BALANCE SHEET

Year: 2003

	Account Number & Title		Last Year	This Year	% Change
1		**Assets and Other Debits**			
2	Utility Plant				
3	101	Electric Plant in Service	$558,559,354	$587,604,301	5.20%
4	101.1	Property Under Capital Leases			
5	102	Electric Plant Purchased or Sold			
6	104	Electric Plant Leased to Others			
7	105	Electric Plant Held for Future Use			
8	106	Completed Constr. Not Classified - Electric			
9	107	Construction Work in Progress - Electric	14,319,115	5,593,056	-60.94%
10	108	(Less) Accumulated Depreciation	(328,623,237)	(340,950,610)	3.75%
11	111	(Less) Accumulated Amortization	(1,671,723)	(2,105,038)	25.92%
12	114	Electric Plant Acquisition Adjustments	10,387,643	10,387,643	0.00%
13	115	(Less) Accum. Amort. Electric Plant Acq. Adj.	(6,749,038)	(7,163,298)	6.14%
14	120	Nuclear Fuel (Net)			
15		Other Utility Plant	282,807,260	291,260,321	2.99%
16		Accum. Depr. and Amort. - Other Utl. Plant	(159,439,636)	(162,265,813)	1.77%
17		**TOTAL Utility Plant**	$369,589,738	$382,360,562	3.46%
18	**Other Property & Investments**				
19	121	Nonutility Property	$174,544	$1,036,084	493.59%
20	122	(Less) Accum. Depr. & Amort. of Nonutil. Prop.	(79,695)	(353,568)	343.65%
21	123	Investments in Associated Companies			
22	123.1	Investments in Subsidiary Companies	1,130,703,822	1,278,850,163	13.10%
23	124	Other Investments	26,757,835	22,254,889	-16.83%
24	125	Sinking Funds			
25		**TOTAL Other Property & Investments**	$1,157,556,506	$1,301,787,568	12.46%
26	**Current & Accrued Assets**				
27	131	Cash	$5,959,888	$861,378	-85.55%
28	132-134	Special Deposits	1,200	1,200	0.00%
29	135	Working Funds	130,965	15,965	-87.81%
30	136	Temporary Cash Investments	3,297,879	8,529,412	158.63%
31	141	Notes Receivable			
32	142	Customer Accounts Receivable	28,398,322	37,004,255	30.30%
33	143	Other Accounts Receivable	2,365,820	3,987,038	68.53%
34	144	(Less) Accum. Provision for Uncollectible Accts.	(241,038)	(319,419)	32.52%
35	145	Notes Receivable - Associated Companies			
36	146	Accounts Receivable - Associated Companies	16,147,799	17,473,063	8.21%
37	151	Fuel Stock	2,233,437	2,753,765	23.30%
38	152	Fuel Stock Expenses Undistributed			
39	153	Residuals and Extracted Products			
40	154	Plant Materials and Operating Supplies	5,894,011	6,197,652	5.15%
41	155	Merchandise	1,012,624	1,139,740	12.55%
42	156	Other Material & Supplies			
43	163	Stores Expense Undistributed			
44	164.1	Gas Stored Underground - Current	15,322,047	18,438,454	20.34%
45	165	Prepayments	7,220,656	8,839,446	22.42%
46	166	Advances for Gas Explor., Devl. & Production			
47	171	Interest & Dividends Receivable			
48	172	Rents Receivable			
49	173	Accrued Utility Revenues	20,628,893	27,625,923	33.92%
50	174	Miscellaneous Current & Accrued Assets	57,814	117,438	103.13%
51		**TOTAL Current & Accrued Assets**	$108,430,317	$132,665,310	22.35%

BALANCE SHEET

	Account Number & Title	Last Year	This Year	% Change
1	**Assets and Other Debits (cont.)**			
2				
3	**Deferred Debits**			
4				
5	181 Unamortized Debt Expense	$1,123,696	$1,533,592	36.48%
6	182.1 Extraordinary Property Losses			
7	182.2 Unrecovered Plant & Regulatory Study Costs			
	182.3 Other Regulatory Assets	3,651,680	4,744,491	29.93%
	183 Prelim. Electric Survey & Investigation Chrg.	1,686,727	1,127,322	-33.17%
8	183.1 Prelim. Nat. Gas Survey & Investigation Chrg.			
9	183.2 Other Prelim. Nat. Gas Survey & Invtg. Chrgs.			
10	184 Clearing Accounts	(40,451)	(124,215)	207.08%
11	185 Temporary Facilities			
12	186 Miscellaneous Deferred Debits	19,360,006	22,910,284	18.34%
13	187 Deferred Losses from Disposition of Util. Plant			
14	188 Research, Devel. & Demonstration Expend.			
15	189 Unamortized Loss on Reacquired Debt	5,627,511	4,518,768	-19.70%
16	190 Accumulated Deferred Income Taxes	20,176,715	21,238,378	5.26%
17	191 Unrecovered Purchased Gas Costs	(2,396,235)	10,518,527	-538.96%
18	192.1 Unrecovered Incremental Gas Costs			
19	192.2 Unrecovered Incremental Surcharges			
20	**TOTAL Deferred Debits**	$49,189,649	$66,467,147	35.12%
21				
22	**TOTAL ASSETS & OTHER DEBITS**	$1,684,766,210	$1,883,280,587	11.78%
	Account Number & Title	This Year	This Year	% Change
23	**Liabilities and Other Credits**			
24				
25	**Proprietary Capital**			
26				
27	201 Common Stock Issued	$74,282,038	$113,716,632	53.09%
28	202 Common Stock Subscribed			
29	204 Preferred Stock Issued	16,300,000	15,000,000	-7.98%
30	205 Preferred Stock Subscribed			
31	207 Premium on Capital Stock	751,331,277	761,023,634	1.29%
32	211 Miscellaneous Paid-In Capital			
33	213 (Less) Discount on Capital Stock			
34	214 (Less) Capital Stock Expense	(3,236,160)	(3,236,160)	0.00%
35	216 Appropriated Retained Earnings	44,231,211	47,203,550	6.72%
36	216.1 Unappropriated Retained Earnings	430,566,718	528,082,638	22.65%
37	217 (Less) Reacquired Capital Stock			
38	219 Accumulated Other Comprehensive Income	(9,803,865)	(7,528,653)	23.21%
39	**TOTAL Proprietary Capital**	$1,303,671,219	$1,454,261,641	11.55%
40				
41	**Long Term Debt**			
42				
43	221 Bonds	$130,850,000	$160,850,000	22.93%
44	222 (Less) Reacquired Bonds			
45	223 Advances from Associated Companies			
46	224 Other Long Term Debt	52,000,000	42,700,000	-17.88%
47	225 Unamortized Premium on Long Term Debt			
48	226 (Less) Unamort. Discount on Long Term Debt-Dr.	(41,116)	(36,671)	-10.81%
49	**TOTAL Long Term Debt**	$182,808,884	$203,513,329	11.33%

BALANCE SHEET

Year: 2003

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Total Liabilities and Other Credits (cont.)**			
3					
4	**Other Noncurrent Liabilities**				
5					
6	227	Obligations Under Cap. Leases - Noncurrent			
7	228.1	Accumulated Provision for Property Insurance			
8	228.2	Accumulated Provision for Injuries & Damages	$1,415,463	$1,017,175	-28.14%
9	228.3	Accumulated Provision for Pensions & Benefits	24,086,968	29,785,661	23.66%
10	228.4	Accumulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds	67,067	299,228	346.16%
12	230	Asset Retirement Obligations		602,589	100.00%
13		**TOTAL Other Noncurrent Liabilities**	$25,569,498	$31,704,653	23.99%
14					
15	**Current & Accrued Liabilities**				
16					
17	231	Notes Payable	$8,000,000	$0	-100.00%
18	232	Accounts Payable	18,828,269	26,572,779	41.13%
19	233	Notes Payable to Associated Companies			
20	234	Accounts Payable to Associated Companies	5,882,199	7,113,407	20.93%
21	235	Customer Deposits	1,472,979	1,584,497	7.57%
22	236	Taxes Accrued	(464,747)	10,323,491	2321.31%
23	237	Interest Accrued	2,212,959	2,307,669	4.28%
24	238	Dividends Declared	17,959,379	19,458,320	8.35%
25	239	Matured Long Term Debt			
26	240	Matured Interest			
27	241	Tax Collections Payable	1,210,339	1,662,094	37.32%
28	242	Miscellaneous Current & Accrued Liabilities	10,489,414	10,665,144	1.68%
29	243	Obligations Under Capital Leases - Current			
30		**TOTAL Current & Accrued Liabilities**	$65,590,791	$79,687,401	21.49%
31					
32	**Deferred Credits**				
33					
34	252	Customer Advances for Construction	$1,533,151	$1,284,167	-16.24%
35	253	Other Deferred Credits	3,058,287	2,461,954	-19.50%
36	254	Other Regulatory Liabilities	14,584,248	16,816,218	15.30%
37	255	Accumulated Deferred Investment Tax Credits	15,563,924	15,633,652	0.45%
38	256	Deferred Gains from Disposition Of Util. Plant			
39	257	Unamortized Gain on Reacquired Debt			
40	281-283	Accumulated Deferred Income Taxes	72,386,208	77,917,572	7.64%
41		**TOTAL Deferred Credits**	$107,125,818	$114,113,563	6.52%
42					
43	**TOTAL LIABILITIES & OTHER CREDITS**		$1,684,766,210	$1,883,280,587	11.78%

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
MDU Resources Group, Inc.	(1) X An Original (2) _ A Resubmission	12/31/2003	Dec 31, 2003

NOTES TO FINANCIAL STATEMENTS (Continued)

NOTE 1

Summary of Significant Accounting Policies

Basis of presentation

The consolidated financial statements of MDU Resources Group, Inc. and its subsidiaries (Company) include the accounts of the following businesses: electric, natural gas distribution, utility services, pipeline and energy services, natural gas and oil production, construction materials and mining, and independent power production and other. The electric, natural gas distribution, and pipeline and energy services businesses are substantially all regulated. Utility services, natural gas and oil production, construction materials and mining, and independent power production and other are nonregulated. For further descriptions of the Company's businesses, see Note 14. The statements also include the ownership interests in the assets, liabilities and expenses of two jointly owned electric generation stations.

The Company uses the equity method of accounting for certain investments including its 49 percent interest in MPX Participacoes, Ltda. (MPX), which was formed to develop electric generation and transmission, steam generation, power equipment and coal mining projects in Brazil. For more information on the Company's equity investments, see new accounting standards in Note 1, as well as Note 2.

The Company's regulated businesses are subject to various state and federal agency regulation. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC). These accounting policies differ in some respects from those used by the Company's nonregulated businesses.

The Company's regulated businesses account for certain income and expense items under the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Regulation." SFAS No. 71 requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 4 for more information regarding the nature and amounts of these regulatory deferrals.

Prior to the sale of the Company's coal operations in 2001, as discussed in Note 14, intercompany coal sales, which were made at prices approximately the same as those charged to others, and the related utility fuel purchases were not eliminated in accordance with the provisions of SFAS No. 71. All other significant intercompany balances and transactions have been eliminated in consolidation.

Cash and cash equivalents

The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Allowance for doubtful accounts

The Company's allowance for doubtful accounts as of December 31, 2003 and 2002, was $8.1 million and $8.2 million, respectively.

Natural gas in underground storage

Natural gas in underground storage for the Company's regulated operations is carried at cost using the last-in, first-out method. The portion of the cost of natural gas in underground storage expected to be used within one year was included in inventories and amounted to $19.6 million at December 31, 2003, and $18.2 million at December 31, 2002. The remainder of natural gas in underground storage was included in other assets and was $42.6 million at December 31, 2003, and $42.2 million at December 31, 2002.

Inventories

Inventories, other than natural gas in underground storage for the Company's regulated operations, consisted primarily of aggregates held for resale of $54.7 million and $39.6 million, materials and supplies of $27.2 million and $23.0 million, and other inventories of $12.6 million and $12.3 million, as of December 31, 2003 and 2002, respectively. These inventories were stated at the lower of average cost or market.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost when first placed in service. Acquired aggregate reserves at the Company's construction materials and mining business are classified based on type of ownership. Owned mineral rights are classified as property, plant and equipment, whereas leased mineral rights are classified as other intangible assets, net. For more information on other intangible assets, net, see Note 3. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for natural gas and oil production properties as described in natural gas and oil properties in Note 1, the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize an allowance for funds used during construction (AFUDC) on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. In addition, the Company capitalizes interest, when applicable, on certain construction projects associated with its other operations. The amount of AFUDC and interest capitalized was $7.4 million, $7.6 million and $6.6 million in 2003, 2002 and 2001, respectively. Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable reserves, which are depleted based on the units-of-production method based on recoverable deposits, and natural gas and oil production properties, which are amortized on the units-of-production method based on total reserves.

Property, plant and equipment at December 31, 2003 and 2002, was as follows:

	2003	2002	Estimated Depreciable Life in Years
	(Dollars in thousands, as applicable)		
Regulated:			
Electric:			
Electric generation, distribution and transmission plant	$ 639,893	$ 619,230	4-50
Natural gas distribution:			
Natural gas distribution plant	252,591	244,930	4-40
Pipeline and energy services:			
Natural gas transmission, gathering and storage facilities	340,841	262,971	3-70
Nonregulated:			
Utility services:			
Land	2,505	2,601	---
Buildings and improvements	10,123	8,768	10-40
Machinery, vehicles and equipment	58,843	54,833	2-10
Other	5,400	4,458	3-10
Pipeline and energy services:			
Natural gas gathering and other facilities	119,613	108,179	3-20
Energy services	1,339	1,270	3-15
Natural gas and oil production:			
Natural gas and oil properties	862,839	748,843	(a)
Other	8,518	6,945	5-7
Construction materials and mining:			

Land	89,545	85,376	---
Buildings and improvements	48,907	43,144	1-40
Machinery, vehicles and equipment	569,295	493,349	1-25
Construction in progress	14,392	10,151	---
Depletable reserves	171,841	172,235	(b)
Independent power production and other:			
Electric generation	153,947	58,000	5-30
Construction in progress	29,805	19,342	---
Land	2,001	2,001	---
Other	15,381	15,182	3-20
Less accumulated depreciation, depletion and amortization	1,175,326	1,019,438	
Net property, plant and equipment	$ 2,222,293	$ 1,942,370	

(a) Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent rate of $.89, $.80, and $.78 for the years ended December 31, 2003, 2002 and 2001, respectively. Includes natural gas and oil production properties accounted for under the full-cost method, of which $104,339 and $145,692 were excluded from amortization at December 31, 2003 and 2002, respectively.
(b) Depleted based on the units-of-production method based on recoverable deposits.

Impairment of long-lived assets
The Company reviews the carrying values of its long-lived assets, excluding goodwill, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. No long-lived assets have been impaired and, accordingly, no impairment losses have been recorded in 2003, 2002 and 2001. Unforeseen events and changes in circumstances could require the recognition of other impairment losses at some future date.

Goodwill
Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. On January 1, 2002, the Company adopted SFAS No. 142, "Goodwill and Other Intangibles," and ceased amortization of its goodwill. Goodwill is required to be tested for impairment annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. In accordance with SFAS No. 142, the Company performed its transitional goodwill impairment testing as of January 1, 2002, and performed its annual goodwill impairment testing as of October 31, 2003 and 2002, and determined that no impairments existed at those dates. Therefore, no impairment loss has been recorded for the years ended December 31, 2003 and 2002. For more information on goodwill, see Note 3.

Natural gas and oil properties
The Company uses the full-cost method of accounting for its natural gas and oil production activities. Under this method, all costs incurred in the acquisition, exploration and development of natural gas and oil properties are capitalized and amortized on the units-of-production method based on total proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are treated as adjustments to the cost of the properties with no gain or loss recognized. Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net revenues of proved reserves based on single point-in-time spot market prices, as mandated under the rules of the Securities and Exchange Commission, and the lower of cost or fair value of unproved properties. Future net revenue is estimated based on end-of-quarter spot market prices adjusted for contracted price changes. If capitalized costs exceed the full-cost ceiling at the end of any quarter, a permanent noncash

write-down is required to be charged to earnings in that quarter unless subsequent price changes eliminate or reduce an indicated write-down.

At December 31, 2003 and 2002, the Company's full-cost ceiling exceeded the Company's capitalized cost. However, sustained downward movements in natural gas and oil prices subsequent to December 31, 2003, could result in a future write-down of the Company's natural gas and oil properties.

The following table summarizes the Company's natural gas and oil properties not subject to amortization at December 31, 2003, in total and by year in which such costs were incurred:

		Year Costs Incurred			
	Total	2003	2002	2001	2000 and prior
			(In thousands)		
Acquisition	$ 48,355	$ 630	$ 17,108	$---	$30,617
Development	39,160	28,351	5,120	---	5,689
Exploration	4,885	4,828	---	23	34
Capitalized interest	11,939	5,642	6,297	---	---
Total costs not subject to amortization	$104,339	$ 39,451	$ 28,525	$ 23	$ 36,340

Costs not subject to amortization as of December 31, 2003, consisted primarily of lease acquisition costs, unevaluated drilling costs and capitalized interest associated with coalbed development in the Powder River Basin of Montana and Wyoming. The Company expects that the majority of these costs will be evaluated over the next three- to five-year period and included in the amortization base as the properties are developed and evaluated and proved reserves are established or impairment is determined.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is probable. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed later. The Company recognizes revenue from natural gas and oil production activities only on that portion of production sold and allocable to the Company's ownership interest in the related well. Revenues at the independent power production operations are recognized based on electricity delivered and capacity provided, pursuant to contractual commitments. The Company recognizes all other revenues when services are rendered or goods are delivered.

Percentage-of-completion method

The Company recognizes construction contract revenue from fixed price and modified fixed price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. Costs in excess of billings on uncompleted contracts of $31.8 million and $19.4 million for the years ended December 31, 2003 and 2002, respectively, represents revenues recognized in excess of amounts billed and was included in receivables, net. Billings in excess of costs on uncompleted contracts of $20.4 million and $24.5 million for the years ended December 31, 2003 and 2002, respectively, represents billings in excess of revenues recognized and was included in accounts payable. Also included in receivables, net were amounts representing balances billed but not paid by customers under retainage provisions in contracts that amounted to $34.3 million and $25.6 million as of December 31, 2003 and 2002, respectively, which are expected to be paid within one year or less.

Derivative instruments
The Company's policy allows the use of derivative instruments as part of an overall energy price, foreign currency and interest rate risk management program to efficiently manage and minimize commodity price, foreign currency and interest rate risk. The Company's policy prohibits the use of derivative instruments for speculating to take advantage of market trends and conditions and the Company has procedures in place to monitor compliance with its policies. The Company is exposed to credit-related losses in relation to derivative instruments in the event of nonperformance by counterparties. The Company's policy requires settlement of natural gas and oil price derivative instruments monthly and all interest rate derivative transactions must be settled over a period that will not exceed 90 days, and any foreign currency derivative transaction settlement periods may not exceed a 12-month period. The Company has policies and procedures that management believes minimize credit-risk exposure. These policies and procedures include an evaluation of potential counterparties' credit ratings and credit exposure limitations. Accordingly, the Company does not anticipate any material effect to its financial position or results of operations as a result of nonperformance by counterparties.

Advertising
The Company expenses advertising costs as incurred and the amount of advertising expense for the years 2003, 2002 and 2001, was $3.9 million, $3.4 million and $2.9 million, respectively.

Natural gas costs recoverable or refundable through rate adjustments
Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 24 months to 28 months from the time such costs are paid. Natural gas costs recoverable through rate adjustments amounted to $10.5 million at December 31, 2003, which is included in prepayments and other current assets. Natural gas costs refundable through rate adjustments amounted to $2.4 million at December 31, 2002, which is included in other accrued liabilities.

Insurance
Certain subsidiaries of the Company are insured for workers' compensation losses, subject to deductibles ranging up to $500,000 per occurrence. Automobile liability and general liability losses are insured, subject to deductibles ranging up to $500,000 per accident or occurrence. These subsidiaries have excess coverage on a claims first-made basis beyond the deductible levels. The subsidiaries of the Company are retaining losses up to the deductible amounts accrued on the basis of estimates of liability for claims incurred and claims incurred but not reported.

Other income - net
Other income - net consisted of the following:

Years ended December 31,	2003	2002	2001
		(In thousands)	
Interest and dividend income	$ 6,722	$ 8,160	$ 5,734
Earnings from equity method investments (Note 2)	5,968	1,341	154
Other income	9,517	4,071	20,933
Total other income - net	$22,207	$13,572	$26,821

Income taxes
The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities resulting from the Company's adoption of SFAS No. 109, "Accounting for Income Taxes," have been recorded as a regulatory liability and are included in other liabilities. These regulatory

liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

The Company uses the deferral method of accounting for investment tax credits and amortizes the credits on electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

Foreign currency translation adjustment
The functional currency of the Company's investment in a 220-megawatt natural gas-fired electric generating facility in Brazil, as further discussed in Note 2, is the Brazilian real. Translation from the Brazilian real to the U.S. dollar for assets and liabilities is performed using the exchange rate in effect at the balance sheet date. Revenues and expenses have been translated using the weighted average exchange rate for each month prevailing during the period reported. Adjustments resulting from such translations are reported as a separate component of other comprehensive income (loss) in common stockholders' equity.

Transaction gains and losses resulting from the effect of exchange rate changes on transactions denominated in a currency other than the functional currency of the reporting entity are recorded in income.

Common stock split
On August 14, 2003, the Company's Board of Directors approved a three-for-two common stock split. For more information on the common stock split, see Note 11.

Earnings per common share
Basic earnings per common share were computed by dividing earnings on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding stock options, restricted stock grants and performance share awards. For the years ended December 31, 2003, 2002 and 2001, 209,805 shares, 3,674,925 shares and 225,945 shares, respectively, with an average exercise price of $24.56, $20.08 and $24.57, respectively, attributable to the exercise of outstanding options, were excluded from the calculation of diluted earnings per share because their effect was antidilutive. For the years ended December 31, 2003, 2002 and 2001, no adjustments were made to reported earnings in the computation of earnings per share. Common stock outstanding includes issued shares less shares held in treasury.

Stock-based compensation
The Company has stock option plans for directors, key employees and employees. In 2003, the Company adopted the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," and began expensing the fair market value of stock options for all awards granted on or after January 1, 2003. Compensation expense recognized for awards granted on or after January 1, 2003, for the year ended December 31, 2003, was $41,000 (after tax).

As permitted by SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure - an amendment of SFAS No. 123," the Company accounts for stock options granted prior to January 1, 2003, under APB Opinion No. 25, "Accounting for Stock Issued to Employees." No compensation expense has been recognized for stock options granted prior to January 1, 2003, as the options granted had an exercise price equal to the market value of the underlying common stock on the date of the grant.

Since the Company adopted SFAS No. 123 effective January 1, 2003, for newly granted options only, the following table illustrates the effect on earnings and earnings per common share for the years ended December 31, 2003, 2002 and 2001, as if the Company had applied SFAS No. 123 and recognized compensation expense for all outstanding and unvested stock options based on the fair value at the date of grant:

	2003	2002	2001
	(In thousands, except per share amounts)		
Earnings on common stock, as reported	$ 174,607	$ 147,688	$ 155,087
Stock-based compensation expense included in reported earnings, net of related tax effects	41	---	---
Total stock-based compensation expense determined under fair value method for all awards, net of related tax effects	(2,139)	(2,862)	(3,799)
Pro forma earnings on common stock	$ 172,509	$ 144,826	$ 151,288
Earnings per common share -- basic -- as reported:			
Earnings before cumulative effect of accounting change	$ 1.64	$ 1.39	$ 1.54
Cumulative effect of accounting change	(.07)	---	---
Earnings per common share -- basic	$ 1.57	$ 1.39	$ 1.54
Earnings per common share -- basic -- pro forma:			
Earnings before cumulative effect of accounting change	$ 1.62	$ 1.36	$ 1.50
Cumulative effect of accounting change	(.07)	---	---
Earnings per common share -- basic	$ 1.55	$ 1.36	$ 1.50
Earnings per common share -- diluted -- as reported:			
Earnings before cumulative effect of accounting change	$ 1.62	$ 1.38	$ 1.52
Cumulative effect of accounting change	(.07)	---	---
Earnings per common share -- diluted	$ 1.55	$ 1.38	$ 1.52
Earnings per common share -- diluted -- pro forma:			
Earnings before cumulative effect of accounting change	$ 1.60	$ 1.36	$ 1.49
Cumulative effect of accounting change	(.07)	---	---
Earnings per common share -- diluted	$ 1.53	$ 1.36	$ 1.49

For more information on the Company's stock-based compensation, see Note 12.

Use of estimates
The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Estimates are used for items such as impairment testing of long-lived assets, goodwill and natural gas and oil properties; fair values of acquired assets and liabilities under the purchase method of accounting; natural gas and oil reserves; property depreciable lives; tax provisions;

uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; the valuation of stock-based compensation; and the fair value of derivative instruments, including the fair value of an embedded derivative in a power purchase agreement related to an equity method investment in Brazil, as discussed in Note 2. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash flow information

Cash expenditures for interest and income taxes were as follows:

Years ended December 31,	2003	2002	2001
		(In thousands)	
Interest, net of amount capitalized	$47,474	$37,788	$42,267
Income taxes	$31,737	$60,988	$75,284

Reclassifications

The Consolidated Statements of Income have been reclassified to include additional disclosures relating to the components comprising operating revenues and operation and maintenance expense.

Certain other reclassifications have been made in the financial statements for prior years to conform to the current presentation. Such reclassifications had no effect on net income or stockholders' equity as previously reported.

New accounting standards

The Company has stock option plans for directors, key employees and employees. In 2003, the Company adopted the fair value recognition provisions of SFAS No. 123, and began expensing the fair market value of stock options for all awards granted on or after January 1, 2003. For a discussion of the effect of the adoption of the fair value recognition provisions of SFAS No. 123 on earnings and earnings per share, see stock-based compensation in Note 1.

In June 2001, the Financial Accounting Standards Board (FASB) approved SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for the recorded amount or incurs a gain or loss. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. For more information on the adoption of SFAS No. 143, see Note 9.

In April 2002, the FASB approved SFAS No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections." FASB No. 4 required all gains or losses from extinguishment of debt to be classified as extraordinary items net of income taxes. SFAS No. 145 requires that gains and losses from extinguishment of debt be evaluated under the provisions of APB Opinion No. 30, and be classified as ordinary items unless they are unusual or infrequent or meet the specific criteria for treatment as an extraordinary item. SFAS No. 145 is effective for fiscal years beginning after May 15, 2002. The adoption of SFAS No. 145 did not have a material effect on the Company's financial position or results of operations.

In November 2002, the FASB issued FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 clarifies the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. FIN 45 also requires a guarantor to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing certain types of guarantees. Certain types of guarantees are not subject to the initial recognition and measurement provisions of FIN 45 but are subject to its disclosure requirements. The initial recognition and initial measurement provisions of FIN 45 are applicable on a prospective basis to guarantees issued or modified after December 31, 2002, regardless of the guarantor's fiscal year-end. The guarantor's previous accounting for guarantees issued prior to the date of the initial application of FIN 45 is not required to be revised or restated. The disclosure requirements in FIN 45 are effective for financial statements of interim or annual periods ended after December 15, 2002. The Company is applying the initial recognition and initial measurement provisions of FIN 45 to guarantees issued or modified after December 31, 2002. For more information on the Company's guarantees and the disclosure requirements of FIN 45, as applicable to the Company, see Note 19.

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS No. 149 provides clarification on the financial accounting and reporting of derivative instruments, including certain derivative instruments embedded in other contracts, and hedging activities; and requires contracts with similar characteristics to be accounted for on a comparable basis. SFAS No. 149 is generally effective for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. The adoption of SFAS No. 149 did not have a material effect on the Company's financial position or results of operations.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity." SFAS No. 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within the scope of SFAS No. 150 as a liability (or an asset in some circumstances). SFAS No. 150 is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. The Company will apply SFAS No. 150 to any financial instruments entered into or modified after May 31, 2003. Beginning in 2003, the Company reported its preferred stock subject to mandatory redemption as a liability in accordance with SFAS No. 150. The transition to SFAS No. 150 did not have a material effect on the Company's financial position or results of operations.

In December 2003, the FASB issued FASB Interpretation No. 46 (revised 2003), "Consolidation of Variable Interest Entities" (FIN 46 (revised)), which revised FASB Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46). FIN 46 (revised) clarifies the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated support. An enterprise shall consolidate a variable interest entity if that enterprise is the primary beneficiary. An enterprise is considered the primary beneficiary if it has a variable interest that will absorb a majority of the entity's expected losses, receive a majority of the entity's expected residual returns or both.

FIN 46 (revised) shall be applied to all entities subject to FIN 46 (revised) no later than the end of the first reporting period that ends after March 15, 2004. However, an entity that applied FIN 46 to an entity prior to the effective date of FIN 46 (revised) shall either continue to apply FIN 46 until the effective date of FIN 46 (revised) or apply FIN 46 (revised) at an earlier date.

The Company had evaluated the provisions of FIN 46 and determined that MPX is a variable interest entity. MPX was formed in August 2001, as a result of MDU Brasil Ltda. (MDU Brasil), an indirect wholly owned Brazilian subsidiary of the Company, entering into a joint venture agreement with a Brazilian firm. MDU Brasil has a 49 percent interest in MPX. Although the Company has determined that MPX is a variable interest entity, MDU Brasil is not considered the primary beneficiary of MPX because MDU Brasil does not absorb a majority of MPX's expected losses, receive a majority of MPX's expected residual returns or both. Therefore, MDU Brasil does not have a controlling financial interest in MPX and is not required to consolidate MPX in its financial statements. MPX is being accounted for under the equity method of accounting. For more information on this equity method investment, see Note 2. The adoption of FIN 46 did not have an effect on the Company's financial position or results of operations. The Company will continue to apply FIN 46 until the effective date of FIN 46 (revised).

In December 2003, the FASB issued SFAS No. 132 (revised 2003), "Employers' Disclosures about Pension and Other Postretirement Benefits." SFAS No. 132 (revised 2003) retains the disclosure requirements contained in SFAS No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits," and requires additional disclosures about the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other postretirement benefit plans. SFAS No. 132 (revised 2003) is effective for financial statements with fiscal years ending after December 15, 2003. The interim-period disclosures required by SFAS No. 132 (revised 2003) are effective for interim periods beginning after December 15, 2003. The Company applied SFAS No. 132 (revised 2003) to its consolidated financial statements issued after December 15, 2003. For more information on the Company's pension and other postretirement benefits, see Note 16.

In January 2004, the FASB issued FASB Staff Position No. FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." FASB Staff Position No. FAS 106-1 permits a sponsor of a postretirement health care plan that provides a prescription drug benefit to make a one-time election to defer accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (2003 Medicare Act). SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other than Pension," requires enacted changes in relevant laws to be considered in current period measurements of postretirement benefit costs and accumulated postretirement benefit obligation. The Company provides prescription drug benefits to certain eligible employees and has elected the one-time deferral of accounting for the effects of the 2003 Medicare Act. These consolidated financial statements and accompanying notes do not reflect the effects of the 2003 Medicare Act on the postretirement benefit plans. The Company intends to analyze the 2003 Medicare Act, along with the authoritative guidance, when issued, to determine if its benefit plans need to be amended and how to record the effects of the 2003 Medicare Act. Specific guidance on the accounting for the federal subsidy provided by the 2003 Medicare Act is pending and that guidance, when issued, could require the Company to change previously reported postretirement benefit information. For more information on the Company's postretirement benefits, see Note 16.

Comprehensive income
Comprehensive income is the sum of net income as reported and other comprehensive income (loss). The Company's other comprehensive income (loss) resulted from gains and losses on derivative instruments qualifying as hedges, minimum pension liability adjustments and foreign currency translation adjustments.

The components of other comprehensive income (loss), and their related tax effects for the years ended December 31, 2003, 2002 and 2001, were as follows:

	2003	2002 (In thousands)	2001
Other comprehensive income (loss):			
Net unrealized gain (loss) on derivative instruments qualifying as hedges:			
Unrealized loss on derivative			

instruments at January 1, 2001, due to cumulative effect of a change in accounting principle, net of tax of $3,970 in 2001	$ ---	$ ---	$(6,080)
Net unrealized gain (loss) on derivative instruments arising during the period, net of tax of $2,132, $2,903 and $1,448 in 2003, 2002 and 2001, respectively	(3,335)	(4,541)	2,218
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $2,903, $1,448 and $3,970 in 2003, 2002 and 2001, respectively	(4,541)	2,218	(6,080)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	1,206	(6,759)	2,218
Minimum pension liability adjustment, net of tax of $38 and $2,876 in 2003 and 2002, respectively	21	(4,464)	---
Foreign currency translation adjustment	1,048	(799)	---
Total other comprehensive income (loss)	$ 2,275	$(12,022)	$ 2,218

The after-tax components of accumulated other comprehensive income (loss) as of December 31, 2003, 2002 and 2001, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Minimum Pension Liability Adjustment	Foreign Currency Translation Adjustment	Total Accumulated Other Comprehensive Income (Loss)
		(In thousands)		
Balance at December 31, 2001	$ 2,218	$ ---	$ ---	$ 2,218
Balance at December 31, 2002	$ (4,541)	$ (4,464)	$ (799)	$ (9,804)
Balance at December 31, 2003	$ (3,335)	$ (4,443)	$ 249	$ (7,529)

NOTE 2

Equity Method Investments

The Company has a number of equity method investments, including MPX, which was formed in August 2001 when MDU Brasil entered into a joint venture agreement with a Brazilian firm. MDU Brasil has a 49 percent interest in MPX, which is being accounted for under the equity method of accounting, as discussed in Note 1. MPX, through a wholly owned subsidiary, owns a 220-megawatt natural gas-fired electric generating facility (Brazil Generating Facility) in the Brazilian state of Ceara. At December 31, 2003, MPX has assets of approximately $109.6 million and long-term debt of approximately $86.8 million, including a loan of $20.0 million from Centennial Energy Resources International Inc, an indirect wholly owned subsidiary of the Company. Petrobras, the Brazilian state-controlled energy company, has agreed to purchase all of the capacity and market all of the Brazil Generating Facility's energy. The power purchase agreement with Petrobras expires in May 2008. Petrobras also is under contract to supply natural gas to the Brazil Generating Facility during the term of the power purchase agreement. This natural gas supply contract is renewable by a wholly owned subsidiary of MPX for an additional 13 years. The functional currency for the Brazil Generating Facility is the Brazilian real. The power purchase agreement with Petrobras contains an embedded derivative, which derives its value from an annual adjustment factor, which largely indexes the contract capacity payments to the U.S. dollar. For the year ended December 31, 2003, the Company's 49 percent share of the loss from the change in the fair value of the embedded derivative in the power purchase agreement was $11.3 million (after tax). For the year ended December 31, 2002, the Company's 49 percent share of the gain from the change in the fair value of the embedded derivative in the power purchase agreement was $13.6 million (after tax). The Company's 49 percent share of the foreign currency gain resulting from the revaluation of the Brazilian real was $2.8 million (after tax) for the year ended December 31, 2003. The Company's 49 percent share of the foreign currency loss resulting from devaluation of the Brazilian real was $9.4 million (after tax) for the year ended December 31, 2002. The Company's investment in the Brazil Generating Facility was approximately $25.2 million, including undistributed earnings of $4.6 million at December 31, 2003. The Company's investment in the Brazil Generating Facility was approximately $27.8 million at December 31, 2002.

The Company's share of income from its equity method investments, including MPX, was $6.0 million, $1.3 million and $154,000 for the years ended December 31, 2003, 2002 and 2001, respectively, and was included in other income - net.

NOTE 3
Goodwill and Other Intangible Assets
On January 1, 2002, in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets," the Company ceased amortization of its goodwill recorded in business combinations that occurred on or before June 30, 2001. The following information is presented as if SFAS No. 142 was adopted as of January 1, 2001. The reconciliation of previously reported earnings and earnings per common share to the amounts adjusted for the exclusion of goodwill amortization, net of the related income tax effects, for the years ended December 31, 2003, 2002 and 2001, were as follows:

	2003	2002	2001
	(In thousands, except per share amounts)		
Reported earnings on common stock	$ 174,607	$ 147,688	$ 155,087
Add: Goodwill amortization, net of tax	---	---	3,649
Adjusted earnings on common stock	$ 174,607	$ 147,688	$ 158,736
Reported earnings per common share -- basic	$ 1.57	$ 1.39	$ 1.54
Add: Goodwill amortization, net of tax	---	---	.03
Adjusted earnings per common share -- basic	$ 1.57	$ 1.39	$ 1.57
Reported earnings per common share -- diluted	$ 1.55	$ 1.38	$ 1.52
Add: Goodwill amortization, net of tax	---	---	.04
Adjusted earnings per common share -- diluted	$ 1.55	$ 1.38	$ 1.56

The changes in the carrying amount of goodwill for the year ended December 31, 2003, were as follows:

	Balance as of January 1, 2003	Goodwill Acquired During the Year	Balance as of December 31, 2003
		(In thousands)	
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
MDU Resources Group, Inc.	(1) X An Original (2) _ A Resubmission	12/31/2003	Dec 31, 2003

NOTES TO FINANCIAL STATEMENTS (Continued)

Utility services	62,487	117	62,604
Pipeline and energy services	9,494	---	9,494
Natural gas and oil production	---	---	---
Construction materials and mining	111,887	8,311	120,198
Independent power production and other	7,131	---	7,131
Total	$190,999	$8,428	$199,427

The changes in the carrying amount of goodwill for the year ended December 31, 2002, were as follows:

	Balance as of January 1, 2002	Goodwill Acquired During the Year (In thousands)	Balance as of December 31, 2002
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Utility services	61,909	578	62,487
Pipeline and energy services	9,336	158	9,494
Natural gas and oil production	---	---	---
Construction materials and mining	102,752	9,135	111,887
Independent power production and other	---	7,131	7,131
Total	$173,997	$17,002	$190,999

Other intangible assets at December 31, 2003 and 2002, were as follows:

	2003	2002
	(In thousands)	
Amortizable intangible assets:		
Leasehold rights	$ 186,419	$ 172,496
Accumulated amortization	(11,779)	(7,494)
	174,640	165,002
Noncompete agreements	12,075	12,075
Accumulated amortization	(9,690)	(9,366)
	2,385	2,709
Other	17,734	7,224
Accumulated amortization	(2,265)	(374)
	15,469	6,850
Unamortizable intangible assets	960	1,603
Total	$ 193,454	$ 176,164

Acquired aggregate reserves at our construction materials and mining business are classified based on type of ownership. Owned mineral rights are classified as property, plant and equipment, whereas leased mineral rights are classified as leasehold rights in other intangible assets, net.

The unamortizable intangible assets were recognized in accordance with SFAS No. 87, "Employers' Accounting for Pensions," which requires that if an additional minimum liability is recognized an equal amount shall be recognized as an intangible asset, provided that the asset recognized shall not exceed the amount of unrecognized prior service cost. The unamortizable intangible asset will be eliminated or adjusted as necessary upon a new determination of the amount of additional liability.

Amortization expense for amortizable intangible assets for the years ended December 31, 2003 and 2002, was $5.9 million and $3.4 million, respectively. Estimated amortization expense for amortizable intangible assets is $6.2 million in 2004, $6.4 million in 2005, $5.2 million in 2006, $5.2 million in 2007, $5.2 million in 2008 and $164.3 million thereafter.

SFAS No. 142 discontinues the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review for impairment. Intangible assets with a determinable useful life will continue to be amortized over that period. The amortization provisions apply to goodwill and intangible assets acquired after June 30, 2001. SFAS No. 141, "Business Combinations," and SFAS No. 142 clarify that more assets should be distinguished and classified between tangible and intangible. The Company did not change or reclassify contractual mineral rights included in property, plant and equipment related to its natural gas and oil production business upon adoption of SFAS No. 142. The Company has included such mineral rights as part of property, plant and equipment under the full-cost method of accounting for natural gas and oil properties. An issue has arisen within the natural gas and oil industry as to whether contractual mineral rights under SFAS No. 142 should be classified as intangible rather than as part of property, plant and equipment. This accounting matter is anticipated to be addressed by the FASB's Emerging Issues Task Force. The resolution of this matter may result in certain reclassifications of amounts in the Consolidated Balance Sheets, as well as changes to Notes to Consolidated Financial Statements in the future. The applicable provisions of SFAS No. 141 and SFAS No. 142 only affect the balance sheet and associated footnote disclosure, so any reclassifications that might be required in the future will not affect the Company's cash flows or results of operations. The Company believes that the resolution of this matter will not have a material effect on the Company's financial position because the mineral rights acquired by its natural gas and oil production business after the June 30, 2001, effective date of SFAS No. 142 were not material.

NOTE 4

Regulatory Assets and Liabilities

The following table summarizes the individual components of unamortized regulatory assets and liabilities as of December 31:

	2003	2002
	(In thousands)	
Regulatory assets:		
Deferred income taxes	$ 29,850	$ 27,378
Natural gas costs recoverable through rate adjustments	10,519	---
Long-term debt refinancing costs	4,519	5,627
Plant costs	2,697	2,330
Postretirement benefit costs	562	616
Other	7,159	4,788
Total regulatory assets	55,306	40,739
Regulatory liabilities:		
Plant removal and decommissioning costs	76,176	68,551
Reserves for regulatory matters	11,970	9,856
Taxes refundable to customers	11,751	11,699
Deferred income taxes	10,663	5,491
Natural gas costs refundable through rate adjustments	---	2,396
Other	658	2,779
Total regulatory liabilities	111,218	100,772
Net regulatory position	$ (55,912)	$ (60,033)

As of December 31, 2003, substantially all of the Company's regulatory assets, other than certain deferred income taxes, were being reflected in rates charged to customers and are being recovered over the next one to 19 years.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of SFAS No. 71 for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income as an extraordinary item in the period in which the discontinuance of SFAS No. 71 occurs.

NOTE 5

Derivative Instruments

The Company adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, on January 1, 2001. SFAS No. 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows derivative gains and losses to offset the related results on the hedged item in the income statement and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

SFAS No. 133 requires that as of the date of initial adoption, the difference between the fair market value of derivative instruments recorded on the balance sheet and the previous carrying amount of those derivative instruments be reported in net income or other comprehensive income (loss), as appropriate, as the cumulative effect of a change in accounting principle in accordance with APB Opinion No. 20, "Accounting Changes." On January 1, 2001, the Company reported a net-of-tax cumulative-effect adjustment of $6.1 million in accumulated other comprehensive loss to recognize at fair value all derivative instruments that are designated as cash flow hedging instruments, which the Company reclassified into earnings during the year ended December 31, 2001. The transition to SFAS No. 133 did not have an effect on the Company's net income at adoption.

In the event a derivative instrument being accounted for as a cash flow hedge does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; or if the derivative instrument expires or is sold, terminated or exercised; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting will be discontinued, and the derivative instrument would continue to be carried at fair value with changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in accumulated other comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that had accumulated in other comprehensive income (loss) would be recognized immediately in earnings. In the event of a sale, termination or extinguishment of a foreign currency derivative, the resulting gain or loss would be recognized immediately in earnings. The Company's policy requires approval to terminate a derivative instrument prior to its original maturity.

As of December 31, 2003, an indirect wholly owned subsidiary of the Company held derivative instruments designated as cash flow hedging instruments.

Hedging activities

The subsidiary of the Company utilizes natural gas and oil price swap and collar agreements to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil on the subsidiary's forecasted sales of natural gas and oil production. Each of the natural gas and oil price swap and collar agreements was designated as a hedge of the forecasted sale of natural gas and oil production.

On an ongoing basis, the balance sheet is adjusted to reflect the current fair market value of the swap and collar agreements. The related gains or losses on these agreements are recorded in common stockholders' equity as a component of other comprehensive income (loss). At the date the underlying transaction occurs, the amounts accumulated in other comprehensive income (loss) are reported in the Consolidated Statements of Income. To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings.

For the years ended December 31, 2003, 2002 and 2001, the subsidiary of the Company recognized the ineffectiveness of cash flow hedges, which is included in operating revenues for the natural gas and oil price swap and collar agreements. For the years ended December 31, 2003, 2002 and 2001, the amount of hedge ineffectiveness recognized was immaterial. For the years ended December 31, 2003, 2002 and 2001, the subsidiary did not exclude any components of the derivative instruments' gain or loss from the assessment of hedge effectiveness and there were no reclassifications into earnings as a result of the discontinuance of hedges.

Gains and losses on derivative instruments that are reclassified from accumulated other comprehensive income (loss) to current-period earnings are included in the line item in which the hedged item is recorded. As of December 31, 2003, the maximum term of the subsidiary's swap and collar agreements, in which the subsidiary of the Company is hedging its exposure to the variability in future cash flows for forecasted transactions, is 12 months. The subsidiary of the Company estimates that over the next 12 months net losses of approximately $3.3 million will be reclassified from accumulated other comprehensive income (loss) into earnings, subject to changes in natural gas and oil market prices, as the hedged transactions affect earnings.

Foreign currency derivative
MDU Brasil has a 49 percent equity investment in the Brazil Generating Facility, which has a portion of its borrowings and payables denominated in U.S. dollars. MDU Brasil has exposure to currency exchange risk as a result of fluctuations in currency exchange rates between the U.S. dollar and the Brazilian real. On August 12, 2002, MDU Brasil entered into a foreign currency collar agreement for a notional amount of $21.3 million with a fixed price floor of R$3.10 and a fixed price ceiling of R$3.40 to manage a portion of its foreign currency risk. The term of the collar agreement was from August 12, 2002, through February 3, 2003, and the collar agreement settled on February 3, 2003. The foreign currency collar agreement was not designated as a hedge and was recorded at fair value on the Consolidated Balance Sheets. Gains or losses on this derivative instrument were recorded in other income - net. The Company recorded a gain of $39,000 (after tax) on the foreign currency collar agreement for the year ended December 31, 2003, and a gain of $566,000 (after tax) for the year ended December 31, 2002.

Energy marketing
The Company had entered into other derivative instruments that were not designated as hedges in its energy marketing operations. In the third quarter of 2001, the Company sold the vast majority of its energy marketing operations. Net unrealized gains and losses on these derivative instruments were not material for the year ended December 31, 2001.

NOTE 6
Fair Value of Other Financial Instruments
The estimated fair value of the Company's long-term debt and preferred stock subject to mandatory redemption is based on quoted market prices of the same or similar issues. As discussed in Note 1, the Company, upon adoption of SFAS No. 150 in 2003, began reporting its preferred stock subject to mandatory redemption as a liability. The estimated fair values of the Company's natural gas and oil price swap and collar agreements were included

in current liabilities at December 31, 2003 and 2002. The estimated fair value of the Company's foreign currency collar agreement was included in current assets at December 31, 2002. The estimated fair values of the Company's natural gas and oil price swap and collar agreements and foreign currency collar agreement reflect the estimated amounts the Company would receive or pay to terminate the contracts at the reporting date based upon quoted market prices of comparable contracts.

The estimated fair value of the Company's long-term debt, preferred stock subject to mandatory redemption, natural gas and oil price swap and collar agreements and foreign currency collar agreement at December 31 was as follows:

	2003 Carrying Amount	2003 Fair Value	2002 Carrying Amount	2002 Fair Value
	(In thousands)			
Long-term debt	$ 967,096	$ 1,012,547	$ 841,641	$ 888,066
Preferred stock subject to mandatory redemption	$ ---	$ ---	$ 1,300	$ 1,168
Natural gas and oil price swap and collar agreements	$ (5,467)	$ (5,467)	$ (7,444)	$ (7,444)
Foreign currency collar agreement	$ ---	$ ---	$ 903	$ 903

The carrying amounts of the Company's remaining financial instruments included in current assets and current liabilities (excluding unsettled derivative instruments) approximate their fair values because of their short-term nature.

NOTE 7

Short-term Borrowings

MDU Resources Group, Inc.

At December 31, 2002, $8.0 million of MDU Resources Group, Inc. (MDU Resources) commercial paper program borrowings were classified as short-term borrowings. The commercial paper borrowings classified as short term were supported by short-term bank lines of credit. There were no amounts outstanding under the bank lines of credit at December 31, 2002. MDU Resources did not have any short-term bank lines of credit at December 31, 2003. For more information on MDU Resources' commercial paper program, see Note 8.

International operations

A subsidiary of the Company had a short-term credit agreement that expired in 2003. Under this agreement $12.0 million was outstanding at December 31, 2002.

NOTE 8

Long-term Debt and Indenture Provisions

Long-term debt outstanding at December 31 was as follows:

	2003	2002
	(In thousands)	
First mortgage bonds and notes:		
Pollution Control Refunding Revenue Bonds, Series 1992, 6.65%, due June 1, 2022	$ 20,850	$ 20,850
Secured Medium-Term Notes, Series A at a weighted average rate of 7.59%, due on dates ranging from October 1, 2004 to April 1, 2012	110,000	110,000
Senior Notes, 5.98%, due December 15, 2033	30,000	---
Total first mortgage bonds and notes	160,850	130,850

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
MDU Resources Group, Inc.	(1) X An Original (2) _ A Resubmission	12/31/2003	Dec 31, 2003

NOTES TO FINANCIAL STATEMENTS (Continued)

Senior notes at a weighted average rate of 6.24%, due on dates ranging from October 30, 2004 to October 30, 2018	718,000	549,100
Commercial paper at a weighted average rate of 1.12%, supported by revolving credit agreements	72,500	151,900
Term credit agreements at a weighted average rate of 5.14%, due on dates ranging from July 15, 2004 to December 1, 2013	14,286	7,873
Pollution control note obligation, 6.20%, due March 1, 2004	1,500	2,000
Discount	(40)	(82)
Total long-term debt	967,096	841,641
Less current maturities	27,646	22,083
Net long-term debt	$ 939,450	$ 819,558

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2003, aggregate $27.6 million in 2004; $70.9 million in 2005; $173.2 million in 2006; $105.8 million in 2007; $160.2 million in 2008 and $429.4 million thereafter.

Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2003.

MDU Resources Group, Inc.
MDU Resources has a revolving credit agreement with various banks totaling $90 million at December 31, 2003. There were no amounts outstanding under the credit agreement at December 31, 2003 and 2002. The credit agreement supports MDU Resources' $75 million commercial paper program. Under the MDU Resources' commercial paper program, $40 million was outstanding at December 31, 2003, which was classified as long-term debt, and $58.0 million was outstanding at December 31, 2002, of which $8.0 million was classified as short-term borrowings and $50.0 million was classified as long-term debt. As discussed in Note 7, the commercial paper borrowings classified as short term were supported by short-term bank lines of credit. The commercial paper borrowings classified as long-term debt are intended to be refinanced on a long-term basis through continued MDU Resources commercial paper borrowings and as further supported by the credit agreement, which expires on July 18, 2006.

In order to borrow under the MDU Resources credit agreement, MDU Resources must be in compliance with the applicable covenants and certain other conditions. The significant covenants include maximum leverage ratios, minimum interest coverage ratio, limitation on sale of assets and limitation on investments. MDU Resources was in compliance with these covenants and met the required conditions at December 31, 2003.

There are no credit facilities that contain cross-default provisions between MDU Resources and any of its subsidiaries.

MDU Resources' issuance of first mortgage debt is subject to certain restrictions imposed under the terms and conditions of its Indenture of Mortgage. Generally, those restrictions require MDU Resources to pledge $1.43 of unfunded property to the trustee for each dollar of indebtedness incurred under the Indenture and that annual earnings (pretax and before interest charges), as defined in the Indenture, equal at least two times its annualized first mortgage bond interest costs. Under the more restrictive of the two tests, as of December 31, 2003, MDU Resources could have issued approximately $313 million of additional first mortgage bonds.

Approximately $421.2 million of the Company's net electric and natural gas distribution properties at December 31, 2003, with certain exceptions, are subject to the lien of the Indenture of Mortgage dated May 1, 1939, as supplemented, amended and restated, from the Company to The Bank of New York and Douglas J. MacInnes, successor trustee, and are subject to the junior lien of the Indenture dated as of December 15, 2003, as supplemented, from the Company to The Bank of New York, as trustee.

Centennial Energy Holdings, Inc.
Centennial Energy Holdings, Inc. (Centennial) has two revolving credit agreements with various banks that support $275 million of Centennial's $350 million commercial paper program. There were no outstanding borrowings under the Centennial credit agreements at December 31, 2003 or 2002. Under the Centennial commercial paper program, $32.5 million and $101.9 million were outstanding at December 31, 2003 and 2002, respectively. The Centennial commercial paper borrowings are classified as long-term debt as Centennial intends to refinance these borrowings on a long-term basis through continued Centennial commercial paper borrowings and as further supported by the Centennial credit agreements. The Centennial credit agreements are for $137.5 million each. One of these agreements expires on September 3, 2004, and allows for subsequent borrowings up to a term of one year. The other agreement expires on September 5, 2006. Centennial intends to negotiate the extension or replacement of these agreements prior to their maturities.

Centennial has an uncommitted long-term master shelf agreement that allows for borrowings of up to $400 million. Under the terms of the master shelf agreement, $384.0 million was outstanding at December 31, 2003, and $360.6 million was outstanding at December 31, 2002. The amount outstanding under the uncommitted long-term master shelf agreement is included in senior notes in the preceding long-term debt table.

In order to borrow under Centennial's credit agreements and the Centennial uncommitted long-term master shelf agreement, Centennial and certain of its subsidiaries must be in compliance with the applicable covenants and certain other conditions. The significant covenants include maximum capitalization ratios, minimum interest coverage ratios, minimum consolidated net worth, limitation on priority debt, limitation on sale of assets and limitation on loans and investments. Centennial and such subsidiaries were in compliance with these covenants and met the required conditions at December 31, 2003.

Certain of Centennial's financing agreements contain cross-default provisions. These provisions state that if Centennial or any subsidiary of Centennial fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the applicable agreements, will be in default. Certain of Centennial's financing agreements and Centennial's practice limit the amount of subsidiary indebtedness.

Williston Basin Interstate Pipeline Company
Williston Basin Interstate Pipeline Company (Williston Basin), an indirect wholly owned subsidiary of the Company, has an uncommitted long-term master shelf agreement that allows for borrowings of up to $100 million. Under the terms of the master shelf agreement, $55.0 million and $30.0 million was outstanding at December 31, 2003 and 2002, respectively.

In order to borrow under Williston Basin's uncommitted long-term master shelf agreement, it must be in compliance with the applicable covenants and certain other conditions. The significant covenants include limitation on consolidated indebtedness, limitation on priority debt, limitation on sale of assets and limitation on investments. Williston Basin was in compliance with these covenants and met the required conditions at December 31, 2003.

NOTE 9
Asset Retirement Obligations

The Company adopted SFAS No. 143 on January 1, 2003, as discussed in Note 1. The Company recorded obligations related to the plugging and abandonment of natural gas and oil wells, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties and certain other obligations associated with leased properties. Removal costs associated with certain natural gas distribution, transmission, storage and gathering facilities have not been recognized as these facilities have been determined to have indeterminate useful lives.

Upon adoption of SFAS No. 143, the Company recorded an additional discounted liability of $22.5 million and a regulatory asset of $493,000, increased net property, plant and equipment by $9.6 million and recognized a one-time cumulative effect charge of $7.6 million (net of deferred income tax benefits of $4.8 million). The Company believes that any expenses under SFAS No. 143 as they relate to regulated operations will be recovered in rates over time and accordingly, deferred such expenses as a regulatory asset upon adoption. The Company will continue to defer those SFAS No. 143 expenses that it believes will be recovered in rates over time. In addition to the $22.5 million liability recorded upon the adoption of SFAS No. 143, the Company had previously recorded a $7.5 million liability related to retirement obligations.

A reconciliation of the Company's liability for the year ended December 31 was as follows:

	2003 (In thousands)
Balance at January 1, 2003	$29,997
Liabilities incurred	2,405
Liabilities acquired	1,803
Liabilities settled	(1,555)
Accretion expense	1,906
Revisions in estimates	77
Balance at December 31, 2003	$34,633

This liability is included in other liabilities. If SFAS No. 143 had been in effect during 2002 and 2001, the Company's liability would have been approximately $30.0 million at December 31, 2002, and $27.0 million at December 31, 2001.

The fair value of assets that are legally restricted for purposes of settling asset retirement obligations at December 31, 2003, was $5.1 million.

NOTE 10
Preferred Stocks
Preferred stocks at December 31 were as follows:

	2003	2002
	(Dollars in thousands)	
Authorized:		
Preferred --		
500,000 shares, cumulative, par value $100, issuable in series		
Preferred stock A --		
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Preference --		
500,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Outstanding:		
Subject to mandatory redemption --		
Preferred --		
5.10% Series - 13,000 shares in 2002	$ ---	$ 1,300
Other preferred stock --		
4.50% Series -- 100,000 shares	10,000	10,000
4.70% Series -- 50,000 shares	5,000	5,000

	15,000	15,000
Total preferred stocks	15,000	16,300
Less sinking fund requirements	---	100
Net preferred stocks	$ 15,000	$ 16,200

As discussed in Note 1, the Company upon adoption of SFAS No. 150 in 2003, began reporting its preferred stock subject to mandatory redemption as a liability. Restatement of prior year information is not permitted under SFAS No. 150.

The 4.50% Series and 4.70% Series preferred stocks outstanding are subject to redemption, in whole or in part, at the option of the Company with certain limitations on 30 days notice on any quarterly dividend date at a redemption price, plus accrued dividends, of $105 and $102, respectively.

In the event of a voluntary or involuntary liquidation, all preferred stock series holders are entitled to $100 per share, plus accrued dividends.

The affirmative vote of two-thirds of a series of the Company's outstanding preferred stock is necessary for amendments to the Company's charter or by-laws that adversely affect that series; creation of or increase in the amount of authorized stock ranking senior to that series (or an affirmative majority vote where the authorization relates to a new class of stock that ranks on parity with such series); a voluntary liquidation or sale of substantially all of the Company's assets; a merger or consolidation, with certain exceptions; or the partial retirement of that series of preferred stock when all dividends on that series of preferred stock have not been paid. The consent of the holders of a particular series is not required for such corporate actions if the equivalent vote of all outstanding series of preferred stock voting together has consented to the given action and no particular series is affected differently than any other series.

Subject to the foregoing, the holders of common stock exclusively possess all voting power. However, if cumulative dividends on preferred stock are in arrears, in whole or in part, for one year the holders of preferred stock would obtain the right to one vote per share until all dividends in arrears have been paid and current dividends have been declared and set aside.

NOTE 11

Common Stock

On August 14, 2003, the Company's Board of Directors approved a three-for-two common stock split to be effected in the form of a 50 percent common stock dividend. The additional shares of common stock were distributed on October 29, 2003, to common stockholders of record on October 10, 2003. Common stock information appearing in the accompanying consolidated financial statements has been restated to give retroactive effect to the stock split. Additionally, preference share purchase rights have been appropriately adjusted to reflect the effects of the split.

At the Annual Meeting of Stockholders held on April 23, 2002, the Company's common stockholders approved an amendment to the Certificate of Incorporation increasing the authorized number of common shares from 150 million shares to 250 million shares with a par value of $1.00 per share.

The Company's Dividend Reinvestment and Direct Stock Purchase Plan (Stock Purchase Plan) provides interested investors the opportunity to make optional cash investments and to reinvest all or a percentage of their cash dividends in shares of the Company's common stock. The Company's 401(k) Retirement Plan (K-Plan) is partially funded with the Company's common stock. Since January 1, 2001, the Stock Purchase Plan and K-Plan, with respect to Company stock, have been funded by the purchase of shares of common stock on the open market. At December 31, 2003, there were 12.1 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

In November 1998, the Company's Board of Directors declared, pursuant to a stockholders' rights plan, a dividend of one preference share purchase right (right) for each outstanding share of the Company's common stock. Each right becomes exercisable, upon the occurrence of certain events, for two-thirds of one one-thousandth of a share of Series B Preference Stock of the Company, without par value, at an exercise price of $125, subject to certain adjustments. The rights are currently not exercisable and will be exercisable only if a person or group (acquiring person) either acquires ownership of 15 percent or more of the Company's common stock or commences a tender or exchange offer that would result in ownership of 15 percent or more. In the event the Company is acquired in a merger or other business combination transaction or 50 percent or more of its consolidated assets or earnings power are sold, each right entitles the holder to receive, upon the exercise thereof at the then current exercise price of the right multiplied by the number of two-thirds of one one-thousandth of a Series B Preference Stock for which a right is then exercisable, in accordance with the terms of the rights agreement, such number of shares of common stock of the acquiring person having a market value of twice the then current exercise price of the right. The rights, which expire on December 31, 2008, are redeemable in whole, but not in part, for a price of $.00667 per right, at the Company's option at any time until any acquiring person has acquired 15 percent or more of the Company's common stock.

NOTE 12
Stock-based Compensation
The Company has stock option plans for directors, key employees and employees. In 2003, the Company adopted the fair value recognition provisions of SFAS No. 123 and began expensing the fair market value of stock options for all awards granted on or after January 1, 2003. As permitted by SFAS No. 148, the Company accounts for stock options granted prior to January 1, 2003, under APB Opinion No. 25.

For a discussion of the adoption of SFAS No. 123 and the effect on earnings and earnings per common share for the years ended December 31, 2003, 2002 and 2001, as if the Company had applied SFAS No. 123, and recognized compensation expense for all outstanding and unvested stock options based on the fair value at the date of grant, see Note 1.

Options granted to key employees automatically vest after nine years, but the plan provides for accelerated vesting based on the attainment of certain performance goals or upon a change in control of the Company, and expire 10 years after the date of grant. Options granted to directors and employees vest at date of grant and three years after date of grant, respectively, and expire 10 years after the date of grant.

A summary of the status of the stock option plans at December 31, 2003, 2002 and 2001, and changes during the years then ended was as follows:

	2003		2002		2001	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance at beginning of year	4,861,268	$18.58	5,208,311	$18.60	1,837,439	$13.74
Granted	27,015	17.29	160,605	19.15	4,039,680	20.09
Forfeited	(188,486)	20.05	(453,840)	19.77	(111,423)	18.16
Exercised	(517,341)	13.88	(53,808)	12.20	(557,385)	13.49
Balance at end of year	4,182,456	19.09	4,861,268	18.58	5,208,311	18.60
Exercisable at end of year	611,404	$15.06	1,135,050	$14.56	1,155,213	$14.27

Summarized information about stock options outstanding and exercisable as of December 31, 2003, was as follows:

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
MDU Resources Group, Inc.	(1) X An Original (2) _ A Resubmission	12/31/2003	Dec 31, 2003

NOTES TO FINANCIAL STATEMENTS (Continued)

	Options Outstanding			Options Exercisable	
Range of Exercisable Prices	Number Outstanding	Remaining Contractual Life in Years	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$ 8.22 - 13.00	23,451	2.5	$ 9.77	23,451	$ 9.77
13.01 - 17.00	647,085	4.3	14.13	511,453	14.15
17.01 - 21.00	3,302,115	7.2	19.77	36,000	19.54
21.01 - 25.70	209,805	7.2	24.56	40,500	25.70
Balance at end of year	4,182,456	6.7	19.09	611,404	15.06

The fair value of each option is estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value of the options granted and the assumptions used to estimate the fair value of options were as follows:

	2003	2002	2001
Weighted average fair value of options at grant date	$4.67	$5.38	$4.92
Weighted average risk-free interest rate	3.91%	5.14%	5.19%
Weighted average expected price volatility	32.28%	30.80%	26.05%
Weighted average expected dividend yield	3.43%	3.43%	3.53%
Expected life in years	7	7	7

In addition, the Company granted restricted stock awards under a long-term incentive plan and deferred compensation agreements totaling 525,588 shares in 2001. The restricted stock awards granted vest to the participants at various times ranging from two years to nine years from date of issuance, but certain grants may vest early based upon the attainment of certain performance goals or upon a change in control of the Company. The weighted average grant date fair value of the restricted stock grant in 2001 was $21.03. The Company also has granted stock awards totaling 31,855 shares, 21,390 shares and 19,009 shares in 2003, 2002 and 2001, respectively, under a nonemployee director stock compensation plan. The weighted average grant date fair value of the stock grants was $21.40, $19.20 and $20.09, in 2003, 2002 and 2001, respectively. Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. Compensation expense recognized for restricted stock grants and stock grants was $4.8 million, $5.2 million and $4.9 million in 2003, 2002 and 2001, respectively.

In 2003, key employees of the Company were awarded performance share awards. Entitlement to performance shares is based on the Company's total shareholder return over designated performance periods as measured against a selected peer group. Target grants of performance shares were made for the following performance periods:

Grant Date	Performance Period	Target Grant of Shares
February 2003	2003-2004	57,655
February 2003	2003-2005	57,655

Participants may earn additional performance shares if the Company's total shareholder return exceeds that of the selected peer group. The final value of the performance units may vary according to the number of shares of Company stock that are ultimately granted based on the performance criteria. Compensation expense recognized for the performance share awards for the year ended December 31, 2003, was $879,000.

The Company is authorized to grant options, restricted stock and stock for up to 14.3 million shares of common stock and has granted options, restricted stock and stock on 6.2

million shares through December 31, 2003.

NOTE 13
Income Taxes
Income tax expense for the years ended December 31 was as follows:

	2003	2002 (In thousands)	2001
Current:			
Federal	$ 26,313	$ 46,389	$ 66,211
State	7,408	9,082	11,160
Foreign	264	---	(44)
	33,985	55,471	77,327
Deferred:			
Income taxes --			
Federal	55,660	26,373	16,972
State	9,861	4,632	4,773
Foreign	(338)	338	---
Investment tax credit	(596)	(584)	(731)
	64,587	30,759	21,014
Total income tax expense	$ 98,572	$ 86,230	$ 98,341

Components of deferred tax assets and deferred tax liabilities recognized at December 31 were as follows:

	2003 (In thousands)	2002
Deferred tax assets:		
Regulatory matters	$ 37,072	$ 34,792
Accrued pension costs	12,122	12,112
Deferred compensation	9,090	6,395
Asset retirement obligations	7,017	263
Bad debts	3,188	2,798
Deferred investment tax credit	954	1,185
Other	21,269	18,444
Total deferred tax assets	90,712	75,989
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	406,589	354,842
Basis differences on natural gas and oil producing properties	105,826	70,464
Regulatory matters	10,663	5,491
Other	9,309	10,412
Total deferred tax liabilities	532,387	441,209
Net deferred income tax liability	$(441,675)	$(365,220)

As of December 31, 2003 and 2002, no valuation allowance has been recorded associated with the above deferred tax assets.

The following table reconciles the change in the net deferred income tax liability from December 31, 2002, to December 31, 2003, to deferred income tax expense:

	2003 (In thousands)
Net change in deferred income tax liability from the preceding table	$ 76,455
Deferred taxes associated with acquisitions	(15,056)
Deferred taxes associated with the cumulative effect of accounting change	4,821
Deferred taxes associated with other comprehensive income	(809)
Other	(824)
Deferred income tax expense for the period	$ 64,587

Total income tax expense differs from the amount computed by applying the statutory federal income tax rate to income before taxes. The reasons for this difference were as follows:

Years ended December 31,	2003 Amount	%	2002 Amount	%	2001 Amount	%
	(Dollars in thousands)					
Computed tax at federal statutory rate	$ 98,520	35.0	$ 82,136	35.0	$ 88,966	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit	11,857	4.2	10,279	4.4	11,311	4.5
Investment tax credit amortization	(596)	(.2)	(584)	(.3)	(731)	(.3)
Depletion allowance	(3,117)	(1.1)	(2,200)	(.9)	(1,820)	(.7)
Renewable electricity production credit	(3,395)	(1.2)	---	---	---	---
Other items	(4,697)	(1.7)	(3,401)	(1.5)	615	.2
Total income tax expense	$ 98,572	35.0	$ 86,230	36.7	$ 98,341	38.7

The Company considers earnings from its foreign equity method investment in a natural gas-fired electric generating facility in Brazil to be reinvested indefinitely outside of the United States and, accordingly, no U.S. deferred income taxes are recorded with respect to such earnings. Should the earnings be remitted as dividends, the Company may be subject to additional U.S. taxes, net of allowable foreign tax credits.

NOTE 14
Business Segment Data
The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The Company has six reportable segments consisting of electric, natural gas distribution, utility services, pipeline and energy services, natural gas and oil production, and construction materials and mining. During the fourth quarter of 2002, the Company separated independent power production and other operations from its reportable segments. The independent power production and other operations do not individually meet the criteria to be considered a reportable segment. Substantially all of the operations of independent power production and other began in 2002; therefore, financial information for years prior to 2002 has not been presented.

The vast majority of the Company's operations are located within the United States. The Company also has investments in foreign countries, which largely consist of an investment in a natural gas-fired electric generating facility in Brazil, as discussed in Note 2. The electric segment generates, transmits and distributes electricity, and the natural gas distribution segment distributes natural gas. These operations also supply related value-added products and services in the northern Great Plains. The utility services segment specializes in electrical line construction, pipeline construction, inside electrical wiring and cabling and the manufacture and distribution of specialty equipment. The pipeline and energy services segment provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. The pipeline and energy services segment also provides energy-related management services, including cable and pipeline magnetization and locating. The natural gas and oil production segment is engaged in natural gas and oil acquisition, exploration and production activities, primarily in the Rocky Mountain region of the United States and in and around the Gulf of Mexico. The construction materials and mining segment mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mixed concrete, cement, asphalt and other value-added products, as well as performs integrated construction services, in the central and western United States and in the states of Alaska and Hawaii. The independent power production and other operations own electric generating facilities in the United States and have an investment in an electric generating facility in Brazil. Electric capacity and energy produced at these facilities are primarily sold under long-term contracts to nonaffiliated entities. These operations also include investments in opportunities that are not directly being pursued by the Company's other businesses.

In 2001, the Company sold its coal operations to Westmoreland Coal Company for $28.2 million in cash and recorded a gain of $10.3 million ($6.2 million after tax) included in other income - net. The sale of the Company's coal operations included active coal mines in North Dakota and Montana, coal sales agreements, reserves and mining equipment, and certain development rights at the Company's former Gascoyne Mine site in North Dakota. The Company retained ownership of lignite deposits and leases at its former Gascoyne Mine site in North Dakota, which were not part of the sale of the coal operations. The Gascoyne Mine site was closed in 1995 due to the cancellation of the coal sale contract. These lignite deposits are currently not being mined and are not associated with an operating mine. These lignite deposits are of a high moisture content and it is not economical to mine and ship the lignite to other distant markets. However, should a power plant be constructed near the area, the Company may have the opportunity to participate in supplying lignite to fuel a plant. As of December 31, 2003, Knife River had under ownership or lease, deposits of approximately 26.9 million tons of recoverable lignite coal.

The information below follows the same accounting policies as described in the Summary of Significant Accounting Policies. Information on the Company's businesses as of December 31 and for the years then ended was as follows:

	2003	2002 (In thousands)	2001
External operating revenues:			
Electric	$ 178,562	$ 162,616	$ 168,837
Natural gas distribution	274,608	186,569	255,389
Pipeline and energy services	187,892	110,224	479,108
	641,062	459,409	903,334
Utility services	434,177	458,660	364,746
Natural gas and oil production	140,281	148,158	148,653
Construction materials and mining	1,104,408	962,312	806,899(a)
Independent power production and other	32,261	2,998	---
	1,711,127	1,572,128	1,320,298
Total external operating revenues	$ 2,352,189	$ 2,031,537	$ 2,223,632
Intersegment operating revenues:			
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Utility services	---	---	4
Pipeline and energy services	64,300	55,034	52,006
Natural gas and oil production	124,077	55,437	61,178
Construction materials and mining	---	---	---
Independent power production and other	2,728	3,778	---
Intersegment eliminations	(191,105)	(114,249)	(113,188)
Total intersegment operating revenues	$ ---	$ ---	$ ---
Depreciation, depletion and amortization:			
Electric	$ 20,150	$ 19,537	$ 19,488
Natural gas distribution	10,044	9,940	9,337
Utility services	10,353	9,871	8,395

	2003	2002	2001
Pipeline and energy services	15,016	14,846	14,341
Natural gas and oil production	61,019	48,714	41,690
Construction materials and mining	63,601	54,334	46,666
Independent power production and other	8,154	719	---
Total depreciation, depletion and amortization	$ 188,337	$ 157,961	$ 139,917
Interest expense:			
Electric	$ 8,013	$ 7,621	$ 8,531
Natural gas distribution	3,936	4,364	3,727
Utility services	3,668	3,568	3,807
Pipeline and energy services	7,952	7,670	9,136
Natural gas and oil production	4,767	2,464	1,359
Construction materials and mining	18,747	18,422	19,339
Independent power production and other	5,865	1,122	---
Intersegment eliminations	(154)	(216)	---
Total interest expense	$ 52,794	$ 45,015	$ 45,899

	2003	2002 (In thousands)	2001
Income taxes:			
Electric	$ 9,862	$ 9,501	$ 10,511
Natural gas distribution	1,823	(1,325)	1,067
Utility services	3,905	4,781	9,131
Pipeline and energy services	11,188	12,462	11,633
Natural gas and oil production	42,993	30,604	40,486
Construction materials and mining	28,168	29,415	25,513
Independent power production and other	633	792	---
Total income taxes	$ 98,572	$ 86,230	$ 98,341
Cumulative effect of accounting change (Note 9):			
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Utility services	---	---	---
Pipeline and energy services	---	---	---
Natural gas and oil production	(7,740)	---	---
Construction materials and mining	151	---	---
Independent power production and other	---	---	---
Total cumulative effect of accounting change	$ (7,589)	$ ---	$ ---
Earnings on common stock:			
Electric	$ 16,950	$ 15,780	$ 18,717
Natural gas distribution	3,869	3,587	677
Utility services	6,170	6,371	12,910
Pipeline and energy services	18,158	19,097	16,406
Natural gas and oil production	63,027	53,192	63,178
Construction materials and mining	54,412	48,702	43,199
Independent power production and other	12,021	959	---
Total earnings on common stock	$ 174,607	$ 147,688	$ 155,087
Capital expenditures:			
Electric	$ 28,537	$ 27,795	$ 14,373

Natural gas distribution	15,672	11,044	14,685
Utility services	7,820	17,242	70,232
Pipeline and energy services	93,004	21,449	51,054
Natural gas and oil production	101,698	136,424	118,719
Construction materials and mining	128,487	106,893	170,585
Independent power production and other	112,858	95,748	---
Net proceeds from sale or disposition of property	(14,439)	(16,217)	(51,641)
Total net capital expenditures	$ 473,637	$ 400,378	$ 388,007

	2003	2002 (In thousands)	2001
Identifiable assets:			
Electric(b)	$ 327,899	$ 322,475	$ 301,982
Natural gas distribution(b)	234,948	208,502	217,402
Utility services	221,824	230,888	239,069
Pipeline and energy services	405,904	312,858	354,336
Natural gas and oil production	602,389	554,420	476,105
Construction materials and mining	1,248,607	1,137,697	1,035,929
Independent power production and other	263,941	148,770	---
Corporate assets(c)	75,080	81,311	51,155
Total identifiable assets	$ 3,380,592	$ 2,996,921	$ 2,675,978
Property, plant and equipment:			
Electric(b)	$ 639,893	$ 619,230	$ 597,080
Natural gas distribution(b)	252,591	244,930	235,771
Utility services	76,871	70,660	59,190
Pipeline and energy services	461,793	372,420	369,775
Natural gas and oil production	871,357	755,788	630,826
Construction materials and mining	893,980	804,255	711,410
Independent power production and other	201,134	94,525	---
Less accumulated depreciation, depletion and amortization	1,175,326	1,019,438	889,816
Net property, plant and equipment	$ 2,222,293	$ 1,942,370	$ 1,714,236

(a) In accordance with the provision of SFAS No. 71, intercompany coal sales of $5,016 in 2001 were not eliminated.
(b) Includes allocations of common utility property.
(c) Corporate assets consist of assets not directly assignable to a business (i.e., cash and cash equivalents, certain accounts receivable and other miscellaneous current and deferred assets).

Earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from utility services, natural gas and oil production, construction materials and mining, and independent power production and other are all from nonregulated operations. Capital expenditures for 2003, 2002 and 2001, related to acquisitions, in the preceding table included the following noncash transactions: issuance of the Company's equity securities of $42.4 million, $47.2 million and $57.4 million in 2003, 2002 and 2001, respectively.

NOTE 15
Acquisitions
In 2003, the Company acquired a number of businesses, none of which was individually material, including construction materials and mining businesses in Montana, North Dakota and Texas and a wind-powered electric generation facility in California. The total purchase consideration for these businesses and adjustments with respect to certain other acquisitions acquired in 2002, including the Company's common stock and cash, was $175.0

million.

In 2002, the Company acquired a number of businesses, none of which was individually material, including utility services companies in California and Ohio, construction materials and mining businesses in Minnesota and Montana, an energy development company in Montana and natural gas-fired electric generating facilities in Colorado. The total purchase consideration for these businesses, consisting of the Company's common stock and cash, was $139.8 million.

In 2001, the Company acquired a number of businesses, none of which was individually material, including construction materials and mining businesses in Hawaii, Minnesota and Oregon; utility services businesses based in Missouri and Oregon; and an energy services company specializing in cable and pipeline locating and tracking systems. The total purchase consideration for these businesses, consisting of the Company's common stock and cash, was $170.1 million.

On April 1, 2000, Fidelity Exploration & Production Company (Fidelity), an indirect wholly owned subsidiary of the Company, purchased substantially all of the assets of Preston Reynolds & Co., Inc. (Preston), a coalbed natural gas development operation based in Colorado with related oil and gas leases and properties in Montana and Wyoming. Pursuant to the asset purchase and sale agreement, Preston could, but was not obligated to purchase, acquire and own an undivided 25 percent working interest (Seller's Option Interest) in certain oil and gas leases or properties acquired and/or generated by Fidelity. Fidelity had the right, but not the obligation, to purchase Seller's Option Interest from Preston for an amount as specified in the agreement. On July 10, 2002, Fidelity purchased the Seller's Option Interest.

The above acquisitions were accounted for under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed have been preliminarily recorded at their respective fair values as of the date of acquisition. Final fair market values are pending the completion of the review of the relevant assets, liabilities and issues identified as of the acquisition date on certain of the above acquisitions made in 2003. The results of operations of the acquired businesses are included in the financial statements since the date of each acquisition. Pro forma financial amounts reflecting the effects of the above acquisitions are not presented, as such acquisitions were not material to the Company's financial position or results of operations.

NOTE 16

Employee Benefit Plans

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans. These financial statements and this Note do not reflect the effects of the 2003 Medicare Act on the postretirement benefit plans. For more information on the 2003 Medicare Act, see new accounting standards in Note 1. Changes in benefit obligation and plan assets for the years ended December 31 and amounts recognized in the Consolidated Balance Sheets at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	2003	2002
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$224,766	$204,046	$ 74,917	$ 67,019
Service cost	5,897	5,135	1,857	1,460
Interest cost	15,211	14,877	5,281	4,915
Plan participants' contributions	---	---	977	834
Amendments	210	372	754	---

Actuarial loss	27,701	12,324	10,338	5,678
Benefits paid	(12,450)	(11,988)	(5,743)	(4,989)
Benefit obligation at end of year	261,335	224,766	88,381	74,917
Change in plan assets:				
Fair value of plan assets at beginning of year	189,143	224,667	40,889	45,175
Actual gain (loss) on plan assets	43,087	(26,543)	6,148	(4,196)
Employer contribution	3,263	3,007	4,963	4,065
Plan participants' contributions	---	---	977	834
Benefits paid	(12,450)	(11,988)	(5,743)	(4,989)
Fair value of plan assets at end of year	223,043	189,143	47,234	40,889
Funded status - over (under)	(38,292)	(35,623)	(41,147)	(34,028)
Unrecognized actuarial loss	41,422	35,662	11,862	3,484
Unrecognized prior service cost	8,556	9,501	706	---
Unrecognized net transition obligation (asset)	(297)	(1,247)	19,362	21,513
Prepaid (accrued) benefit cost	$ 11,389	$ 8,293	$ (9,217)	$ (9,031)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Prepaid benefit cost	$ 19,671	$ 16,175	$ 614	$ 780
Accrued benefit liability	(8,282)	(7,882)	(9,831)	(9,811)
Additional minimum liability	---	(4,905)	---	---
Intangible asset	---	533	---	---
Accumulated other comprehensive loss	---	4,372	---	---
Net amount recognized	$ 11,389	$ 8,293	$ (9,217)	$ (9,031)

Employer contributions and benefits paid in the above table include only those amounts contributed directly to, or paid directly from, plan assets.

The accumulated benefit obligation for the defined benefit pension plans reflected above was $212.0 million and $186.4 million at December 31, 2003 and 2002, respectively.

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets at December 31, 2003, were as follows:

	2003	2002
	(In thousands)	
Projected benefit obligation	$ 38,845	$32,768
Accumulated benefit obligation	$ 28,840	$24,656
Fair value of plan assets	$ 24,508	$20,615

Components of net periodic benefit cost (income) for the Company's pension and other postretirement benefit plans were as follows:

	Pension Benefits			Other Postretirement Benefits		
Years ended December 31,	2003	2002	2001	2003	2002	2001
	(In thousands)					
Components of net periodic benefit cost:						
Service cost	$ 5,897	$ 5,135	$ 4,716	$ 1,857	$ 1,460	$ 1,376
Interest cost	15,211	14,877	14,498	5,281	4,915	4,691

Expected return on assets	(20,730)	(21,110)	(20,672)	(3,933)	(3,843)	(3,619)
Amortization of prior service cost	1,156	1,148	1,247	48	---	---
Recognized net actuarial gain	(417)	(1,855)	(2,687)	(255)	(566)	(930)
Settlement (gain) loss	---	---	(884)	---	---	15
Amortization of net transition obligation (asset)	(950)	(947)	(965)	2,151	2,151	2,227
Net periodic benefit cost (income)	167	(2,752)	(4,747)	5,149	4,117	3,760
Less amount capitalized	14	(352)	(391)	601	404	329
Net periodic benefit cost (income)	$ 153	$ (2,400)	$(4,356)	$ 4,548	$ 3,713	$ 3,431

Weighted average assumptions used to determine benefit obligations at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	2003	2002
Discount rate	6.00%	6.75%	6.00%	6.75%
Rate of compensation increase	4.70%	4.50%	4.50%	4.50%

Weighted average assumptions used to determine net periodic benefit cost for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	2003	2002
Discount rate	6.75%	7.25%	6.75%	7.25%
Expected return on plan assets	8.50%	8.50%	7.50%	7.50%
Rate of compensation increase	4.50%	5.00%	4.50%	5.00%

The expected rate of return on plan assets is based on the targeted asset allocation of 70 percent equity securities and 30 percent fixed income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

Health care rate assumptions for the Company's other postretirement benefit plans as of December 31 were as follows:

	2003	2002
Health care trend rate assumed for next year	6.0%-9.5%	6.0%-11.0%
Health care cost trend rate - ultimate	5.0%-6.0%	5.0%-6.0%
Year in which ultimate trend rate achieved	1999-2012	1999-2011

The Company's other postretirement benefit plans include health care and life insurance benefits for certain employees. The plans underlying these benefits may require contributions by the employee depending on such employee's age and years of service at retirement or the date of retirement. The accounting for the health care plans anticipates future cost-sharing changes that are consistent with the Company's expressed intent to generally increase retiree contributions each year by the excess of the expected health care cost trend rate over 6 percent.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2003:

1 Percentage 1 Percentage

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
MDU Resources Group, Inc.	(1) X An Original (2) _ A Resubmission	12/31/2003	Dec 31, 2003

NOTES TO FINANCIAL STATEMENTS (Continued)

	Point Increase	Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 250	$ (972)
Effect on postretirement benefit obligation	$ 3,479	$(9,554)

The Company's defined benefit pension plans asset allocation at December 31, 2003 and 2002, and weighted average targeted asset allocations at December 31, 2003, were as follows:

Asset Category	Percentage of Plan Assets 2003	2002	Weighted Average Targeted Asset Allocation Percentage 2003
Equity securities	72%	56%	70%
Fixed income securities	25	40	30*
Other	3	4	---
Total	100%	100%	100%

*Includes target for both fixed income securities and other.

The Company's pension assets are managed by nine outside investment managers. The Company's other postretirement assets are managed by one outside investment manager. The Company's investment policy with respect to pension and other postretirement assets is to make investments solely in the interest of the participants and beneficiaries of the plans and for the exclusive purpose of providing benefits accrued and defraying the reasonable expenses of administration. The Company strives to maintain investment diversification to assist in minimizing the risk of large losses. The Company's policy guidelines allow for investment of funds in cash equivalents, fixed income securities and equity securities. The guidelines prohibit investment in commodities and future contracts, equity private placement, employer securities and leveraged or derivative securities. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

The Company's other postretirement benefit plans asset allocation at December 31, 2003 and 2002, and weighted average targeted asset allocation at December 31, 2003, were as follows:

Asset Category	Percentage of Plan Assets 2003	2002	Weighted Average Targeted Asset Allocation Percentage 2003
Equity securities	66%	50%	70%
Fixed income securities	30	45	30*
Other	4	5	---
Total	100%	100%	100%

*Includes target for both fixed income securities and other.

The Company expects to contribute approximately $1.6 million to its defined benefit pension plans and approximately $5.0 million to its postretirement benefit plans in 2004.

In addition to company-sponsored plans, certain employees are covered under multi-employer defined benefit plans administered by a union. Amounts contributed to the multi-employer plans were $27.2 million, $27.8 million and $19.9 million in 2003, 2002 and 2001, respectively.

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of Note 16, the Company also has an unfunded, nonqualified benefit plan for executive officers and certain key management employees that provides for defined benefit payments upon the employee's retirement or to their beneficiaries upon death for a 15-year period or as an equivalent life annuity. Investments consist of life insurance carried on plan participants, which is payable to the Company upon the employee's death. The cost of these benefits was $5.3 million, $5.1 million and $4.3 million in 2003, 2002 and 2001, respectively. The total projected obligation for this plan was $51.1 million and $40.5 million at December 31, 2003 and 2002, respectively. The accumulated benefit obligation for this plan was $40.7 million and $33.3 million at December 31, 2003 and 2002, respectively. The additional minimum liability relating to this plan was $8.2 million and $4.0 million at December 31, 2003 and 2002, respectively. The Company has a related intangible asset recognized as of December 31, 2003 and 2002, of $1.0 million and $1.1 million, respectively. A discount rate of 6.0 percent and 6.75 percent at December 31, 2003 and 2002, respectively, and a rate of compensation increase of 4.75 percent and 4.50 percent at December 31, 2003 and 2002, respectively, were used to determine benefit obligations.

A discount rate of 6.75 percent and 7.25 percent at December 31, 2003 and 2002, respectively, and a rate of compensation increase of 4.50 percent and 5.00 percent at December 31, 2003 and 2002, respectively, were used to determine net periodic benefit cost. The increase in minimum liability included in other comprehensive income was $2.6 million in 2003 and $1.8 million in 2002.

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were $9.8 million in 2003, $9.6 million in 2002 and $7.2 million in 2001. The costs incurred in each year reflect additional participants as a result of business acquisitions.

NOTE 17

Jointly Owned Facilities

The consolidated financial statements include the Company's 22.7 percent and 25.0 percent ownership interests in the assets, liabilities and expenses of the Big Stone Station and the Coyote Station, respectively. Each owner of the Big Stone and Coyote stations is responsible for financing its investment in the jointly owned facilities.

The Company's share of the Big Stone Station and Coyote Station operating expenses was reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income.

At December 31, the Company's share of the cost of utility plant in service and related accumulated depreciation for the stations was as follows:

	2003	2002
	(In thousands)	
Big Stone Station:		
Utility plant in service	$ 52,154	$ 53,018
Less accumulated depreciation	34,993	34,456
	$ 17,161	$ 18,562
Coyote Station:		
Utility plant in service	$ 124,086	$ 122,476
Less accumulated depreciation	72,850	70,778
	$ 51,236	$ 51,698

NOTE 18

Regulatory Matters and Revenues Subject To Refund

On May 30, 2003, Montana-Dakota Utilities Co. (Montana-Dakota), a public utility division of MDU Resources, filed an application with the North Dakota Public Service Commission (NDPSC) for an electric rate increase. Montana-Dakota requested a total of $7.8 million annually or 9.1 percent above current rates. On July 23, 2003, Montana-Dakota and the NDPSC Staff filed a Settlement Agreement with the NDPSC agreeing on the issues of rate of return, capital structure and cost of capital components. On October 22, 2003, the NDPSC approved the Settlement Agreement. On November 19, 2003, Montana-Dakota and the NDPSC Staff filed an additional Settlement Agreement to resolve all remaining outstanding issues with the NDPSC. This Settlement Agreement reflected an increase of $1.0 million annually and a sharing mechanism between Montana-Dakota and retail customers of wholesale electric sales margins. On December 18, 2003, the NDPSC approved the November 2003 Settlement Agreement and required Montana-Dakota to file a compliance filing with the NDPSC. On January 14, 2004, the NDPSC approved Montana-Dakota's compliance filing, which was filed on January 7, 2004, with rates effective with service rendered on and after January 23, 2004.

In December 2002, Montana-Dakota filed an application with the South Dakota Public Utilities Commission (SDPUC) for a natural gas rate increase. Montana-Dakota requested a total of $2.2 million annually or 5.8 percent above current rates. On October 27, 2003, Montana-Dakota and the SDPUC Staff filed a Settlement Stipulation with the SDPUC agreeing to an increase of $1.3 million annually. On December 2, 2003, the SDPUC approved the Settlement Stipulation effective with service rendered on and after December 2, 2003.

In October 2002, Great Plains Natural Gas Co. (Great Plains), a public utility division of MDU Resources, filed an application with the Minnesota Public Utilities Commission (MPUC) for a natural gas rate increase. Great Plains requested a total of $1.6 million annually or 6.9 percent above current rates. In December 2002, the MPUC issued an Order setting interim rates that approved an interim increase of $1.4 million annually effective December 6, 2002. Great Plains began collecting such rates effective December 6, 2002, subject to refund until the MPUC issued a final order. On October 9, 2003, the MPUC issued a Final Order authorizing an increase of $1.1 million annually and requiring Great Plains to file a compliance filing with the MPUC. On January 16, 2004, the MPUC issued an Order accepting Great Plains' compliance filing, which was filed on November 10, 2003, effective with service rendered on and after January 16, 2004.

Reserves have been provided for a portion of the revenues that have been collected subject to refund for certain of the above proceedings. The Company believes that such reserves are adequate based on its assessment of the ultimate outcome of the proceedings.

In December 1999, Williston Basin filed a general natural gas rate change application with the FERC. Williston Basin began collecting such rates effective June 1, 2000, subject to refund. In May 2001, the Administrative Law Judge (ALJ) issued an Initial Decision on Williston Basin's natural gas rate change application. The Initial Decision addressed numerous issues relating to the rate change application, including matters relating to allowable levels of rate base, return on common equity, and cost of service, as well as volumes established for purposes of cost recovery, and cost allocation and rate design. On July 3, 2003, the FERC issued its Order on Initial Decision. The Order on Initial Decision affirmed the ALJ's Initial Decision on many of the issues including rate base and certain cost of service items as well as volumes to be used for purposes of cost recovery, and cost allocation and rate design. However, there are other issues as to which the FERC differed with the ALJ including return on common equity and the correct level of corporate overhead expense. On August 4, 2003, Williston Basin requested a rehearing of a number of issues including determinations associated with cost of service, throughput, and cost allocation and rate design, as discussed in the FERC's Order on Initial Decision. On September 3, 2003, the FERC issued an Order granting Williston Basin's request for rehearing of the July 3, 2003, Order on Initial Decision. The Company is awaiting a decision from the FERC on the merits of the Company's rehearing request and is unable to predict the timing of the FERC's decision.

Reserves have been provided for a portion of the revenues that have been collected subject to refund with respect to Williston Basin's pending regulatory proceeding. Williston Basin believes that such reserves are adequate based on its assessment of the ultimate outcome of the proceeding.

NOTE 19
Commitments and Contingencies
Litigation
In January 2002, Fidelity Oil Co. (FOC), one of the Company's natural gas and oil production subsidiaries, entered into a compromise agreement with the former operator of certain of FOC's oil production properties in southeastern Montana. The compromise agreement resolved litigation involving the interpretation and application of contractual provisions regarding net proceeds interests paid by the former operator to FOC for a number of years prior to 1998. The terms of the compromise agreement are confidential. As a result of the compromise agreement, the natural gas and oil production segment reflected a nonrecurring gain in its financial results for the first quarter of 2002 of approximately $16.6 million after tax. As part of the settlement, FOC gave the former operator a full and complete release, and FOC is not asserting any such claim against the former operator for periods after 1997.

In June 1997, Jack J. Grynberg (Grynberg) filed a Federal False Claims Act suit against Williston Basin and Montana-Dakota and filed over 70 similar suits against natural gas transmission companies and producers, gatherers, and processors of natural gas. Grynberg, acting on behalf of the United States under the Federal False Claims Act, alleged improper measurement of the heating content and volume of natural gas purchased by the defendants resulting in the underpayment of royalties to the United States. In April 1999, the United States Department of Justice decided not to intervene in these cases. In response to a motion filed by Grynberg, the Judicial Panel on Multidistrict Litigation consolidated all of these cases in the Federal District Court of Wyoming.

The matter is currently in the discovery stage. Grynberg has not specified the amount he seeks to recover. Williston Basin and Montana-Dakota are unable to estimate their potential exposure and will be unable to do so until discovery is completed. Williston Basin and Montana-Dakota believe that the Grynberg case will ultimately be dismissed because Grynberg is not, as is required by the Federal False Claims Act, the original source of the information underlying the action. Failing this, Williston Basin and Montana-Dakota believe Grynberg will not recover damages from Williston Basin and Montana-Dakota because insufficient facts exist to support the allegations.

Williston Basin and Montana-Dakota believe the claims of Grynberg are without merit and intend to vigorously contest this suit. Williston Basin and Montana-Dakota believe it is not probable that Grynberg will ultimately succeed given the current status of the litigation.

Fidelity has been named as a defendant in, and/or certain of its operations are the subject of, 11 lawsuits filed in connection with its coalbed natural gas development in the Powder River Basin in Montana and Wyoming. These lawsuits were filed in federal and state courts in Montana between June 2000 and December 2003 by a number of environmental organizations, including the Northern Plains Resource Council and the Montana Environmental Information Center as well as the Tongue River Water Users' Association and the Northern Cheyenne Tribe. Two of the lawsuits have been transferred to Federal District Court in Wyoming. The lawsuits involve allegations that Fidelity and/or various government agencies are in violation of state and/or federal law, including the Federal Clean Water Act and the National Environmental Policy Act. The lawsuits seek injunctive relief, invalidation of various permits and unspecified damages. Fidelity is unable to quantify the damages sought, and will be unable to do so until after completion of discovery. Fidelity is vigorously defending all coalbed-related lawsuits in which it is involved. If the plaintiffs are successful in these lawsuits, the ultimate outcome of the actions could have a material effect on Fidelity's existing coalbed natural gas operations and/or the future development of its coalbed natural gas properties.

Montana-Dakota has joined with two electric generators in appealing a finding by the North Dakota Department of Health (Department) in September 2003 that the Department may unilaterally revise operating permits previously issued to electric generating plants.

Although it is doubtful that any revision of Montana-Dakota's operating permits by the Department would reduce the amount of electricity its plants could generate, the finding, if allowed to stand, could increase costs for sulfur dioxide removal and/or limit Montana-Dakota's ability to modify or expand operations at its North Dakota generation sites. Montana-Dakota and the other electric generators filed their appeal of the order on October 8, 2003, in the Burleigh County District Court in Bismarck, North Dakota. Proceedings have been stayed pending discussions with the United States Environmental Protection Agency (EPA), the Department and the other electric generators.

In a related case, the Dakota Resource Council filed an action in Federal District Court in Denver, Colorado, on September 30, 2003, to require the EPA to enforce certain air quality standards in North Dakota. If successful, the action could require the curtailment of discharges of sulfur dioxide into the atmosphere by existing electric generating facilities and could preclude or hinder the construction of future generating facilities in North Dakota. The Company has filed a Motion to Intervene in the lawsuit and has joined in a brief supporting a Motion to Dismiss filed by the EPA.

The Company cannot predict the outcome of the Department or Dakota Resource Council matters or their ultimate impact on its operations.

The Company is also involved in other legal actions in the ordinary course of its business. Although the outcomes of any such legal actions cannot be predicted, management believes that the outcomes with respect to these other legal proceedings will not have a material adverse effect upon the Company's financial position or results of operations.

Environmental matters

In December 2000, Morse Bros., Inc. (MBI), an indirect wholly owned subsidiary of the Company, was named by the EPA as a Potentially Responsible Party in connection with the cleanup of a commercial property site, acquired by MBI in 1999, and part of the Portland, Oregon, Harbor Superfund Site. Sixty-eight other parties were also named in this administrative action. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. To date, costs of the overall remedial investigation of the harbor site for both the EPA and the Oregon State Department of Environmental Quality (DEQ) are being recorded, and initially paid, through an administrative consent order by the Lower Willamette Group (LWG), a group of 10 entities that does not include MBI. The LWG estimates the overall remedial investigation and feasibility study will cost approximately $10 million. It is not possible to estimate the cost of a corrective action plan until the remedial investigation and feasibility study has been completed, the EPA has decided on a strategy, and a record of decision has been published. While the remedial investigation and feasibility study for the harbor site has commenced, it is expected to take several years to complete. The development of a proposed plan and record of decision on the harbor site is not anticipated to occur until 2006, after which a cleanup plan will be undertaken.

Based upon a review of the Portland Harbor sediment contamination evaluation by the DEQ and other information available, MBI does not believe it is a Responsible Party. In addition, MBI has notified Georgia-Pacific West, Inc., the seller of the commercial property site to MBI, that it intends to seek indemnity for any and all liabilities incurred in relation to the above matters, pursuant to the terms of their sale agreement.

The Company believes it is not probable that it will incur any material environmental remediation costs or damages in relation to the above administrative action.

Operating leases

The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2003, were $18.1 million in 2004, $12.4 million in 2005, $8.7 million in 2006, $5.1 million in 2007, $3.9 million in 2008 and $22.1 million thereafter. Rent expense was approximately $27.2 million, $26.9 million and $31.5 million for the years ended December 31, 2003, 2002 and 2001, respectively.

Purchase commitments
The Company has entered into various commitments, largely natural gas and coal supply, purchased power, natural gas transportation, construction materials supply and electric generation construction contracts. These commitments range from one to 21 years. The commitments under these contracts as of December 31, 2003, were $167.2 million in 2004, $67.2 million in 2005, $50.1 million in 2006, $31.0 million in 2007, $30.9 million in 2008 and $146.3 million thereafter. Amounts purchased under these various commitments for the years ended December 31, 2003, 2002 and 2001, were approximately $204.6 million, $152.1 million and $193.0 million, respectively. These commitments are not reflected in the Company's consolidated financial statements.

Guarantees
Centennial has unconditionally guaranteed a portion of certain bank borrowings of MPX in connection with the Company's equity method investment in the natural gas-fired electric generating facility in Brazil, as discussed in Note 2. The Company, through MDU Brasil, owns 49 percent of MPX. The main business purpose of Centennial extending the guarantee to MPX's creditors is to enable MPX to obtain lower borrowing costs. At December 31, 2003, the aggregate amount of borrowings outstanding subject to these guarantees was $45.5 million and the scheduled repayment of these borrowings is $11.0 million in 2004, $10.7 million in 2005, $10.7 million in 2006, $10.7 million in 2007 and $2.4 million in 2008. The individual investor (who through EBX Empreendimentos Ltda. (EBX), a Brazilian company, owns 51 percent of MPX) has also guaranteed a portion of these loans. In the event MPX defaults under its obligation, Centennial and the individual investor would be required to make payments under their guarantees. Centennial and the individual investor have entered into reimbursement agreements under which they have agreed to reimburse each other to the extent they may be required to make any guarantee payments in excess of their proportionate ownership share in MPX. These guarantees are not reflected on the Consolidated Balance Sheets.

In addition, WBI Holdings, Inc. (WBI Holdings), an indirect wholly owned subsidiary of the Company, has guaranteed certain of its subsidiary's natural gas and oil price swap and collar agreement obligations. The amount of the subsidiary's obligations at December 31, 2003, was $1.8 million. There is no fixed maximum amount guaranteed in relation to the natural gas and oil price swap and collar agreements, as the amount of the obligation is dependent upon natural gas and oil commodity prices. The amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the natural gas and oil price swap and collar agreements at December 31, 2003, expire in 2004; however, the subsidiary continues to enter into additional hedging activities and, as a result, WBI Holdings from time to time may issue additional guarantees on these hedging obligations. At December 31, 2003, the amount outstanding was reflected on the Consolidated Balance Sheets. In the event the above subsidiary defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company that are related to natural gas transportation and sales agreements, electric power supply agreements, insurance policies and certain other guarantees. At December 31, 2003, the fixed maximum amounts guaranteed under these agreements aggregated $46.4 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $20.1 million in 2004; $5.9 million in 2005; $3.5 million in 2006; $500,000 in 2007; $900,000 in 2009; $12.0 million in 2012; $500,000, which is subject to expiration 30 days after the receipt of written notice and $3.0 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $372,000 and was reflected on the Consolidated Balance Sheets at December 31, 2003. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

Fidelity and WBI Holdings have outstanding guarantees to Williston Basin. These guarantees are related to natural gas transportation and storage agreements that guarantee the performance of Prairielands Energy Marketing, Inc. (Prairielands), an indirect wholly owned subsidiary of the Company. At December 31, 2003, the fixed maximum amounts guaranteed under these agreements aggregated $22.9 million. Scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $2.9 million in 2005 and $20.0 million in 2009. In the event of Prairielands' default in its payment obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee. The amount outstanding by Prairielands under the above guarantees was $837,000, which was not reflected on the Consolidated Balance Sheet at December 31, 2003, because these intercompany transactions are eliminated in consolidation.

In addition, Centennial has issued guarantees related to the Company's purchase of maintenance items to third parties for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under its obligation in relation to the purchase of certain maintenance items, Centennial would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these maintenance items were reflected on the Consolidated Balance Sheet at December 31, 2003.

As of December 31, 2003, Centennial was contingently liable for the performance of certain of its subsidiaries under approximately $360 million of surety bonds. These bonds are principally for construction contracts and reclamation obligations of these subsidiaries entered into in the normal course of business. Centennial indemnifies the respective surety bond companies against any exposure under the bonds. The purpose of Centennial's indemnification is to allow the subsidiaries to obtain bonding at competitive rates. In the event a subsidiary of the Company does not fulfill its obligations in relation to its bonded contract or obligation, Centennial may be required to make payments under its indemnification. A large portion of these contingent commitments are expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. The surety bonds were not reflected on the Consolidated Balance Sheets.

NOTE 20
Investment in Subsidiaries
The Respondent owns one wholly owned subsidiary, Centennial Energy Holdings, Inc.

As required by the Federal Energy Regulatory Commission for Form 1 report purposes, MDU Resources Group, Inc. reports its subsidiary investment using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiary, as required by generally accepted accounting principles. If generally accepted accounting principles were followed, utility plant, other property and investments would increase by $583,119,019 and $440,603,661; current and accrued assets would increase by $480,874,653 and $429,117,903; deferred debits would increase by $433,317,248 and $382,761,205; preferred stock would decrease by $0 and $100,000; long-term debt would increase by $735,936,753 and $636,749,515; other noncurrent liabilities and current and accrued liabilities would increase by $202,668,975 and $208,485,102; deferred credits would increase by $562,331,004 and $410,973,964 as of December 31, 2003 and 2002, respectively. Furthermore, operating revenues would increase by $1,899,020,074 and $1,682,352,992; and operating expenses, excluding income taxes, would increase by $1,629,210,888 and $1,452,565,545 for the year ended December 31, 2003 and 2002, respectively. In addition, net cash provided by operating activities would increase by $368,926,000; net cash used in investing activities would increase by $385,821,000; net cash used by financing activities would decrease by $35,662,000; and the net change in cash and cash equivalents would be an increase of $18,767,000 for the year ended December 31, 2003. Reporting its subsidiary investment using the equity method rather than generally accepted accounting principles has no effect on net income or retained earnings.

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2003

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Intangible Plant**			
3					
4	301	Organization			
5	302	Franchises & Consents			
6	303	Miscellaneous Intangible Plant	$2,690,312	$2,662,973	-1.02%
7					
8		**TOTAL Intangible Plant**	$2,690,312	$2,662,973	-1.02%
9					
10		**Production Plant**			
11					
12	Steam Production				
13					
14	310	Land & Land Rights	$254,056	$246,133	-3.12%
15	311	Structures & Improvements	10,641,270	10,679,959	0.36%
16	312	Boiler Plant Equipment	34,870,301	34,617,687	-0.72%
17	313	Engines & Engine Driven Generators			
18	314	Turbogenerator Units	8,536,876	8,765,513	2.68%
19	315	Accessory Electric Equipment	3,108,295	3,105,191	-0.10%
20	316	Miscellaneous Power Plant Equipment	3,153,966	3,433,668	8.87%
21					
22		**TOTAL Steam Production Plant**	$60,564,764	$60,848,151	0.47%
23					
24	Nuclear Production				
25					
26	320	Land & Land Rights			
27	321	Structures & Improvements			
28	322	Reactor Plant Equipment		NOT	
29	323	Turbogenerator Units		APPLICABLE	
30	324	Accessory Electric Equipment			
31	325	Miscellaneous Power Plant Equipment			
32					
33		**TOTAL Nuclear Production Plant**			
34					
35	Hydraulic Production				
36					
37	330	Land & Land Rights			
38	331	Structures & Improvements			
39	332	Reservoirs, Dams & Waterways		NOT	
40	333	Water Wheels, Turbines & Generators		APPLICABLE	
41	334	Accessory Electric Equipment			
42	335	Miscellaneous Power Plant Equipment			
43	336	Roads, Railroads & Bridges			
44					
45		**TOTAL Hydraulic Production Plant**			

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2003

Account Number & Title		Last Year	This Year	% Change
Production Plant (cont.)				
Other Production				
340	Land & Land Rights	$9,318	$16,002	71.73%
341	Structures & Improvements	59,333	88,392	48.98%
342	Fuel Holders, Producers & Accessories	66,792	66,642	-0.22%
343	Prime Movers			
344	Generators	2,184,153	6,532,036	199.06%
345	Accessory Electric Equipment	178,436	178,038	-0.22%
346	Miscellaneous Power Plant Equipment	6,981	6,965	-0.23%
TOTAL Other Production Plant		$2,505,013	$6,888,075	174.97%
TOTAL Production Plant		$63,069,777	$67,736,226	7.40%
Transmission Plant				
350	Land & Land Rights	$648,896	$642,731	-0.95%
352	Structures & Improvements	433	432	-0.23%
353	Station Equipment	12,130,492	12,723,366	4.89%
354	Towers & Fixtures	1,056,088	1,053,739	-0.22%
355	Poles & Fixtures	5,862,705	5,962,362	1.70%
356	Overhead Conductors & Devices	5,562,847	5,544,518	-0.33%
357	Underground Conduit			
358	Underground Conductors & Devices			
359	Roads & Trails			
TOTAL Transmission Plant		$25,261,461	$25,927,148	2.64%
Distribution Plant				
360	Land & Land Rights	$249,321	$249,633	0.13%
361	Structures & Improvements			
362	Station Equipment	3,987,690	3,995,048	0.18%
363	Storage Battery Equipment			
364	Poles, Towers & Fixtures	5,263,043	5,379,917	2.22%
365	Overhead Conductors & Devices	4,160,846	4,246,097	2.05%
366	Underground Conduit	12,967	12,967	
367	Underground Conductors & Devices	4,242,381	4,431,399	4.46%
368	Line Transformers	6,083,807	6,263,420	2.95%
369	Services	3,400,852	3,542,576	4.17%
370	Meters	2,053,171	2,075,263	1.08%
371	Installations on Customers' Premises	518,458	541,643	4.47%
372	Leased Property on Customers' Premises			
373	Street Lighting & Signal Systems	1,526,216	1,544,921	1.23%
TOTAL Distribution Plant		$31,498,752	$32,282,884	2.49%

Company Name: Montana-Dakota Utilities Co.

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2003

	Account Number & Title		Last Year	This Year	% Change
1					
2	**General Plant**				
3					
4	389	Land & Land Rights	$2,061	$2,061	
5	390	Structures & Improvements	86,501	86,490	-0.01%
6	391	Office Furniture & Equipment	256,540	262,881	2.47%
7	392	Transportation Equipment	836,844	970,757	16.00%
8	393	Stores Equipment	20,667	20,667	
9	394	Tools, Shop & Garage Equipment	478,036	508,984	6.47%
10	395	Laboratory Equipment	277,862	277,782	-0.03%
11	396	Power Operated Equipment	1,450,841	1,582,068	9.04%
12	397	Communication Equipment	581,599	575,157	-1.11%
13	398	Miscellaneous Equipment	31,687	31,663	-0.08%
14	399	Other Tangible Property			
15					
16	**TOTAL General Plant**		$4,022,638	$4,318,510	7.36%
17					
18	**Common Plant**				
19					
20	389	Land & Land Rights	$174,235	$171,370	-1.64%
21	390	Structures & Improvements	2,811,525	2,806,977	-0.16%
22	391	Office Furniture & Equipment	1,248,850	921,598	-26.20%
23	392	Transportation Equipment	959,291	1,387,035	44.59%
24	393	Stores Equipment	11,540	11,416	-1.07%
25	394	Tools, Shop & Garage Equipment	197,545	196,444	-0.56%
26	395	Laboratory Equipment			
27	396	Power Operated Equipment	13,878	7,784	-43.91%
28	397	Communication Equipment	616,714	383,013	-37.89%
29	398	Miscellaneous Equipment	80,165	76,552	-4.51%
30	399	Other Tangible Property			
31					
32	**TOTAL Common Plant**		$6,113,743	$5,962,189	-2.48%
33					
34					
35	**TOTAL Electric Plant in Service**		$132,656,683	$138,889,930	4.70%

MONTANA DEPRECIATION SUMMARY

Year: 2003

	Functional Plant Classification	Plant Cost	Accumulated Depreciation Last Year Bal.	Accumulated Depreciation This Year Bal.	Current Avg. Rate
1					
2	Steam Production 1/	$65,516,363	$45,886,399	$47,572,288	4.17%
3	Nuclear Production				
4	Hydraulic Production				
5	Other Production	6,888,075	1,940,122	2,104,008	2.02%
6	Transmission	25,927,148	14,748,712	15,234,552	2.31%
7	Distribution	32,282,884	17,360,654	18,220,153	3.29%
8	General	5,188,400	2,382,656	2,664,928	3.69%
9	Common	7,755,272	3,560,308	3,241,922	5.27%
10	**TOTAL**	$143,558,142	$85,878,851	$89,037,851	3.57%

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock	$585,597	$743,519	26.97%
3	152 Fuel Stock Expenses Undistributed			
4	153 Residuals			
5	154 Plant Materials & Operating Supplies:			
6	Assigned to Construction (Estimated)			
7	Assigned to Operations & Maintenance			
8	Production Plant (Estimated)	428,635	426,183	-0.57%
9	Transmission Plant (Estimated)	210,169	236,242	12.41%
10	Distribution Plant (Estimated)	395,518	446,723	12.95%
11	Assigned to Other			
12	155 Merchandise			
13	156 Other Materials & Supplies			
14	157 Nuclear Materials Held for Sale			
15	163 Stores Expense Undistributed			
16				
17	**TOTAL Materials & Supplies**	$1,619,919	$1,852,667	14.37%

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

	Commission Accepted - Most Recent		% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number	86.5.28			
2	Order Number	5219b			
3					
4	Common Equity		35.548%	12.300%	4.372%
5	Preferred Stock		11.280%	9.019%	1.017%
6	Long Term Debt - First Mortgage Bonds		44.491%	10.232%	4.552%
7	Other Long Term Debt		8.681%	8.222%	0.714%
8	**TOTAL**		100.000%		10.655%
9					
10	Actual at Year End				
11					
12	Common Equity		47.325%	12.300%	5.821%
13	Preferred Stock		4.779%	4.620%	0.221%
14	Long Term Debt		47.896%	8.606%	4.122%
15	Other				
16	**TOTAL**		100.000%		10.164%

1/ Includes deferred AFUDC, depreciation and interest on Coyote and acquisition adjustment.

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 23

STATEMENT OF CASH FLOWS

Year: 2003

	Description	Last Year	This Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2				
3	**Cash Flows from Operating Activities:**			
4	Net Income	$148,443,958	$175,324,972	18.11%
5	Depreciation	29,476,227	30,195,105	2.44%
6	Amortization	1,340,106	1,252,461	-6.54%
7	Deferred Income Taxes - Net	7,430,927	4,469,701	-39.85%
8	Investment Tax Credit Adjustments - Net	(583,775)	(596,333)	2.15%
9	Change in Operating Receivables - Net	(9,986,431)	(11,474,034)	-14.90%
10	Change in Materials, Supplies & Inventories - Net	9,697,089	(4,067,492)	-141.95%
11	Change in Operating Payables & Accrued Liabilities - Net	(10,398,195)	22,096,610	312.50%
12	Change in Other Regulatory Assets	(181,217)	(1,092,811)	-503.04%
13	Change in Other Regulatory Liabilities	(760,117)	672,317	188.45%
14	Allowance for Funds Used During Construction (AFUDC)	(132,880)	(217,797)	63.91%
15	Change in Other Assets & Liabilities - Net	(18,612,724)	(13,303,142)	28.53%
16	Less Undistributed Earnings from Subsidiary Companies	(128,320,376)	(153,788,920)	19.85%
17	Other Operating Activities (explained on attached page)			
18	**Net Cash Provided by/(Used in) Operating Activities**	$27,412,592	$49,470,637	80.47%
19				
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment			
22	(net of AFUDC & Capital Lease Related Acquisitions)	($36,510,374)	($45,338,342)	24.18%
23	Acquisition of Other Noncurrent Assets	(934,861)	4,502,946	-581.67%
24	Proceeds from Disposal of Noncurrent Assets			
25	Investments In and Advances to Affiliates	(96,870,417)	(50,630,421)	-47.73%
26	Contributions and Advances from Affiliates	51,045,000	56,273,000	10.24%
27	Disposition of Investments in and Advances to Affiliates			
28	Other Investing Activities: Depreciation & RWIP on Nonutility Plant	43,342	49,965	15.28%
29	**Net Cash Provided by/(Used in) Investing Activities**	($83,227,310)	($35,142,852)	-57.77%
30				
31	**Cash Flows from Financing Activities:**			
32	Proceeds from Issuance of:			
33	Long-Term Debt	$25,000,000	$30,000,000	20.00%
34	Preferred Stock			
35	Common Stock	96,035,929	49,126,951	-48.85%
36	Other:			
37	Net Increase in Short-Term Debt			
38	Other: Commercial Paper	8,000,000		-100.00%
39	Payment for Retirement of:			
40	Long-Term Debt	(500,000)	(10,500,000)	2000.00%
41	Preferred Stock	(100,000)	(100,000)	0.00%
42	Common Stock			
43	Other:			
44	Net Decrease in Short-Term Debt		(8,000,000)	-100.00%
45	Dividends on Preferred Stock	(756,406)	(718,155)	-5.06%
46	Dividends on Common Stock	(67,530,664)	(74,118,558)	9.76%
47	Other Financing Activities (explained on attached page)			
48	**Net Cash Provided by (Used in) Financing Activities**	$60,148,859	($14,309,762)	-123.79%
49				
50	**Net Increase/(Decrease) in Cash and Cash Equivalents**	$4,334,141	$18,023	-99.58%
51	**Cash and Cash Equivalents at Beginning of Year**	$5,054,591	$9,388,732	85.75%
52	**Cash and Cash Equivalents at End of Year**	$9,388,732	$9,406,755	0.19%

LONG TERM DEBT

Year: 2003

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost % 1/
1	8.25 % Secured MTN, Series A	04/92	04/07	$30,000,000	$26,111,796	$30,000,000	8.25%	$3,053,100	10.18%
2	8.60 % Secured MTN, Series A	04/92	04/12	35,000,000	28,906,532	35,000,000	8.60%	3,857,000	11.02%
3	6.52 % Secured MTN, Series A	09/97	10/04	15,000,000	14,082,923	15,000,000	6.52%	1,171,650	7.81%
4	6.71 % Secured MTN, Series A	09/97	10/09	15,000,000	13,488,404	15,000,000	6.71%	1,229,250	8.20%
5	5.83 % Secured MTN, Series A	09/98	10/08	15,000,000	14,813,914	15,000,000	5.83%	912,900	6.09%
6	Grant County 6.20 % PCN	03/74	03/04	5,600,000	5,427,042	1,500,000	6.20%	98,340	6.56%
7	5.98 % Senior Notes	12/03	12/33	30,000,000	29,456,832	30,000,000	5.98%	1,861,500	6.21%
8	Mercer County 6.65 % 2/	06/92	06/22	15,000,000	14,061,276	15,000,000	6.65%	1,093,200	7.29%
9	Richland County 6.65 % 2/	06/92	06/22	3,250,000	3,063,677	3,250,000	6.65%	235,398	7.24%
10	Morton County 6.65 % 2/	06/92	06/22	2,600,000	2,420,986	2,600,000	6.65%	190,944	7.34%
11	5.10% Cummulative Preferred Stock 3/ 4/	05/61	12/14	5,000,000	4,947,548	1,200,000	5.10%	63,420	5.29%
12									
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26	**TOTAL**			$171,450,000	$156,780,930	$163,550,000		$13,766,702	8.42%

1/ Includes interest expense, bond discount expense, debt issuance expense and loss on bond reacquistion and redemption.
2/ Pollution Control Refunding Revenue Bonds.
3/ Classified as long-term debt upon adoption of SFAS No. 150 in 2003.
4/ Mandatory annual redemption of $100,000.

PREFERRED STOCK

Year: 2003

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price 1/	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1	4.50 % Cumulative	01/51	100,000	$100	$105	$10,000,000	4.50%	$10,000,000	$450,000	4.50%
2	4.70 % Cumulative	12/55	50,000	100	102	5,000,000	4.70%	5,000,000	235,000	4.70%
3										
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30										
31										
32	**TOTAL**					$15,000,000		$15,000,000	$685,000	4.57%

1/ Plus accrued dividends.

COMMON STOCK

Year: 2003

		Avg. Number of Shares Outstanding 2/	Book Value Per Share	Earnings Per Share 3/	Dividends Per Share	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio 4/
1									
2									
3									
4	January								
5									
6	February								
7									
8	March 1/	110,318,489	$11.55	$0.18	$0.16	11.11%	$18.87	$16.41	14.0 X
9									
10	April								
11									
12	May								
13									
14	June 1/	110,601,720	11.79	0.39	0.16	58.97%	22.66	18.55	15.0 X
15									
16	July								
17									
18	August								
19									
20	September 1/	112,358,576	12.40	0.58	0.17	70.69%	23.32	20.37	14.4 X
21									
22	October								
23									
24	November								
25									
26	December	112,617,604	12.66	0.41	0.17	58.54%	24.35	20.37	15.4 X
27									
28									
29									
30	TOTAL Year End	111,482,820	$12.66	$1.56	$0.66	57.69%			15.4 X

1/ Restated to reflect three-for-two common stock split effected October 29, 2003.
2/ Basic shares.
3/ Basic earnings per share.
4/ Calculated on 12 months ended using closing stock price.

MONTANA EARNED RATE OF RETURN

Year: 2003

	Description	Last Year	This Year	% Change
	Rate Base			
1				
2	101 Plant in Service 1/	$134,986,929	$141,051,725	4.49%
3	108 (Less) Accumulated Depreciation 2/	84,246,742	87,309,431	3.64%
4				
5	**NET Plant in Service**	$50,740,187	$53,742,294	5.92%
6				
7	CWIP in Service Pending Reclassification	$236,587	$535,923	126.52%
8				
9	Additions			
10	151 Fuel Stocks	$585,597	$743,519	26.97%
11	154, 156 Materials & Supplies	1,034,322	1,109,148	7.23%
12	165 Prepayments	51,037	75,433	47.80%
13	Other Additions			
14				
15	**TOTAL Additions**	$1,670,956	$1,928,100	15.39%
16				
17	Deductions			
18	190 Accumulated Deferred Income Taxes	$11,178,155	$11,269,136	0.81%
19	252 Customer Advances for Construction	118,423	154,832	30.74%
20	255 Accumulated Def. Investment Tax Credits	607,347	552,857	-8.97%
21	Other Deductions			
22				
23	**TOTAL Deductions**	$11,903,925	$11,976,825	0.61%
24	**TOTAL Rate Base**	$40,743,805	$44,229,492	8.56%
25				
26	**Net Earnings**	$4,635,368	$5,507,593	18.82%
27				
28	**Rate of Return on Average Rate Base**	11.16%	12.96%	16.13%
29				
30	**Rate of Return on Average Equity**	13.49%	18.21%	34.99%
31				
32	Major Normalizing Adjustments & Commission			
33	Ratemaking adjustments to Utility Operations 3/			
34				
35	Adjustment to Operating Revenues			
36	Late Payment Revenues	$15,068	$9,559	-36.56%
37				
38				
39	Adjustment to Operating Expenses			
40	Elimination of Promotional & Institutional Advertising	(6,832)	(9,710)	42.13%
41				
42	Total Adjustments to Operating Income	$21,900	$19,269	-12.01%
43				
44				
45	**Adjusted Rate of Return on Average Rate Base**	11.22%	13.01%	15.95%
46				
47	**Adjusted Rate of Return on Average Equity**	13.61%	18.31%	34.53%

1/ Excludes Acquisition Adjustment of $2,512,027 for 2002 and $2,506,417 for 2003.
2/ Excludes Acquisition Adjustment of $1,632,109 for 2002 and $1,728,420 for 2003.
3/ Updated amounts, net of taxes.

MONTANA COMPOSITE STATISTICS

Year: 2003

		Description	Amount
2		Plant (Intrastate Only) (000 Omitted)	
4	101	Plant in Service	$115,503
5	107	Construction Work in Progress	1,070
6	114	Plant Acquisition Adjustments	
7	105	Plant Held for Future Use	
8	154, 156	Materials & Supplies	1,109
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	87,309
11	252	Contributions in Aid of Construction	155
13		**NET BOOK COSTS**	$30,218
15		Revenues & Expenses (000 Omitted)	
17	400	Operating Revenues	$42,123
19	403 - 407	Depreciation & Amortization Expenses	$5,131
20		Federal & State Income Taxes	2,556
21		Other Taxes	2,593
22		Other Operating Expenses	26,335
23		TOTAL Operating Expenses	$36,615
25		Net Operating Income	$5,508
27		Other Income	209
28		Other Deductions	1,842
30		**NET INCOME**	$3,875
32		Customers (Intrastate Only)	
34		Year End Average:	
35		Residential	18,395
36		Small General	4,838
37		Large General	249
38		Other	178
40		**TOTAL NUMBER OF CUSTOMERS**	23,660
42		Other Statistics (Intrastate Only)	
44		Average Annual Residential Use (Kwh))	8,184
45		Average Annual Residential Cost per (Kwh) (Cents) *	$0.074
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	$50.00
48		Gross Plant per Customer	$4,882

MONTANA CUSTOMER INFORMATION

Year: 2003

	City/Town	Population (Includes Rural) 1/	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Antelope	43	54	12	3	69
2	Bainville	153	84	33	5	122
3	Baker	1,695	925	302	13	1,240
4	Brockton	245	99	26	3	128
5	Carlyle	Not Available	2	4		6
6	Culbertson	716	350	132	3	485
7	Fallon	138	186	76	1	263
8	Fairview	709	368	87	3	458
9	Flaxville	87	61	19	3	83
10	Forsyth	1,944	1,033	265	11	1,309
11	Froid	195	136	41	4	181
12	Glendive	4,729	3,193	742	31	3,966
13	Homestead	Not Available	19	9	1	29
14	Ismay	26	21	14	1	36
15	Medicine Lake	269	171	45	4	220
16	Miles City	8,487	4,496	973	41	5,510
17	Outlook	82	56	20	3	79
18	Outlook Oil Field	Not Available		5	10	15
19	Plentywood	2,061	960	251	6	1,217
20	Plevna	138	89	25	3	117
21	Poplar	911	907	168	15	1,090
22	Poplar Oil Field	Not Available		4	11	15
23	Redstone	Not Available	21	13	1	35
24	Reserve	37	28	9	3	40
25	Rosebud	Not Available	72	43	2	117
26	Savage	Not Available	128	29	2	159
27	Scobey	1,082	592	174	3	769
28	Sidney	4,774	2,250	486	25	2,761
29	Terry	611	356	104	10	470
30	Whitetail	Not Available	27	13	1	41
31	Wibaux	567	287	95	8	390
32	Wolf Point	2,663	1,517	325	11	1,853
33	Kinsey	Not Available	110	32	2	144
34	MT Oil Fields	Not Available	8	42	78	128
35	**TOTAL Montana Customers**	32,362	18,606	4,618	321	23,545

1/ 2000 Census.

MONTANA EMPLOYEE COUNTS 1/

Year: 2003

	Department	Year Beginning	Year End	Average
1	Electric	20	19	20
2	Gas	41 (1)	42	41 (1)
3	Accounting	20	20	20
5	Management	6	6	6
7	Service 2/	56 (3)	58(3)	57 (3)
4	Marketing/Communications	5	7	6
6	Power	26	27	27
10				
11				
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41				
42	**TOTAL Montana Employees**	174 (4)	179 (3)	177 (4)

1/ Parentheses denotes part-time.

2/ Reflects service employees such as meter readers and servicemen.

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) Year: 2003

	Project Description	Total Company	Total Montana	
1	Projects>$1,000,000			
2				
3	Common-General			
4	Develop Geospacial Enterprise Management System	$1,292,830	$329,393	1/
5				
6	Electric-Steam Production			
7	Replace High and Intermediate Pressure Turbine - Big Stone	1,677,770	404,827	1/
8				
9	Electric-Transmission			
10	Construct 17.4 Miles of 115 KV Line South of Baker, MT	1,068,378	1,068,378	2/
11				
12	Other Projects<$1,000,000			
13				
14	Electric			
15	Production	4,238,610	1,022,735	1/
16	Transmission:			
17	Integrated	2,915,471	870,858	1/
18	Direct	1,017,739	458,854	2/
19	Distribution	5,565,988	953,129	2/
20	General	1,246,284	279,053	2/
21	Common:			
22	General Office	1,671,269	378,477	1/
23	Other Direct	621,320	190,111	2/
24	Total Electric	17,276,681	4,153,217	
25				
26	Gas			
27	Production	28,541	-	1/
28				
29	Distribution	7,816,014	2,307,610	2/
30	General	2,445,092	675,589	2/
31	Common:			
32	General Office	1,281,489	329,072	1/
33	Other Direct	318,971	156,523	2/
34	Total Gas	11,890,107	3,468,794	
35				
36				
37				
38				
39				
40				
41				
42	TOTAL	$33,205,766	$9,424,609	

1/ Allocated to Montana.

2/ Directly assigned to Montana.

Company Name: Montana-Dakota Utilities Co. SCHEDULE 32

TOTAL INTEGRATED SYSTEM & MONTANA PEAK AND ENERGY

Year: 2003

Integrated System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	23	1200	343.5	286,552	86,863
2	Feb.	24	1100	339.9	260,302	72,673
3	Mar.	7	1100	326.9	284,644	91,855
4	Apr.	2	2100	292.6	185,740	23,269
5	May	29	1800	316.8	213,162	44,802
6	Jun.	30	1700	387.5	225,859	54,855
7	Jul.	24	1700	449.9	279,209	63,104
8	Aug.	14	1800	470.5	287,257	66,833
9	Sep.	8	1600	387.2	257,109	82,801
10	Oct.	29	1900	308.2	246,537	71,081
11	Nov.	24	1900	329.6	305,118	110,927
12	Dec.	10	1900	351.9	271,656	72,574
13	**TOTAL**				3,103,145	841,637

Montana

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
14	Jan.	23	1200	86.2		
15	Feb.	24	1100	86.6		
16	Mar.	7	1100	81.7		
17	Apr.	2	2100	77.4		
18	May	29	1800	84.3		
19	Jun.	30	1700	93.3		
20	Jul.	24	1700	111.0	Not Available	Not Available
21	Aug.	14	1800	113.7		
22	Sep.	8	1600	94.1		
23	Oct.	29	1900	82.4		
24	Nov.	24	1900	90.2		
25	Dec.	10	1900	95.2		
26	**TOTAL**					

TOTAL SYSTEM Sources & Disposition of Energy

SCHEDULE 33

	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	2,366,362	Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	2,359,888
4	Hydro - Conventional			
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	18,522	for Resale	
7	(Less) Energy for Pumping			
8	**NET Generation**	2,384,884	Non-Requirements Sales	
9	Purchases	920,171	for Resale	841,637
10	Power Exchanges			
11	Received	22,316	Energy Furnished	
12	Delivered	19,758	Without Charge	
13	**NET Exchanges**	2,558		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	1,293,866	Electric Utility	
16	Delivered	1,202,846		
17	**NET Transmission Wheeling**	91,020	Total Energy Losses	167,194
18	Transmission by Others Losses	(29,914)		
19	**TOTAL**	3,368,719	**TOTAL**	3,368,719

Montana-Dakota's annual peak occurred during HE1800 August 14, 2003. All generation units were available for operation durning the peak hour. The following units were on line and providing energy.

Heskett #1	19.1
Heskett #2	69.1
Lewis & Clark	38.7
Glendive Turbine	32.2
Miles City Turbine	3.2
Coyote	100.0
Big Stone	99.0

In addition to the above units, Montana-Dakota was purchasing 67 MW of its 67 MW share of the Antelope Valley Unit 2. Montana-Dakota also sold 5 MW to other MAPP/MISO utilities with the remaining amount needed to meet the peak demand.

SOURCES OF ELECTRIC SUPPLY

Year: 2003

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Combustion Turbine	Williston Plant	Williston, ND	10.6	(78.8)
2	Combustion Turbine	Miles City Turbine	Miles City, MT	29.4	2,252.1
3	Thermal	Lewis & Clark Station	Sidney, MT	47.6	323,167.0
4	Combustion Turbine	Glendive Turbine	Glendive, MT	72.3	16,348.2
5	Thermal	Heskett Station	Mandan, ND	103.1	605,187.1
6	Thermal	Big Stone Station	Milbank, SD	106.6	734,902.0
7				(MDU SHARE)	
8	Thermal	Coyote Station	Beulah, ND	106.8	703,106.1
9				(MDU SHARE)	
10	Purchases	Basin Electric	10-31-2006	66.4	561,556.0
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43	**Total**			542.8	2,946,439.7

Company Name: Montana-Dakota Utilities Co. SCHEDULE 34A

Outage Start Date/Time	Outage End Date/Time	Brief Description of Primary Cause 1/
		Big Stone Plant
1/22/2003 14:12	1/23/2003 0:26	Unit trip - breaker failed
1/29/2003 12:58	1/29/2003 14:04	Unit trip - low condenser vacuum
2/26/2003 18:21	3/2/2003 22:58	Boiler wash outage
3/2/2003 23:34	3/3/2003 0:49	Unit trip - low condenser vacuum
3/3/2003 1:24	3/3/2003 3:14	Unit trip - low condenser vacuum
3/3/2003 9:01	3/3/2003 11:14	Unit trip - low drum level
4/22/2003 15:53	4/22/2003 20:10	Valve leak
4/22/2003 20:28	4/22/2003 21:48	Unit trip - boiler drum level high
4/26/2003 4:19	4/27/2003 10:36	Forced outage - RH tube leak repair
6/3/2003 17:43	6/11/2003 18:21	Scheduled boiler wash
6/12/2003 6:25	6/17/2003 18:51	Unit trip - turbin OPC control problem
6/17/2003 19:35	6/17/2003 20:37	Unit trip - low drum level
6/28/2003 2:15	6/28/2003 3:46	Unit trip - low drum level
7/14/2003 12:39	7/14/2003 13:41	Unit trip - furnace pressure trip
10/6/2003 9:53	10/6/2003 11:45	Turbine trip - problems with functional testing
12/5/2003 18:13	12/13/2003 22:00	Off line for scheduled boiler convection pass HP wash
12/13/2003 22:00	12/21/2003 3:16	Off line for scheduled generator service
		Coyote Station
1/21/2003 13:27	1/21/2003 15:01	Trip due to M-A card on DA level control
2/16/2003 20:41	2/18/2003 20:34	Tube lead in primary superheater
2/18/2003 23:04	2/19/2003 0:28	Gland steam seal system overpressure
2/26/2003 9:27	2/26/2003 11:03	Control system glitch
3/28/2003 0:00	5/11/2003 0:00	Planned Outage
5/11/2003 0:00	5/28/2003 16:00	Outage extension - Generator work
5/28/2003 16:21	5/28/2003 17:58	Trip due to generator stator high temperatures
5/28/2003 23:29	5/31/2003 5:44	Overspeed trip test
5/31/2003 9:10	5/31/2003 13:13	Trip due to generator 3rd harmonic over-voltage
5/31/2003 16:34	5/31/2003 20:23	Trip due to generator 3rd harmonic over-voltage
7/9/2003 11:37	7/9/2003 15:11	Trip due to A FD fan and low furnace pressure
7/9/2003 16:40	7/9/2003 18:29	Trip due to high funace pressure as 2nd FD started
10/9/2003 23:44	10/13/2003 3:51	Scheduled fall boiler clean outage

Outage Start Date/Time	Outage End Date/Time	Brief Description of Primary Cause 1/
		Heskett Unit 1
1/31/2003 22:26	2/2/2003 7:02	Electrostatic precipitator fields were out of service
3/30/2003 12:39	4/3/2003 4:24	Platen superheat tube leaks
7/5/2003 15:51	7/5/2003 16:02	Turbine trip solenoid linkage
7/30/2003 13:03	7/30/2003 13:16	Turbine trip solenoid linkage
7/30/2003 13:51	7/30/2003 15:03	Turbine trip solenoid linkage
9/25/2003 23:22	10/3/2003 5:30	Maintenance Outage
10/3/2003 5:30	10/3/2003 11:39	Packing blew out on the after seat drain valve
12/3/2003 8:37	12/3/2003 9:06	Low vacuum
12/3/2003 9:07	12/3/2003 9:24	Low vacuum
		Heskett Unit 2
1/15/2003 23:54	1/21/2003 12:49	Maintenance Outage
6/13/2003 21:52	6/23/2003 0:01	Maintenance Outage
6/23/2003 0:01	6/25/2003 22:35	Turbine stop valve sticking
7/30/2003 0:35	8/3/2003 15:51	Fires and clinkers in precipitator
9/3/2003 3:50	9/7/2003 19:10	Generator potential transformer fuses
12/23/2003 11:39	12/31/03 24:00	Maintenance Outage
		Lewis & Clark Station
1/11/2003 2:50	1/11/2003 3:47	Master Fuel Trip
1/11/2003 5:04	1/11/2003 13:49	Repack feed water valve
3/4/2003 11:15	3/4/2003 13:51	UPS failed to operate properly
4/11/2003 23:58	4/25/2003 10:49	Boiler maintenance
4/25/2003 11:06	4/25/2003 14:52	Boiler feed pump valve control
5/27/2003 5:57	5/27/2003 15:29	High range feedwater valve
8/15/2003 7:46	8/15/2003 19:48	Scrubber disc leak
9/6/2003 1:37	9/6/2003 3:19	Feedwater valve trip
9/8/2003 22:23	9/9/03 0:46	Lightening strike knocked ID fan off line
10/3/2003 21:50	10/10/2003 6:39	Circulating water pumps

1/ Outages longer than 1 hour, other than reserve shutdowns for economic dispatch.

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2003

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings **(MW & MWH)**	Achieved Savings **(MW & MWH)**	Difference **(MW & MWH)**
1							
2	Weatherization Program	$127,200	$127,200		N/A	N/A	N/A
3							
4	Energy Audits	10,000	10,500	-4.76%	N/A	N/A	N/A
5							
6	Lighting Retrofits	30,589	36,655	-16.55%	N/A	N/A	N/A
7							
8							
9	**TOTAL**	$167,789	$174,355	-3.77%	N/A	N/A	N/A

** Note - The residential conservation programs listed are administered through the Universal Systems Benefits Program (USBP). USBP funds were directed to these programs through third parties. Estimated savings are not available.

MONTANA CONSUMPTION AND REVENUES

Year: 2003

	Sales of Electricity	Operating Revenues Current Year	Operating Revenues Previous Year	MegaWatt Hours Sold Current Year	MegaWatt Hours Sold Previous Year	Avg. No. of Customers Current Year	Avg. No. of Customers Previous Year
1	Residential	$11,036,914	$10,638,169	150,544	145,041	18,395	18,437
2	Small General	6,208,889	5,963,331	101,994	97,620	4,838	4,769
3	Large General	15,345,026	13,966,697	339,729	305,900	249	247
4	Lighting	675,140	671,699	9,684	9,653	77	78
5	Municipal Pumping	323,038	319,265	6,992	6,894	101	101
6	Sales to Other Utilities	6,832,812	4,195,466	Not Applicable	Not Applicable	Not Applicable	Not Applicable
7							
8							
9							
10							
11							
12							
13	TOTAL	$40,421,819	$35,754,627	608,943	565,108	23,660	23,632