YEAR 2000

ANNUAL REPORT

OF

The Montana Power Company

NATURAL GAS 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

NATURAL GAS ANNUAL REPORT

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Sch. 1	IDENTIFICATION	
1		
2	Legal Name of Respondent:	The Montana Power Company
3		
4	Name Under Which Respondent Does Business:	The Montana Power Company
5		
6	Date Utility Service First Offered in Montana:	Electricity - Dec 12, 1912
7		Natural Gas - Jan 01, 1933
8		Propane - Oct 13, 1995
9		
10	Person Responsible for Report:	Ernest J. Kindt
11		
12	Telephone Number for Report Inquiries:	(406) 497-2233
13		
14	Address for Correspondence Concerning Report:	40 East Broadway
15		Butte, Montana 59701
16		
17		
18		
19	If direct control over respondent is held by another entity, provide below the name,	
20	address, means by which control is held and percent ownership of controlling	
21	entity.	
22		
23		
24	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. 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. 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. 5	CORPORATE ALLOCATIONS					
	Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
1	Shared Administrative					
2	Services - 1/					
3						
4	Executive Management &	Includes the following departments: CEO &	All overhead costs not charged directly	$7,393,359	46.66%	$8,452,901
5	Office of the Corporation	Chairman; Vice Chairman & CFO Vice Pres.	are allocated to the Utility & Nonutilities			
6	Secretary	& Secretary; Vice Pres. & CLC; Corporate	based on number of employees or on %'s			
7		Communications; Governmental and	developed using formulas based on net			
8		Legislative Affairs; Environmental Compliance	plant, revenues and gross payroll.			
9		Flight Services; Investor Services; Community				
10		Relations; MPC Foundation; Vice-Pres. -				
11		Marketing; Market Research and Planning				
12		Strategic Planning.				
13						
14	Human Resources	Includes the following departments: Human	All overhead costs not charged directly	(180,775)	61.20%	(114,597)
15		Resources; Benefits; Compensation & Labor	are allocated to the Utility & Nonutilities			
16		Relations; Employment; Organizational	based on number of employees or on %'s			
17		Development; Technology Training;	developed using formulas based on net			
18		HR Liaison to Energy Supply; HR Liaison	plant, revenues and gross payroll.			
19		to Energy Services				
20						
21	Financial Accounting	Includes the following departments: Audit	All overhead costs not charged directly	3,566,847	45.10%	4,341,632
22		Services; Commodity Risk; Controller	are allocated to the Utility & Nonutilities			
23		Administration; Corporate Accounting; Property	based on number of employees or on %'s			
24		Records; Corporate Tax; Disbursements;	developed using formulas based on net			
25		Financial Reporting; CS Liaison to Energy	plant, revenues and gross payroll.			
26		Supply; CS Liaison to Energy Services;				
27		G&T Admin. Services; Gas Oper. Admin.				
28		Services				
29						
30	Treasury Services &	Includes the following departments:	All overhead costs not charged directly	2,224,670	46.93%	2,515,237
31	Facilities	Treasury Services; Facilities; Mailing	are allocated to the Utility & Nonutilities			
32		Services; Financial Services; Financial	based on number of employees or on %'s			
33		Systems; Investor Relations; Risk Mgmt.;	developed using formulas based on net			
34		Credit and Cash	plant, revenues and gross payroll.			
35						
36						

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 - NATURAL GAS (INCLUDES CMP) - 1/					
	Account Number & Title	This Year Cons. Utility	Glacier Gas	This Year Montana	Last Year Montana	% Change
1						
2	400 Operating Revenues	$120,230,631		$ 120,230,631	$ 104,273,704	15.30%
3						
4	**Total Operating Revenues**	120,230,631	-	120,230,631	104,273,704	15.30%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expense	102,196,981	18,928	102,178,053	62,735,402	62.87%
9	402 Maintenance Expense	4,594,620	-	4,594,620	5,719,028	-19.66%
10	403 Depreciation Expense	8,439,001	125	8,438,876	8,255,590	2.22%
11	404-405 Amort. & Depletion of Gas Plant	327,088	-	327,088	958,809	-65.89%
12	408.1 Taxes Other Than Income Taxes	14,178,846	12,861	14,165,985	14,255,860	-0.63%
13	409.1 Income Taxes-Federal	1,287,989	(15,336)	1,303,325	(201,855)	745.67%
14	-Other	261,983	(248)	262,231	(79,440)	430.10%
15	410.1 Deferred Income Taxes-Dr.	5,962,563	60	5,962,503	246,353	2320.31%
16	411.1 Deferred Income Taxes-Cr.	(17,434,645)	(750)	(17,433,895)	1,124	-1551158.26%
17	411.4 Investment Tax Credit Adj.	(123,713)	-	(123,713)	(134,861)	8.27%
18						
19	**Total Operating Expenses**	119,690,713	15,640	119,675,073	91,756,010	30.43%
20	**NET OPERATING INCOME**	$ 539,918	$(15,640)	$ 555,558	$ 12,517,694	-95.56%

Sch. 9	MONTANA REVENUES - NATURAL GAS (INCLUDES CMP)			
	Account Number & Title	This Year Cons. Utility	Last Year Montana	% Change
1				
2	**Core Distribution Business Units**			
3	**(DBUs)**			
4	440 Residential	$69,806,882	$60,420,611	15.53%
5	442.1 Commercial	30,965,854	27,376,692	13.11%
6	442.2 Industrial Firm	3,293,973	1,254,911	162.49%
7	445 Public Authorities	123,664	(11,586)	1167.36%
8	448 Interdepartmental Sales	387,754	190,263	103.80%
9	491.2 CNG Station	10,624	10,469	1.48%
10				
11	**Total Sales to Core DBUs**	104,588,751	89,241,360	117.20%
12				
13	447 Sales for Resale	662,300	611,451	8.32%
14				
15	**Total Sales of Natural Gas**	662,300	611,451	8.32%
16				
17	**Transportation**			
18				
19	489 Transportation (inc. CMP)	12,628,796	12,137,714	4.05%
20	495 Storage	2,507,240	2,079,928	20.54%
21				
22	**Total Revenues From Transportation**	15,136,036	14,217,642	6.46%
23				
24	**Other Operating Revenue**			
25				
26	Montana Power Company	(156,456)	203,251	-176.98%
27				
28	**Total Other Operating Revenue**	(156,456)	203,251	-176.98%
29	**TOTAL OPERATING REVENUE**	120,230,631	104,273,704	15.30%
30				
31	Glacier Gas Co. discontinued operations in November 1999 and did not generate			
32	revenues in 2000. The column "This Year's Consolidated Utility" does not therefore			
33	include Glacier Gas revenue. For more information on the sale of Glacier Gas Co.,			
34	see note 1 of Schedule 10.			

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Glacier Gas 1/	This Year Montana	Last Year Montana	% Change
1	**Production Expenses**					
2	**Production & Gathering-Operation**					
3	750 Supervision & Engineering	$0		$0	$36,629	-100.00%
4	751 Maps & Records	-	-	-	-	
5	752 Gas Wells Expenses	318	318	-	214	-100.00%
6	753 Field Lines Expenses	-	-	-	-	-
7	754 Field Compressor Station Expense	3,352	3,352	-	756	-100.00%
8	755 Field Comp. Station Fuel & Power	138	138	-	974	-100.00%
9	756 Field Meas. & Reg. Station Expense	1,148	1,148	-	376	-100.00%
10	757 Dehydration Expense	270	270	-	13	-100.00%
11	758 Gas Well Royalties	(3,446)	(3,446)	-	-	
12	759 Other Expenses	1,761	1,761	-	2,800	-100.00%
13	760 Rents	-	-	-	-	-
14	**Total Oper.-Production & Gathering**	3,541	3,541	-	41,762	-100.00%
15						
16	**Other Gas Supply Expense-Operation**					
17	800 NG Wellhead Purchases	46,774,067	7,495	46,766,572	15,927,558	193.62%
18	800 NG Wellhead Purchases, Intraco.	-	-	-	16,634,023	-100.00%
19	803 NG Transmission Line Purchases	988,913	-	988,913	802,754	23.19%
20	805 Other Gas Purchases	(10,392,647)	-	(10,392,647)		
21	805 Purchased Gas Cost Adjustments	-	-	-	421,862	-100.00%
22	805 Incremental Gas Cost Adjustments					
23	805 Deferred Gas Cost Adjustments					
24	806 Exchange Gas					
25	807 Well Expenses-Purchased Gas	198,751	156	198,595	232,896	-14.73%
26	807 Purch. Gas Meas. Stations-Oper.	-	-	-	45,235	-100.00%
27	807 Purch. Gas Meas. Stations-Maint.	-	-	-	71,975	-100.00%
28	807 Purch. Gas Calculations Expenses	-	-	-	22,279	-100.00%
29	808 Other Purchased Gas Expenses	-	-	-	120,148	-100.00%
30	808 Gas Withdrawn from Storage -Dr.	8,454,544		8,454,544	10,518,341	-19.62%
31	809 Gas Delivered to Storage -Cr.	(8,560,238)		(8,560,238)	(11,558,935)	25.94%
32	810 Gas Used-Comp. Station Fuel-Cr.					
33	811 Gas Used-Products Extraction-Cr.					
34	812 Gas Used-Other Utility Oper.-Cr.					
35	813 Other Gas Supply Expenses	-	-	-	-	-
36	**Total Other Gas Supply Expenses**	37,463,390	7,651	37,455,739	33,238,136	12.69%
37	**Total Production Expenses**	37,466,931	11,192	37,455,739	33,279,898	-87.31%

Sch. 10	cont. **MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)**					
	Account Number & Title	This Year Cons. Utility	Glacier Gas	This Year Montana	Last Year Montana	% Change
1	**Storage Expenses**					
2						
3	**Underground Storage-Operation**					
4	814 Supervision & Engineering	224,213		224,213	317,243	-29.32%
5	815 Maps & Records	35,084		35,084	100,357	-65.04%
6	816 Wells	81,877		81,877	80,122	2.19%
7	817 Lines	17,137		17,137	12,765	34.25%
8	818 Compressor Station	133,039		133,039	110,166	20.76%
9	819 Compressor Station Fuel & Power	3,899		3,899	11,052	-64.72%
10	820 Measuring & Regulating Station	22,497		22,497	30,507	-26.25%
11	821 Purification	65,402		65,402	47,345	38.14%
12	824 Other Expenses	76,461		76,461	93,916	-18.59%
13	825 Storage Well Royalties	87,848		87,848	122,537	-28.31%
14	826 Rents	14,443		14,443	(500)	2988.54%
15	**Total Operation-Underground Storage**	761,900	-	761,900	925,510	-17.68%
16						
17	**Underground Storage-Maintenance**					
18	830 Supervision & Engineering	22,430		22,430	57,349	-60.89%
19	831 Structures & Improvements	32,357		32,357	14,183	128.13%
20	832 Reservoirs & Wells	17,105		17,105	36,728	-53.43%
21	833 Lines	19,645		19,645	47,749	-58.86%
22	834 Compressor Station Equipment	72,556		72,556	155,662	-53.39%
23	835 Meas. & Reg. Station Equipment	13,394		13,394	37,707	-64.48%
24	836 Purification Equipment	4,422		4,422	9,323	-52.57%
25	837 Other Equipment	9,716		9,716	9,178	5.87%
26	**Total Maintenance-Underground Storage**	191,625	-	191,625	367,879	-47.91%
27	**Total Underground Storage Expenses**	953,525	-	953,525	1,293,389	-26.28%
28	**Transmission Expenses**					
29	**Transmission-Operation**					
30	850 Supervision & Engineering	2,056,909		2,056,909	792,170	159.65%
31	851 System Control & Load Dispatching	493,048		493,048	476,948	3.38%
32	853 Compressor Station Labor & Expens	416,013		416,013	312,776	33.01%
33	855 Other Fuel & Power for Comp. Stat.	29,578		29,578	60,957	-51.48%
34	856 Mains	515,289	2,320	512,969	502,828	2.02%
35	857 Measuring & Regulating Station	603,254		603,254	296,063	103.76%
36	858 Transmission & Comp.-By Others	29,673		29,673	103,032	-71.20%
37	859 Other Expenses	997,163	1,034	996,129	832,038	19.72%
38	860 Rents	1,399		1,399	116,210	-98.80%
39	**Total Operation-Transmission**	5,142,326	3,354	5,138,972	3,493,022	47.12%
40	**Transmission-Maintenance**					
41	861 Supervision & Engineering	482,643		482,643	306,691	57.37%
42	862 Structures & Improvements	63,177		63,177	78,989	-20.02%
43	863 Mains	577,934		577,934	813,652	-28.97%
44	864 Compressor Station Equipment	448,871		448,871	722,275	-37.85%
45	865 Meas. & Reg. Station Equipment	318,647		318,647	416,986	-23.58%
46	867 Other Equipment	14,951		14,951	20,743	-27.92%
47	**Total Maintenance-Transmission**	1,906,223	-	1,906,223	2,359,336	-19.21%
48	**Total Transmission Expenses**	7,048,549	3,354	7,045,194	5,852,358	20.38%

Sch. 10 cont.	MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Glacier Gas	This Year Montana	Last Year Montana	% Change
1	**Distribution Expenses**					
2	**Distribution-Operation**					
3	870 Supervision & Engineering	434,832		434,832	670,150	-35.11%
4	872 Compressor Station Labor & Expens	4,518		4,518	10,049	-55.04%
5	873 Compressor Station Fuel and Power	-		-	15	-100.00%
6	874 Mains and Services	982,215		982,215	1,346,283	-27.04%
7	875 Meas. & Reg. Station-General	21,535		21,535	42,437	-49.25%
8	876 Meas. & Reg. Station-Industrial	2,999		2,999	9,481	-68.37%
9	877 Meas. & Reg. Station-City Gate	32,438		32,438	94,829	-65.79%
10	878 Meter & House Regulator	770,384		770,384	637,594	20.83%
11	879 Customer Installations	2,830,064		2,830,064	3,559,160	-20.49%
12	880 Other Expenses	835,453		835,453	612,670	36.36%
13	881 Rents	13,957		13,957	6,119	128.11%
14	**Total Operation-Distribution**	5,928,395	-	5,928,395	6,988,787	-15.17%
15	**Distribution-Maintenance**					
16	885 Supervision & Engineering	324,473		324,473	376,446	-13.81%
17	886 Structures & Improvements	16,941		16,941	14,613	15.93%
18	887 Mains	788,259		788,259	683,744	15.29%
19	889 Meas. & Reg. Station Exp.-General	76,894		76,894	40,045	92.02%
20	890 Meas. & Reg. Station Exp.-Industrial	3,493		3,493	693	404.03%
21	891 Meas. & Reg. Station Exp.-City Gate	15,062		15,062	5,710	163.81%
22	892 Services	454,337		454,337	387,242	17.33%
23	893 Meters & House Regulators	281,138		281,138	217,824	29.07%
24	894 Other Equipment	22,624		22,624	4,062	457.02%
25	**Total Maintenance-Distribution**	1,983,221	-	1,983,221	1,730,379	14.61%
26	**Total Distribution Expenses**	7,911,616	-	7,911,616	8,719,166	-9.26%
27	**Customer Accounts Expenses**					
28	**Customer Accounts-Operation**					
29	901 Supervision			-	-	-
30	902 Meter Reading	303,842		303,842	559,250	-45.67%
31	903 Customer Records & Collection	2,002,022		2,002,022	2,448,417	-18.23%
32	904 Uncollectible Accounts	839,594		839,594	384,124	118.57%
33	905 Miscellaneous Customer Accounts	345		345	160	115.09%
34	**Total Customer Accounts Expenses**	3,145,803	-	3,145,803	3,391,951	-7.26%
35						
36	**Customer Service & Information Expenses**					
37	**Customer Service-Operation**					
38	907 Supervision	31,402		31,402	27,825	12.86%
39	908 Customer Assistance	881,433	-	881,433	821,564	7.29%
40	909 Inform. & Instructional Advertising	167,216		167,216	195,857	-14.62%
41	910 Misc. Customer Service & Inform.	1,081		1,081	3,617	-70.11%
42	**Total Customer Service & Information Exp.**	1,081,132	-	1,081,132	1,048,863	3.08%
43						
44	**Sales Expenses**					
45	**Sales-Operation**					
46	911 Supervision	61,439		61,439	171,343	-64.14%
47	912 Demonstrating & Selling	293,819		293,819	489,535	-39.98%
48	913 Advertising	172,385		172,385	25,269	582.21%
49	916 Miscellaneous Sales	11,076		11,076	3,001	269.07%
50	**Total Sales Expenses**	538,719	-	538,719	689,148	-21.83%

Sch. 10	cont. **MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)**					
	Account Number & Title	This Year Cons. Utility	Glacier Gas	This Year Montana	Last Year Montana	% Change
1	**Administrative & General Expenses**					
2	**Admin. & General - Operation**					
3	407 Amortization of Regulatory Asset	33,181,738	-	33,181,738	142,832	23131.37%
4	920 Administrative & General Salaries	6,717,282	752	6,716,530	6,344,266	5.87%
5	921 Employee Travel	348,129	-	348,129		-
6	921 Office Supplies & Expenses	1,161,399	61	1,161,338	1,796,810	-35.37%
7	922 Administrative Exp. Transferred-Cr.	(994,079)	-	(994,079)	(894,486)	-11.13%
8	923 Outside Services Employed	2,446,430	3,500	2,442,930	1,510,933	61.68%
9	924 Property Insurance	11,530	-	11,530	80,243	-85.63%
10	925 Legal & Claim Department	720,889	71	720,818	642,296	12.23%
11	926 Employee Pensions & Benefits	(85,482)	-	(85,482)	(224,513)	61.93%
12	928 Regulatory Commission Expenses	92,261	-	92,261	74,167	24.40%
13	930 General Advertising	243,566	-	243,566		-
14	930 Miscellaneous General Expenses	629,384	(2)	629,386		-
15	930 USBC Expenses	1,391,578	-	1,391,578	1,906,824	-27.02%
16	931 Rents	2,267,150	-	2,267,150	1,538,851	47.33%
17	**Total Operation-Admin. & General**	48,131,775	4,382	48,127,393	12,918,223	272.55%
18	**Admin. & General - Maintenance**					
19	935 General Plant	513,551	-	513,551	1,261,437	-59.29%
20	**Total Admin. & General Expenses**	48,645,326	4,382	48,640,944	14,179,660	243.03%
21	**TOTAL OPER. & MAINT. EXPENSES**	$106,791,601	$18,928	$106,772,673	68,454,433	55.98%
22						
23	In July 2000, the production assets of Glacier Gas Co. were sold to the the oil and natural gas operations of Entech					
24	and Glacier's pipeline assets to a third party. In October 2000 the Glacier Gas Co. was included in the sale of Entech's					
25	oil and natural businesses to PanCanadian. Glacier Gas Co. incurred operating expenses until the sale of its assets					
26	in July 2000.					

Sch. 11	MONTANA TAXES OTHER THAN INCOME - NATURAL GAS (INCLUDES CMP)			
	Description	This Year	Last Year	% Change
1				
2	**Federal Taxes**			
3	Federal Social Security Old Age & Medicare			
4	and Federal & State Unemployment	$595,708	$1,715,375	-65.27%
5				
6	**Montana Taxes**			
7	Real Estate & Personal Property	13,498,406	13,264,874	1.76%
8	Old Fund Liability	-	(546)	100.00%
9	Severance	362	408	-11.37%
10	Consumer Counsel	92,463	98,976	-6.58%
11	Public Service Commission	293,771	266,849	10.09%
12	City Licenses	1,158	3,280	-64.69%
13	Production	16,491	36,005	-54.20%
14	Crow Tribe RR and Utility Tax	65,786	66,198	-0.62%
15	Accrued Other Taxes	54,402	-	0.00%
16				
17	**District of Columbia Taxes**			
18	Social Security Unemployment	72	72	0.00%
19	Personal Property	-	44	-100.00%
20				
21	**Canadian Taxes**			
22	Ad Valorem	71,752	53,642	33.76%
23				
24	**Other**			
25	Payroll Tax Credit	(524,386)	(1,249,320)	58.03%
26				
27	**TOTAL TAXES OTHER THAN INCOME**	$14,165,985	$14,255,857	-0.63%
28				
29				
30				
31	Glacier Gas taxes other than income	12,861		

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	CONFIDENTIAL INFORMATION				
Corporate Secretary					
	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.

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Notes to the Financial Statements

❑ 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	**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

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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 2000	Shares Issued and Outstanding 1999	Thousands of Dollars 2000	Thousands of Dollars 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.

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Long-term debt consists of the following:

	December 31 2000	December 31 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."

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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)

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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 - NATURAL GAS (INCLUDES CMP)			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1	**Intangible Plant**			
2	2301 Organization	$12,873	$21,631	-40.49%
3	2302 Franchises and Consents	258,020	258,020	-
4	2303 Miscellaneous Intangible Plant	396,672	418,127	-5.13%
5	**Total Intangible Plant**	667,565	697,778	-4.33%
6				
7	**Underground Storage Plant**			
8	2350 Land and Land Rights	3,944,064	3,938,482	0.14%
9	2351 Structures and Improvements	2,729,021	1,901,943	43.49%
10	2352 Wells	7,787,497	7,051,311	10.44%
11	2353 Lines	6,593,845	6,180,553	6.69%
12	2354 Compressor Station Equipment	7,114,168	4,883,939	45.66%
13	2355 Measuring & Regulating Equip.	1,715,655	1,526,497	12.39%
14	2356 Purification Equipment	223,171	223,950	-0.35%
15	2357 Other Equipment	831,995	827,326	0.56%
16	**Total Underground Storage Plant**	30,939,416	26,534,001	16.60%
17				
18	**Transmission Plant**			
19	2365 Rights of Way	5,276,289	5,273,932	0.04%
20	2366 Structures and Improvements	8,272,854	7,849,504	5.39%
21	2367 Mains	128,110,841	127,057,640	0.83%
22	2368 Compressor Station Equipment	16,522,666	14,737,093	12.12%
23	2369 Meas. & Reg. Station Equipment	9,096,923	8,909,201	2.11%
24	2370 Communication Equipment	66,875	66,875	0.00%
24	2371 Other Equipment	69,441	73,320	-5.29%
25	**Total Transmission Plant**	167,415,889	163,967,565	2.10%
26				
27	**Distribution Plant**			
28	2374 Land and Land Rights	858,309	859,272	-0.11%
29	2375 Structures and Improvements	213,859	211,344	1.19%
30	2376 Mains	68,143,862	66,662,914	2.22%
31	2377 Compressor Station Equipment			
32	2378 M&R Station Equip.-General	2,037,883	2,043,364	-0.27%
33	2379 M&R Station Equip.-City Gate	337,497	341,128	-1.06%
34	2380 Services	52,021,516	52,060,771	-0.08%
35	2381 Customers Meters and Regulators	16,458,262	14,876,051	10.64%
36	2382 Meter Installations	9,573,802	9,324,408	2.67%
37	2383 House Regulators			
38	2384 House Regulator Installations			
39	2385 M&R Station Equip.-Industrial	51,651	45,085	14.56%
40	2386 Other Prop. on Customers' Premises			
41	2387 Other Equipment	-	(1,518)	100.00%
42	**Total Distribution Plant**	149,696,641	146,422,819	2.24%

	Sch. 19 cont. **MONTANA PLANT IN SERVICE - NATURAL GAS (INCLUDES CMP)**			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1	**General Plant**			
2	2389 Land and Land Rights	104,550	104,550	-
3	2390 Structures and Improvements	677,992	677,335	0.10%
4	2391 Office Furniture and Equipment	1,576,897	1,781,286	-11.47%
5	2392 Transportation Equipment	6,357,874	6,299,990	0.92%
6	2393 Stores Equipment	11,710	12,616	-7.18%
7	2394 Tools, Shop & Garage Equipment	3,832,107	3,791,138	1.08%
8	2395 Laboratory Equipment	815,000	826,005	-1.33%
9	2396 Power Operated Equipment	1,693,402	1,707,902	-0.85%
10	2397 Communication Equipment	1,175,775	1,086,112	8.26%
11	2398 Miscellaneous Equipment	43,602	46,947	-7.13%
12	2399 Other Tangible Property	-	-	-
13	**Total General Plant**	16,288,909	16,333,881	-0.28%
14	**Total Gas Plant in Service**	365,008,420	353,956,044	3.12%
15				
16	4101 Gas Plant Allocated from Common	14,012,437	13,447,245	4.20%
17	2105 Gas Plant Held for Future Use	8,984	8,984	-
18	2107 Gas Construction Work in Progress	569,897	235,913	141.57%
19	2117 Gas in Underground Storage	40,695,109	44,877,231	-9.32%
20				
21				
22	**Total Gas Plant**	$420,294,847	$412,525,417	1.88%

Sch. 20	MONTANA DEPRECIATION SUMMARY - NATURAL GAS (INCLUDES CMP)				
	Functional Plant Class	Montana Plant Cost 1\	This Year Montana	Last Year Montana	Current Avg. Rate
1	**Accumulated Depreciation**				
2					
3	Production and Gathering	$0	$0	$0	0.00%
4					
5					
6	Underground Storage	26,532,310	12,965,688	12,257,165	2.68%
7					
8	Other Storage				
9					
10	Transmission	163,925,033	55,433,973	52,553,935	1.76%
11					
12	Distribution	146,363,113	51,595,412	47,491,663	3.11%
13					
14	General and Intangible	17,006,942	9,345,117	9,084,440	5.00%
15					
16	Common	13,447,245	3,114,332	2,674,764	4.13%
17					
18	**TOTAL DEPRECIATION**	$367,274,643	$132,454,522	$124,061,967	2.55%
19					
20	1\ "Montana Plant Cost" lists the plant balances as they existed at the end of the previous				
21	year or the beginning of the year being reported. Thus, in the 2000 report, "Montana				
22	Plant Cost" lists the 12/31/99 plant balances. In the 1999 report, however, the 12/31/99				
23	plant balances were listed instead of the 12/31/98 plant balances.				

Sch. 21	MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED) - NATURAL GAS			
	Account Number & Title	This Year Cons. Utility	Last Year Montana 1/	%Change
1				
2	151 Fuel Stock			
3				
4	152 Fuel Stock Expenses Undistributed			
5				
6	153 Residuals			
7				
8	154 Plant Materials & Operating Supplies			
9	Assigned and Allocated to;			
10	Operation & Maintenance			
11	Construction			
12	Storage Plant	$ 2,103,751	$ 234,954	795.39%
13	Transmission Plant	0	1,451,902	-100.00%
14	Distribution Plant	0	1,296,547	-100.00%
15				
16	155 Merchandise			
17				
18	156 Other Materials & Supplies			
19				
20	157 Nuclear Materials Held for Sale			
21				
22	163 Stores Expense Undistributed			
23				
24	**TOTAL MATERIALS & SUPPLIES**	$2,103,751	$2,983,403	-29.48%
25				
26	/1 We revised the distribution of materials and supplies for the year end 1999 based			
27	on accurate 1999 natural gas plant categories. The sale of Glacier Gas Co. in 2000			
28	obviates the need for consolidating that entity and showing the elimination of its			
29	materials and supplies in a separate column.			

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - GAS			
		% Capital Structure	% Cost Rate	Weighted Cost
1	**Commission Accepted - Most Recent**			
2				
3	Docket Number: 2000.8.113			
4	Order Number : 6271c			
5				
6	Common Equity	45.00%	10.75%	4.84%
7	Preferred Stock	6.97%	6.40%	0.45%
8	QUIPs Preferred 2/	7.86%	8.54%	0.67%
9	Long Term Debt	40.17%	7.13%	2.86%
10	**TOTAL**	100.00%		8.82%
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 1/	9.65%	8.54%	0.82%
17	Long Term Debt 2/	36.07%	7.82%	2.82%
18	**TOTAL**	100.00%		9.10%
19				
20	1/ Docket 2000.8.113, Order 627c specifies the authorized capital structure and associated costs for			
21	the regulated gas utility effective May 8, 2001.			
22				
23	2/ The cost of the QUIPS securities is treated as tax deductible for income tax purposes.			
24	See footnote on Schedule 25.			
25				
26	3/ The cost rate cannot 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/

Line	Description	Issue Date	Maturity Date	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem./Disc.	Total Cost %
1									
2	**First Mortgage Bonds**								
3	8.25% Series, Due 2007	12/05/91	02/01/07	$55,000,000	$54,550,100	$364,959	8.260%	$32,626	8.94%
4	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%
5	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%
6	**Total First Mortgage Bonds**			155,000,000	153,461,600	7,167,135		558,770	7.80%
7									
8	**Pollution Control Bonds**								
9	6-1/8% Series, Due 2023	06/30/93	05/01/23	90,205,000	88,199,743	88,703,858	5.841%	5,619,668	6.34%
10	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%
11	**Total Pollution Control Bonds**			170,205,000	167,240,543	167,965,837		10,450,696	6.22%
12									
13	**Other Long Term Debt**								
14	Quarterly Income Preferred Securities,								
15	8.45%, Series A (QUIPS) , 2/	11/96	11/01	65,000,000	62,567,385	65,000,000		5,553,304	8.54%
16	Medium Term Notes-Secured Series	Various	Various	128,000,000	126,807,269	28,000,000		2,074,554	7.41%
17	Medium Term Notes-Unsecured Series B	Various	Various	115,000,000	113,851,197	39,825,514		3,069,288	7.71%
18	Cost Associated with Prior Debt Retirements	N/A	N/A	0	-	-		163,999	N/A
19	**Total Other Long Term Debt**			308,000,000	303,225,851	132,825,514		10,861,145	8.18%
20	**TOTAL LONG TERM DEBT**			$633,205,000	$623,927,994	$307,958,486		$21,870,611	7.10%

21

22 1/ Total Long-Term Debt does not include ESOP debt of $12,666,000, as ESOP debt is not used for rate making purposes.

23 Total Long-Term Debt does not include amounts due within 1 year of $63,531,000.

24

25 2/ The Company believes and intends to take the position that the securities associated with the QUIPS issue will constitute indebtedness

26 for United States federal income tax purposes. As such, the cost of QUIPS are deemed to be tax deductible. The Company will have

27 the right to redeem securities (i) on or after November 6, 2001 or (ii) upon occurance and continuation of a Tax Event or an

28 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 - GAS			
	Description	This Year	Last Year	% Change
1	**Rate Base**			
2	101 Plant in Service	$369,531,253	$360,909,980	2.39%
3	108 Accumulated Depreciation	(129,051,425)	(121,807,785)	-5.95%
4				
5	**Net Plant in Service**	240,479,828	239,102,195	0.58%
6	Additions:			
7	154, 156 Materials & Supplies	3,323,790	3,316,499	0.22%
8	Other Additions 1/	48,276,676	57,603,007	-16.19%
9				
10	**Total Additions**	51,600,466	60,919,506	-15.30%
11	Deductions:			
12	190 Accumulated Deferred Income Taxes 1/	35,461,385	37,758,397	-6.08%
13	252 Customer Advances for Construction	3,263,784	2,919,585	11.79%
14	Other Deductions 1/	20,818,300	24,429,076	-14.78%
15				
16	**Total Deductions**	59,543,469	65,107,058	-8.55%
17	**Total Rate Base**	232,536,825	234,914,643	-1.01%
18	**Net Earnings**	555,558	12,517,694	-95.56%
19	**Rate of Return on Average Rate Base**	0.239%	5.329%	-95.52%
20	**Rate of Return on Average Equity 2/**	-12.979%	0.301%	-4411.96%
21				
22	**Major Normalizing and**			
23	**Commission Ratemaking Adjustments**			
24	Removal of Gas Securitization Activity	-	18,498	-100.00%
25	Rate Schedule Revenues	1,805,414	4,165,666	-56.66%
26	Gain sharing on sale of Oil & Gas	32,549,128	-	
27				
28	Non-Allowables:			
29	Advertising	289,895	200,276	44.75%
30	Benefit Restoration Plan	156,456	162,267	-3.58%
31	Dues, Contributions, Other	2,442	14,890	-83.60%
32	Corporate Overhead	119,121	77,456	53.79%
33	Associated Income Taxes	(13,755,082)	(1,827,207)	-652.79%
34	**Total Adjustments**	21,167,374	2,811,846	652.79%
35	**Revised Net Earnings**	$21,722,932	$15,329,540	41.71%
36	**Adjusted Rate of Return on Average Rate Base**	9.342%	6.526%	43.16%
37	**Adjusted Rate of Return on Average Equity 2/**	6.931%	3.006%	130.57%
38				
39	1/ Includes adjustments related to FAS 109.			
40				
41	2/ ROE calculation utilizes the common equity component on Sch. 22 of this Report, applied to			
42	rate base for the denominator of the equations. The 1999 common equity component applied			
43	to rate base was 44.25%.			

Sch. 27 cont.	MONTANA EARNED RATE OF RETURN - GAS			
	Description	This Year	Last Year	% Change
1				
2	**Detail - Other Additions**			
3	FAS 109 Regulatory Asset	$8,093,582	$11,135,290	-27.32%
4	Gas Stored Underground	38,669,601	45,244,689	-14.53%
5	Cost of Refinancing Debt	1,251,053	1,002,472	24.80%
6	1994 Severance Plan	59,099	59,099	0.00%
7	1995 and 1996 Severance Plans	144,736	144,736	0.00%
8	1997 and 1998 Severance Plans	41,884	-	0.00%
9	Division Centralization	16,721	16,721	0.00%
10				
11	**Total Other Additions**	48,276,676	57,603,007	-16.19%
12				
13	**Detail - Other Deductions**			
14	Personal Injury and Property Damage	989,319	664,474	48.89%
15	Gross Cash Requirements	1,298,377	4,725,902	-72.53%
16	Bond Refinancing CTC - GP	4,369,094	4,369,094	0.00%
17	Bond Refinancing CTC - RA	13,915,459	13,915,459	0.00%
18	Deferred Storage Gas Sales	246,051	754,147	-67.37%
19	**Total Other Deductions**	$20,818,300	$24,429,076	-14.78%

Sch. 28	MONTANA COMPOSITE STATISTICS - NATURAL GAS (INCLUDES CMP)		
	Description		Amount
1			
2		**Plant (Intrastate Only)**	
3			
4	101	Plant in Service (Includes Allocation from Common)	$379,020,857
5	105	Plant Held for Future Use	8,984
6	107	Construction Work in Progress	569,897
7	117	Gas in Underground Storage	40,695,109
8	151-163	Materials & Supplies	2,103,751
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	132,454,522
11	252	Contributions in Aid of Construction	3,976,820
12	**NET BOOK COSTS**		285,967,256
13			
14		**Revenues & Expenses**	
15			
16	400	Operating Revenues	120,230,631
17			
18	**Total Operating Revenues**		120,230,631
19			
20	401-402	Other Operating Expenses	106,772,673
21	403-407	Depreciation & Amortization Expenses	8,765,964
22	408.1	Taxes Other than Income Taxes	14,165,985
23	409-411	Federal & State Income Taxes	(10,029,549)
24			
25	**Total Operating Expenses**		119,675,073
26	**Net Operating Income**		555,558
27			
28	415-421.1	Other Income	1,069,741
29	421.2-426.5	Other Deductions	185,959
30	**NET INCOME BEFORE INTEREST EXPENSE**		$1,439,340
31			
32		**Average Customers (Intrastate Only)**	
33		Residential	133,082
34		Commercial	18,437
35		Industrial	364
36		Other	96
37	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		151,979
38			
39		**Other Statistics (Intrastate Only)**	
40		Average Annual Residential Use (Mcf)	93.9
41		Average Annual Residential Cost per (Mcf)	$5.58
42		Average Residential Monthly Bill	$43.71
43			
44		Plant in Service (Gross) per Customer	$2,494

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,234	451	78		532
2	Amsterdam	727				-
3	Anaconda	9,417	3,403	335		3,761
4	Augusta	284	193	45		235
5	Barber		3			3
6	Belfry	219	5			5
7	Belgrade	5,728	2,937	380		3,424
8	Bigfork	1,421	726	127		875
9	Big Mountain		97	19		118
10	Big Sandy	703	308	81		393
11	Big Sky	1,221				68
12	Big Timber	1,650	851	186		1,038
13	Billings	89,847	12	5	2	15
14	Bonner	1,693	77	4		80
15	Boulder	1,300	470	80		553
16	Bozeman	27,509	13,617	2,042		15,961
17	Browning	3,877	1,070	156		1,251
18	Buffalo		5			5
19	Butte	33,892	12,476	1,373	5	14,180
20	Cardwell	40	17	5		22
21	Carter	62	29	9		39
22	Chester	871	379	127		507
23	Chinook	1,386	736	150		894
24	Choteau	1,802	842	177		1,023
25	Clancy	1,406	1,106	77	2	1,204
26	Clinton		331	17		360
27	Columbia Falls	3,645	2,744	301	1	3,082
28	Columbus	1,748	980	151		1,130
29	Conrad	2,753	1,155	220		1,377
30	Coram	337	114	18		132
31	Corbin-Jefferson					-
32	Corvallis	443	763	78		849
33	Cut Bank	3,105	50	17		67
34	Deer Lodge	3,421	1,611	205	1	1,836
35	Dillon	3,752	1,945	342	1	2,303
36	Drummond	318	210	64		278
37	East Glacier	396	124	46		166
38	East Helena	1,642	1,770	105	1	1,885
39	Elliston	225	92	13		106
40	Essex		57	14		72
41	Fairfield	659	401	91		490
42	Florence	901	934	63		1,002
43	Floweree		45	8		54
44	Fort Belknap	1,262	15	12		27
45	Fort Benton	1,594	618	160		779
46	Fort Harrison			57		59
47	Fort Shaw	274	108	13		121
48	Gallatin Gateway		149	28		179
49	Galata		3	1		3
50	Garneill		9	1		10
51	Garrison	112	24	5		30
52	Gildford	185	80	31		111

Sch. 29

Montana Customer Information- Natural Gas, 1/

	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Gransdale		21	2		24
2	Great Falls	2,122	951	50	1	1,003
3	Greycliff	2,082	44	5		50
4	Hall		59	14		75
5	Hamilton	7,141	3,290	579		3,903
6	Harlem	1,711	668	121		801
7	Harlowtown	149	537	97		637
8	Havre	189	4,571	620		5,238
9	Helena	45,819	14,656	2,107		16,921
10	Hingham	157	92	31		124
11	Hungry Horse	934	255	38		294
12	Inverness	103	42	14		57
13	Jefferson City	295	109	12		124
14	Joplin	210	102	27		130
15	Judith Gap	164	76	15		92
16	Kalispell	14,223	9,111	1,652	1	10,949
17	Kremlin	126	54	16		68
18	Laurel	6,255	10		2	12
19	Ledger		6	1		6
20	Lewistown	6,178	2,840	468		3,317
21	Livingston	7,348	3,647	522		4,205
22	Logan		2			2
23	Lohman		2	1		3
24	Lolo	3,388	1,291	81		1,391
25	Loma	92	39	19		57
26	Manhattan	1,396	1,071	127		1,209
27	Martin City	331	112	17		131
28	Milltown		75	8		86
29	Missoula	57,053	25,147	3,223	1	28,677
30	Moore	186	2	1		3
31	Philipsburg	914	421	69		491
32	Ramsay		37	7		44
33	Red Lodge	2,177	1,482	253		1,753
34	Reedpoint	185	90	16		106
35	Roberts		145	18		166
36	Rocker		7	1		8
37	Rudyard	275	136	32		169
38	Shawmut		25	4		29
39	Sheridan	659	371	62		436
40	Silver Star		22	5		27
41	Simms	373	164	17		184
42	Shelby	3,216	9	2	2	13
43	Somers	556	222	18		245
44	Springdale		2			2
45	Stevensville	1,553	1,297	210		1,542
46	Sun River	131	113	19		134
47	Three Forks	1,728	736	116	3	869
48	Townsend	1,867	1			
49	Trident		2			1
50	Turah		76			77
51	Twin Bridges	400	212	55		265
52	Valier	498	306	66		369

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Vaughn	1,833	333	27		363
2	Victor	859	437	68		509
3	West Glacier		108	37		144
4	Whitefish	5,032	2,915	415		3,379
5	Whitehall	1,044	664	110		786
6	Whitlash		2			2
7	Willow Creek	209	95	11		106
8	Wolf Creek		49	25		75
9	**Total**	394,222	133,501	19,049	23	154,577
10						
11	1/ Customer populations represent an average of the 12 month period from 5/1/00 to 4/30/01.					

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 wil 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	TRANSMISSION, DISTRIBUTION and STORAGE SYSTEMS -NATURAL GAS						
	Transmission System-Sales and Transportation						
		Peak Day of Month		Peak Day Volume(Mcf@14.9)		Monthly Volumes(Mcf@14.9)	
	Month	Total Company	Montana	Total Company	Montana	Total Company, 2/	Montana, 3/
1	January					5,706,671	4,314,467
2	February					4,547,336	4,001,039
3	March					4,059,955	3,707,043
4	April		NOT AVAILABLE			2,768,362	3,401,152
5	May					2,461,053	2,850,331
6	June					1,852,813	2,496,468
7	July					2,047,227	2,263,920
8	August					1,748,952	2,220,628
9	September					2,351,425	2,585,632
10	October					3,429,505	2,841,701
11	November					5,650,066	3,440,049
12	December					6,313,866	4,044,247
13	TOTAL					42,937,231	38,166,677
14							
15							
16	Distribution System-Sales and Transportation						
17		Sales Volumes		Transportation Volumes		Monthly Volumes(Mcf@14.9)	
18	Month	Total Company	Montana, 1/	Total Company	Montana, 1/	Total Company, 4/	Montana, 5/
19	January	2,741,341		385,797		3,127,138	2,741,341
20	February	2,596,723		263,591		2,860,314	2,596,723
21	March	2,164,201		230,154		2,394,355	2,164,201
22	April	1,576,098		216,478		1,792,576	1,576,098
23	May	1,077,454		163,629		1,241,083	1,077,454
24	June	684,182		134,187		818,369	684,182
25	July	496,964		98,080		595,044	496,964
26	August	366,268		81,115		447,383	366,268
27	September	539,313		84,028		623,341	539,313
28	October	1,117,777		119,427		1,237,204	1,117,777
29	November	2,007,270		156,365		2,163,635	2,007,270
30	December	3,012,968		233,141		3,246,109	3,012,968
31	TOTAL	18,380,559		2,165,992		20,546,551	18,380,559
32							
33							
34	Storage System-Sales and Transportation						
35		Peak Day & Peak Day Vol.		Total Monthly Volumes(Mcf@14.9)			
36		Total Company	Montana	Total Company 4/		Montana 5/	
37	Month	1/	1/	Injection	Withdrawal	Injection	Withdrawal
38	January			2,006	1,606,003	-	913,007
39	February			12,043	1,533,316	-	799,307
40	March			122,058	1,202,390	-	388,293
41	April			379,145	477,873	53,206	-
42	May			304,556	318,290	362,537	-
43	June			908,791	584,374	712,887	-
44	July			1,122,403	604,940	866,184	-
45	August			991,626	211,637	670,548	-
46	September			588,316	377,982	597,023	-
47	October			103,542	894,707	289	-
48	November			3,569	2,556,301	-	1,004,558
49	December			11,844	2,843,701	-	1,537,440
50	TOTAL			4,549,899	13,211,514	3,262,674	4,642,605

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

Sch. 33	SOURCES OF CORE NATURAL GAS SUPPLY				
	Name of Supplier	Last Year Volumes Mcf	This Year Volumes Mcf	Last Year Avg. Commodity Cost *	This Year Avg. Commodity Cost
1					
2	Montana Purchase	5,940,007	6,938,189	$1.9250	$3.5180
3	MP Gas	10,517,147	9,300,643	1.5820	1.4950
4	Rosza	342,523	713,998	1.8900	3.5700
5	Blaine #3	917,122	533,500	1.9640	3.3550
6	Stor Trans	0	657,964	0.0000	4.9450
7	Carway	798,360	314,402	2.4370	2.8970
8	**TOTAL CORE SUPPLY**	18,515,159	18,458,696	$1.7535	$2.5363
9					
10	* "This year average commodity cost" of $1.7186 in the 1999 Annual Report did not				
11	include Rosza. We have restated the 1999 average commodity cost in this year's				
12	report to reflect the inclusion of Rosza.				

Sch. 34

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS - NATURAL GAS 1/ , 2/ & 3/

Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Achieved Savings dkt
Residential E+ Audits - 4/	$327,000	$851,219	-61.58%	11,596
E+ Free Weatherization5/	650,171	162,613	299.83%	7,791
TOTAL	$977,171	$1,013,832	-3.62%	19,387

1/ MPC administrative costs are included here.

2/ No residential audits or weatherization projects were performed among MPC's regulated customers in 2000.

3/ Additional low-income natural gas USB dollars were diredted to MPC's 15% Low-Income Discount.

4/ Expenditures through October 1997. Effective November 21, 1997, Gas conservation programs were assigned to the CTC-RA (Competitive Transition Charge - Regulatory Assets) per MPSC Order 5898d. Small Commercial audit pilot program results are included.

5/ Free Weatherization Program natural gas USB expenditures include gas appliance tune-up, repairs and replacement of condemned appliances, for which no conservation estimates are available. Expenditures through 1997. Effective November 21, 1997, Gas conservation programs were assigned to the CTC-RA (Competitive Transition Charge - Regulatory Assets) per MPSC Order 5898d. Small Commercial audit pilot program results are included.

OVERALL NOTE: In 1999, MPC moved from DSM to Universal System Benefits programs making comparisons difficult. The transition resulted in a reduction of activity in the commercial sector in 1999. In addition to the funds spent in 2000, USB revenues collected in 1999 have been committed to qualifying activities in 2000. These investments do not include the funds or results related to self-directed activities by qualifying USB Large Customers. USB funds are directed to low income energy assistance, conservation, market transformation, revewable resources, and research and development. Additional USB funds collected in 2000 will be directed to residential and commercial conservation and market transformation funds.

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

Sch. 35		MONTANA CONSUMPTION AND REVENUES - NATURAL GAS					
		Operating Revenues		MCF Sold		Average Customers	
		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	Sales of Natural Gas						
2							
3	Residential	$ 69,806,882	$60,420,611	12,499,817	12,657,878	133,082	129,888
4	Commercial	30,965,854	27,376,692	5,881,594	5,618,834	18,437	17,892
5	Industrial Firm	3,293,973	1,254,911	211,421	281,461	364	398
6	Public Authorities	123,664	-11,586	10,422	-27,020	13	8
7	Interdepartmental	387,754	198,189	47,999	39,088	80	37
8	CNG Station	10,624	10,469	234	3,035	-	
9	Sales to Other Utilities	662,300	611,451	222,992	228,729	3	1
10	TOTAL SALES	105,251,051	89,860,737	18,874,479	18,802,005	151,979	148,224
11		Operating Revenues		Dkt Transported		Average Customers	
12		Current	Previous	Current	Previous	Current	Previous
13		Year	Year	Year	Year	Year	Year
14	Transportation of Gas						
15							
16	Firm - DBU	1,793,725	1,690,808	3,140,550	3,184,167	214	214
17	Firm - S & TBU	8,182,737	7,408,536	11,459,101	11,631,664	19	19
18							
19	Interruptible - DBU	83,275	19,240	193,260	163,954	5	5
20	Interruptible - S & TBU	1,207,768	712,476	5,242,698	5,096,505	1	1
21	Interruptible - Off System	976,258	1,945,988	3,466,365	4,565,454		
22	Sales Subscriptions						
23							
24	Firm - GTAC Refund						
25	Interruptible - GTAC Balance						
26	Gathering & Processing						
27							
28	Storage	2,507,240	2,079,928	-	-		
29							
30	**TOTAL TRANSPORTATION**	$14,751,003	$13,856,976	23,501,974	24,641,744	239	239