4,119	5,318
Other	(14,174)	(1,056)
Actual income tax expense	$ (16,334)	$ 11,930

Income tax expense as shown on the Consolidated Statement of Income consists of the following components:

	Year Ended December 31	
	2000	1999
	(Thousands of Dollars)	
Current:		
United States	$ 6,706	$ 157,950
Canada	16	63
State	(861)	31,905
	5,861	189,918
Deferred:		
United States	(20,448)	(149,979)
Canada	-	-
State	(1,747)	(28,009)
	(22,195)	(177,988)
Income tax expense attributable to continuing operations	$ (16,334)	$ 11,930

Deferred tax (assets) liabilities are comprised of the following:

	December 31	
	2000	1999
	(Thousands of Dollars)	
Plant related	$ 221,632	$ 216,281
Other	36,063	39,812
Gross deferred tax liabilities	257,695	256,093
Amortization of gain on sale/leaseback	(4,681)	(4,681)
Investment tax credit amortization	(14,056)	(14,056)
Other	(154,322)	(131,754)
Gross deferred tax assets	(173,059)	(150,491)
Net deferred tax liabilities	$ 84,636	$ 105,602

The change in net deferred tax (assets) liabilities differs from current year deferred tax expense as a result of the following:

	Thousands of Dollars
Increase(decrease)in total deferred tax liabilities (assets)	$ (20,966)
Regulatory assets related to income taxes	2,618
Balance sheet only-generation sale regulatory asset	(3,681)
Amortization of investment tax credits	(166)
Other	-
Deferred tax expense	$ (22,195)

NOTE 7 - COMMON STOCK

On June 22, 1999, the Board of Directors approved a two-for-one split of our outstanding common stock. As a result of the split, which was effective August 6, 1999, for all shareholders of record on July 16, 1999, 55,099,015 outstanding shares of common stock were converted to 110,198,030 outstanding shares of common stock. We have retroactively applied the split to all earlier periods presented.

❑ SHARE REPURCHASE PROGRAM

In 1998, the Board of Directors authorized a share repurchase program over the next five years to repurchase up to 20,000,000 shares, (approximately 18 percent of our then-outstanding common stock) on the open market or in privately negotiated transactions. As of December 31, 2000, we had 103,742,934 common shares outstanding. The number of shares to be purchased and the timing of the purchases will be based on the level of cash balances, general business conditions, and other factors, including alternative investment opportunities.

Subsequent to this authorization, we entered into a Forward Equity Acquisition Transaction (FEAT) program with a bank that committed to purchase shares on our behalf. Under the terms of the program, the amount owed to the bank and the number of shares held by the bank cannot exceed certain limits. In March 2000, these limits were amended and now are $125,000,000 and 2,500,000 shares. The expiration date of the program is August 1, 2001. Until that date, when all transactions must be settled, we can elect to fully or partially settle either on a full physical (cash) or a net share basis. A full physical settlement would be the purchase of shares from the bank for cash at the bank's average purchase price plus interest costs less dividends. A net share settlement would be the exchange of shares between the parties so that the bank receives shares with value equivalent to its original purchase price plus interest costs less dividends.

In December 1999, when the limits described above were $200,000,000 and 8,000,000 shares, we used proceeds from the sale of our generation assets to acquire 4,682,100 shares of our stock under the FEAT program. We purchased these shares at prices, including commissions, which ranged from $27.05 per share to $33.52 per share. The total cost was $144,872,000 for an average price of approximately $30.94 per share. In December 2000, we acquired an additional 1,933,900 shares of our stock under the program. The prices, including commissions, for these shares ranged from $27.26 per share to $33.53 per share and their total cost was $60,784,000 for an average price of approximately $31.43 per share. We have reflected the entire 6,616,000 shares purchased as "Reacquired Capital Stock" with a cost of $205,656,000 on the Comparative Balance Sheet. As of March 16, 2001, the bank had acquired no further shares on our behalf.

❑ SHAREHOLDER PROTECTION RIGHTS PLAN

We have a Shareholder Protection Rights Plan (SPRP) that provides one preferred share purchase right on each outstanding common share. Each purchase right entitles the registered holder, upon the occurrence of certain events, to purchase from us one one-hundredth of a share of Participating Preferred Shares, A Series, without par value. If it should become exercisable, each purchase right would have economic terms similar to one share of common stock. The purchase rights trade with the underlying shares and will, except under certain circumstances described in the SPRP, expire on June 6, 2009, unless redeemed earlier or exchanged by us.

❑ DIVIDEND REINVESTMENT AND STOCK PURCHASE PLAN

Our Dividend Reinvestment and Stock Purchase Plan permits participants to: (a) acquire additional shares of common stock through the reinvestment of dividends on all or any specified number of common and/or preferred shares registered in their own names, or through optional cash payments of up to $60,000 per year; and (b) deposit common and preferred stock certificates into their Plan accounts for safekeeping. It also allows for other interested investors (residents of certain states) to make initial purchases of its common shares with a minimum of $100 and a maximum of $60,000 per year.

In conjunction with the pending divestiture of our energy businesses and our transition to a telecommunications enterprise, our Board of Directors voted in October 2000 to eliminate the dividend payment on our common stock effective the first quarter 2001. The final quarterly dividend on our common stock was $0.20 per share, payable on November 1, 2000. The Board's decision did not affect dividends on our preferred stock.

❑ RETIREMENT SAVINGS PLAN

We have a 401(k) Retirement Savings Plan that covers eligible employees. We contribute, on behalf of the employee, a matching percentage of the amount contributed to the Plan by the employee. In 1990, we borrowed $40,000,000 at an interest rate of 9.2 percent to be repaid in equal annual installments over 15 years. The proceeds of the loan were lent on similar terms to the Plan Trustee, which used the proceeds to purchase 3,844,594 shares of our common stock. Shares acquired with loan proceeds are allocated monthly to Plan participants to help meet the Company's matching obligation. The loan, which is reflected as long-term debt, is offset by a similar amount in common shareholders' equity as unallocated stock. Our contributions plus the dividends on the shares held under the Plan are used to meet principal and interest payments on the loan with the Plan Trustee. As principal payments on the loan are made, long-term debt and the offset in common shareholders' equity are both reduced. At December 31, 2000, 2,756,662 shares had been allocated to the participants' accounts. We recognize expense for the Plan using the Shares Allocated Method, and the pretax expense was $2,570,000 and $3,768,000 for 2000 and 1999, respectively.

❑ LONG-TERM INCENTIVE PLAN

Under the Long-Term Incentive Plan, we have issued options to our employees. Options issued to employees are not reflected in balance sheet accounts until exercised, at which time: (1) authorized, but unissued shares are issued to the employee; (2) the capital stock account is credited with the proceeds; and (3) no charges or credits to income are made.

Options were granted at the average of the high and low prices as reported on the New York Stock Exchange composite tape on the date granted and expire ten years from that date.

Option activity is summarized below:

	2000		1999	
	Shares	Wtd Avg Exercise Price	Shares	Wtd Avg Exercise Price
Outstanding,				
Beginning of year........	3,280,325	$25.63	2,548,094	$22.71
Granted..................	1,199,545	34.36	919,510	32.14
Exercised................	149,834	17.07	88,857	10.83
Cancelled................	253,792	26.88	98,422	24.08
Outstanding, end of year...	4,076,244	$28.43	3,280,325	$25.63

Shares under option at December 31, 2000, are summarized below:

	Options Outstanding			Options Exercisable	
Exercise Price Range	Shares	Wtd Avg Exercise Price	Wtd Avg Exercise Life	Shares	Wtd Avg Exercise Price
$10.81 to $11.31	228,099	$11.05	5 yrs	228,099	$11.05
$18.00 to $23.06	472,999	19.48	8 yrs	383,446	18.64
$26.53 to $32.50	2,359,346	28.21	9 yrs	1,507,154	26.62
$35.36 to $38.69	1,015,800	37.00	9 yrs	258	35.36
	4,076,244			2,118,957	

As permitted by SFAS No. 123, "Accounting for Stock-Based Compensation," we have elected to follow Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25), and related interpretations in accounting for our employee stock options. Under APB 25, because the exercise price of the employee stock options equals the market price of the underlying stock on the date of grant, no compensation expense is recognized. Disclosure of pro forma information regarding net income and earnings per share is required by SFAS No. 123. This information has been determined as if we had accounted for our employee stock options under the fair value method of that statement. The weighted-average fair value of options granted in 2000 and 1999 was $16.35 and $7.03, respectively. We employed the binomial option-pricing model to estimate the fair value of each option grant on the date of grant. We used the following weighted-average assumptions for grants in 2000 and 1999, respectively: (1) risk-free interest rate of 6.05 percent and 6.35 percent; (2) expected life of 6.2 and 9.8; (3) expected volatility of 42.00 percent and 24.92 percent; and (4) a dividend yield of zero percent and 5.97 percent. Had we elected to use SFAS No. 123, compensation expense would have increased $11,827,000 in 2000, $5,280,000 in 1999, and $795,000 in 1998. The 2000 pro forma net income would be $188,632,000, and the 1999 pro forma net income would be $143,456,000.

NOTE 8 - PREFERRED STOCK

We have 5,000,000 authorized shares of preferred stock. We cannot declare or pay dividends on our common stock while we have not either declared and set apart cumulative dividends or paid dividends on any of our preferred stock.

Our preferred stock is in three series as detailed in the following table:

Series	Stated and Liquidation Price*	Shares Issued and Outstanding		Thousands of Dollars	
		2000	1999	2000	1999
$6.875	$100	360,800	360,800	$36,080	$36,080
6.00	100	159,589	159,589	15,959	15,959
4.20	100	60,000	60,000	6,025	6,025
Discount		-	-	(410)	(410)
		580,389	580,389	$57,654	$57,654

*Plus accumulated dividends.

We have the option of redeeming our preferred stock with the consent or affirmative vote of the holders of a majority of the common shares on 30 days notice at $110 per share for our $6.00 Series and $103 per share for our $4.20 Series, plus accumulated dividends. Our $6.875 Series is redeemable in whole or in part, at any time on or after November 1, 2003, for a price beginning at $103.438 per share, which decreases annually through October 2013. After that time, the redemption price is $100 per share.

As discussed in Note 3, "Upcoming Special Meeting of Shareholders," we have asked our shareholders of common stock to vote in favor of the redemption of our outstanding Preferred Stock, $4.20 Series, and $6.00 Series. In addition, our Board of Directors will seek approval to redeem our Preferred Stock, $6.875 Series. We are not requesting our shareholders to take any action on this matter at this time.

NOTE 9 - COMPANY OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUST

We established Montana Power Capital I (Trust) as a wholly owned business trust to issue common and preferred securities and hold Junior Subordinated Deferrable Interest Debentures (Subordinated Debentures) that we issue. At December 31, 2000 and 1999, the Trust has issued 2,600,000 units of 8.45 percent Cumulative Quarterly Income Preferred Securities, Series A (QUIPS). Holders of the QUIPS are entitled to receive quarterly distributions at an annual rate of 8.45 percent of the liquidation preference value of $25 per security. The sole asset of the Trust is $67,000,000 of our Subordinated Debentures, 8.45 percent Series due 2036. The Trust will use interest payments received on the Subordinated Debentures that it holds to make the quarterly cash distributions on the QUIPS. The QUIPS' $65,000,000 liquidation value is included with Other Long Term Debt on the balance sheet.

On or after November 6, 2001, we can wholly redeem the Subordinated Debentures at any time, or partially redeem the Subordinated Debentures from time to time. We also can wholly redeem the Subordinated Debentures if certain events occur before that time. Upon repayment of the Subordinated

Debentures at maturity or early redemption, the Trust Securities must be redeemed. In addition, we can terminate the Trust at any time and cause the pro rata distribution of the Subordinated Debentures to the holders of the Trust Securities.

Besides our obligations under the Subordinated Debentures, we have agreed to certain Back-up Undertakings. We have guaranteed, on a subordinated basis, payment of distributions on the Trust Securities, to the extent the Trust has funds available to pay such distributions. We also have agreed to pay all of the expenses of the Trust. Considered together with the Subordinated Debentures, the Back-up Undertakings constitute a full and unconditional guarantee of the Trust's obligations under the QUIPS. We are the owners of all the common securities of the Trust, which constitute 3 percent of the aggregate liquidation amount of all the Trust Securities.

We established Montana Power Capital I (Trust) as a wholly owned business trust to issue common and preferred securities and hold Junior Subordinated Deferrable Interest Debentures (Subordinated Debentures) that we issue. At December 31, 2000 and 1999, the Trust has issued 2,600,000 units of 8.45 percent Cumulative Quarterly Income Preferred Securities, Series A (QUIPS). Holders of the QUIPS are entitled to receive quarterly distributions at an annual rate of 8.45 percent of the liquidation preference value of $25 per security. The sole asset of the Trust is $67,000,000 of our Subordinated Debentures, 8.45 percent Series due 2036. The Trust will use interest payments received on the Subordinated Debentures that it holds to make the quarterly cash distributions on the QUIPS.

On or after November 6, 2001, we can wholly redeem the Subordinated Debentures at any time, or partially redeem the Subordinated Debentures from time to time. We also can wholly redeem the Subordinated Debentures if certain events occur before that time. Upon repayment of the Subordinated Debentures at maturity or early redemption, the Trust Securities must be redeemed. In addition, we can terminate the Trust at any time and cause the pro rata distribution of the Subordinated Debentures to the holders of the Trust Securities.

Besides our obligations under the Subordinated Debentures, we have agreed to certain Back-up Undertakings. We have guaranteed, on a subordinated basis, payment of distributions on the Trust Securities, to the extent the Trust has funds available to pay such distributions. We also have agreed to pay all of the expenses of the Trust. Considered together with the Subordinated Debentures, the Back-up Undertakings constitute a full and unconditional guarantee of the Trust's obligations under the QUIPS. We are the owner of all the common securities of the Trust, which constitute 3 percent of the aggregate liquidation amount of all the Trust Securities.

NOTE 10 - LONG-TERM DEBT

The Mortgage and Deed of Trust (Mortgage) imposes a first mortgage lien on all physical properties owned, exclusive of subsidiary company assets and certain property and assets specifically excepted. The obligations collateralized are First Mortgage Bonds, including those First Mortgage Bonds designated as Secured Medium-Term Notes (MTNs) and those securing Pollution Control Revenue Bonds.

Long-term debt consists of the following:

	December 31	
	2000	1999
	(Thousands of Dollars)	
First Mortgage Bonds:		
7 ½% series, due 2001	$ -	$ 25,000
7% series, due 2005	5,386	50,000
8 ¼% series, due 2007	365	55,000
8.95% series, due 2022	1,446	50,000
Secured Medium-Term Notes- maturing 2000-2025 7.20%-8.11%...........	28,000	88,000
Pollution Control Revenue Bonds:		
City of Forsyth, Montana 6 1/8% series, due 2023................................	90,205	90,205
5.90% series, due 2023	80,000	80,000
Unsecured Medium-Term Notes:		
Series A - maturing 2000-2022 8.68%-8.80% .	-	17,000
Series B - maturing 2001-2026 7.05%-7.96% .	100,000	100,000
8.45% QUIPS.................................	65,000	65,000
ESOP Notes Payable - 9.20%, due 2004.........	16,197	19,431
Other	-	10,178
Unamortized Discount and Premium............	(2,444)	(3,346)
Total Long-term Debt....................	$384,155	$646,468

On April 13, 2000, we retired, prior to maturity, $25,000,000 of our 7.5 percent First Mortgage Bonds (Bonds) due April 1, 2001.

On April 25, 2000, we offered to purchase any or all of the following series of our outstanding debt: 8.95 percent Bonds due February 1, 2022; 7.33 percent Secured MTNs due April 15, 2025; 8.11 percent Secured MTNs due January 25, 2023; 7.00 percent Bonds due March 1, 2005; and 8.25 percent Bonds due February 1, 2007. The total amount outstanding for these issues was $190,000,000 as of April 25, 2000. On May 24, 2000, we retired $182,803,000 of this amount, as follows:

- $44,614,000 of 7.00 percent Bonds due March 1, 2005;
- $54,635,000 of 8.25 percent Bonds due February 1, 2007;
- $48,554,000 of 8.95 percent Bonds due February 1, 2022;
- $20,000,000 of 7.33 percent Secured Series A MTNs due April 15, 2025; and
- $15,000,000 of 8.11 percent Secured Series A MTNs due January 25, 2023.

We retired two additional issues of Series A Secured MTNs during 2000. On January 13, 2000, we retired $5,000,000 of 7.25 percent notes due January 19, 2024, and on June 1, 2000, we retired at maturity $20,000,000 of 7.20 percent notes.

On January 14, 2000, we retired $7,000,000 of 8.68 percent Series A Unsecured MTNs due February 7, 2022. We retired $10,000,000 of 8.80 percent Series A Unsecured MTNs at maturity on February 22, 2000.

All of the above debt retirements, including transaction costs, were made from the proceeds received from the 1999 sale of our electric generating assets.

As discussed in Note 13, "Contingencies," we recorded long-term debt of approximately $57,000,000 regarding the Kerr mitigation in June 1997. This amount represented the net present value of future costs to be paid over the life of the license. With the sale of the generating assets, payments after the sale date are no longer our responsibility. Therefore, we reduced debt on the sale date to approximately $24,300,000. On December 30, 1999, we paid approximately $14,100,000 of this amount. We included the remaining balance of $10,200,000 at December 31, 1999, in "Other" in the table above. The final payment for $10,200,000 occurred on January 3, 2000.

Scheduled debt repayments on the long-term debt outstanding at December 31, 2000, amount to: $63,531,000 in 2001; $3,856,000 in 2002; $19,211,000 in 2003; $4,599,000 in 2004; zero in 2005; and $292,958,000 thereafter.

NOTE 11 - SHORT-TERM BORROWING

We have short-term borrowing facilities with commercial banks that provide both committed and uncommitted lines of credit and the ability to sell commercial paper. Bank borrowings either bear interest at the lender's floating base rate and may be repaid at any time, or have fixed rates of interest and maturities. Commercial paper has fixed rates of interest and maturities.

At December 31, 2000, we had lines of credit consisting of $85,000,000 committed and $40,000,000 uncommitted. In addition, Entech, Inc. (Entech, a wholly owned non-utility subsidiary of MPC) shares with us an uncommitted credit line of $30,000,000, from which either company may borrow but the total of which they cannot exceed. Facility fees or commitment fees on the committed lines of credit are not significant. We also have the ability to issue up to $85,000,000 of commercial paper based on the total of unused committed lines of credit and revolving credit agreements.

At December 31, 2000, we had outstanding notes payable to banks for $75,000,000 at an average annual interest rate of 8.05 percent. Of these outstanding notes, $25,000,000 was issued from our committed lines of credit and the other $50,000,000 from our uncommitted lines of credit and the uncommitted line shared with Entech.

NOTE 12 - RETIREMENT PLANS

We maintain trusteed, noncontributory retirement plans covering substantially all of our employees. Prior to 1998, our retirement benefits were based on salary, years of service, and social security integration levels. In 1998, we amended our retirement plan's benefit provisions. Our retirement benefits are now based on salary, age, and years of service.

Our plan assets consist primarily of domestic and foreign corporate stocks, domestic corporate bonds, and United States Government securities.

We also have an unfunded, nonqualified benefit plan for senior management executives and directors. In December 1998, we froze the benefits earned and curtailed the plan.

As a result of the sale of our electric generating assets to PPL Montana, 454 participants related to electric generation operations were curtailed from the retirement plan and approximately $22,700,000 in assets were transferred from the retirement plan trust in December 1999. Pursuant to the agreement, when the calculation was finalized in February 2000, approximately $3,200,000 of additional assets was transferred to the PPL trust. In accordance with SFAS 88, we calculated a curtailment gain of approximately $4,100,000 and a settlement gain of approximately $7,800,000 in 1999. Due to regulatory accounting treatment, the gains were recorded as regulatory liabilities or offsets to regulatory assets, resulting in no income statement impact.

We offered a Special Retirement Program (SRP) to certain eligible employees during 2000. The SFAS 88 special termination charge resulting from 130 utility participants electing the SRP amounted to approximately $6,443,000. Due to regulatory accounting treatment, the expense was recorded as regulatory liabilities or offsets to regulatory assets, resulting in no income statement impact.

We also provide certain health care and life insurance benefits for eligible retired employees. In 1994, we established a pre-funding plan for postretirement benefits for Utility employees retiring after January 1,1993. The plan assets consist primarily of domestic and foreign corporate stocks, domestic corporate bonds, and United States Government securities. The PSC allows us to include in rates all utility Other Postretirement Benefits costs on the accrual basis provided by SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions."

We also have a voluntary retirement savings plan in conjunction with our retirement plans. We contribute a matching percentage comprised of shares from a leveraged Employee Stock Ownership Plan arrangement and shares purchased on the open market. For costs associated with these plans, see Note 7, "Common Stock."

Annual Report of The Montana Power Company
to the Montana Public Service Commission
Notes to the Financial Statements

The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ending December 31, 2000, and a statement of the funded status as of December 31 of both years:

	Pension Benefits		Other Benefits	
	2000	1999	2000	1999
	(Thousands of Dollars)			
CHANGE IN BENEFIT OBLIGATION:				
Benefit obligation at January 1....	$ 173,477	$202,666	$ 16,707	$ 20,081
Service cost on benefits earned....	2,964	5,039	324	548
Interest cost on projected benefit obligation......................	14,045	14,394	1,375	1,429
Plan amendments..................	7,578	8,512	-	-
Assumption changes................	4,611	-	-	-
Actuarial (gain)loss..............	(4,038)	(22,720)	4,484	(397)
Adjustment for liability transfer..	9,332	-	-	-
Curtailments......................	-	(5,712)	-	(3,092)
Settlements.......................	-	(18,096)	-	-
Special termination benefits.......	6,443	-	-	-
Assets allocated to related companies.......................	-	-	-	-
Gross benefits paid...............	(11,624)	(10,606)	(2,596)	(1,862)
Benefit obligation at December 31..	$202,788	$173,477	$ 20,294	$ 16,707
CHANGE IN PLAN ASSETS:				
Fair value of plan assets at January 1.......................	$ 204,922	$222,484	$ 8,709	$ 7,898
Actual return on plan assets.......	(4,240)	14,515	353	142
Employer contributions............	-	-	1,851	2,531
Acquisitions/divestitures.........	(3,200)	(22,707)	-	-
Assets allocated (to)/from related companies.......................	11,450	(545)	-	-
Gross benefits paid...............	(9,806)	(8,825)	(2,596)	(1,862)
Fair value of plan assets at December 31..................	$199,126	$204,922	$ 8,317	$ 8,709
RECONCILIATION OF FUNDED STATUS:				
Funded status at end of year.......	$ (3,662)	$ 31,445	$(11,977)	$ (7,998)
Unrecognized net:				
Actuarial gain..................	(18,835)	(43,612)	(93)	(4,464)
Prior service cost..............	18,899	12,686	1,233	1,356
Transition obligation...........	(161)	(202)	9,064	9,820
Net amount recognized at December 31..................	$ (3,759)	$ 317	$ (1,773)	$ (1,286)

Annual Report of The Montana Power Company
to the Montana Public Service Commission
Notes to the Financial Statements

The following table provides the amounts recognized in the statement of financial position as of December 31:

	Pension Benefits 2000	Pension Benefits 1999	Other Benefits 2000	Other Benefits 1999
	(Thousands of Dollars)			
Prepaid benefit cost	$ 11,028	$ 7,379	-	-
Accrued benefit cost	(14,787)	(7,062)	$ (1,773)	$ (1,286)
Net amount recognized at December 31	$ (3,759)	$ 317	$ (1,773)	$ (1,286)

The following tables provide the components of net periodic benefit cost for the pension and other postretirement benefit plans, portions of which have been deferred or capitalized, for fiscal years 2000 and 1999:

	Pension Benefits 2000	Pension Benefits 1999
	(Thousands of Dollars)	
Service cost on benefits earned	$ 2,964	$ 5,038
Interest cost on projected benefit obligation	14,045	14,394
Expected return on plan assets	(17,825)	(19,598)
Amortization of:		
Transition obligation	(40)	(40)
Prior service cost	1,364	1,279
Actuarial (gain) loss	(2,472)	(1,208)
Net periodic benefit cost	(1,964)	(135)
Curtailment (gain) loss	-	(3,751)
Settlement (gain) loss	-	(7,844)
Net periodic benefit cost after curtailments and settlements	$ 4,479	$(11,730)

	Other Benefits 2000	Other Benefits 1999
	(Thousands of Dollars)	
Service cost on benefits earned	$ 324	$ 548
Interest cost on projected benefit obligation	1,375	1,429
Expected return on plan assets	(712)	(645)
Amortization of:		
Transition obligation	756	955
Prior service cost	123	135
Actuarial (gain) loss	(110)	(100)
Net periodic benefit cost	1,756	2,322
Curtailment (gain) loss	-	(374)
Net periodic benefit cost after curtailments	$ 1,756	$ 1,948

In 2000, funding for pension costs exceeded SFAS No. 87, "Employers Accounting for Pensions," pension expense by $3,078,000. In 1999, pension costs exceeded SFAS No. 87 pension expense by $1,631,000. The PSC allows recovery for the funding of pension costs through rates. Any differences between funding and expense are deferred for recognition in future periods. At December 31, 2000, the regulatory liability was $10,614,000.

The following assumptions were used in the determination of actuarial present values of the projected benefit obligations:

	Pension Benefits		Other Benefits	
	2000	1999	2000	1999
	(Thousands of Dollars)			
Weighted average assumptions as of December 31:				
Discount rate......................	7.50%	7.75%	7.50%	7.75%
Expected return on plan assets.....	9.00%	9.00%	9.00%	9.00%
Rate of compensation increase......	4.40%	4.40%	4.40%	4.40%

Assumed health care costs trend rates have a significant effect on the amounts reported for the health care plans. A change of 1 percent in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(Thousands of Dollars)	
Effect on the total of service and interest cost components of net periodic post-retirement health care benefit cost......	$ 73	$ (61)
Effect on the health care component of the accumulated postretirement benefit obligation..............................	512	(429)

The assumed 2001 health care cost trend rates used to measure the expected cost of benefits covered by the plans is 9.00 percent. The trend rate decreases through 2007 to 5.50 percent.

NOTE 13 - CONTINGENCIES

❑ KERR PROJECT

A FERC order that preceded our sale of the Kerr Project required us to implement a plan to mitigate the effect of the Kerr Project operations on fish, wildlife, and habitat. To implement this plan, we were required to make payments of approximately $135,000,000 between 1985 and 2020, the term during which we would have been the licensee. The net present value of the total payments, assuming a 9.5 percent annual discount rate, was approximately $57,000,000, an amount we recognized as license costs in plant and long-term debt on the Consolidated Balance Sheet in 1997. In the sale of the Kerr Project, the purchaser of our electric generating assets assumed the obligation to make post-closing license compliance payments.

In December 1998 and January 1999, we asked the United States Court of Appeals for the District of Columbia Circuit to review this and another of FERC's orders and the United States Department of Interior's conditions contained in them. In December 2000, FERC issued an order approving a settlement among the parties. On February 15, 2001, the Circuit Court dismissed the petitions for review. Consequently, the approximately $24,000,000 that we paid into escrow in 2000 will be released to the

Confederated Salish and Kootenai Tribes (Tribes) to be used in accordance with the terms of the settlement and, when we subsequently transfer to the Tribes 669 acres of land on the Flathead Indian Reservation, we will have fulfilled our obligations under the terms of this settlement. Because PPL Montana assumed the obligation in excess of $24,000,000, the basis in the properties sold decreased and the regulatory liability associated with the deferred gain on the sale increased accordingly.

❑ LONG-TERM POWER SUPPLY AGREEMENTS

Long-term power supply agreements, primarily an agreement with a non-core large industrial customer, have exposed us losses and potential future losses. That agreement obligates us to deliver to our customer one half of its electric energy at a fixed price and the remainder at an index-based price with a cap. When the agreement expires at the end of 2002, the customer has an option to extend the agreement through 2004. If the customer exercises this option, however, only index-based prices with no cap would apply during the extension period. Until the end of 2002, we must supply this and other industrial customers with electric energy purchased through an agreement indexed to the Mid-Columbia (Mid-C) market. As a result, we are exposed to the risk that electric energy we purchase at Mid-C prices can be higher than the fixed and capped sales rates.

In June 1998, we entered into a swap with the industrial customer whose agreement exposes us to most of our risk, so that the customer could effectively purchase all of its electric energy from us at a fixed rate. At the same time, we entered into a separate fixed-price purchase and related Mid-C index sale of equivalent volumes with other counterparties to hedge that swap and thus eliminate our exposure to fluctuating market prices. Both the purchase and sale agreements with the other counterparties remain effective through May 2001. During the third quarter 2000, however, our industrial customer whose contract exposes us to most of the commodity price risk increased its electric energy consumption, and wholesale electric prices increased substantially. The swap and related physical offset did not extend to the increase in our customer's consumption.

Specifically, the average monthly purchases of electric energy by this industrial customer increased more than 30 percent during the third quarter 2000 compared to the second quarter 2000. Average monthly wholesale electric prices in the Pacific Northwest, based on the Mid-C price index, more than doubled during the third quarter 2000 compared to the second quarter 2000. Because of these two events, the expenses of supplying our industrial customers with electric energy during the third quarter 2000 exceeded the associated revenues earned from these customers and the swap and physical offset by approximately $8,400,000. By contrast, for the entire six months ended June 30, 2000, the expenses incurred to supply these customers exceeded the associated revenues earned from these customers and the swap and physical offset by approximately $2,000,000.

To mitigate future losses, we entered into a five-month agreement in October 2000 with a counterparty - a fixed-for-variable financial swap whereby we fixed our purchase price on a portion of the electric energy needed to supply our industrial customers in exchange for a Mid-C index-based price. As long as our industrial customers do not materially change their estimated electric usage, this swap allows us to fix the total cost of supplying their electric energy during the term of the swap and, therefore, in conjunction with our existing agreements, should limit our losses from supplying these customers.

Based on the effects of the existing purchase and sales agreements, the financial swaps, and customer usage, we incurred losses of approximately $6,000,000 in the fourth quarter 2000 and, assuming customer usage stays relatively constant, we expect to experience losses of approximately $4,000,000 in the first quarter 2001. If we continue to purchase electric energy at index-based market rates, or do not have other effective swaps in place, we estimate that the losses on agreements with these industrial customers - based on customer usage estimates and on forward price projections and broker quotations as of December 29, 2000 - could aggregate approximately $25,000,000 in the second quarter 2001. Because of the volatility of the electric energy market in the western United States, particularly in the Pacific Northwest, and future possibilities of supplying these customers from alternative sources, we believe that estimating losses beyond the second quarter 2001 would not be reasonably indicative of actual results.

We continue to seek other opportunities to mitigate the commodity price risk associated with our power supply agreements, although we cannot assure that these efforts ultimately will be successful.

❑ **MISCELLANEOUS**

We and our subsidiaries are parties to various other legal claims, actions, and complaints arising in the ordinary course of business. We do not expect the conclusion of any of these matters to have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

NOTE 14 - COMMITMENTS

❑ **PURCHASE COMMITMENTS**

Electric Utility

The Public Utilities Regulatory Policies Act (PURPA) requires a public utility to purchase power from QFs at a rate equal to what it would pay to generate or purchase power. These QFs are power production or co-generation facilities that meet size, fuel use, ownership, and operating and efficiency criteria specified by PURPA. The electric utility has 15 long-term QF contracts with expiration terms ranging from 2003 through 2032 that require us to make payments for energy capacity and energy received at prices established by the PSC. Three contracts account for 96 percent of the 101 MWs of capacity provided by these facilities. Montana's Electric Act designates the above-market portion of the QF costs as Competitive Transition Costs (CTCs) and allows for their recovery. For more information about CTCs, see Note 5, "Deregulation, Regulatory Matters, and 1999 Sale of Electric Generating Assets."

The Asset Purchase Agreement with PPL Montana, dated as of October 31, 1998 and amended June 29, 1999 and October 29, 1999, included two Wholesale Transition Service Agreements (WTSAs), effective December 17, 1999. These agreements enable us to fulfill our obligation to supply power until July

2002 to those customers who have not chosen another supplier. One agreement commits us to purchase 200 MWs per hour through December 2001, and the other agreement to purchase through June 2002 any power requirements remaining after having received power through the first WTSA, QFs, and Milltown Dam. Both agreements price the power sold at a market index, with a monthly floor and an annual cap. Under both agreements, the annual cap is $22.25/MWh, which has been in effect for most of 2000 because wholesale electric energy prices in the Pacific Northwest have been higher than this amount. Assuming an 8.05 percent discount rate (our average short-term borrowing rate at December 31, 2000), current market indices, and current load forecasts, we estimate the net present value of the power purchased under the WTSAs at $81,000,000 for 2001 and $34,000,000 for 2002.

Our former affiliate, The Montana Power Trading & Marketing Company (MPT&M) - which we sold on October 31, 2000 as part of the oil and natural gas businesses - had entered into several power purchase agreements in 1998. These agreements were assigned to the electric utility in 2000. One agreement obligates us to purchase 40 MWs per hour at a fixed rate until May 2001, and the other to purchase 100 MWs per hour of firm capacity and firm energy at 100 percent load factor at a market-indexed rate until August 2001.

Natural Gas Utility

The natural gas utility entered into take-or-pay contracts with Montana natural gas producers to provide adequate supplies of natural gas for our utility customers. We currently have six of these contracts, with expirations between 2002 and 2006. If we can supply customers with less expensive natural gas, we purchase the minimum required by the take-or-pay contracts. The cost of purchases through take-or-pay contracts is part of those costs submitted to the PSC for recovery in future rates. Since 1998, the natural gas utility enters only into one-year take-or-pay contracts, because of the uncertainty about the number and timing of customers who will choose another natural gas supplier under Montana's Natural Gas Act.

Contractual Payments and Present Value

Total payments under all of these contracts for the prior three years were as follows:

	Utility		Total
	Electric	Natural Gas	
	(Thousands of Dollars)		
2000	$272,075	$ 7,101	$279,176
1999	61,274	4,069	65,343

Under the above agreements, the present value of future minimum payments, at a discount rate of 8.05 percent, is as follows:

	Utility		Total
	Electric	Natural Gas	
	(Thousands of Dollars)		
2001	$224,435	$ 5,003	$229,438
2002	42,905	4,450	47,355
2003	8,380	641	9,021
2004	8,001	546	8,547
2005	7,537	465	8,002
Remainder	97,486	395	97,881
	$388,744	$ 11,500	$400,244

❑ LEASE COMMITMENTS

We have no material minimum operating lease payments. What capitalized leases we have are not material and are included in other long-term debt.

Rental expense for the prior two years was $6,800,000 for 2000 and $22,139,000 for 1999.

NOTE 15 - NEW ACCOUNTING PRONOUNCEMENTS

❑ Staff Accounting Bulletin No. 101

SAB No. 101, "Revenue Recognition in Financial Statements" was issued by the SEC in December 1999 and is applicable to us beginning in the fourth quarter 2000.

As it relates to our companies, SAB No. 101 mainly affects Touch America. It requires that particular one-time charges received from customers be recognized as revenues over the period of time that the charges are earned rather than as revenues when assessed or paid. Our telecommunications operations realize payment of one-time fees for such items as installations and activations. Prior to SAB No. 101, we recognized these revenues when received. With the adoption of SAB No. 101 in the fourth quarter 2000, we now recognize these revenues over the period in which they are earned, which coincides with the number of years that those customers are anticipated to be customers of Touch America. The one-time charges all are received either from wholesale or commercial customers and, due to the number of transactions, the amounts cannot be segregated into the two customer classes. Under our policy, therefore, we amortize these deferred revenues over the average lives of wholesale and commercial customers. We have not deferred any costs for installations, activations, or subscriber acquisitions.

We have evaluated SAB No. 101, and the cumulative catch-up for its adoption had no material effect on our consolidated financial position, results of operations, or cash flows. The adoption of SAB No. 101 affected only our 2000 operations.

❑ SFAS Nos. 133, 137, and 138

In June 2000, the FASB issued SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities," which amends some accounting and reporting standards of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 was issued in June 1998. In July 1999, the FASB issued SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities: Deferral of the Effective Date of FASB Statement No. 133." SFAS No. 137 delayed for one year the effective date of SFAS No. 133, meaning that we are required to adopt SFAS No. 133 on January 1, 2001.

SFAS No. 133 expands the definition of a derivative and requires that all derivative instruments be recorded on an entity's balance sheet at fair value. As discussed in Note 2, "Decision to Sell Energy Businesses," we sold our oil and natural gas businesses - including MPT&M, which engaged in energy trading activities - on October 31, 2000.

We have reviewed our commodity purchase and sale agreements to evaluate exposure to potential embedded derivatives under SFAS No. 133 and SFAS No. 138. Effective January 1, 2001, we have accounted for the electric swap agreements described in Note 1, "Summary of Significant Accounting Policies," in the "Derivative Financial Instruments" section, as effective cash flow hedges pursuant to SFAS No. 133. Accordingly, these instruments have been marked to market, at January 1, 2001, with a corresponding credit entry made to Other Comprehensive Income for approximately $18,800,000 before income taxes, representing our cumulative transition adjustment in adopting SFAS No. 133.

NOTE 16 - SUBSEQUENT EVENTS

In the first quarter 2001, we recorded a pretax gain of approximately $50,800,000 for the sale of Continental Energy. On April 30, 2001, we closed the sale of our coal businesses to Westmoreland Coal Company for $138,000,000, subject to customary closing and to post-closing adjustments. In connection with structuring its acquisition, in April 2001, Westmoreland assigned its right to purchase two of our coal business subsidiaries - Western Energy Company and Northwestern Resources Co. - to Westmoreland's wholly owned subsidiary, Westmoreland Mining LLC. Based on the net book value of our coal businesses, we expect to record a gain on this sale, net of income taxes, in the second quarter 2001. Because Continental Energy, Western Energy Company, and Northwestern Resources Co. had always been nonutility subsidiaries of MPC, these gains do not effect the income of MPC's utilities for the year 2001.

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	-
4	302 Franchises and Consents	2,004		2,004	2,004	-
5	303 Miscellaneous Intangible Plant	1,322,515		1,322,515	1,328,696	-0.47%
6	**Total Intangible Plant**	1,344,514	-	1,344,514	1,350,695	-0.46%
7						
8	**Production Plant**					
9						
10	**Steam Production**					
11	310 Land and Land Rights	1,292		1,292	-	-
12	311 Structures and Improvements	60,420		60,420	-	-
13	312 Boiler Plant Equipment	426,612		426,612	-	-
14	313 Engines, Engine Driven Generator	-		-	-	-
15	314 Turbogenerator Units	309,314		309,314	-	-
16	315 Accessory Electric Equipment	-		-	-	-
17	316 Misc. Power Plant Equipment	116,028		116,028	-	-
18	**Total Steam Production Plant**	913,666	-	913,666	-	-
19						
20	**Nuclear Production**					
21	320 - 325 Not Applicable					
22	**Total Nuclear Production Plant**	-	-	-	-	-
23						
24	**Hydraulic Production**					
25	330 Land and Land Rights	58,620		58,620	58,620	-
26	331 Structures and Improvements	119,451		119,451	119,451	-
27	332 Reservoirs, Dams and Waterways	8,976,477		8,976,477	8,895,177	0.91%
28	333 Water Wheel, Turbine, Generators	124,613		124,613	124,613	-
29	334 Accessory Electric Equipment	99,660		99,660	99,660	-
30	335 Misc. Power Plant Equipment	90,351		90,351	90,351	-
31	336 Roads, Railroads and Bridges	60,077		60,077	35,337	70.01%
32	**Total Hydraulic Production Plant**	9,529,249	-	9,529,249	9,423,208	1.13%
33						
34	**Other Production**					
35	340 Land and Land Rights					
36	341 Structures and Improvements	26,050	15,967	10,083	10,082	0.01%
37	342 Reservoirs, Dams and Waterways	112,084	112,084	-	-	-
38	343 Water Wheel, Turbine, Generators	-	-	-	-	-
39	344 Accessory Electric Equipment	2,270,065	2,255,293	14,772	14,772	-
40	345 Misc. Power Plant Equipment	119,307	101,896	17,411	17,411	-
41	346 Roads, Railroads and Bridges	7,554	7,554	-	-	-
42	**Total Other Production Plant**	2,535,060	2,492,794	42,266	42,265	-
43	**Total Production Plant**	12,977,975	2,492,794	10,485,181	9,465,473	10.77%

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	15,616,467	-	15,616,467	15,016,321	4.00%
4	352 Structures and Improvements	3,996,250	-	3,996,250	3,892,391	2.67%
5	353 Station Equipment	125,260,188	-	125,260,188	116,982,029	7.08%
6	354 Towers and Fixtures	22,995,734	-	22,995,734	17,373,814	32.36%
7	355 Poles and Fixtures	117,024,024	710,150	116,313,874	114,028,483	2.00%
8	356 Overhead Conductors & Devices	105,352,081	594,293	104,757,788	96,922,660	8.08%
9	357 Underground Conduit	137,878	102,286	35,592	(3,523)	1110.40%
10	358 Undergrnd Conductors & Devices	1,410,535	554,036	856,499	625,074	37.02%
11	359 Roads and Trails	2,324,128	44,906	2,279,222	2,222,968	2.53%
12	**Total Transmission Plant**	394,117,285	2,005,671	392,111,614	367,060,217	6.82%
13						
14	**Distribution Plant**					
15	360 Land and Land Rights	3,587,487	601	3,586,886	3,418,150	4.94%
16	361 Structures and Improvements	3,980,691	141,867	3,838,824	3,530,097	8.75%
17	362 Station Equipment	90,459,792	1,921,163	88,538,629	83,301,350	6.29%
18	363 Storage Battery Equipment	-	-	-	-	-
19	364 Poles, Towers, and Fixtures	105,682,728	223,656	105,459,072	101,577,874	3.82%
20	365 Overhead Conductors & Devices	66,082,114	325,922	65,756,192	63,552,377	3.47%
21	366 Underground Conduit	21,298,249	92,647	21,205,602	17,700,231	19.80%
22	367 Undergrnd Conductors & Devices	65,031,571	2,478,781	62,552,790	59,573,770	5.00%
23	368 Line Transformers	122,271,724	714,984	121,556,740	114,831,762	5.86%
24	369 Services	59,616,318	212,052	59,404,266	57,513,184	3.29%
25	370 Meters	28,948,112	67,143	28,880,969	26,612,854	8.52%
26	371 Installations on Cust. Premises	-	-	-	-	-
27	372 Leased Property on Cust. Premises	-	-	-	-	-
28	373 Street Lighting and Signal Systems	37,111,046	19,872	37,091,174	35,721,033	3.84%
29	**Total Distribution Plant**	604,069,832	6,198,688	597,871,144	567,332,680	5.38%
30						
31	**General Plant**					
32	389 Land and Land Rights	415,080	-	415,080	326,186	27.25%
33	390 Structures and Improvements	7,257,764	84,207	7,173,557	7,014,747	2.26%
34	391 Office Furniture and Equipment	838,042	-	838,042	1,925,052	-56.47%
35	392 Transportation Equipment	24,530,717	93,890	24,436,827	23,389,506	4.48%
36	393 Stores Equipment	434,209	-	434,209	436,080	-0.43%
37	394 Tools, Shop & Garage Equipment	4,223,538	38,750	4,184,788	4,104,394	1.96%
38	395 Laboratory Equipment	4,331,782	7,388	4,324,394	4,416,397	-2.08%
39	396 Power Operated Equipment	2,242,288	-	2,242,288	2,242,579	-0.01%
40	397 Communication Equipment	19,904,442	74,172	19,830,270	18,196,947	8.98%
41	398 Miscellaneous Equipment	213,512	81,139	132,373	45,759	189.28%
42	399 Other Tangible Equipment	824,515	-	824,515	824,515	-
43	**Total General Plant**	65,215,889	379,546	64,836,343	62,922,162	3.04%
44	**Total Plant in Service**	1,077,725,495	11,076,699	1,066,648,796	1,008,131,227	5.80%
45						
46	4101 El Plant Allocated from Common	23,746,825		23,746,825	24,447,691	-2.87%
47	105 El Plant Held for Future Use	-		-	-	-
48	107 El Construction Work in Progress	1,236,057		1,236,057	3,017,434	-59.04%
49	114.2 El Plant Acquisition Adjustment	3,106,285		3,106,285	3,106,285	-
50						
51	**TOTAL ELECTRIC PLANT**	$1,105,814,662	$11,076,699	$1,094,737,963	$1,038,702,637	5.39%

Sch. 20	MONTANA DEPRECIATION SUMMARY - ELECTRIC (EXCLUDES UNIT 4)						
	Functional Plant Class	Montana Plant Cost 1\	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	Current Avg. Rate
1	**Accumulated Depreciation**						
2							
3	Steam Production	$913,666	($1,164,218)	$ -	($1,164,218)	($1,226,080)	-
4							
5	Nuclear Production						
6							
7	Hydraulic Production	9,447,948	5,317,515	-	5,317,515	4,799,019	5.45%
8							
9	Other Production	42,266	1,322,974	1,322,974	-	-	-
10							
11	Transmission	383,243,118	117,378,770	1,115,089	116,263,681	101,408,759	2.92%
12							
13	Distribution	567,179,641	218,152,849	2,371,338	215,781,511	194,550,950	3.85%
14							
15	General and Intangible	64,360,606	29,719,850	208,992	29,510,858	27,003,206	5.55%
16							
17	Common	24,447,691	4,975,285	-	4,975,285	4,794,067	4.13%
18							
19	**TOTAL DEPRECIATION**	$1,049,634,936	$375,703,025	$5,018,393	$370,684,632	$331,329,921	3.62%
20							
21	1\ "Montana Plant Cost" lists the plant balances as they existed at the end of the previous year or the beginning of the year						
22	being reported. Thus, in the 2000 report, "Montana Plant Cost" lists the 12/31/99 plant balances. In the 1999 report,						
23	however, the 12/31/99 plant balances were listed instead of the 12/31/98 plant balances.						

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	$151,070		$151,070	$29,920	404.91%
3						
4	154 Plant Materials & Operating Supplies					
5	Assigned and Allocated to:					
6	Operation & Maintenance	-		-	-	-
7	Construction	-		-	-	-
8	Production Plant	85,258		85,258	(364,271)	123.41%
9	Transmission Plant	3,188,365		3,188,365	2,373,561	34.33%
10	Distribution Plant	4,861,451		4,861,451	3,688,520	31.80%
11						
12						
13	**TOTAL MATERIALS & SUPPLIES**	$8,286,144	$ -	$8,286,144	$5,727,730	44.67%

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - ELECTRIC			
		% Capital Structure	% Cost Rate	Weighted Cost
1	**Commission Accepted - Most Recent 1/**			
2				
3	Docket Number: 2000.8.113			
4	Order Number : 6271c			
5				
6	Common Equity	43.00%	10.75%	4.62%
7	Preferred Stock	6.97%	6.40%	0.45%
	QUIPS Preferred 2/	7.86%	8.54%	0.67%
8	Long Term Debt	42.17%	6.46%	2.72%
9	Other			
10	**TOTAL**	100.00%		8.46%
11				
12	**Actual at Year End**			
13				
14	Common Equity	45.72%	10.75%	4.91%
15	Preferred Stock	8.56%	6.40%	0.55%
16	QUIPS Preferred 2/	9.65%	8.54%	0.82%
17	Long Term Debt 3/	36.07%	6.34%	2.29%
18	Other			
19	**TOTAL**	100.00%		8.57%
20				
21	1/ Docket 2000.8.113, Order 627c specifies the authorized capital structure and associated costs for			
22	the regulated electric utility effective May 8, 2001.			
23				
24	2/ The cost of the QUIPS securities is treated as tax deductible for income tax purposes.			
25	See footnote on Schedule 25.			
26				
27	3/ The cost rate can not be tied directly to Schedule 24, which is presented on a consolidated basis.			

Sch. 23	STATEMENT OF CASH FLOWS (INCLUDES UNIT 4) - 1/			
	Description	This year	Last Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2	**Cash Flows from Operating Activities:**			
3	Net Income	$199,490,689	$150,346,186	32.69%
4	Depreciation	48,266,339	65,379,227	-26.17%
5	Amortization	94,939	94,964	-0.03%
6	Deferred Income Taxes - Net	(15,883,186)	(229,860,897)	93.09%
7	Investment Tax Credit Adjustments - Net	(166,770)	(20,489,428)	99.19%
8	Change in Operating Receivables - Net	(21,580,392)	(84,975,028)	74.60%
9	Change in Materials, Supplies & Inventories - Net	(92,138)	9,976,648	-100.92%
10	Change in Operating Payables & Accrued Liabilities - Net	(52,468,014)	46,124,030	-213.75%
11	Allowance for Funds Used During Construction (AFUDC)	(446,286)	(1,306,462)	65.84%
12	Change in Other Assets & Liabilities - Net	-	-	-
13	Other Operating Activities:			
14	Undistributed Earnings from Subsidiary Companies	(193,438,772)	(83,060,370)	-132.89%
15	Amortization of Loss on Long-Term Sale of Power	-	-	-
16	Other (net)	4,975,607	81,075,012	-93.86%
17	Change in Regulatory Assets	(15,464,321)	36,714,914	-142.12%
18	Change in Regulatory Liabilities	36,517,739	14,449,446	152.73%
19	**Net Cash Provided by/(Used in) Operating Activities**	(10,194,566)	(15,531,758)	34.36%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(49,747,654)	(61,706,077)	19.38%
22	(net of AFUDC & Capital Lease Related Acquisitions)			
23	Sale of Generation Assets	-	758,191,797	-100.00%
24	Contributions In and Advances to Affiliates	(99,001,000)	-	-
25	Other Investing Activities:			
26	Miscellaneous Special Funds	473,237,760	(473,460,039)	199.95%
27	**Net Cash Provided by/(Used in) Investing Activities**	324,489,106	223,025,681	45.49%
28	**Cash Flows from Financing Activities:**			
29	Proceeds from Issuance of:			
30	Long-Term Debt	35,556,648	23,195,420	53.29%
31	Common Stock	2,445,313	606,635	303.09%
32	Other: Manditorily Redeem. Pref. Securities of Sub. Trust			
33	Dividends from Subsidiaries	-	138,900,000	-100.00%
34	Net Increase in Short-Term Debt	75,000,000	-	-
35	Other: Return of Subsidiary Capital			
36	Payment for Retirement of:			
37	Long-Term Debt	(297,868,964)	(143,184,896)	-108.03%
38	Preferred Stock	-	-	-
39	Net Decrease in Short-Term Debt			
40	Dividends on Preferred Stock	(3,690,034)	(3,690,034)	-
41	Dividends on Common Stock	(62,426,418)	(88,155,092)	29.19%
42	Other Financing Activities (explained on attached page)	(60,784,409)	(144,871,974)	58.04%
43	**Net Cash Provided by (Used in) Financing Activities**	(311,767,864)	(217,199,941)	-43.54%
44				
45	**Net Increase/(Decrease) in Cash and Cash Equivalents**	2,526,676	(9,706,018)	126.03%
46	**Cash and Cash Equivalents at Beginning of Year**	(7,065,455)	2,640,563	-367.57%
47	**Cash and Cash Equivalents at End of Year**	($4,538,779)	($7,065,455)	35.76%
48				
49	1/ The cash balances on the 2000 and 1999 balance sheets includes CMP, whereas the cash flows			
50	statement does not.			
51				
52	2/ The amount listed on line 42 is the amount paid to reacquire Company Stock.			

Sch. 24

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	$364,959	8.260%	$32,626	8.94%
8.95% Series, Due 2022	12/05/91	02/01/22	50,000,000	49,536,500	1,436,762	8.957%	131,489	9.15%
7.00% Series, Due 2005	03/01/93	03/01/05	50,000,000	49,375,000	5,365,414	7.075%	394,655	7.36%
Total First Mortgage Bonds			155,000,000	153,461,600	7,167,135		558,770	7.80%
Pollution Control Bonds								
6-1/8% Series, Due 2023	06/30/93	05/01/23	90,205,000	88,199,743	88,703,858	5.841%	5,619,668	6.34%
5.90% Series, Due 2023	12/30/93	12/01/23	80,000,000	79,040,800	79,261,979	6.428%	4,831,028	6.10%
Total Pollution Control Bonds			170,205,000	167,240,543	167,965,837		10,450,696	6.22%
Other Long Term Debt								
Quarterly Income Preferred Securities,								
8.45%, Series A (QUIPS) , 2/	11/96	11/01	65,000,000	62,567,385	65,000,000		5,553,304	8.54%
Medium Term Notes-Secured Series	Various	Various	128,000,000	126,807,269	28,000,000		2,074,554	7.41%
Medium Term Notes-Unsecured Series B	Various	Various	115,000,000	113,851,197	39,825,514		3,069,288	7.71%
Cost Associated with Prior Debt Retirements	N/A	N/A	0	-	-		163,999	N/A
Total Other Long Term Debt			308,000,000	303,225,851	132,825,514		10,861,145	8.18%
TOTAL LONG TERM DEBT			$633,205,000	$623,927,994	$307,958,486		$21,870,611	7.10%

1/ Total Long-Term Debt does not include ESOP debt of $12,666,000, as ESOP debt is not used for rate making purposes.
Total Long-Term Debt does not include amounts due within 1 year of $63,531,000.

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. The Company will have the right to redeem securities (i) on or after November 6, 2001 or (ii) upon occurance and continuation of a Tax Event or an Investment Company Event, as defined in the Prospectus dated November 1, 1996.

Sch. 25

PREFERRED STOCK

	Series	Issue Date	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embedded Cost %
1										
2	$6.00 Series Cumulative	1929-1932	159,589	$100	$110.000	$15,958,900	6.00%	$15,958,900	$957,534	6.00%
3										
4	$4.20 Series Cumulative	May 1954	60,000	$100	$103.000	6,024,600	4.18%	6,024,600	252,000	4.18%
5										
6	$6.875 Series Cumulative 1/	Nov 1993	360,800	$100	$103.438	35,670,412	6.88%	35,670,412	2,480,500	6.95%
7										
8										
9										
10	**TOTAL PREFERRED STOCK**		580,389			$57,653,912	6.40%	$57,653,912	$3,690,034	6.40%
11										
12	1/ Not redeemable prior to November 1, 2003, at which point call price will decrease by .344 per year to equal 100.00 at November 1, 2013.									

Sch. 26

COMMON STOCK

	Avg. Number of Shares Outstanding 1/	Book Value Per Share 2/	Earnings Per Share	Dividends Per Share (Declared)	Retention Ratio	Market Price	
						High	Low
January	105,541,014	$9.63				$46.00	$34.63
February	105,555,466	9.72				45.38	38.38
March	105,559,851	9.62	$0.29	$0.20		65.75	38.81
April	105,567,101	9.67				64.63	39.31
May	105,610,737	9.72				45.50	36.00
June	105,615,687	9.81	0.33	0.20		43.81	35.31
July	105,621,241	9.94				38.69	28.50
August	105,631,096	10.01				36.31	29.06
September	105,631,096	9.76	0.29	0.20		39.94	31.44
October	105,665,479	9.75				37.38	26.63
November	105,673,329	9.78				28.38	22.13
December	103,742,934	10.66	0.95			23.75	18.50
TOTAL COMMON	105,451,253	$10.66	$1.86	$0.60	67.74%	$65.75	$18.50

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for 2000.

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/ The "Price/Earnings Ratio" column has been eliminated, because a choice of bases is arbitrary.

Sch. 27		MONTANA EARNED RATE OF RETURN - ELECTRIC			
		Description	This Year	Last Year	% Change
1		**Rate Base**			
2	101	Plant in Service	$1,039,063,190	$1,748,181,224	-40.56%
3	108	Accumulated Depreciation	(351,411,120)	(607,582,266)	42.16%
4					
5		**Net Plant in Service**	687,652,070	1,140,598,958	-39.71%
6		Additions:			
7	154, 156	Materials & Supplies	7,437,251	12,028,433	-38.17%
8		Other Additions 1/	120,593,479	182,971,835	-34.09%
9					
10		**Total Additions**	128,030,730	195,000,268	-34.34%
11		Deductions:			
12	190	Accumulated Deferred Income Taxes 1/	142,677,086	218,662,186	-34.75%
13	252	Customer Advances for Construction	14,704,355	15,072,721	-2.44%
14	255	Accumulated Def. Investment Tax Credits	-	-	
15		Other Deductions	13,338,485	60,153,616	-77.83%
16					
17		**Total Deductions**	170,719,926	293,888,523	-41.91%
18		**Total Rate Base**	644,962,874	1,041,710,703	-38.09%
19		**Net Earnings**	24,778,741	79,944,108	-69.00%
20		**Rate of Return on Average Rate Base**	3.842%	7.674%	-49.94%
21		**Rate of Return on Average Equity 2/**	-2.695%	7.883%	-134.19%
22					
23		**Major Normalizing and**			
24		**Commission Ratemaking Adjustments**			
25					
26		Rate Schedule Revenues	1,624,115	4,619,636	-64.84%
26		Revenue Choice Customers	-	32,537,920	-100.00%
27		Off-System Sales Market	-	(33,245,970)	100.00%
28		Sales-Purchased Power	-	(1,141,133)	100.00%
29		Hydro Generation	-	(4,094,620)	100.00%
30		Thermal Generation	-	(2,583,750)	100.00%
31		Interest Excess Proceeds Generation Sale	3,389,057	346,640	877.69%
32					
33		Non-Allowables:			
34		Advertising	662,320	769,816	-13.96%
35		Benefit Restoration Plan	332,469	350,970	-5.27%
36		Dues, Contributions, Other	46,611	109,552	-57.45%
37		Corporate Overhead	278,994	318,156	-12.31%
38		Other Settlement Items	-	-	
39					
40		Associated Income Taxes	(2,494,633)	792,785	-414.67%
41		**Total Adjustments**	3,838,933	(1,219,998)	414.67%
42		**Revised Net Earnings**	$28,617,674	$78,724,110	-63.65%
43		**Adjusted Rate of Return on Average Rate Base**	4.437%	7.557%	-41.29%
44		**Adjusted Rate of Return on Average Equity 2/**	-1.393%	7.618%	-118.29%
45					
46		1/ Includes adjustments related to FAS 109.			
47					
48		2/ ROE calculation utilizes the common equity component on Sch. 22 of this Report, applied to			
49		rate base for the denominator of the equations. The 1999 common equity component applied			
50		to rate base was 44.25%.			

Sch. 27 cont.	MONTANA EARNED RATE OF RETURN - ELECTRIC			
	Description	This Year	Last Year	% Change
1				
2	**Detail - Other Additions**			
3	FAS 109 Regulatory Asset	$49,316,832	$103,089,382	-52.16%
4	Conservation Expenditures	27,989,827	30,924,544	-9.49%
5	Cost of Refinancing Debt	3,398,428	7,071,181	-51.94%
6	Colstrip Unit 3 Carrying Charge	38,349,152	39,409,802	-2.69%
7	Corette PS&I	311,674	334,471	-6.82%
8	Fuel	145,336	800,770	-81.85%
8	Division Centralization	72,348	93,953	-23.00%
9	Qualifying Facilities Buyout	11,590	11,590	0.00%
10	1995 & 1996 Severance Costs	622,866	813,235	-23.41%
11	1994 Severance Costs	375,426	422,907	-11.23%
12	**Total Other Additions**	120,593,479	182,971,835	-34.09%
13				
14	**Detail - Other Deductions**			
15	Personal Injury and Property Damage	2,102,304	1,993,422	5.46%
16	Unamortized Gain on Reacquired Debt	26,987	36,239	-25.53%
17	Gross Cash Requirements	6,021,372	11,160,965	-46.05%
18	Mystic Lake Adjustment	-	419,336	-100.00%
19	Storm Damage Reserve	879,912	315,527	178.87%
20	WAPA/BPA Billing Adjustment	-	2,198,666	-100.00%
21	Materials & Supplies Non-Consumable Parts	9,668	321,086	-96.99%
22	USBC Expenses	4,298,242	560,468	666.90%
23	Net Kerr Mitigation	-	43,147,907	-100.00%
24				
25	**Total Other Deductions**	$13,338,485	$60,153,616	-77.83%

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)	$ 1,090,395,621
5	105	Plant Held for Future Use	-
6	107	Construction Work in Progress	1,236,057
7	114	Plant Acquisition Adjustments	3,106,285
8	151-163	Materials & Supplies	8,286,144
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	370,684,632
11	252	Contributions in Aid of Construction	16,967,762
12	**NET BOOK COSTS**		715,371,713
13			
14		**Revenues & Expenses**	
15			
16	400	Operating Revenues	470,337,501
17			
18	**Total Operating Revenues**		470,337,501
19			
20	401-402	Other Operating Expenses	363,915,323
21	403-407	Depreciation & Amortization Expenses	36,827,042
22	408.1	Taxes Other than Income Taxes	38,443,641
23	409-411	Federal & State Income Taxes	6,372,754
24			
25	**Total Operating Expenses**		445,558,760
26	**Net Operating Income**		24,778,741
27			
28	415-421.1	Other Income	1,301,581
29	421.2-426.5	Other Deductions	80,893
30	**NET INCOME BEFORE INTEREST EXPENSE**		25,999,430
31			
32		**Average Customers (Intrastate Only)**	
33		Residential	235,785
34		Commercial & Industrial	50,301
35		Other	4,783
36			
37	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		290,868
38			
39		**Other Statistics (Intrastate Only)**	
40		Average Annual Residential Use (Kwh)	8,420
41		Average Annual Residential Cost per (Kwh)	$0.065
42		Average Residential Monthly Bill	$45.34
43			
44		Plant in Service (Gross) per Customer	$3,749

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,234	451	113	8	581
2	Alberton	374	336	76	22	431
3	Alder	116	180	56	17	248
4	Amsterdam	727			1	1
5	Anaconda	9,417	4,160	689	45	4,923
6	Armington		1			1
7	Arrow Creek		5	3		8
8	Augusta	284	232	87	8	326
9	Austin		1			1
10	Avon	124	91	52	2	144
11	Barber		50	9	2	59
12	Basin	255	157	63	2	224
13	Bearcreek-Washoe	83	55	13	4	88
14	Belfry	219	197	61	22	268
15	Belgrade	5,728	4,386	815	50	5,400
16	Belt	633	608	199	14	818
17	Benchland		7	7		14
18	Big Sandy	703	363	139	14	518
19	Big Sky	1,221	1,612	292	5	1,997
20	Big Timber	1,650	1,101	325	24	1,455
21	Bigfork	1,421				-
22	Billings	89,847	39,010	6,270	532	46,216
23	Black Eagle		431	100	57	554
24	Bonner	1,693	82	18	4	103
25	Boulder	1,300	718	202	31	949
26	Box Elder	794	123	72	8	206
27	Bozeman	27,509	17,704	3,237	164	21,468
28	Brady		96	38	8	145
29	Bridger	745	393	128	28	544
30	Broadview	150	204	141	9	353
31	Buffalo			1		1
32	Butte	33,892	14,155	2,120	342	16,753
33	Cameron		184	76	6	254
34	Canyon			1		16
35	Canyon Creek		151	27	8	181
36	Carter	62	117	63	1	182
37	Cascade	819	953	233	15	1,202
38	Centerville		15	13	10	32
39	Checkerboard		56	13		70
40	Chester	871	495	264	24	783
41	Chinook	1,386	833	289	26	1,148
42	Choteau	1,781	951	340	39	1,331
43	Churchill		1			1
44	Clancy	1,406	1,377	203	2	1,615
45	Clinton	549	93	31	2	124
46	Coffee Creek		54	21		75
47	Colstrip	2,346	942	179	36	1,176
48	Columbus	1,748	919	281	22	1,224
49	Conrad	2,753	1,277	460	38	1,787
50	Corbin-Jefferson		2	1	1	1
51	Corvallis	443	604	135	54	758

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Craig		88	16	4	105
2	Custer	2,070		3		3
3	Darby	225	672	194	18	889
4	Deer Lodge	1,017	2,016	447	67	2,539
5	Denton	329	188	79	6	274
6	Dillon	6,215	1,828	479	70	2,373
7	Divide		54	9	3	64
8	Dodson	709	121	53	16	188
9	Drummond	138	349	195	26	560
10	Dutton	389	253	119	26	389
11	East Helena	1,642	2,366	300	19	2,696
12	Edgar		241	70	11	319
13	Elliston	225	194	63	31	260
14	Ennis	840	1,347	395	27	1,783
15	Fairfield	659	392	149	31	565
16	Fishing Bridge					1
17	Florence	901	312	100	17	423
18	Floweree		107	58		165
19	Fort Belknap	1,262	16	13	1	30
20	Fort Benton	1,594	798	316	17	1,117
21	Fort Harrison		1	79	5	84
22	Fromberg	486	293	65	22	372
23	Gallatin Gateway		896	214	12	1,140
24	Gardiner	851	708	248	11	970
25	Garrison	112	103	54	5	160
26	Geraldine	284	282	141	7	374
27	Geyser		64	30	5	100
28	Gildford	185	92	68	9	171
29	Glasgow	3,253	1,728	568	89	2,398
30	Glen		2		4	2
31	Gold Creek		54	27	4	81
32	Gransdale		23	4	22	29
33	Grant Village					15
34	Great Falls	56,690	25,728	4,213	384	31,151
35	Greycliff	56	49	27	13	77
36	Hall		179	51	45	232
37	Hamilton	3,705	4,476	1,073	60	5,655
38	Hardin	3,384	1,415	407	70	1,888
39	Harlem	848	874	264	33	1,176
40	Harlowtown	1,062	659	248	30	929
41	Harrison	162	157	50	19	217
42	Haugan-Deborgia	69	196	63	1	261
43	Havre	10,594	4,911	992	249	6,244
44	Helena	45,819	19,189	3,755	341	23,497
45	Hingham	157	112	68	4	186
46	Hinsdale		140	44	9	191
47	Hobson	244	153	51	12	213
48	Huson		98	25	2	125
49	Inverness	103	48	27	2	78
50	Jardine			3	1	4
51	Jeffers		2	2		4
52	Jefferson City	295	202	33	4	243

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Joliet	214	357	82	20	458
2	Joplin	3,388	103	50	7	160
3	Judith Gap	137	93	36	4	134
4	Kremlin	57,053	73	41	2	115
5	Lake					27
6	Laruin-Alder					-
7	Laurel	627	2,889	384	16	3,318
8	Lavina	60	179	81	12	269
9	Lennep-Ringling		18	11		99
10	Lewistown	325	3,208	800	79	4,105
11	Lincoln	230	971	201	3	1,186
12	Livingston	95	4,158	914	61	5,172
13	Logan		3	9	2	12
14	Lohman		20	17	6	40
15	Lolo	71	1,153	150	19	1,343
16	Loma	1,814	75	45	5	121
17	Lothair		15	9		23
18	Madison Junction					1
19	Malta	2,120	1,334	422	71	1,822
20	Mammoth		163	68	2	234
21	Manhattan	1,396	1,487	287	76	1,824
22	Martinsdale		110	66	7	181
23	Marysville		54	25		78
24	Maxville		2			2
25	McAllister		116	26	4	144
26	Melrose		1		2	1
27	Melstone	136	155	303	14	469
28	Melville		80	43	1	125
29	Milltown		77	21		103
30	Missoula	57,053	28,309	4,949	428	34,092
31	Moccasin		47	28	63	79
32	Molt		17	15		32
33	Monarch		318	46		364
34	Moore	186	101	37	8	145
35	Musselshell	60	63	27	1	92
36	Nashua	325	205	60	10	271
37	Neihart	91	178	27	1	208
38	Norris		55	31	4	91
39	Nye		24	2		26
40	Old Faithful			1		28
41	Paradise	184	149	48	8	206
42	Park City	870	380	54	6	435
43	Philipsburg	914	1,518	235	17	1,785
44	Plains	1,126	1,278	356	32	1,676
45	Pony		116	22	20	142
46	Power	171	81	41	6	128
47	Pray		19	1	1	20
48	Radersburg	70	59	4		64
49	Ramsay		44	21		67
50	Raynesford		58	31	2	13
51	Red Lodge	2,177	1,614	341	32	2,002
52	Reedpoint	185	137	49	8	190

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Rocker		12	5	13	18
2	Rocvale		1			2
3	Roscoe		73	9		82
4	Roundup	1,867	1,098	407	22	1,520
5	Rudyard	261	160	67	7	237
6	Ryegate	957	141	61	11	208
7	Saco	194	159	81	12	245
8	Saint Marie	498	182	56	21	256
9	Salesia		27	5	2	33
10	Saltese		34	20	2	56
11	Sand Coulee		130	41	1	171
12	Sapphire Village		59	3		62
13	Shawmut		46	24	1	71
14	Sheridan	5,032	770	188	23	971
15	Springdale		35	15	4	51
16	Square Butte		41	22		65
17	St. Regis	859	385	132	12	536
18	Stanford	237	343	181	18	546
19	Stevensville	185	1,596	454	44	2,119
20	Stockett		167	44		212
21	Sumatra			3		3
22	Superior	748	753	253	37	1,027
23	Tampico			1		1
24	Thompson Falls	381	916	286	25	1,247
25	Three Forks	186	1,158	389	46	1,604
26	Tiber			4		4
27	Toston	105	49	51	29	103
28	Tower Junction					5
29	Townsend	1,867	1,034	246	32	1,300
30	Tracy		100	14	1	115
31	Trident		2			1
32	Twin Bridges	400	305	137	31	451
33	Twodot		50	39	18	92
34	Ulm	750	352	106	4	468
35	Utica		2	4		7
36	Valier	498	362	170	26	550
37	Vaughn	701	220	39	7	265
38	Victor	859	704	225	17	943
39	Virginia City	130	138	77	4	225
40	Wagner		44	17	14	62
41	Warm Springs			2		2
42	White Sulphur Springs	984	798	325	35	1,041
43	Whitehall	1,044	913	229	48	1,192
44	Williamsburg		1	1		2
45	Willow Creek	209	131	47	23	182
46	Windham		52	27	17	80
47	Winston	73	83	25	4	110
48	Wolf Creek		389	122	4	518
49	Yellowstone Park		1	6		16
50	Zurich		103	61	13	169
51	**Total**	490,960	235,884	49,137	5,259	292,735
52	1/ Customer populations represent an average of the 12 month period from 5/1/00 to 4/30/01.					Page 29C

Sch. 30	MONTANA EMPLOYEE COUNTS			
	Department	Year Beginning 1/, 2/	Year End 1/, 2/	Average
1				
2	**Utility Operations**			
3	Executive			
4	Financial, Risk Mgmt. & Information Services			
5	Administrative & Regulatory Affairs			
6	Utility Services & Division Administration	703	706	705
7	Corporate Administration	170	140	155
8	Business Development & Regulatory Affairs	18	18	18
9	Transmission	199	214	206
10	Generation	1	1	1
11	**Total Utility**	1,091	1,079	1,085
12				
13	**Other Corporate**			
14	Office of the Corporation			
15	**Total Other Corporate**	0		0
16	**TOTAL EMPLOYEES**	1,091	1,079	1,085
17				
18	1/ Part time employees have been converted to full time equivalents.			
19				
20	2/ The total number of employees is for The Montana Power Company only. In the past, a portion of			
21	The Montana Power Services Company employees were included in the total. During 2001,			
22	approximately 180 employees of The Montana Power Services Company will become employees of			
23	The Montana Power Company.			

Sch. 31	MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3			
4	Hauser 69 kv Rebuild 10 miles ET	$1,100,000	$1,100,000
5	Rainbow Helena Tower Line Reconductoring ET	2,071,600	2,071,600
6	Rainbow 100 kV line to Butte Tap to Boulder Auto Sub	1,641,000	1,641,000
7			
8			
9	All Other Projects < $1 Million Each	35,843,400	35,843,400
10			
11	**Total Electric Utility Construction Budget**	40,656,000	40,656,000
12			
13	**Natural Gas Operations**		
14			
15	Station W. Compressor	1,000,000	1,000,000
16	Telstad Compressor Station Upgrade	1,000,000	1,000,000
17			
18	All Other Projects < $1 Million Each	11,414,300	11,414,300
19			
20	**Total Natural Gas Utility Construction Budget**	13,414,300	13,414,300
21			
22	**Common**		
23			
24	All Other Projects < $1 Million Each	2,574,000	2,574,000
25	(Includes Milltown, SAS, DES, OCL, AP, Reg Affairs, Carry over)		
26			
27			
28	**Total Common Utility Construction Budget**	2,574,000	2,574,000
29			
30	**Colstrip Unit 4**	1,800,000	1,800,000
31			
32			
33			
34			
35			
36	**Total Colstrip Unit 4 Construction Budget**	1,800,000	1,800,000
37	**TOTAL CONSTRUCTION BUDGET**	$58,444,300	$58,444,300

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	3	1900	1,311	806,492	197,581
2	February	18	1900	1,256	773,889	201,794
3	March	8	900	1,202	548,392	216,795
4	April	14	900	1,168	682,282	190,372
5	May	22	1700	1,161	681,692	151,503
6	June	30	1700	1,307	683,160	134,798
7	July	31	1700	1,422	1,320,432	162,013
8	August	1	1700	1,417	796,191	187,380
9	September	15	1700	1,175	668,785	176,830
10	October	30	800	1,197	686,061	175,992
11	November	9	1800	1,310	767,788	191,952
12	December	11	1900	1,439	821,772	185,423
13	**TOTALS**				9,236,936	2,172,433
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	1,471,651		
3	Nuclear	-	**Sales to Ultimate Consumers**	7,810,312
4	Hydro - Conventional	14,416	(Include Interdepartmental)	
5	Hydro - Pumped Storage	-		
6	Other	481	Sales for Resale	
7	(Less) Energy for Pumping	-	Requirement Sales	278,669
8	**Net Generation**	1,486,548	Non-Requirement Sales	2,172,433
9	**Purchases**	7,251,743	**Sales for Resale**	2,451,102
10	Power Exchanges		Energy Furnished w/o Charge	
11	Received	1,027,343		
12	Delivered	1,038,695		-
13	**Net Power Exchanges**	(11,352)	**Energy Furnished**	-
14	Transmission Wheeling for Others		Energy Used Within Utility	
15	Received	4,463,614	Electric Department	
16	Delivered	4,536,517	(Less) Station Use	-
17	**Net Transmission Wheeling**	(72,903)	**Net Energy Used Within Util.**	-
18	**Transmission by Others Losses**	-	**Energy Losses**	(1,607,378)
19	**TOTAL SOURCES**	8,654,036	**TOTAL DISPOSITIONS**	8,654,036

Sch. 34	SOURCES OF ELECTRIC SUPPLY /1				
	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Hydro	Milltown	Missoula, MT	2.4	14,416.6
2	Subtotal			2.4	14,416.6
3	Internal Combustion	Lake	Yellowstone Nat'l Park	0.0	110.6
4	Internal Combustion	Old Faithful	Yellowstone Nat'l Park	0.0	149.1
5	Internal Combustion	Tower Falls	Yellowstone Nat'l Park	0.0	9.6
6	Internal Combustion	Grant Village	Yellowstone Nat'l Park	0.0	211.6
7	Subtotal			0.0	481.0
8	Purchases	Small Power Producers	Colstrip Energy, Ltd.	0.0	295,829.0
9	Purchases	Small Power Producers	Billings Generation, Inc.	0.0	436,654.0
10	Purchases	Small Power Producers	State of Montana - DNRC	0.0	48,359.0
11	Purchases	Small Power Producers	Others	0.0	14,255.0
12					
13	Purchases	Nonassociated Utilities	Washington Water Power	0.0	878,400.0
14	Purchases	Nonassociated Utilities	Duke Energy	0.0	1,200.0
15	Purchases	Nonassociated Utilities	PPL Montana	0.0	5,101,311.0
16					
17	Purchases	Marketing Agencies	Avista Energy	0.0	472,608.0
18	Purchases	Marketing Agencies	Montana Power Trading & Marketing	0.0	3,127.0
19	Subtotal			0.0	7,251,743.0
20	Total			2.4	7,266,640.6
21					
22	\1 An outage report does not accompany schedule 34 because of the sale of almost all of our generation assets				
23	in December 1999.				

Sch. 35 MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS - ELECTRIC 1/ , 2/ & 3/

Program Description	Current Year Expenditures	Last Year Expenditures 4/	% Change	Achieved Savings 5/ MW	Achieved Savings 5/ MWH
Residential					
E+ Free Weatherization Program 6/	$492,549	$162,613	203%	0.540	924
E+ Audit Program- Residential 7/	907,138	851,219	7%	0.572	3,120
Commercial/Industrial					
Business Partners Retrofit	125,045	26,694	368%	0.271	1,358
Renewable Resources / R & D	1,314,548	71,838	1730%	0.117	379
E+ Lighting Program	204,725	77,410	164%	0.823	3,063
Northwest Energy Efficiency Alliance 8/	698,750	518,123	35%	0.000	2,568
TOTAL	$3,742,755	$1,707,897	119%	2.32	11,412

1/ USB funds expended in 2000 include dollars carried over from 1999, as noted in the 1999 and 2000 reports to The Department of Revenue.

2/ 2000 USB funds carried over to 2001 are not included in this report. Associated energy savings estimates are not included in this report.

3/ MPC's 1999 & 2000 promotion and administrative costs are included.

4/ These are corrected figures for 1999. The Residential E+ Free Weatherization Program was originally reported at $425,713 and the Commercial/Industrial Renewable Resources/R&D at $0.

5/ Energy savings for 2000 includes savings acquired with the expenditure of funds carried over from 1999.

6/ Includes all low-income conservation projects completed in 2000.

7/ E+ Audit Program - Commercial Pilot expenditures and savings are included in the E+ Audit Program-Residential values.

8/ Northwest Energy Efficiency Alliance programs do not report capacity savings and include infrastructure investments that may not provide direct conservation savings for reporting purposes.

OVERALL NOTE: 1999 was a transitional year, with reduced participation in commercial programs. Unspent 1999 USB funds were committed to projects that were completed in 2000. Savings associated with 1999 USB funds that carried over to 2000 are included in the conservation values for 2000.

SOURCE: 1999 and 2000 Montana Power USB Report filed with DOR

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	$128,288,475	$129,891,846	1,985,295	1,826,574	235,785	232,328
4	Commercial & Industrial	206,810,913	217,470,674	5,492,525	5,322,257	50,301	48,876
5	Public Street, Highway Lighting						
6	& Other Sales to Public Authorities /1	6,907,178	13,053,799	156,112	102,047	4,722	3,250
7	Sales to Cooperatives	9,042,724	18,087,200	278,669	513,913	55	54
8	Sales to Other Utilities	65,831,927	90,829,362	2,138,068	3,816,163	6	59
9	Interdepartmental	771,982	613,054	15,139	12,022	na	236
10	**TOTAL SALES**	$417,653,198	$463,927,628	10,065,808	11,592,976	290,868	284,803
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. The "Previous Year" was reclassified for purposes of comparability.						