

**MONTANA-DAKOTA UTILITIES CO.
CASE NO. PU-399-04-_____
STATEMENTS A – O**

**In the Matter of the Application of
Montana-Dakota Utilities Co. for
Authority to Establish Increased Rates
For Natural Gas Service in the
State of North Dakota**

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED BALANCE SHEET
DECEMBER 31, 2002 AND
DECEMBER 31, 2003

	2002	2003
<u>Assets and Other Debits</u>		
Utility Plant	\$845,518,266	\$881,126,491
Construction Work in Progress	18,641,586	11,357,572
Less Acc. Provision for Depreciation and Amortization	496,483,634	512,484,759
Net Utility Plant	367,676,218	379,999,304
Gas Stored Underground - Noncurrent	1,913,520	2,361,258
 <u>Other Property and Investments</u>		
Nonutility Property	174,544	1,036,084
(Less) Accum. Prov. for Depr. And Amort.	79,695	353,568
Investment in Subsidiary Companies	1,130,703,822	1,278,850,163
Other investments	26,757,835	22,254,889
Net Other Property and Investments	1,157,556,506	1,301,787,568
 <u>Current and Accrued Assets</u>		
Cash	5,959,888	861,378
Special Deposits	1,200	1,200
Working Fund	130,965	15,965
Temporary Cash Investments	3,297,879	8,529,412
Customer Accounts Receivable	28,398,322	37,004,255
Other Accounts Receivable	2,365,820	3,987,038
(Less) Accum.Prov. For Uncollectible Acct. - Credit	241,038	319,419
Accounts Receivable from Assoc.Companies	16,147,799	17,473,063
Fuel Stock	2,233,437	2,753,765
Plant Materials and Operating Supplies	5,894,011	6,197,652
Merchandise	1,012,624	1,139,740
Gas Stored Underground - Current	15,322,047	18,438,454
Prepayments	7,220,656	8,839,446
Interest and Dividends Receivable		
Accrued Utility Revenues	20,628,893	27,625,923
Miscellaneous Current and Accrued Assets	57,814	117,438
Total Current and Accrued Assets	108,430,317	132,665,310
 <u>Deferred Debits</u>		
Unamortized Debt Expenses	1,123,696	1,533,592
Other Regulatory Assets	3,651,680	4,744,491
Prelim. Survey and Investigation Charges (Electric)	1,686,727	1,127,322
Clearing Accounts	(40,451)	(124,215)
Miscellaneous Deferred Debits	19,360,006	22,910,284
Unamortized Loss on Reaquired Debt	5,627,511	4,518,768
Accumulated Deferred Income Taxes	20,176,715	21,238,378
Unrecovered Purchased Gas Costs	(2,396,235)	10,518,527
Total Deferred Debits	49,189,649	66,467,147
 Total Assets and Other Debits	\$1,684,766,210	\$1,883,280,587

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED BALANCE SHEET
DECEMBER 31, 2002 AND
DECEMBER 31, 2003

	2002	2003
<u>Liabilities and Other Credits</u>		
<u>Proprietary Capital</u>		
Common Stock Issued	\$74,282,038	\$113,716,632
Preferred Stock Issued	16,300,000	16,200,000
Premium on Capital Stock	751,331,277	761,023,634
(Less) Capital Stock Expense	3,236,160	3,236,160
Retained Earnings	44,231,211	47,203,550
Unappropriated Undistributed Sub Earnings	430,566,718	528,082,638
Accumulated Other Comprehensive Income	(9,803,865)	(7,528,653)
Total Proprietary Capital	1,303,671,219	1,455,461,641
 <u>Long-Term Debt</u>		
Bonds	130,850,000	160,850,000
Other Long-Term Debt	52,000,000	41,500,000
(Less) Unamortized Discount on Long-Term Debt-Debit	41,116	36,671
Total Long-Term Debt	182,808,884	202,313,329
 <u>Other Noncurrent Liabilities</u>		
Accumulated Provision for Injuries and Damages	1,415,463	1,017,175
Accumulated Provision for Pensions and Benefits	24,086,968	29,785,661
Accumulated Provision for Rate Refunds	67,067	299,228
Asset Retirement Obligations	0	602,589
Total Other Noncurrent Liabilities	25,569,498	31,704,653
 <u>Current and Accrued Liabilities</u>		
Notes Payable	8,000,000	0
Accounts Payable	18,828,269	26,572,779
Accounts Payable to Associated Companies	5,882,199	7,113,407
Customer Deposits	1,472,979	1,584,497
Taxed Accrued	(464,747)	10,323,491
Interest Accrued	2,212,959	2,307,669
Dividends Declared	17,959,379	19,458,320
Tax Collections Payable	1,210,339	1,662,094
Miscellaneous Current and Accrued Liabilities	10,489,414	10,665,144
Total Current and Accrued Assets	65,590,791	79,687,401
 <u>Deferred Debits</u>		
Customer Advances for Construction	1,533,151	1,284,167
Accumulated Deferred Investment Tax Credit	3,058,287	2,461,954
Other Deferred Credits	14,584,248	16,816,218
Other Regulatory Liabilities	15,563,924	15,633,652
Accumulated Deferred Income Taxes	72,386,208	77,917,572
Total Deferred Credits	107,125,818	114,113,563
Total Liabilities and Equity	\$1,684,766,210	\$1,883,280,587

NOTES TO THE FINANCIAL STATEMENTS

MDU RESOURCES GROUP, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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
<i>(Dollars in thousands, as applicable)</i>			
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:

	Total	Year Costs Incurred			
		2003	2002	2001	2000 and prior
		<i>(In thousands)</i>			
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
		<i>(In thousands)</i>	
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
	<i>(In thousands, except per share amounts)</i>		
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)
<u>Pro forma earnings on common stock</u>	<u>\$172,509</u>	<u>\$144,826</u>	<u>\$151,288</u>
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)	---	---
<u>Earnings per common share -- basic</u>	<u>\$ 1.57</u>	<u>\$ 1.39</u>	<u>\$ 1.54</u>
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)	---	---
<u>Earnings per common share -- basic</u>	<u>\$ 1.55</u>	<u>\$ 1.36</u>	<u>\$ 1.50</u>
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)	---	---
<u>Earnings per common share -- diluted</u>	<u>\$ 1.55</u>	<u>\$ 1.38</u>	<u>\$ 1.52</u>
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)	---	---
<u>Earnings per common share -- diluted</u>	<u>\$ 1.53</u>	<u>\$ 1.36</u>	<u>\$ 1.49</u>

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

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
<i>(In thousands)</i>			
Electric	\$ ---	\$ ---	\$ ---
Natural gas distribution	---	---	---
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	Balance as of December 31, 2002
<i>(In thousands)</i>			
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)
	<u>174,640</u>	<u>165,002</u>
Noncompete agreements	12,075	12,075
Accumulated amortization	(9,690)	(9,366)
	<u>2,385</u>	<u>2,709</u>
Other	17,734	7,224
Accumulated amortization	(2,265)	(374)
	<u>15,469</u>	<u>6,850</u>
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
	<i>(In thousands)</i>	
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
<u>Total regulatory assets</u>	<u>55,306</u>	<u>40,739</u>
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
<u>Total regulatory liabilities</u>	<u>111,218</u>	<u>100,772</u>
<u>Net regulatory position</u>	<u>\$ (55,912)</u>	<u>\$ (60,033)</u>

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		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	<i>(In thousands)</i>			
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
	<i>(In thousands)</i>	
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
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
	<i>(In thousands)</i>
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
<u>Balance at December 31, 2003</u>	<u>\$34,633</u>

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
	<i>(Dollars in thousands)</i>	
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:

Range of Exercisable Prices	Options Outstanding			Options Exercisable	
	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	2001
		<i>(In thousands)</i>	
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	2002
	<i>(In thousands)</i>	
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
	<i>(In thousands)</i>
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		2002		2001	
	Amount	%	Amount	%	Amount	%
<i>(Dollars in thousands)</i>						
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	2001
		(In thousands)	
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
	<u>641,062</u>	<u>459,409</u>	<u>903,334</u>
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	---
	<u>1,711,127</u>	<u>1,572,128</u>	<u>1,320,298</u>
Total external operating revenues	<u>\$2,352,189</u>	<u>\$2,031,537</u>	<u>\$2,223,632</u>
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	<u>\$ ---</u>	<u>\$ ---</u>	<u>\$ ---</u>
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
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	<u>\$ 188,337</u>	<u>\$ 157,961</u>	<u>\$ 139,917</u>
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	<u>\$ 52,794</u>	<u>\$ 45,015</u>	<u>\$ 45,899</u>

	2003	2002	2001
	(In thousands)		
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	2001
	(In thousands)		
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
	<i>(In thousands)</i>			
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
	<i>(In thousands)</i>	
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:

Years ended December 31,	Pension Benefits			Other Postretirement Benefits		
	2003	2002	2001	2003	2002	2001
	<i>(In thousands)</i>					
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 Point Increase	1 Percentage Point Decrease
<i>(In thousands)</i>		
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		Weighted Average Targeted Asset Allocation Percentage
	2003	2002	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		Weighted Average Targeted Asset Allocation Percentage
	2003	2002	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
	<i>(In thousands)</i>	
Big Stone Station:		
Utility plant in service	\$ 52,154	\$ 53,018
Less accumulated depreciation	34,993	34,456
	<u>\$ 17,161</u>	<u>\$ 18,562</u>
Coyote Station:		
Utility plant in service	\$124,086	\$122,476
Less accumulated depreciation	72,850	70,778
	<u>\$ 51,236</u>	<u>\$ 51,698</u>

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 Prairiелands Energy Marketing, Inc. (Prairiелands), 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.

Independent Auditors' Report

To the Board of Directors and Stockholders of MDU Resources Group, Inc.:

We have audited the accompanying consolidated balance sheets of MDU Resources Group, Inc. (the "Company") as of December 31, 2003 and 2002, and the related consolidated statements of income, common stockholders' equity, and cash flows for the years then ended. Our audits also included the 2003 and 2002 financial statement schedules listed in the Index at Item 15. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. The consolidated financial statements and financial statement schedule of the Company for the year ended December 31, 2001, before the adjustments described in Note 11, additional transitional disclosures described in Notes 3 and 9, and the reclassifications to the consolidated financial statements described in Note 1, were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on those consolidated financial statements and stated that such 2001 financial statement schedule, when considered in relation to the 2001 basic consolidated financial statements taken as a whole, presented fairly, in all material respects, the information set forth therein, in their reports dated January 23, 2002.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the 2003 and 2002 consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2003 and 2002, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the 2003 and 2002 financial statement schedules, when considered in relation to the 2003 and 2002 consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed above, the consolidated financial statements of the Company for the year ended December 31, 2001 were audited by other auditors who have ceased operations. As described in Note 11, those consolidated financial statements have been revised to give effect to the stock split on October 29, 2003. We audited the adjustments described in Note 11

that were applied to revise the 2001 consolidated financial statements for such stock split. Our audit procedures included (1) comparing the amounts shown in the earnings per share disclosures for 2001 to the Company's underlying accounting analysis obtained from management, (2) comparing the previously reported shares outstanding and income statement amounts per the Company's accounting analysis to the previously issued consolidated financial statements, and (3) recalculating the additional shares to give effect to the stock split and testing the mathematical accuracy of the underlying analysis. Also, as described in Note 3, these consolidated financial statements have been revised to include the transitional disclosures required by Statement of Financial Accounting Standards ("SFAS") No. 142, *Goodwill and Other Intangible Assets*, which was adopted by the Company as of January 1, 2002. Our audit procedures, with respect to the disclosures in Note 3 with respect to the 2001 disclosures, included (a) comparing the previously reported net income to the previously issued consolidated financial statements and the adjustments to reported net income representing amortization expense (including any related tax effects) recognized in those periods related to goodwill that is no longer being amortized as a result of initially applying SFAS No. 142 (including any tax effects) to the Company's underlying analysis obtained from management, and (b) testing the mathematical accuracy of (i) the reconciliation of adjusted net income to reported net income and (ii) the related earnings per share amounts. Also, as described in Note 1, these consolidated financial statements have been reclassified to include additional disclosures relating to the components comprising operating revenues and operation and maintenance expenses. Our audit procedures with respect to 2001 as it relates to the reclassifications described in Note 1 included (1) comparing the previously reported operating revenues and operation and maintenance expenses to previously issued consolidated financial statements, (2) comparing the operating revenues and operation and maintenance expenses to the Company's underlying analysis obtained from management, and (3) testing the mathematical accuracy of the underlying analysis. Also, as described in Note 9, these consolidated financial statements have been revised to include disclosures required by SFAS No. 143, *Accounting for Asset Retirement Obligations*, which was adopted by the Company as of January 1, 2003. Our audit procedures with respect to the disclosures in Note 9 as they relate to 2001 included testing the mathematical accuracy of the underlying analysis. In our opinion, the 2001 adjustments for the stock split described in Note 11 have been properly applied, the goodwill disclosures for 2001 in Note 3 and the asset retirement disclosures for 2001 in Note 9 are appropriate, and the reclassifications to the consolidated financial statements described in Note 1 have been properly applied. However, we were not engaged to audit, review, or apply any procedures to the 2001 consolidated financial statements of the Company other than with respect to such adjustments, reclassifications, and disclosures and, accordingly, we do not express an opinion or any other form of assurance on the 2001 consolidated financial statements taken as a whole.

As discussed in Notes 1 and 9 to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations; and as discussed in Notes 1 and 3 to the consolidated financial statements, effective January 1, 2002, the Company changed its method of accounting for goodwill.

/s/ DELOITTE & TOUCHE LLP
DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 17, 2004

THIS IS A COPY OF A REPORT PREVIOUSLY ISSUED BY ARTHUR ANDERSEN LLP. THIS REPORT HAS NOT BEEN REISSUED BY ARTHUR ANDERSEN LLP NOR HAS ARTHUR ANDERSEN LLP PROVIDED A CONSENT TO THE INCLUSION OF ITS REPORT IN THIS ANNUAL REPORT.

Report of Independent Public Accountants

To MDU Resources Group, Inc.:

We have audited the accompanying consolidated balance sheets of MDU Resources Group, Inc. (a Delaware corporation) and Subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, common stockholders' equity and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of MDU Resources Group, Inc. and Subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As explained in Note 1 to the consolidated financial statements, effective January 1, 2001, the company changed its method of accounting for derivative instruments due to the adoption of a new accounting pronouncement.

/s/ ARTHUR ANDERSEN LLP
ARTHUR ANDERSEN LLP

Minneapolis, Minnesota
January 23, 2002

THIS IS A COPY OF A REPORT PREVIOUSLY ISSUED BY ARTHUR ANDERSEN LLP.
THIS REPORT HAS NOT BEEN REISSUED BY ARTHUR ANDERSEN LLP NOR HAS ARTHUR
ANDERSEN LLP PROVIDED A CONSENT TO THE INCLUSION OF ITS REPORT IN THIS
ANNUAL REPORT.

To MDU Resources Group, Inc.:

We have audited in accordance with auditing standards generally accepted in the United States, the financial statements included in MDU Resources Group, Inc.'s annual report to stockholders incorporated by reference in this Form 10-K, and have issued our report thereon dated January 23, 2002. Our audit was made for the purpose of forming an opinion on those statements taken as a whole. Schedule II is the responsibility of the company's management and is presented for purposes of complying with the Securities and Exchange Commission's rules and is not part of the basic financial statements. This schedule has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, fairly states in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

/S/ ARTHUR ANDERSEN LLP
ARTHUR ANDERSEN LLP

Minneapolis, Minnesota,
January 23, 2002

MDU RESOURCES GROUP, INC.
SUPPLEMENTARY FINANCIAL INFORMATION

Quarterly Data (Unaudited)

The following unaudited information shows selected items by quarter for the years 2003 and 2002:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	<i>(In thousands, except per share amounts)</i>			
2003				
Operating revenues	\$467,753	\$548,219	\$716,099	\$620,118
Operating expenses	414,806	473,534	600,433	551,344
Operating income	52,947	74,685	115,666	68,774
Income before cumulative effect of accounting change	27,697	43,473	65,521	46,222
Cumulative effect of accounting change	(7,589)	---	---	---
Net income	20,108	43,473	65,521	46,222
Earnings per common share -- basic:				
Earnings before cumulative effect of accounting change	.25	.39	.58	.41
Cumulative effect of accounting change	(.07)	---	---	---
Earnings per common share -- basic	.18	.39	.58	.41
Earnings per common share -- diluted:				
Earnings before cumulative effect of accounting change	.25	.39	.58	.40
Cumulative effect of accounting change	(.07)	---	---	---
Earnings per common share -- diluted	.18	.39	.58	.40
Weighted average common shares outstanding:				
Basic	110,318	110,602	112,359	112,618
Diluted	111,094	111,532	113,368	113,804

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
<i>(In thousands, except per share amounts)</i>				
<u>2002</u>				
Operating revenues	\$381,935	\$480,218	\$612,398	\$556,986
Operating expenses	336,138	429,023	522,227	478,032
Operating income	45,797	51,195	90,171	78,954
Net income	23,722	24,853	53,931	45,938
Earnings per common share:				
Basic	.23	.23	.51	.42
Diluted	.22	.23	.50	.42
Weighted average common shares outstanding:				
Basic	104,203	105,684	106,385	108,142
Diluted	105,020	106,540	107,017	108,864
Pro forma amounts assuming retroactive application of accounting change:				
Net income	\$ 23,126	\$ 24,255	\$ 53,332	\$ 45,339
Earnings per common share -- basic	.22	.23	.50	.42
Earnings per common share -- diluted	.22	.23	.50	.41

Certain Company operations are highly seasonal and revenues from and certain expenses for such operations may fluctuate significantly among quarterly periods. Accordingly, quarterly financial information may not be indicative of results for a full year.

Natural Gas and Oil Activities (Unaudited)

Fidelity is involved in the acquisition, exploration, development and production of natural gas and oil resources. Fidelity's activities include the acquisition of producing properties with potential development opportunities, exploratory drilling and the operation and development of natural gas production properties. Fidelity shares revenues and expenses from the development of specified properties located primarily in the Rocky Mountain region of the United States and in and around the Gulf of Mexico in proportion to its ownership interests.

Fidelity owns in fee or holds natural gas leases for the properties it operates in Colorado, Montana, North Dakota and Wyoming. These rights are in the Bonny Field located in eastern Colorado, the Cedar Creek Anticline in southeastern Montana and southwestern North Dakota, the Bowdoin area located in north-central Montana and in the Powder River Basin of Montana and Wyoming.

The information that follows includes Fidelity's proportionate share of all its natural gas and oil interests.

The following table sets forth capitalized costs and accumulated depreciation, depletion and amortization related to natural gas and oil producing activities at December 31:

	2003	2002	2001
		<i>(In thousands)</i>	
Subject to amortization	\$758,500	\$603,151	\$506,155
Not subject to amortization	104,339	145,692	122,354
Total capitalized costs	862,839	748,843	628,509
Less accumulated depreciation, depletion and amortization	305,349	239,964	195,469
Net capitalized costs	\$557,490	\$508,879	\$433,040

Capital expenditures, including those not subject to amortization, related to natural gas and oil producing activities were as follows:

Years ended December 31,	2003*	2002	2001
		<i>(In thousands)</i>	
Acquisitions	\$ 3,027	\$ 31,439	\$ 1,695
Exploration	19,193	5,325	13,938
Development**	77,583	94,943	102,670
Total capital expenditures	\$99,803	\$131,707	\$118,303

* Excludes \$14,724 of additions to property, plant and equipment related to the recognition of future liabilities associated with the plugging and abandonment of natural gas and oil wells in accordance with SFAS No. 143, as discussed in Note 9.

**Includes expenditures for proved undeveloped reserves of \$23.3 million, \$10.1 million and \$15.0 million for the years ended December 31, 2003, 2002 and 2001, respectively.

The following summary reflects income resulting from the Company's operations of natural gas and oil producing activities, excluding corporate overhead and financing costs:

Years ended December 31,	2003	2002*	2001
		(In thousands)	
Revenues:			
Sales to external customers	\$140,034	\$145,170	\$139,939
Sales to affiliates	124,077	55,437	61,178
Production costs	67,292	52,520	44,435
Depreciation, depletion and amortization	60,072**	48,064	41,223
Pretax income	136,747	100,023	115,459
Income tax expense	51,925	36,886	45,245
Results of operations for producing activities before cumulative effect of accounting change	84,822	63,137	70,214
Cumulative effect of accounting change	(7,740)	---	---
Results of operations for producing activities	\$ 77,082	\$ 63,137	\$ 70,214

* Includes the compromise agreement as discussed in Note 19.

**Includes \$1,356 of accretion of discount for asset retirement obligations in 2003 in accordance with SFAS No. 143, as discussed in Note 1.

The following table summarizes the Company's estimated quantities of proved natural gas and oil reserves at December 31, 2003, 2002 and 2001, and reconciles the changes between these dates. Estimates of economically recoverable natural gas and oil reserves and future net revenues therefrom are based upon a number of variable factors and assumptions. For these reasons, estimates of economically recoverable reserves and future net revenues may vary from actual results.

	2003		2002		2001	
	Natural Gas	Oil	Natural Gas	Oil	Natural Gas	Oil
<i>(In thousands of Mcf/barrels)</i>						
Proved developed and undeveloped reserves:						
Balance at beginning of year	372,500	17,500	324,100	17,500	309,800	15,100
Production	(54,700)	(1,900)	(48,200)	(2,000)	(40,600)	(2,000)
Extensions and discoveries	113,300	3,300	80,100	2,200	66,400	2,000
Purchases of proved reserves	900	---	1,200	100	1,000	100
Sales of reserves in place	---	(100)	(4,400)	(300)	---	---
Revisions of previous estimates	(20,300)	100	19,700	---	(12,500)	2,300
Balance at end of year	411,700	18,900	372,500	17,500	324,100	17,500

Proved developed reserves:		
January 1, 2001	263,400	14,200
December 31, 2001	291,300	17,100
December 31, 2002	331,300	14,800
December 31, 2003	342,800	15,000

All of the Company's interests in natural gas and oil reserves are located in the United States and in and around the Gulf of Mexico.

The standardized measure of the Company's estimated discounted future net cash flows of total proved reserves associated with its various natural gas and oil interests at December 31 was as follows:

	2003	2002	2001
<i>(In thousands)</i>			
Future cash inflows	\$2,547,400	\$1,726,000	\$ 974,200
Future production costs	651,300	513,200	361,600
Future development costs	67,100	61,200	64,600
Future net cash flows before income taxes	1,829,000	1,151,600	548,000
Future income tax expense	601,000	324,000	112,000
Future net cash flows	1,228,000	827,600	436,000
10% annual discount for estimated timing of cash flows	491,200	321,300	174,000
Discounted future net cash flows relating to proved natural gas and oil reserves	\$ 736,800	\$ 506,300	\$ 262,000

The following are the sources of change in the standardized measure of discounted future net cash flows by year:

	2003	2002	2001
	<i>(In thousands)</i>		
Beginning of year	\$ 506,300	\$ 262,000	\$ 921,300
Net revenues from production	(220,000)	(112,900)	(153,500)
Change in net realization	318,600	296,100	(1,119,700)
Extensions, discoveries and improved recovery, net of future production-related costs	245,800	117,000	40,200
Purchases of proved reserves	2,800	3,700	2,600
Sales of reserves in place	(600)	(8,900)	---
Changes in estimated future development costs	(4,000)	(1,100)	(6,700)
Development costs incurred during the current year	35,300	19,400	31,600
Accretion of discount	62,400	27,300	122,700
Net change in income taxes	(172,000)	(124,700)	436,500
Revisions of previous estimates	(35,500)	30,000	(11,700)
Other	(2,300)	(1,600)	(1,300)
Net change	230,500	244,300	(659,300)
End of year	\$ 736,800	\$ 506,300	\$ 262,000

The estimated discounted future cash inflows from estimated future production of proved reserves were computed using year-end natural gas prices and oil prices. Future development and production costs attributable to proved reserves were computed by applying year-end costs to be incurred in producing and further developing the proved reserves. Future development costs estimated to be spent in each of the next three years to develop proved undeveloped reserves are \$37.1 million in 2004, \$6.7 million in 2005 and \$4.4 million in 2006. Future income tax expenses were computed by applying statutory tax rates (adjusted for permanent differences and tax credits) to estimated net future pretax cash flows.

The standardized measure of discounted future net cash flows does not purport to represent the fair market value of natural gas and oil properties. There are significant uncertainties inherent in estimating quantities of proved reserves and in projecting rates of production and the timing and amount of future costs. In addition, future realization of natural gas and oil prices over the remaining reserve lives may vary significantly from current prices.

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED INCOME STATEMENT
TWELVE MONTHS ENDING DECEMBER 31, 2003

Operating Income

Electric Utility

Operating Revenues	\$178,561,980
Operating Expenses:	
Operation Expenses	101,790,710
Maintenance Expenses	13,176,267
Depreciation Expenses	20,150,400
Taxes Other Than Income Taxes	7,683,325
Income Taxes:	
Federal Taxes on Income	7,844,316
State Taxes on Income	1,381,596
Deferred Income Taxes	1,383,686
Total Electric Expenses	153,410,300
Net Electric Operation	\$25,151,680

Gas Utility

Operating Revenues	\$274,607,103
Operating Expenses:	
Operation Expenses	250,033,668
Maintenance Expenses	2,792,254
Depreciation Expenses	10,044,705
Taxes Other Than Income Taxes	5,234,669
Income Taxes:	
Federal Taxes on Income	(3,267,639)
State Taxes on Income	(564,828)
Deferred Income Taxes	4,510,834
Total Gas Expenses	268,783,663
Net Gas Operation	\$5,823,440

Net Utility Operating Income \$30,975,120

Revenues from Merchandising, Jobbing and Contract Work	\$12,638,073
(Less) Costs and Exp. Of Merch., Jobbing and Contract Work	11,055,815
Revenues from Nonutility Operations	211,102
Equity in Earnings of Subsidiary Companies	153,788,920
Interest and Dividend Income	3,636,870
Miscellaneous Nonoperating Income	743
Gain on Disposition of Property	54,123
Total Other Income	159,274,016

Loss on Disposition of Property	9,749
Miscellaneous Income Deductions	2,564,974
Total Other Income Deductions	2,574,723

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED INCOME STATEMENT
TWELVE MONTHS ENDING DECEMBER 31, 2003

Taxes other than Income Taxes	5,120
Income Taxes - Federal	1,377,137
Income Taxes - State	221,809
Provision for Deferred Income Taxes	(606,763)
Investment Tax Credits	(596,333)
Total Taxes on Other Income and Deductions	<u>400,970</u>
Net Other Income and Deductions	\$156,298,323
Interest On Long-Term Debt	10,629,946
Amortization of Debt Discount and Expense	1,252,461
Other Interest Expense	250,711
(Less) Allow for Borrowed Funds Used during Const.	217,797
Net Interest Charges	<u>11,915,321</u>
Net Income	<u><u>\$175,358,122</u></u>

**MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003**

<u>Function</u>	<u>Balance @ 12/31/02</u>	<u>Balance @ 12/31/03</u>	<u>Average 2003</u>
Distribution	\$56,767,544	\$59,033,353	\$57,900,449
General	7,167,081	6,340,261	6,753,671
Intangible Plant - General	181,686	180,280	180,983
Common	5,539,841	5,607,000	5,573,420
Intangible Plant - Common	2,010,760	2,066,890	2,038,825
Gas Plant Leased to Others	11,374	11,374	11,374
Acquisition Adjustment	97,266	97,266	97,266
Construction Work in Progress (CWIP)			
In Service not yet Classified	<u>405,134</u>	<u>449,173</u>	<u>427,154</u>
Total Plant in Service	<u><u>\$72,180,686</u></u>	<u><u>\$73,785,597</u></u>	<u><u>\$72,983,142</u></u>

**MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003**

<u>No.</u>	<u>Account</u>	<u>Balance @ 12/31/02</u>	<u>Balance @ 12/31/03</u>	<u>Average Balance</u>
	<u>Distribution Plant</u>			
374.1	Land	\$41,999	\$41,687	\$41,843
374.2	Rights of Way	49,075	49,074	49,075
375	Structures & Improvements	180,117	180,117	180,117
376	Mains	27,754,953	28,904,066	28,329,509
378	Meas. & Reg. Equip.-General	572,331	588,208	580,270
379	Meas. & Reg. Equip.-City Gate	174,002	174,002	174,002
380	Services	12,434,694	12,956,082	12,695,388
381	Positive Meters	12,579,688	13,088,403	12,834,045
383	Service Regulators	1,712,228	1,783,339	1,747,784
385	Ind. Meas. & Reg. Station Eqpt.	370,108	370,108	370,108
386.1	Misc. Property on Cust. Premise	1,680	1,680	1,680
386.2	Other Property on Cust. Premise	113,207	113,207	113,207
387.1	Cathodic Protection Equip.	451,864	451,864	451,864
387.2	Other Distribution Equip.	331,598	331,516	331,557
	Total Distribution Plant	\$56,767,544	\$59,033,353	\$57,900,449
	<u>General Plant</u>			
389	Land	\$154,460	\$154,772	\$154,616
390	Structures and Improvements	892,950	889,138	891,044
391.1	Furniture and Fixtures	218,802	49,595	134,199
391.3	Computer Equip. - PC	287,816	361,058	324,436
392.1	Trans. Equip., Non-Unitized	41,617	41,617	41,617
392.2	Trans. Equip., Unitized	2,173,356	2,265,130	2,219,243
393	Stores Equipment	74,396	45,588	59,992
394.1	Tools,Shop&Gar. Eq.-Non-Un.	1,115,009	550,760	832,884
394.2	Tools,Shop&Gar. Eq.-Unitized	123,956	39,059	81,508
394.3	Vehicle Maintenance Equip.	6,615	6,615	6,615
394.4	Vehicle Refueling Equip.	97,809	63,469	80,639
395	Laboratory Equipment	172,593	137,257	154,924
396.1	Power Operated Equip.	114,117	111,701	112,909
396.2	Work Equipment Trailers	1,370,028	1,343,917	1,356,973
397.1	Radio Comm. Equip.-Fixed	119,094	130,522	124,808
397.2	Radio Comm. Equip.-Mobile	100,180	101,606	100,893
397.3	General Tele. Comm. Equip.	28,055	15,659	21,857
397.5	Supervisory & Tele. Equip.	1,830		915
397.8	Network Equipment	11,988	11,999	11,994
398	Miscellaneous Equipment	62,410	20,799	41,605
	Total General Plant	\$7,167,081	\$6,340,261	\$6,753,671

**MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003**

<u>No.</u>	<u>Account</u>	<u>Balance @ 12/31/02</u>	<u>Balance @ 12/31/03</u>	<u>Average Balance</u>
303	Intangible Plant - General	\$181,686	\$180,280	\$180,983
	<u>Common Plant</u>			
389	Land	\$213,977	\$215,955	\$214,965
390	Structures and Improvements	2,504,686	2,565,285	2,534,986
391.1	Furniture and Fixtures	482,943	296,124	389,533
391.2	Computer Equip.- Bull/AS400	12,498	2,028	7,263
391.3	Computer Equip. - PC	557,843	560,899	559,371
391.5	Computer Equip. - Other	110,507	9,876	60,192
392.1	Trans. Equip., Non-Unitized	36,746	36,464	36,605
392.2	Trans. Equip., Unitized	675,194	672,455	673,824
392.3	Aircraft	144,636	629,292	386,964
393	Stores Equipment	5,210	5,244	5,227
394.1	Tools, Shop & Gar. Equip.	39,294	39,921	39,607
394.3	Vehicle Maint. Equip.	16,045	17,712	16,879
394.4	Vehicle Refueling Equip.	112,825	114,538	113,682
396.2	Work Equipment Trailers	32,647	15,472	24,060
397.1	Radio Comm. Equip.-Fixed	92,108	55,797	73,952
397.2	Radio Comm. Equip.-Mobile	167,505	122,577	145,041
397.3	General Tele. Comm. Equip.	101,520	92,273	96,897
397.5	Supervisory & Tele. Equip.	10,199	9,944	10,072
397.8	Network Equipment	130,996	53,988	92,492
398	Miscellaneous Equipment	92,462	91,156	91,808
	Total Common Plant	<u>\$5,539,841</u>	<u>\$5,607,000</u>	<u>\$5,573,420</u>
303	Intangible Plant - Common	\$2,010,760	\$2,066,890	\$2,038,825
386.3	Gas Plant Leased to Others	11,374	11,374	11,374
114.2	Acquisition Adjustment	<u>97,266</u>	<u>97,266</u>	<u>97,266</u>
	Total Gas Plant in Service	<u><u>\$71,775,552</u></u>	<u><u>\$73,336,424</u></u>	<u><u>\$72,555,988</u></u>

MONTANA-DAKOTA UTILITIES CO.
 DETAILED COST OF PLANT
 GAS UTILITY
 FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

Acct. No.	Account	Balance @ 12/31/02	Additions	Retirements	Transfers	Balance @ 12/31/03
<u>Distribution Plant</u>						
374.1	Land	\$109,547	\$0	(\$384)	(\$312)	\$108,851
374.2	Rights of Way	95,588	1,496	(65)	0	97,019
375	Structures & Improvements	521,210	10,178	(450)	0	530,938
376	Mains	80,182,712	3,785,387	(234,006)	0	83,734,093
378	Measuring & Regulating Equip. - Gen.	1,423,150	45,097	(10,744)	0	1,457,503
379	Measuring & Regulating Equip. - City Gate	1,009,137	23,172	(4,388)	0	1,027,921
380	Services	33,733,349	2,103,050	(163,649)	0	35,672,750
381	Meters	32,113,684	1,433,811	(13,398)	0	33,534,097
383	Service Regulators	4,402,528	208,127	(11,656)	0	4,598,999
385	Industrial Measuring & Regulating Equip.	578,786	55,439	(6,164)	0	628,061
386.1	Misc. Property on Customer Premise	1,680	0	0	0	1,680
386.2	Other Property on Customer Premise	432,812	0	0	0	432,812
387.1	Catholic Protection Equipment	1,476,915	44,534	(5,054)	0	1,516,395
387.2	Other Distribution Equipment	557,184	1,415	(1,945)	0	556,654
	Total Distribution Plant	\$156,638,282	\$7,711,706	(\$451,903)	(\$312)	\$163,897,773
<u>General Plant</u>						
389	Land	\$851,350	(\$107)	\$0	\$312	\$851,555
390	Structures & Improvements	5,689,188	22,040	(9,314)	0	5,701,914
391.1	Office Furniture & Equipment	755,201	18,121	(404,720)	3,483	372,085
391.3	Computer Equip. -PC	786,659	244,662	(57,519)	0	973,802
392.1	Transportation Equipment - Non-Un.	155,417	16,065	0	0	171,482
392.2	Transportation Equipment - Unitized	6,457,020	902,779	(551,428)	103,664	6,912,035
393	Stores Equipment	192,629	14,254	(63,868)	0	143,015
394.1	Tools,Shop&Gar. Equip.-Non-Un.	2,610,721	144,680	(1,286,765)	0	1,468,636
394.2	Tools,Shop&Gar. Equip.-Non-Un.	299,810	0	(193,745)	0	106,065
394.3	Vehicle Maintenance Equipment	31,177	0	0	0	31,177
394.4	Vehicle Refueling Equipment	361,344	0	(168,497)	0	192,847
395	Laboratory Equipment	324,158	0	(111,337)	0	212,821
396.1	Work Equipment Trailers	359,619	0	(5,323)	0	354,296

MONTANA-DAKOTA UTILITIES CO.
 DETAILED COST OF PLANT
 GAS UTILITY
 FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

Acct. No.	Account	Balance @ 12/31/02	Additions	Retirements	Transfers	Balance @ 12/31/03
396.2	Power Operated Equipment	4,120,765	1,718,894	(1,487,415)	136,299	4,488,543
397.1	Radio Communication Equip. - Fixed	482,215	0	27,488	0	509,703
397.2	Radio Communication Equip. - Mobile	413,977	1,226	1,427	0	416,630
397.3	General Tele. Comm. Equip.	101,422	0	(58,268)	0	43,154
397.5	Supervisory & Tele. Equip.	124,167	0	(123,043)	0	1,124
397.6	Scada System	30,894	0	(30,894)	0	0
397.8	Network Equipment	31,698	7,899	0	(308)	39,289
398	Miscellaneous Equipment	147,510	542	(101,445)	0	46,607
	Total General Plant	\$24,326,941	\$3,091,055	(\$4,624,666)	\$243,450	\$23,036,780
303	General Intangible	477,530	0	0	0	477,530
	Common Plant - Gas 1/	19,155,659				19,728,338
386.3	Gas Plant Leased to Others CNG Demo/Lease	25,773	0	0	0	25,773
114.3	Acquisition Adjustments	97,266	0	0	0	97,266
	Total Gas Plant in Service	\$200,721,451	\$10,802,761	(\$5,076,569)	\$243,138	\$207,263,460

1/ Common plant is either directly assigned or allocated to gas and electric plant. Total common plant additions, retirements, transfers and adjustments for the twelve months ended December 31, 2003 are \$6,361,627, \$5,558,638, and (\$790,319) respectively.

MONTANA-DAKOTA UTILITIES CO.
 GAS CWIP IN SERVICE
 GAS UTILITY - NORTH DAKOTA
 FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

Work Order Number	Description	State	Total	Distribution	General	Common
J138318	Upgrade Bismarck I.P. system	ND	(\$11,717)	(\$11,717)		
J142889	Extend 10,500 feet of 4" plastic I.P. - Minot	ND	(2,521)	(2,521)		
J133977	Replace meter reading system	ND	(457)		(457)	
J136907	Replace Conquest aircraft	ND	(1,546)		(1,546)	
J141071	Reconstruct Transportation building	ND	(554)		(554)	
J141541	Purchase welding truck	ND	373		373	
J143593	Remodel Annex	ND	(38)		(38)	
Small items grouped 1/:						
(115)	Distribution	ND	386,063	386,063		
(33)	General	ND	56,026		56,026	
(22)	Common	ND	23,544			23,544
Total			\$449,173	371,825	53,804	23,544

1/ Numbers in brackets indicate the number of work orders involved in each item of construction.

**MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED RESERVE FOR DEPRECIATION
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003**

<u>Function</u>	<u>Balance @ 12/31/02</u>	<u>Balance @ 12/31/03</u>	<u>Average 2003</u>
Distribution	\$41,390,274	\$43,570,560	\$42,480,417
General	3,764,369	2,879,364	3,321,866
Intangible Plant - General	175,819	176,497	176,158
Common	2,796,890	2,468,018	2,632,454
Intangible Plant - Common	904,330	1,120,967	1,012,649
Gas Plant Leased to Others	4,697	5,760	5,228
Acquisition Adjustment		29,837	14,919
Total Accumulated Reserve	<u>\$49,036,379</u>	<u>\$50,251,003</u>	<u>\$49,643,691</u>

MONTANA-DAKOTA UTILITIES CO.
BOOK CHANGES IN ACCUMULATED PROVISION FOR
DEPRECIATION AND AMORTIZATION - GAS UTILITY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

	Beginning Balance 12/31/02	Annual Provision	Retirements (Original Cost)	Salvage	Removal Costs	Adjustments	Ending Balance 12/31/03
Gas Utility							
Account 111.2 - Intangible	\$447,917	\$10,455					\$458,372
Account 108 Distribution	105,038,561	6,785,125	\$799,928	\$129,163	\$437,618	\$256,182	110,971,485
General	9,493,634	1,193,769	4,050,001	1,053,238	1,008	(949,952)	6,739,680
Total Account 108	114,532,195	7,978,894	4,849,929	1,182,401	438,626	(693,770)	117,711,165
Account 115 - Acquisition Adjustment	0	29,837					29,837
Total	<u>\$114,980,112</u>	<u>\$8,019,186</u>	<u>\$4,849,929</u>	<u>\$1,182,401</u>	<u>\$438,626</u>	<u>(\$693,770)</u>	<u>\$118,199,374</u>
Common 1/	\$6,858,790						\$7,704,993

1/ Common Plant is assigned by state on an actual site and use basis when applicable, and the remainder is allocated by state to gas and electric on a plant in service basis. Total common changes for the twelve months ended December 31, 2003 are:

	Beginning Balance 12/31/02	Annual Provision	Retirements (Original Cost)	Salvage	Removal Costs	Adjustments	Ending Balance 12/31/03
Common Utility							
Account 111.4	\$6,426,442	\$1,358,967	\$0	\$0	\$0	\$0	\$7,785,409
Account 108	19,876,689	2,215,960	4,772,909	831,296	11,992	(1,142,452)	16,996,592
Total Accounts 111.4 and 108	<u>\$26,303,131</u>	<u>\$3,574,927</u>	<u>\$4,772,909</u>	<u>\$831,296</u>	<u>\$11,992</u>	<u>(\$1,142,452)</u>	<u>\$24,782,001</u>

**MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF WORKING CAPITAL AND
CUSTOMER ADVANCES FOR CONSTRUCTION
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003**

<u>Working Capital</u>	Balance @ 12/31/02	Balance @ 12/31/03
Materials and Supplies	\$376,334	\$409,023
Fuel Stocks	23,626	25,616
Prepayments	33,397	65,958
Gas IRP	<u>70,984</u>	<u>17,984</u>
Total Working Capital	<u>\$504,341</u>	<u>\$518,581</u>
Customer Advances for Construction	<u>\$286,881</u>	<u>\$307,320</u>

**MONTANA-DAKOTA UTILITIES CO.
MATERIALS AND SUPPLIES
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003**

	<u>Amount</u>
December 2002	\$376,334
January 2003	370,904
February	407,668
March	503,799
April	545,338
May	499,717
June	534,146
July	539,959
August	506,734
September	487,922
October	508,818
November	482,851
December	409,023

MONTANA-DAKOTA UTILITIES CO.
FUEL STOCKS
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003

	<u>Amount</u>
December 2002	\$23,626
January 2003	23,626
February	23,962
March	12,712
April	22,233
May	22,562
June	16,648
July	19,003
August	19,085
September	21,249
October	21,276
November	33,614
December	25,616

**MONTANA-DAKOTA UTILITIES CO.
PREPAID INSURANCE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003**

	<u>Amount</u>
December 2002	\$33,397
January 2003	9,962
February	163,774
March	143,887
April	231,145
May	202,805
June	189,541
July	166,072
August	133,274
September	109,823
October	99,155
November	110,003
December	65,958

**MONTANA-DAKOTA UTILITIES CO.
GAS INTEGRATED RESOURCE PLAN
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003**

	<u>Amount</u>
December 2002	\$70,984
January 2003	66,567
February	62,150
March	57,734
April	53,317
May	48,900
June	44,484
July	40,067
August	35,651
September	31,234
October	26,817
November	22,401
December	17,984

**MONTANA-DAKOTA UTILITIES CO.
CUSTOMER ADVANCES FOR CONSTRUCTION
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003**

	<u>Amount</u>
December 2002	\$286,881
January 2003	239,365
February	191,455
March	191,701
April	224,387
May	223,824
June	239,570
July	240,610
August	241,173
September	288,906
October	311,456
November	311,960
December	307,320

MONTANA-DAKOTA UTILITIES CO.
AVERAGE UTILITY CAPITAL STRUCTURE
2003

	<u>Balance</u>	<u>Capital Ratio</u>	<u>Cost</u>	<u>Required Return</u>
Long Term Debt	\$147,600,000	45.783%	8.878%	4.065%
Preferred Stock	16,250,000	5.040%	4.622%	0.233%
Common Equity	158,539,438	49.177%	11.500%	5.655%
Total	<u>\$322,389,438</u>	<u>100.000%</u>		<u>9.953%</u>

**MONTANA-DAKOTA UTILITIES CO.
AVERAGE UTILITY CAPITAL STRUCTURE
PROJECTED 2004**

	<u>Balance</u>	<u>Capital Ratio</u>	<u>Cost</u>	<u>Required Return</u>
Long Term Debt	\$154,100,000	45.589%	8.624%	3.932%
Preferred Stock	16,150,000	4.778%	4.618%	0.221%
Common Equity	167,772,745	49.633%	11.500%	5.708%
Total	<u>\$338,022,745</u>	<u>100.000%</u>		<u>9.861%</u>

**MONTANA-DAKOTA UTILITIES CO.
AVERAGE UTILITY CAPITAL STRUCTURE
PROJECTED 2005**

	<u>Balance</u>	<u>Capital Ratio</u>	<u>Cost</u>	<u>Required Return</u>
Long Term Debt	\$153,350,000	43.535%	8.518%	3.708%
Preferred Stock	16,050,000	4.557%	4.614%	0.210%
Common Equity	182,843,012	51.908%	11.500%	5.969%
Total	<u>\$352,243,012</u>	<u>100.000%</u>		<u>9.887%</u>

MONTANA-DAKOTA UTILITIES CO.
AVERAGE LONG-TERM DEBT
2003

	<u>Balance Outstanding</u>	<u>Annual Cost</u>	<u>Adjusted Embedded Cost</u>
<u>First Mortgage Bonds</u>			
Balance at 12/31/02	\$130,850,000	\$11,743,442	8.975%
Amortization of Gain/Loss		361,666	
	<u>130,850,000</u>	<u>12,105,108</u>	
Balance at 12/31/03	160,850,000	13,604,942	8.458%
Amortization of Gain/Loss		268,627	
	<u>160,850,000</u>	<u>13,873,569</u>	
Average Balance	\$145,850,000	\$12,674,192	8.690%
Average Amort. of Gain/Loss		315,147	
	<u>\$145,850,000</u>	<u>\$12,989,339</u>	<u>8.906%</u>
<u>Pollution Control Bonds</u>			
Balance at 12/31/02	\$2,000,000	\$131,120	6.556%
Balance at 12/31/03	1,500,000	98,340	6.556%
Average Balance	<u>\$1,750,000</u>	<u>\$114,730</u>	<u>6.556%</u>
Total Average Long Term Debt	<u>\$147,600,000</u>	<u>\$13,104,069</u>	<u>8.878%</u>

MONTANA-DAKOTA UTILITIES CO.
AVERAGE LONG-TERM DEBT
PROJECTED 2004

	Balance Outstanding	Annual Cost	Adjusted Embedded Cost
<u>First Mortgage Bonds</u>			
Balance at 12/31/03	\$160,850,000	\$13,604,942	8.458%
Amortization of Gain/Loss		268,627	
	<u>160,850,000</u>	<u>13,873,569</u>	
Balance at 12/31/04	145,850,000	12,433,292	8.525%
Amortization of Gain/Loss		174,668	
	<u>145,850,000</u>	<u>12,607,960</u>	
Average Balance	\$153,350,000	\$13,019,117	8.490%
Average Amort. of Gain/Loss		221,648	
	<u>\$153,350,000</u>	<u>\$13,240,765</u>	<u>8.634%</u>
<u>Pollution Control Bonds</u>			
Balance at 12/31/03	\$1,500,000	\$98,340	6.556%
Balance at 12/31/04	0	0	
Average Balance	<u>\$750,000</u>	<u>\$49,170</u>	<u>6.556%</u>
Total Average Long Term Debt	<u>\$154,100,000</u>	<u>\$13,289,935</u>	<u>8.624%</u>

**MONTANA-DAKOTA UTILITIES CO.
AVERAGE LONG-TERM DEBT
PROJECTED 2005**

	Balance Outstanding	Annual Cost	Adjusted Embedded Cost
<u>First Mortgage Bonds</u>			
Balance at 12/31/04	\$145,850,000	\$12,433,292	8.525%
Amortization of Gain/Loss		174,668	
	<u>145,850,000</u>	<u>12,607,960</u>	
Balance at 12/31/05	160,850,000	13,483,292	8.383%
Amortization of Gain/Loss		34,738	
	<u>160,850,000</u>	<u>13,518,030</u>	
Average Balance	\$153,350,000	\$12,958,292	8.450%
Average Amort. of Gain/Loss		104,703	
	<u>\$153,350,000</u>	<u>\$13,062,995</u>	<u>8.518%</u>
<u>Pollution Control Bonds</u>			
Balance at 12/31/04	\$0	\$0	
Balance at 12/31/05	0	0	
Average Balance	<u>\$0</u>	<u>\$0</u>	
Total Average Long Term Debt	<u>\$153,350,000</u>	<u>\$13,062,995</u>	<u>8.518%</u>

**MONTANA-DAKOTA UTILITIES CO.
LONG-TERM DEBT CAPITAL
DECEMBER 31, 2003**

Description	Date of Issuance	Date of Maturity	Interest Rate	Principal Amount of Issue	Gross Proceeds	Underwriters' Commission		Loss on Reacquisition and Issuance Expense	
						Amount	% Gross Proceeds	Amount	% Gross Proceeds
First Mortgage Bonds:									
Secured Medium-term Notes, Series A:									
8.25%	04/01/92	04/01/07	8.250%	\$30,000,000	\$30,000,000	\$225,000	0.750%	\$3,663,204	12.211%
8.6%	04/01/92	04/01/12	8.600%	35,000,000	34,911,100	306,250	0.877%	5,698,318	16.322%
6.52%	09/30/97	10/01/04	6.520%	15,000,000	15,000,000	90,000	0.600%	827,077	5.514%
6.71%	09/30/97	10/01/09	6.710%	15,000,000	15,000,000	93,750	0.625%	1,417,846	9.452%
5.83%	09/18/98	10/01/08	5.830%	15,000,000	15,000,000	93,750	0.625%	92,336	0.616%
5.98% - Senior Note	12/15/03	12/15/33	5.980%	30,000,000	30,000,000	262,500	0.875%	280,668	0.936%
Pollution Control Refunding Revenue Bonds:									
Mercer County 6.65%	06/01/92	06/01/22	6.650%	15,000,000	15,000,000	0	0.000%	938,724	6.258%
Richland County 6.65%	06/01/92	06/01/22	6.650%	3,250,000	3,250,000	0	0.000%	186,323	5.733%
Morton County 6.65%	06/01/92	06/01/22	6.650%	2,600,000	2,600,000	0	0.000%	179,014	6.885%
Pollution Control Notes:									
Grant County 6.2%	03/01/74	03/01/04	6.200%	5,600,000	5,600,000	84,000	1.500%	88,958	1.589%
				<u>\$166,450,000</u>	<u>\$166,361,100</u>	<u>\$1,155,250</u>		<u>\$13,372,468</u>	
Description	Net Proceeds Amount	Per Unit	Cost of Money 1/	Principal Outstanding	Annual Cost	Embedded Cost			
						Amount	%		
First Mortgage Bonds:									
Secured Medium-term Notes, Series A:									
8.25%	\$26,111,796	87.039%	10.177%	\$30,000,000	\$3,053,100				
8.6%	28,906,532	82.590%	11.020%	35,000,000	3,857,000				
6.52%	14,082,923	93.886%	7.811%	15,000,000	1,171,650				
6.71%	13,488,404	89.923%	8.195%	15,000,000	1,229,250				
5.83%	14,813,914	98.759%	6.086%	15,000,000	912,900				
5.98% - Senior Note	29,456,832	98.189%	6.205%	30,000,000	1,861,500				
Pollution Control Refunding Revenue Bonds:									
Mercer County 6.65%	14,061,276	93.742%	7.288%	15,000,000	1,093,200				
Richland County 6.65%	3,063,677	94.267%	7.243%	3,250,000	235,398				
Morton County 6.65%	2,420,986	93.115%	7.344%	2,600,000	190,944				
Total First Mortgage Bonds	<u>146,406,340</u>			<u>160,850,000</u>	<u>13,604,942</u>			<u>8,458</u>	
Pollution Control Notes:									
Grant County 6.2%	5,427,042	96.911%	6.556%	1,500,000	98,340			<u>6,556</u>	
Total Long-Term Debt Capital	<u>\$151,833,382</u>			<u>\$162,350,000</u>	<u>\$13,703,282</u>			<u>8,441</u>	

1/ Yield to maturity based upon the life, net proceeds, semiannual compounding of stated interest rate, and amortization of indenture revision costs.

MONTANA-DAKOTA UTILITIES CO.
AMORTIZATION OF LOSS ON REACQUIRED DEBT
PROJECTED 2004

		<u>Projected Average Amortization</u>
<u>Acct. 1890 - Unamortized Loss</u>		
9 1/8% due 05-15-06	1/04 - 12/04	\$268,627
9 1/8% due 05-15-06	1/05 - 12/05	174,668
Average at 12/31/04		<u><u>\$221,648</u></u>

**MONTANA-DAKOTA UTILITIES CO.
AMORTIZATION OF LOSS ON REACQUIRED DEBT
PROJECTED 2005**

		<u>Projected Average Amortization</u>
<u>Acct. 1890 - Unamortized Loss</u>		
9 1/8% due 05-15-06	1/05 - 12/05	\$174,668
9 1/8% due 05-15-06	1/06 - 12/06	34,738
Average at 12/31/05		<u>\$104,703</u>

MONTANA-DAKOTA UTILITIES CO.
AVERAGE PREFERRED STOCK
2003

<u>Description</u>	<u>Balance Outstanding</u>	<u>Annual Cost</u>	<u>Adjusted Embedded Cost</u>
Balance at 12/31/02	\$16,300,000	\$753,705	4.624%
Redemptions: 5.1% Series	(100,000)	(5,285)	
Balance at 12/31/03	<u>\$16,200,000</u>	<u>\$748,420</u>	<u>4.620%</u>
Average Preferred Stock	<u>\$16,250,000</u>	<u>\$751,063</u>	<u>4.622%</u>

**MONTANA-DAKOTA UTILITIES CO.
 AVERAGE PREFERRED STOCK
 PROJECTED 2004**

<u>Description</u>	<u>Balance Outstanding</u>	<u>Annual Cost</u>	<u>Adjusted Embedded Cost</u>
Balance at 12/31/03	\$16,200,000	\$748,420	4.620%
Redemptions: 5.1% Series	(100,000)	(5,285)	
Balance at 12/31/04	<u>\$16,100,000</u>	<u>\$743,135</u>	<u>4.616%</u>
Average Preferred Stock	<u>\$16,150,000</u>	<u>\$745,778</u>	<u>4.618%</u>

**MONTANA-DAKOTA UTILITIES CO.
AVERAGE PREFERRED STOCK
PROJECTED 2005**

<u>Description</u>	<u>Balance Outstanding</u>	<u>Annual Cost</u>	<u>Adjusted Embedded Cost</u>
Balance at 12/31/04	\$16,100,000	\$743,135	4.616%
Redemptions: 5.1% Series	(100,000)	(5,285)	
Balance at 12/31/05	<u>\$16,000,000</u>	<u>\$737,850</u>	<u>4.612%</u>
Average Preferred Stock	<u>\$16,050,000</u>	<u>\$740,493</u>	<u>4.614%</u>

**MONTANA-DAKOTA UTILITIES CO.
PREFERRED STOCK CAPITAL
DECEMBER 31, 2003**

Description	Date of Issuance	Call (Redemption) Price	Dividend Rate	Par Value of Issue	Gross Proceeds (000's)	Underwriters' Commission		Issuance Expense	
						Amount	% Gross Proceeds	Amount	% Gross Proceeds
4.5% Series	01/01/51	\$105	4.5%	\$100	\$10,000				
4.7% Series	12/07/55	102	4.7%	100	5,000				
5.1% Series	05/23/61	100/102	5.1%	100	5,000	\$25,000	0.50%	\$27,452	0.549%
Net Proceeds									
Description	Amount (000's)	Per Unit	Cost of Money 1/2/	Principal Outstanding	December 31, 2003		Method of Offering		
					Annual Cost	Embedded Cost			
4.5% Series	\$10,000	100.0000%	4.500%	\$10,000,000	\$450,000		Public		
4.7% Series	5,000	100.0000%	4.700%	5,000,000	235,000		Public		
5.1% Series	4,948	98.9511%	5.285%	1,200,000	63,420		Private		
Total				<u>\$16,200,000</u>	<u>\$748,420</u>	<u>4.620%</u>			

1/ Yield to maturity based upon the life, net proceeds, and quarterly compounding of the stated dividend rate of each issue.
2/ 4.5% Series and 4.7% Series issue expense fully recovered.

MONTANA-DAKOTA UTILITIES CO.
AVERAGE UTILITY COMMON EQUITY
2003

<u>Description</u>	<u>Amount</u>
Common Equity - 12/31/02	\$1,287,371,219
Unappropriated Retained Earnings of Subsidiaries	430,566,718
Additional Equity of Subsidiaries (Centennial)	700,137,104
Utility Common Equity - 12/31/02	<u>\$156,667,397</u>
Common Equity - 12/31/03	\$1,439,261,641
Unappropriated Retained Earnings of Subsidiaries	528,082,638
Additional Equity of Subsidiaries (Centennial)	750,767,525
Utility Common Equity - 12/31/03	<u>\$160,411,478</u>
Average Common Utility Equity - 12/31/03	<u>\$158,539,438</u>

**MONTANA-DAKOTA UTILITIES CO.
AVERAGE UTILITY COMMON EQUITY
PROJECTED 2004**

<u>Description</u>	<u>Amount</u>
Common Equity - 12/31/03	\$1,439,261,641
Unappropriated Retained Earnings of Subsidiaries	528,082,638
Additional Equity of Subsidiaries	<u>750,767,525</u>
Utility Common Equity - 12/31/03	<u>\$160,411,478</u>
Common Equity Infusion	18,000,000
Projected Equity Earnings	14,662,000
Less: Utility Dividends	<u>(17,939,466)</u>
Utility Common Equity - 12/31/04	<u>\$175,134,012</u>
Average Common Utility Equity - 12/31/04	<u>\$167,772,745</u>

**MONTANA-DAKOTA UTILITIES CO.
AVERAGE UTILITY COMMON EQUITY
PROJECTED 2005**

<u>Description</u>	<u>Amount</u>
Utility Common Equity - 12/31/03	\$160,411,478
Common Equity Infusion	18,000,000
Projected Equity Earnings	14,662,000
Less: Utility Dividends	<u>(17,939,466)</u>
Utility Common Equity - 12/31/04	<u>\$175,134,012</u>
Common Equity Infusion	\$10,000,000
Projected Equity Earnings	17,955,000
Less: Utility Dividends	<u>(12,537,000)</u>
Utility Common Equity - 12/31/05	<u>\$190,552,012</u>
Average Common Utility Equity - 12/31/05	<u>\$182,843,012</u>

**MDU RESOURCES GROUP, INC.
STOCK DIVIDENDS, STOCK SPLITS OR
CHANGES IN PAR OR STATED VALUE
FOR THE FIVE-YEAR PERIOD ENDING DECEMBER 31, 2003**

On April 30, 1999, the MDU Resources Group, Inc. Certificate of Incorporation was amended pursuant to stockholder approval. The amendment to the Certificate of Incorporation increased the number of shares of common stock which the company is authorized to issue from 75,000,000 shares of common stock with a par value of \$3.33 to 150,000,000 shares with a par value of \$1.00.

On October 29, 2003, MDU Resources Group, Inc. issued 37,862,129 additional shares of Common Stock, Par value \$1.00, in connection with a three-for-two Common Stock split to be effected in the form of a fifty percent stock dividend.

MDU RESOURCES GROUP, INC.
COMMON STOCK DATA
FOR THE FIVE YEARS ENDED DECEMBER 31, 2003

Year Ended December 31:	Avg. Number of Shares Outstanding (000's) 2/	Annual Diluted Earnings (per share) 2/	Annual Dividends (per share) 2/	Dividend/Earnings Ratio	Average Market Price 1/	Price/Earnings Ratio	Dividend/Price Ratio
1999	82,306	1.01	0.5467	54%	15.27	15.1	3.6%
2000	92,085	1.20	0.5733	48%	16.02	13.4	3.6%
2001	101,803	1.52	0.6000	39%	20.17	13.3	3.0%
2002	106,863	1.38	0.6266	45%	17.59	12.7	3.6%
2003	112,460	1.55	0.6600	43%	20.91	13.5	3.2%
Twelve Months:							
January 2003	107,427	1.28	0.6266	49%	17.54	13.7	3.6%
February	107,845	1.25	0.6333	51%	17.46	14.0	3.6%
March	108,362	1.33	0.6333	48%	18.09	13.6	3.5%
April	108,831	1.36	0.6333	47%	19.09	14.0	3.3%
May	109,232	1.40	0.6400	46%	20.30	14.5	3.2%
June	109,610	1.48	0.6400	43%	22.18	15.0	2.9%
July	110,083	1.53	0.6400	42%	21.84	14.3	2.9%
August	110,601	1.56	0.6500	42%	21.67	13.9	3.0%
September	111,117	1.57	0.6500	41%	22.68	14.4	2.9%
October	111,648	1.58	0.6500	41%	23.22	14.7	2.8%
November	112,155	1.55	0.6600	43%	22.97	14.8	2.9%
December	112,460	1.55	0.6600	43%	23.84	15.4	2.8%

1/ The average market price is based on monthly high and low for the year.

2/ Common stock amounts reflect the Company's three-for-two common stock split effective October 29, 2003.

3/ Includes the cumulative effect of the change in accounting for asset retirement obligations as required by the adoption of Statement of Financial Accounts Standards No. 143 (February - December 2003).

**MONTANA-DAKOTA UTILITIES CO.
REACQUISITION OF BONDS OR PREFERRED STOCK
FOR THE FIVE-YEAR PERIOD ENDING DECEMBER 31, 2003**

First Mortgage Bonds

There was no reacquisition of bonds during the five years ending December 31, 2003.

Preferred Stock

<u>Title</u>	<u>Principal Amount</u>	<u>Reacquisition Cost</u>	<u>Gain or (Loss)</u>
Preferred Stock: 5.1% Preferred Stock	\$500,000	\$500,000	\$0

**MONTANA-DAKOTA UTILITIES CO.
SALES AND TRANSPORTATION REVENUE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003**

	Dk	Revenue
<u>Sales</u>		
Residential	8,083,189	\$55,219,376
Firm General	5,742,272	36,194,291
Air Force		
Firm	37,297	205,237
Interruptible	840,351	3,649,414
Total Air Force	877,648	3,854,651
Small Interruptible	712,806	3,580,856
Large Interruptible	63,410	326,534
Total Sales	15,479,325	\$99,175,708
 <u>Transportation</u>		
Small Interruptible	768,415	\$408,789
Large Interruptible	2,387,332	365,559
Total Transportation	3,155,747	\$774,348
Unbilled Revenue		2,733,102
Total Throughput	18,635,072	\$102,683,158
 <u>Other Revenue</u>		
Miscellaneous Service Revenue		\$38,475
Rent from Property		301,707
Other Revenue		65,566
Total Other Revenue		\$405,748

**MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF REVENUES
GAS UTILITY - NORTH DAKOTA
PROJECTED 2004 AND PROJECTED 2005**

Rate Reporting Class	Projected 2004		Projected 2005	
	Billing Units	Revenues	Billing Units	Revenues
<u>Sales</u>				
Residential				
Residential	73,908	\$66,544,060	74,677	\$66,643,837
Propane	241	166,064	242	165,340
Total Residential	<u>74,149</u>	<u>66,710,124</u>	<u>74,919</u>	<u>66,809,177</u>
Air Force	3	4,986,326	3	4,986,326
Firm General				
Firm General	11,386	43,849,268	11,448	43,683,941
Seasonal	11	111,137	11	111,137
Propane	73	237,539	73	235,331
Total Firm General	<u>11,470</u>	<u>44,197,944</u>	<u>11,532</u>	<u>44,030,409</u>
Interruptible				
Small Interruptible	82	3,481,200	82	3,481,200
Large Interruptible	0	0	0	0
Total Interruptible	<u>82</u>	<u>3,481,200</u>	<u>82</u>	<u>3,481,200</u>
Total Sales	<u>85,704</u>	<u>119,375,594</u>	<u>86,536</u>	<u>119,307,112</u>
<u>Transportation</u>				
Small Interruptible	57	401,449	57	401,449
Large Interruptible	10	381,588	10	381,588
Total Transportation	<u>67</u>	<u>783,037</u>	<u>67</u>	<u>783,037</u>
Total Sales & Transportation	<u>85,771</u>	<u>\$120,158,631</u>	<u>86,603</u>	<u>\$120,090,149</u>

1/ Gas rates effective with service rendered on and after September 1, 2003, PGA effective with bills rendered on and after February 1, 2004, exclusive of surcharge.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

	Total Company	North Dakota
Cost of Gas	\$181,536,759	\$81,904,699
Other Gas Supply	441,640	209,668
Distribution	13,577,649	5,557,824
Customer Accounts	7,190,582	2,763,194
Customer Service & Infor.	291,830	166,788
Sales	1,244,148	496,319
Administrative and General	<u>13,537,918</u>	<u>5,498,904</u>
Total Operation and Maintenance Expenses	<u><u>\$217,820,526</u></u>	<u><u>\$96,597,396</u></u>

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

Account No.		Total Company	North Dakota
	<u>Other Gas Supply Expenses</u>		
804	Natural Gas City Gate Purchases	\$197,660,433	\$86,313,563
805	Purchased Gas Cost Adjustments	(13,034,226)	(4,387,234)
808.1	Gas Withdrawn from Storage	39,049,256	17,813,204
808.2	Gas Delivered to Storage	(42,138,704)	(17,834,834)
812	Gas Used for Other Utility Operations - Cr.		
813	Other Gas Supply Expenses	441,640	209,668
	Total Other Gas Supply Expenses	\$181,978,399	82,114,367
	<u>Distribution Expenses</u>		
	<u>Operation</u>		
870	Supervision and Engineering	\$1,560,936	\$561,859
871	Distribution Load Dispatching	175,037	72,026
874	Mains and Services	2,607,450	988,155
875	Measuring & Reg. Station Exp. - General	77,124	37,387
876	Measuring & Reg. Station Exp. - Industrial	49,653	28,955
877	Measuring & Reg. Station Exp. - City Gate	31,758	5,227
878	Meters and House Regulators	1,555,081	660,887
879	Customer Installations	2,235,403	895,890
880	Other Expenses	3,384,375	1,475,119
881	Rents	71,259	22,228
	Total Operation Expenses	11,748,076	4,747,733
	<u>Maintenance</u>		
885	Supervision & Engineering	631,581	289,936
886	Structures & Improvements	4,029	2,484
887	Mains	237,645	107,431
889	Measuring & Reg. Station Exp. - General	46,416	21,043
890	Measuring & Reg. Station Exp. - Industrial	24,257	2,943
891	Measuring & Reg. Station Exp. - City Gate	2,091	224
892	Services	167,028	100,102
893	Meters and House Regulators	227,091	99,852
894	Other Equipment	489,435	186,076
	Total Maintenance Expenses	1,829,573	810,091
	Total Distribution Expenses	\$13,577,649	\$5,557,824
	<u>Customer Accounts Expenses</u>		
	<u>Operation</u>		
901	Supervision	\$617,329	\$262,999
902	Meter Reading Expenses	1,554,294	572,434
903	Customer Records and Collection Exp.	3,957,171	1,591,194
904	Uncollectible Accounts	604,262	178,014
905	Misc. Customer Accounts Expenses	457,526	158,553
	Total Customer Accounts Expenses	\$7,190,582	\$2,763,194

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

<u>Account No.</u>		<u>Total Company</u>	<u>North Dakota</u>
	<u>Customer Service & Information Expenses</u>		
	<u>Operation</u>		
907	Supervision	\$42,938	\$28,682
908	Customer Assistance Expenses	185,303	106,187
909	Informational and Instructional Expenses	57,417	25,981
910	Misc. Customer Service & Info. Exp.	6,172	5,938
	Total Customer Service & Info. Exp.	\$291,830	\$166,788
	<u>Sales Expenses</u>		
	<u>Operation</u>		
911	Supervision	\$297,490	\$133,722
912	Demonstrating and Selling Expenses	777,615	298,413
913	Advertising Expenses	89,324	34,221
916	Misc. Sales Expenses	79,719	29,963
	Total Sales Expenses	\$1,244,148	\$496,319
	<u>Administrative & General Expenses</u>		
	<u>Operation</u>		
920	Administrative and General Salaries	\$3,872,624	1,534,164
921	Office Supplies and Expenses	2,164,380	853,116
923	Outside Services Employed	567,873	219,243
924	Property Insurance	409,344	162,164
925	Injuries and Damages	1,175,336	427,908
926	Employee Pensions and Benefits	3,919,744	1,609,730
927	Franchise Requirements		
928	Regulatory Commission Expenses	162,519	43,222
930.1	General Advertising Expenses	157,980	112,485
930.2	Miscellaneous General Expenses	277,962	102,566
931	Rents	313,923	208,057
	Total Operation Expenses	13,021,685	5,272,655
	<u>Maintenance</u>		
935	Maintenance of General Plant	516,233	226,249
	Total Administrative & General Expenses	\$13,537,918	\$5,498,904
	Total Operation & Maintenance Expenses	\$217,820,526	\$96,597,396

**MONTANA-DAKOTA UTILITIES CO.
DEPRECIATION EXPENSE AND AMORTIZATION
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003**

	Total Company	North Dakota
Distribution	\$6,782,714	\$2,358,371
General	506,088	165,893
Common	581,985	235,781
Amortization of Intangible Plant - General	10,013	2,035
Amortization of Intangible Plant - Common	564,093	201,313
Gas Plant Leased to Others	2,409	1,063
Amortization of Acquisition Adjustment	29,837	29,837
Total Depreciation and Amort. Expense	<u>\$8,477,139</u>	<u>\$2,994,293</u>

**MONTANA-DAKOTA UTILITIES CO.
DEPRECIATION AND AMORTIZATION EXPENSES
GAS UTILITY – NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003**

See Pages 3 through 5 for Montana-Dakota's depreciation rates as authorized in Case No. PU-399-02-183 and derived from a study by AUS Consultants as of December 31, 2001 for gas and common plant.

Montana-Dakota Utilities Company
Gas Division

SETTLEMENT POSITION
Summary or Original Cost of Utility Plant in Service as of December 31, 2001
and Related Annual Depreciation Expense Under Present and Proposed Rates

Account No. (a)	Description (b)	Original	Present Rates		Proposed Rates		Net Change Depr. Exp (h)
		Cost 12/31/01 (c)	Rate % (d)	Annual Accrual (e)	Rate % (f)	Annual Accrual (g)	
DEPRECIABLE PLANT							
Distribution Plant							
374.20	Rights of Way	89,641	2.58%	2,313	0.75%	672	-1,640
375.00	Distr. Meas & Reg Station Structures	521,210	2.40%	12,509	2.57%	13,395	886
376.00	Mains	78,334,154	4.05%	3,172,533	1.92%	1,504,016	-1,668,517
378.00	Meas & Reg Station Equip-General	1,367,334	2.30%	31,449	2.96%	40,473	9,024
379.00	Meas & Reg Station Equip-City Gate	1,009,137	2.74%	27,650	3.54%	35,723	8,073
380.00	Services	32,476,717	7.60%	2,468,231	5.66%	1,838,182	-630,048
381.00	Meters	30,462,008	2.58%	785,920	3.19%	971,738	185,818
383.00	Service Regulators	4,296,862	2.37%	101,836	2.59%	111,289	9,453
385.00	Industrial Meas. & Reg. Station Equipment	578,200	1.91%	11,044	3.04%	17,577	6,534
						4,533,066	
MISCELLANEOUS EQUIPMENT							
386.10	Miscellaneous Property on Customers Premise	1,680	9.35%	157	5.19%	87	-70
386.20	CNG Refueling station	432,811	9.35%	40,468	3.70%	16,014	-24,454
	TOTAL Account 386	434,491	9.35%	40,625	3.71%	16,101	-24,524
OTHER EQUIPMENT							
387.10	Cathodic Protection Equipment	1,450,657	5.21%	75,579	5.75%	83,413	7,834
387.20	Other Distribution Equipment	557,184	5.21%	29,029	1.42%	7,912	-21,117
	TOTAL Account 387	2,007,841	5.21%	104,609	4.55%	91,325	-13,284
	TOTAL Distribution Plant	151,577,594	4.46%	6,758,717	3.06%	4,640,492	-2,118,225
General Plant							
390.00	General Structures	1,922,983	2.34%	44,998	3.73%	71,727	26,729
OFFICE FURNITURE & EQUIPMENT							
391.10	Office Furniture & Equipment	544,275	4.05%	22,043	4.97%	27,034	4,991
391.30	Computer Equipment - PC	780,995	12.50%	97,624	26.13%	204,035	106,411
	TOTAL Account 391	1,325,269	9.03%	119,667	17.44%	231,069	111,401
TRANSPORTATION EQUIPMENT							
392.10	Transportation Equipment (Trailers)	147,187	5.74%	8,449	4.36%	6,417	-2,031
392.20	Transportation Equipment (Cars & Trucks)	6,080,561	5.74%	349,024	21.13%	1,284,823	935,798
	TOTAL Account 392	6,227,748	5.74%	357,473	20.73%	1,291,240	933,767
393.00	Stores Equipment	186,729	0.90%	1,681	2.49%	4,658	2,978
TOOLS, SHOP & GARAGE EQ.							
394.10	Tools, Shop & Garage Equip. (Non-Unitized)	2,495,422	3.57%	89,087	6.62%	165,153	76,067
394.20	Tools, Shop & Garage Equip. (Unitized)	299,810	4.83%	14,481	2.40%	7,201	-7,280
394.30	Vehicle Maintenance Equipment	31,177	4.21%	1,313	5.78%	1,803	491
394.40	Vehicle Refueling Equipment	361,344	9.35%	33,786	4.72%	17,065	-16,721
	TOTAL Account 394	3,187,752	4.35%	138,666	6.00%	191,222	52,557
395.00	Laboratory Equipment	271,033	2.32%	6,288	7.67%	20,801	14,513
POWER OPERATED EQUIPMENT							
396.10	Work Equipment (Trailers)	293,543	4.83%	14,178	5.76%	16,908	2,730
396.20	Power Operated Equipment	4,081,768	4.83%	197,149	0.00%	0	-197,149
	TOTAL Account 396	4,375,312	4.83%	211,328	0.39%	16,908	-194,419

Montana-Dakota Utilities Company
Gas Division

SETTLEMENT POSITION
Summary of Original Cost of Utility Plant in Service as of December 31, 2001
and Related Annual Depreciation Expense Under Present and Proposed Rates

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Present Rates		Proposed Rates		Net Change Depr. Exp. (h)
			Rate % (d)	Annual Accrual (e)	Rate % (f)	Annual Accrual (g)	
COMMUNICATION EQUIPMENT							
397.10	Radio Communication Equip. (Fixed)	481,655	3.67%	17,677	7.37%	35,511	17,834
397.20	Radio Communication Equip. (Mobile)	401,528	3.67%	14,736	7.34%	29,469	14,733
397.30	General Telephone Communication Equip.	90,518	6.56%	5,938	9.88%	8,941	3,003
397.50	Supervisory & Telemetering Equip.	124,167	6.67%	8,282	0.25%	311	-7,971
397.60	SCADA System	30,894	15.07%	4,656	0.00%	0	-4,656
397.80	Network Equipment	30,338	12.50%	3,792	26.26%	7,968	4,176
	TOTAL Account 397	1,159,100	4.75%	55,081	7.09%	82,199	27,119
398.00	Miscellaneous Equipment	145,270	0.59%	82,199	1.27%	1,851	-80,348
	TOTAL General Plant	18,801,196	5.41%	1,017,380	10.17%	1,911,676	894,296
	TOTAL Depreciable Plant	170,378,791	4.56%	7,776,097	3.85%	6,552,168	-1,223,929
<u>NON-DEPRECIABLE PLANT</u>							
374.10	Land (Distribution)	108,920					
389.00	Land & Land Rights (General)	301,149					
	Total Land	410,069					
INTANGIBLE PLANT							
303.00	Miscellaneous Intangible Plant	477,530					
	Total Intangible Plant	477,530					
	TOTAL Non-Depreciable Plant	887,598					
	TOTAL Plant in Service	171,266,389					

Montana-Dakota Utilities Company
Common Plant
MDU Settlement

Summary or Original Cost of Utility Plant in Service as of December 31, 2001
and Related Annual Depreciation Expense Under Present and Proposed Rates

Account No. (a)	Description (b)	Original	Present Rates		Proposed Rates		Net
		Cost 12/31/01 (c)	Rate % (d)	Annual Accrual (e)	Rate % (f)	Annual Accrual (g)	Change Depr. Exp. (h)
<u>DEPRECIABLE PLANT</u>							
<u>General Plant</u>							
390.0	General Structures	18,048,459.30	3.76%	678,622.07	2.93%	528,819.86	-149,802.21
OFFICE FURNITURE & EQUIPMENT							
391.1	Office Furniture & Equipment	3,716,416.91	1.48%	55,002.97	4.95%	184,032.14	129,029.17
391.2	Computer Equipment - Honeywell	93,392.30	14.17%	13,233.69	1.52%	1,416.58	-11,817.11
391.3	Computer Equipment - PC	4,212,743.17	12.50%	526,592.90	23.29%	981,147.88	454,554.98
391.5	Computer Equipment - Other	820,399.57	26.51%	217,487.93	0.46%	3,797.58	-213,690.35
	TOTAL Account 391	8,842,951.95	9.19%	812,317.49	13.24%	1,170,394.18	358,076.69
TRANSPORTATION EQUIPMENT							
392.1	Transportation Equipment (Trailers)	251,165.84	5.74%	14,416.92	0.00%	0.00	-14,416.92
392.2	Transportation Equipment (Cars & Trucks)	4,429,701.58	5.74%	254,264.87	13.33%	590,479.22	336,214.35
	TOTAL Account 392	4,680,867.42	5.74%	268,681.79	12.61%	590,479.22	321,797.43
393.0	Stores Equipment	47,385.55	3.36%	1,592.15	2.80%	1,327.61	-264.54
TOOLS, SHOP & GARAGE EQ.							
394.1	Tools, Shop & Garage Equip. (Non-Unitized)	235,026.00	3.44%	8,084.89	6.11%	14,362.50	6,277.61
394.3	Vehicle Maintenance Equipment	102,746.14	4.46%	4,582.48	4.75%	4,877.05	294.57
394.4	Vehicle Refueling Equipment	838,830.77	8.42%	70,629.55	4.38%	36,709.31	-33,920.24
	TOTAL Account 394	1,176,602.91	7.08%	83,296.92	4.76%	55,948.86	-27,348.06
396.2	Power Operated Equipment	157,572.62	4.83%	7,610.76	2.69%	4,238.70	-3,372.06
COMMUNICATION EQUIPMENT							
397.1	Radio Communication Equip. (Fixed)	646,187.02	4.33%	27,979.90	4.99%	32,241.83	4,261.93
397.2	Radio Communication Equip. (Mobile)	1,285,023.00	6.68%	85,839.54	4.08%	52,474.26	-33,365.28
397.3	General Telephone Communication Equip.	779,821.23	10.62%	82,817.01	8.72%	68,036.36	-14,780.65
397.5	Supervisory & Telemetering Equip.	48,295.94	0.59%	284.95	0.35%	170.00	-114.95
397.8	Network Equipment	824,948.21	12.50%	103,118.53	17.95%	148,037.04	44,918.51
	TOTAL Account 397	3,584,275.40	8.37%	300,039.93	8.40%	300,959.49	919.56
398.0	Miscellaneous Equipment	592,894.94	2.51%	14,881.66	2.41%	14,291.82	-589.84
	Sub-Total (General Plant) Amortization	10,031,367.58	6.83%	685,535.25	5.60%	561,774.08	-123,761.17
	TOTAL General Plant	37,131,010.09	5.84%	2,167,042.77	7.18%	2,666,459.74	499,416.97
	TOTAL Depreciable Plant	37,131,010.09	5.84%	2,167,042.77	7.18%	2,666,459.74	499,416.97
<u>Amortizable Plant</u>							
392.3	Aircraft Equipment	1,024,349.51					
	TOTAL Amortizable Plant	1,024,349.51					
<u>NON-DEPRECIABLE PLANT</u>							
389.0	Land & Land Rights (General)	1,547,408.83					
	Total Land	1,547,408.83					
INTANGIBLE PLANT							
303.0	Miscellaneous Intangible Plant	13,553,859.20					
	Total Intangible Plant	13,553,859.20					
	TOTAL Non-Depreciable Plant	15,101,268.03					
	TOTAL Plant in Service	53,256,627.63					

**MONTANA-DAKOTA UTILITIES CO.
RECONCILIATION OF DEPRECIABLE GAS PLANT
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003**

	Balance @ 12/31/02	Balance @ 12/31/03	Average Balance
<u>Depreciable Plant</u>			
Distribution	\$56,725,545	\$58,991,666	\$57,858,606
General	3,189,547	2,384,065	2,786,805
General - Amortized	181,686	180,280	180,983
Gas Plant Leased to Others	11,374	11,374	11,374
	<u>\$60,108,152</u>	<u>\$61,567,385</u>	<u>\$60,837,768</u>
<u>Depreciable Plant Charged to a Clearing Account</u>			
Transportation Equipment	\$2,214,973	\$2,306,747	\$2,260,860
Tools, Shop & Garage Equipment - Unitized	123,956	39,059	81,508
Power Operated Equipment	114,117	111,701	112,909
Work Equipment	1,370,028	1,343,917	1,356,973
	<u>\$3,823,074</u>	<u>\$3,801,424</u>	<u>\$3,812,250</u>
<u>Non-Depreciable Plant</u>			
Distribution	\$41,999	\$41,687	\$41,843
General	154,460	154,772	154,616
	<u>\$196,459</u>	<u>\$196,459</u>	<u>\$196,459</u>
<u>Common Plant in Service - Gas</u>			
Depreciable	\$4,436,641	\$4,037,362	\$4,237,002
Charged to Clearing Account	889,223	1,353,683	1,121,453
Depreciable - Amortized	2,010,760	2,066,890	2,038,824
Non-Depreciable	213,977	215,955	214,965
	<u>\$7,550,601</u>	<u>\$7,673,890</u>	<u>\$7,612,244</u>
Acquisition Adjustment - Amortized	<u>\$97,266</u>	<u>\$97,266</u>	<u>\$97,266</u>
Total Gas Plant in Service	<u><u>\$71,775,552</u></u>	<u><u>\$73,336,424</u></u>	<u><u>\$72,555,987</u></u>

**MONTANA-DAKOTA UTILITIES CO.
TAXES OTHER THAN INCOME
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003**

<u>Type of Tax</u>	<u>Total Company</u>	<u>North Dakota</u>
Ad Valorem 1/	\$2,665,287	\$627,260
O&M Related Taxes		
Payroll:		
FICA	\$1,433,129	\$614,541
Federal & State Unemployment	76,009	19,898
Total Payroll	<u>\$1,509,138</u>	<u>\$634,439</u>
Delaware Franchise	62,155	24,850
Total O&M Related Taxes	<u>\$1,571,293</u>	<u>\$659,289</u>
Other		
Hettinger Franchise	\$12,075	\$12,075
Wyoming Franchise	84,234	
Montana Consumer Counsel	66,214	
Montana PSC	163,885	
South Dakota Special Hearing Fund	52,574	
Wyoming Revolving Fund	30,731	
Secretary of State	674	270
Highway Use Tax	560	203
Total Other	<u>\$410,947</u>	<u>\$12,548</u>
 Total Taxes Other Than Income	 <u><u>\$4,647,527</u></u>	 <u><u>\$1,299,097</u></u>

1/ Statement J, page 2.

MONTANA-DAKOTA UTILITIES CO.
TAXES OTHER THAN INCOME
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

<u>Type of Tax</u>	<u>Total Company</u>
<u>Ad Valorem</u>	
Montana	
Distribution	\$1,308,097
General	75,596
Common	96,466
Total Montana	<u>\$1,480,159</u>
North Dakota	
Distribution	\$512,281
General	54,208
Common	57,915
Intangible - General	2,856
Total North Dakota	<u>\$627,260</u>
South Dakota	
Distribution	\$403,141
General	79,594
Common	31,264
Intangible - General	872
Total South Dakota	<u>\$514,871</u>
Wyoming	
Distribution	\$28,992
General	1,243
Common	12,610
Intangible - General	152
Total Wyoming	<u>\$42,997</u>
Total Ad Valorem Taxes	<u><u>\$2,665,287</u></u>

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF RECORDED STATE AND FEDERAL INCOME TAXES
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

	Total Company	North Dakota
Operating Revenue	<u>\$237,207,834</u>	<u>\$103,088,906</u>
Operating Expense:		
O&M Expense	217,820,526	96,597,396
Depreciation Expense	8,477,139	2,994,293
Taxes Other than Income	4,647,527	1,299,097
Total Operating Expense	<u>230,945,192</u>	<u>100,890,786</u>
Operating Income	6,262,642	2,198,120
Interest Expense	<u>3,265,633</u>	<u>975,871</u>
Book Taxable Income before Adjustments	<u>2,997,009</u>	<u>1,222,249</u>
Deductions and Adjustments to Book Income:		
Tax Deductions 1/	12,715,396	4,311,402
Preferred Dividend Paid Deduction	<u>52,184</u>	<u>15,397</u>
Total Deductions and Adjustments	<u>12,767,580</u>	<u>4,326,799</u>
Taxable Income - Before State Income Tax	(9,770,571)	(3,104,550)
Less: State Income Taxes	<u>(582,346)</u>	<u>(367,346)</u>
Federal Taxable Income	(9,188,225)	(2,737,204)
Federal Income Taxes @ 35%	(3,215,879)	(958,021)
Credits and Adjustments	(7,532)	(3,011)
State Income Taxes	<u>(582,346)</u>	<u>(367,346)</u>
Federal and State Income Taxes	<u>(3,805,757)</u>	<u>(1,328,378)</u>
Closing, Filing, and Out of Period Adjustment	<u>(318,854)</u>	<u>(133,496)</u>
Total Federal and State Income Taxes	<u><u>(\$4,124,611)</u></u>	<u><u>(\$1,461,874)</u></u>

1/ See page 2.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF RECORDED STATE AND FEDERAL INCOME TAXES
TAX DEDUCTIONS
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

	Total Company	North Dakota
<u>1900 Account M-1's</u>		
Management Incentive Compensation	(\$191,611)	(\$76,609)
Pension Expense	657,311	262,803
Sundry Reserves	914	270
Property Insurance Adjustment	214,996	76,732
Bad Debt Expense	(82,083)	(19,647)
Accrued Vacation	(201,310)	(80,487)
Capitalized Overheads	(104,056)	(41,603)
Customer Advances	148,585	(20,439)
FAS 106 - OPRB	4,836	1,934
Deferred Compensation	(226,864)	(90,704)
BOD Retirement	14,173	5,667
Demand Charges	345,925	118,336
PCB related income	11,720	4,468
Restricted Stock Bonus Plan	(241,823)	(96,684)
<u>2820 Account M-1's</u>		
Liberalized Depreciation and Other Property Timing Differences	(364,589)	(172,087)
Contributions in Aid of Construction	(147,896)	(134,406)
Acquisition Adjustments	(29,837)	(29,837)
<u>2830 Account M-1's</u>		
Purchased Gas Cost Adjustment	13,427,981	4,780,020
Rate Case Expense	47,577	12,039
Amortization of Loss on Bond Retirements	(321,439)	(94,840)
FAS 106 - Deferred Expense	(54,531)	
Gas IRP	(88,708)	(53,000)
<u>Permanent M-1's</u>		
Meals & Entertainment	(86,095)	(34,422)
Federal Nonhwy Use Tax Credit	(8,169)	(3,266)
Preferred Stock Compensation	(9,611)	(2,836)
Total M-1 Deductions	\$12,715,396	\$4,311,402

**MONTANA-DAKOTA UTILITIES CO.
DEFERRED INCOME TAXES
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003**

	<u>Total Utility</u>	<u>North Dakota</u>
<u>Gas Utility - Rate Base Deductions:</u>		
Depreciation, Retirements and Other Timing		
Differences Required to be Normalized	(\$358,397)	(\$161,023)
Contributions In Aid of Construction	(56,870)	(52,149)
Customer Advances	57,569	(8,096)
Acquisition Adjustment	(11,577)	(11,577)
Total Rate Base Deductions	<u>(369,275)</u>	<u>(232,845)</u>
<u>Gas Utility - Current Timing Differences:</u>		
Management Incentive Compensation	(73,055)	(30,345)
Pension Expense	250,609	104,096
Sundry Reserves	344	106
Property Insurance Adjustment	81,544	30,393
Bad Debt Expense	(31,301)	(7,782)
Accrued Vacation	(76,752)	(31,880)
Capitalized Overheads	(39,673)	(16,479)
FAS 106	(18,943)	766
Deferred Compensation	(86,494)	(35,927)
BOD Retirement	5,404	2,244
Demand Charges	131,774	46,873
PCB Related Income	4,469	1,770
Restricted Stock Bonus Plan	(92,199)	(38,297)
Unrecovered Purchased Gas Cost	5,097,135	1,893,366
Rate Case Expense	14,749	4,769
Amort of Loss on Bond Retirements	(121,000)	(37,566)
Gas IRP	(35,062)	(20,993)
Closing and Filing	328,924	141,108
Total Current Timing Differences	<u>5,340,473</u>	<u>2,006,222</u>
 Total Deferred Income Taxes	 <u>\$4,971,198</u>	 <u>\$1,773,377</u>

MONTANA-DAKOTA UTILITIES CO.
ANALYSIS OF ACCUMULATED DEFERRED INCOME TAXES
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

	Total Company		North Dakota		Average Balance
	Balance 12/31/02	Balance 12/31/03	Balance 12/31/02	Balance 12/31/03	
<u>Gas Utility - Rate Base Deductions:</u>					
Depreciation, Retirements and Other Timing Differences Required to be Normalized	\$10,128,333	\$10,308,699	\$3,746,094	\$3,715,814	3,730,954
Contributions In Aid of Construction	(241,476)	(300,282)	(103,405)	(157,479)	(130,442)
Full Normalization	339,490	122,555	465,365	374,305	419,835
Customer Advances for Construction	(275,701)	(218,132)	(101,031)	(109,127)	(105,079)
Montana Net Salvage	369,676	410,444			0
Acquisition Adjustment		(11,577)		(11,577)	(5,789)
Total	\$10,320,322	\$10,311,707	\$4,007,023	\$3,811,936	\$3,909,479

MONTANA-DAKOTA UTILITIES CO.
ANALYSIS OF UNAMORTIZED INVESTMENT TAX CREDITS
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

	<u>Total Company</u>	<u>North Dakota</u>
<u>Balance @</u> December 31, 2002	\$518,742	\$235,403
December 31, 2003	<u>\$413,147</u>	<u>\$178,210</u>
Average Balance	<u>\$465,945</u>	<u>\$206,807</u>

**MONTANA-DAKOTA UTILITIES CO.
INCOME STATEMENT
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2003**

Case No. _____
Statement L
Page 1 of 4

	Total Company	North Dakota	Other	Reference
Operating Revenues				
Sales	\$233,447,443	\$101,923,886	\$131,523,557	Statement G
Transportation	2,756,722	759,272	1,997,450	Statement G
Other	1,003,669	405,748	597,921	Statement G
Total Revenues	237,207,834	103,088,906	134,118,928	
Operating Expenses				
Operation and Maintenance				
Cost of Gas	181,536,759	81,904,699	99,632,060	Statement H
Other O&M	36,283,767	14,692,697	21,591,070	Statement H
Total O&M	217,820,526	96,597,396	121,223,130	
Depreciation	8,477,139	2,994,293	5,482,846	Statement I
Taxes Other Than Income	4,647,527	1,299,097	3,348,430	Statement J
Current Income Taxes	(4,124,611)	(1,461,874)	(2,662,737)	Statement K
Deferred Income Taxes	4,971,198	1,773,377	3,197,821	Statement K
Total Expenses	231,791,779	101,202,289	130,589,490	
Operating Income	\$5,416,055	\$1,886,617	\$3,529,438	

**MONTANA-DAKOTA UTILITIES CO.
RATE BASE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2003**

	Total Company	North Dakota	Other	Reference
Gas Plant in Service	\$207,228,077	\$73,336,424	\$133,891,653	Statement C
Accumulated Reserve for Depreciation	126,784,629	50,251,003	76,533,626	Statement D
Net Gas Plant in Service	80,443,448	23,085,421	57,358,027	
CWIP in Service Pending Reclassification	1,194,868	449,173	745,695	Statement C
Total Gas Plant in Service	81,638,316	23,534,594	58,103,722	
Additions				
Materials and Supplies	1,151,403	409,023	742,380	Statement E
Fuel Stocks	25,616	25,616	0	Statement E
Gas in Underground Storage	6,112,241	0	6,112,241	
Prepayments	1,378,658	65,958	1,312,700	Statement E
Other	214,751	17,984	196,767	Statement E
Total Additions	8,882,669	518,581	8,364,088	
Total Before Deductions	\$90,520,985	\$24,053,175	\$66,467,810	
Deductions				
Accumulated Deferred Income Taxes	10,311,707	3,811,936	6,499,771	Statement K
Accumulated Investment Tax Credits	413,147	178,210	234,937	Statement K
Customer Advances	587,187	307,320	279,867	Statement E
Total Deductions	11,312,041	4,297,466	7,014,575	
Total Rate Base	<u>\$79,208,944</u>	<u>\$19,755,709</u>	<u>\$59,453,235</u>	

MONTANA-DAKOTA UTILITIES CO.
AVERAGE RATE BASE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2003

	<u>2002</u>	<u>2003</u>	<u>Average</u>
Gas Plant in Service	\$71,775,552	\$73,336,424	\$72,555,988
Accumulated Reserve for Depreciation	49,036,379	50,251,003	49,643,691
Net Gas Plant in Service	<u>22,739,173</u>	<u>\$23,085,421</u>	<u>22,912,297</u>
CWIP in Service Pending Reclassification	405,134	449,173	427,154
Total Gas Plant in Service	<u>23,144,307</u>	<u>23,534,594</u>	<u>23,339,451</u>
Additions			
Materials and Supplies	376,334	409,023	392,679
Fuel Stock	23,626	25,616	24,621
Prepayments	33,397	65,958	49,677
Other	70,984	17,984	44,484
Total Additions	<u>504,341</u>	<u>518,581</u>	<u>511,461</u>
Total Before Deductions	\$23,648,648	\$24,053,175	\$23,850,912
Deductions			
Accumulated Deferred Income Taxes	4,007,023	3,811,936	3,909,479
Accumulated Investment Tax Credits	235,403	178,210	206,807
Customer Advances	286,881	307,320	297,101
Total Deductions	<u>4,529,307</u>	<u>4,297,466</u>	<u>4,413,387</u>
Total Rate Base	<u>\$19,119,341</u>	<u>\$19,755,709</u>	<u>\$19,437,525</u>

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
GAS UTILITY - NORTH DAKOTA
PROJECTED 2005
(000s)

	Before Additional Revenue Re- quirements	Additional Revenue Requirements	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	\$119,307	\$3,337	\$122,644
Transportation	783		783
Other	406		406
Total Revenues	<u>120,496</u>	<u>3,337</u>	<u>123,833</u>
Operating Expenses			
Operation and Maintenance			
Cost of Gas	99,473		99,473
Other O&M	17,546		17,546
Total O&M	<u>117,019</u>		<u>117,019</u>
Depreciation	2,615		2,615
Taxes Other Than Income	1,421		1,421
Current Income Taxes	263	1,320	1,583
Deferred Income Taxes	(873)		(873)
Total Expenses	<u>120,445</u>	<u>1,320</u>	<u>121,765</u>
Operating Income	<u>\$51</u>	<u>\$2,017</u>	<u>\$2,068</u>
Rate Base	<u>\$20,914</u>		<u>\$20,914</u>
Rate of Return			
	<u>0.244%</u>		<u>9.887%</u>

MONTANA-DAKOTA UTILITIES CO.
REVENUES UNDER CURRENT AND PROPOSED RATES
GAS UTILITY - NORTH DAKOTA
Proposed Final Rates

Customer Class/Rate	Customers	Projected 2005		Revenue	Total Proposed Revenue	Proposed Revenue Increase	Percent Increase
		Dk					
Residential - Rate 60	74,919	8,152,728		\$66,809,177	\$69,145,273	\$2,336,096	3.5%
Firm General Service - Rate 70	11,532	5,747,216		44,030,409	45,028,539	998,130	2.3%
Air Force - Rate 64							
Firm	1	37,297		252,218	252,218	0	0.0%
Interruptible	2	842,568		4,734,108	4,734,108	0	0.0%
Total Air Force	3	879,865		4,986,326	4,986,326	0	0.0%
Small Interruptible							
Sales - Rate 71	82	570,263		3,481,200			0.0%
Transport - Rate 81	57	703,084		401,449			0.0%
Total Small Interruptible	139	1,273,347		3,882,649	3,882,649	0	0.0%
Large Interruptible							
Sales - Rate 85	0	0		0			
Transport - Rate 82	10	2,229,392		381,588			
Total Large Interruptible	10	2,229,392		381,588	381,588	0	0.0%
Total North Dakota	86,603	18,282,548		\$120,090,149	\$123,424,375	\$3,334,226	2.8%

MONTANA-DAKOTA UTILITIES CO.
 GAS UTILITY - NORTH DAKOTA
 EMBEDDED CLASS COST OF SERVICE STUDY
 COST OF SERVICE BY COMPONENT
 PROJECTED 2005

Cost of Service By Component	Total		Residential		Firm General	
	North Dakota	Demand	Energy	Customer	Energy	Customer
Projected Rate Base	20,914,274	3,896,450	8,412	8,944,297	2,700,477	4,258,247
Operating Income for Proposed Return	2,067,794	385,242	832	884,323	266,996	421,013
Projected Operating Income	50,905	(1,006,616)	2,993,218	(2,404,887)	(697,639)	(643,206)
Increase in Operating Income	2,016,889	1,391,858	(2,992,386)	3,289,210	964,635	1,064,219
Related Taxes for Increase						
Federal Income	1,319,571	910,637	(1,957,798)	2,151,998	631,122	696,276
Total Increase in Revenue	3,336,460	2,302,495	(4,950,184)	5,441,208	1,595,757	1,760,495
Projected Revenues before Increase	120,495,896	11,654,512	47,292,339	8,119,292	8,215,021	3,571,687
Total Cost of Service	123,832,356	13,957,007	42,342,155	13,560,500	9,810,778	5,332,182
Required From Rates	99,473,000	11,590,339	42,062,661	0	8,170,536	0
Less Projected Cost of Gas						
Net Distribution Costs	24,359,356	2,366,668	279,494	13,560,500	1,640,242	5,332,182
Billing Units at Customer						
Dk Throughput		8,152,728	8,152,728	0	5,747,216	0
Bills		0	0	899,028	0	138,384
Unit Cost of Service						
\$ Per Dk		0.290	0.034	0.000	0.285	0.000
\$ Per Customer Per Month		0.000	0.000	15.084	0.000	38.532

MONTANA-DAKOTA UTILITIES CO.
 GAS UTILITY - NORTH DAKOTA
 EMBEDDED CLASS COST OF SERVICE STUDY
 COST OF SERVICE BY COMPONENT
 PROJECTED 2005

Cost of Service By Component	Air Force		Small Interruptible	
	Demand	Energy	Demand	Energy
Projected Rate Base	36,066	0	214,615	0
Operating Income for Proposed Return	3,566	0	21,219	0
Projected Operating Income	(8,591)	48,535	(55,434)	311,874
Increase in Operating Income	12,157	(48,535)	76,653	(311,874)
Related Taxes for Increase Federal Income	7,954	(31,754)	50,151	(204,047)
Total Increase in Revenue	20,111	(80,289)	126,804	(515,921)
Projected Revenues before Increase	326,219	4,645,834	200,712	3,484,791
Total Cost of Service Required From Rates	346,330	4,565,545	327,516	2,968,870
Less Projected Cost of Gas	324,411	4,535,589	197,204	2,943,796
Net Distribution Costs	21,919	29,956	130,312	25,074
Billing Units at Customer Dk Throughput Bills	879,865 0	879,865 0	1,273,347 0	1,273,347 0
Unit Cost of Service \$ Per Dk \$ Per Customer Per Month	0.025 0.000	0.034 0.000	0.102 0.000	0.020 0.000
		1,283,056	0.000	300.670

MONTANA-DAKOTA UTILITIES CO.
 GAS UTILITY - NORTH DAKOTA
 EMBEDDED CLASS COST OF SERVICE STUDY
 COST OF SERVICE BY COMPONENT
 PROJECTED 2005

Cost of Service By Component	Large Interruptible		
	Demand	Energy	Customer
Projected Rate Base	147,578	0	177,753
Operating Income for Proposed Return	14,591	0	17,574
Projected Operating Income	(38,125)	167,526	(1,678)
Increase in Operating Income	52,716	(167,526)	19,252
Related Taxes for Increase Federal Income	34,490	(109,606)	12,596
Total Increase in Revenue	87,206	(277,132)	31,848
Projected Revenues before Increase	2,404	294,688	89,891
Total Cost of Service Required From Rates	89,610	17,556	121,739
Less Projected Cost of Gas	0	0	0
Net Distribution Costs	89,610	17,556	121,739
Billing Units at Customer			
Dk Throughput	2,229,392	2,229,392	0
Bills	0	0	120
Unit Cost of Service			
\$ Per Dk	0.040	0.008	0.000
\$ Per Customer Per Month	0.000	0.000	1,014.492

**MONTANA-DAKOTA UTILITIES CO.
 GAS UTILITY - NORTH DAKOTA
 EMBEDDED CLASS COST OF SERVICE STUDY
 SUMMARY REPORT
 PROJECTED 2005**

Projected Operating Income and Rate of Return	Total		Firm		Small Interruptible	Large Interruptible
	North Dakota	Residential	General	Air Force		
Operating Revenues	120,495,896	67,066,143	44,159,576	4,988,428	3,894,766	386,983
Operating Expenses						
O&M Cost of Purchased Gas	99,473,000	53,653,000	37,819,000	4,860,000	3,141,000	0
Other O&M Expense	17,546,697	11,967,948	4,924,935	70,841	443,213	139,760
Total Operation & Maint. Exp.	117,019,697	65,620,948	42,743,935	4,930,841	3,584,213	139,760
Depreciation	2,614,999	1,606,629	886,116	7,287	84,559	30,408
Taxes Other Than Income Taxes	1,420,998	925,163	435,245	5,623	39,871	15,096
Fed. & State Inc. Taxes - Current	262,296	(157,342)	214,921	35,310	88,424	80,983
Deferred Income Taxes	(872,999)	(510,970)	(308,229)	(19,522)	(27,291)	(6,987)
Total Operating Expenses	120,444,991	67,484,428	43,971,988	4,959,539	3,769,776	259,260
Operating Income	50,905	(418,285)	187,588	28,889	124,990	127,723
Rate Base	20,914,274	12,849,159	6,972,312	106,538	660,934	325,331
Rate of Return	0.243%	-3.255%	2.690%	27.116%	18.911%	39.259%

**MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
RATE BASE REPORT
PROJECTED 2005**

Projected Rate Base	Total		Firm		Air Force	Small		Large
	North Dakota	Residential	General	Interruptible		Interruptible	Interruptible	
Gas Plant in Service	77,873,268	48,079,957	26,018,803	297,628	2,418,280	1,058,600		
Less: Accumulated Depreciation	53,571,997	33,204,051	17,863,948	179,033	1,634,586	690,379		
Net Gas Plant in Service	24,301,271	14,875,906	8,154,855	118,595	783,694	368,221		
CWIP in Service	0	0	0	0	0	0		
Total Plant	24,301,271	14,875,906	8,154,855	118,595	783,694	368,221		
Additions								
Materials & Supplies	475,000	293,271	158,706	1,815	14,750	6,458		
Fuel Stocks	22,000	8,412	13,588	0	0	0		
Prepaid Insurance	190,000	117,307	63,483	727	5,900	2,583		
Gas IRP Costs - Other	0	0	0	0	0	0		
Rate Case Expense	0	0	0	0	0	0		
Total Additions	687,000	418,990	235,777	2,542	20,650	9,041		
Total Before Deductions	24,988,271	15,294,896	8,390,632	121,137	804,344	377,262		
Deductions								
Accumulated Deferred Income Tax	(3,673,998)	(2,268,374)	(1,227,546)	(14,042)	(114,092)	(49,944)		
Investment Tax Credit Balance	(145,999)	(90,142)	(48,781)	(557)	(4,533)	(1,986)		
Customer Advances For Constr.	(254,000)	(87,221)	(141,993)	0	(24,786)	0		
Total Deductions	(4,073,997)	(2,445,737)	(1,418,320)	(14,599)	(143,411)	(51,930)		
Total Rate Base	20,914,274	12,849,159	6,972,312	106,538	660,933	325,332		

**MONTANA-DAKOTA UTILITIES
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
PROJECTED CHANGES IN OPERATING INCOME**

Projected Changes in Operating Income	Total		Firm		Small		Large	
	North Dakota	Residential	General	Air Force	Interruptible	Interruptible	Interruptible	Interruptible
Revenue @ Current Rates								
Sales Revenue	20,140,093	11,589,801	7,836,118	1,131,675	(106,996)	(310,505)		
Unbilled Revenue	(2,733,100)	(1,509,956)	(989,720)	(105,404)	(109,095)	(18,925)		
Total Revenue	17,406,993	10,079,845	6,846,398	1,026,271	(216,091)	(329,430)		
Cost of Gas	17,568,301	9,478,869	6,678,717	854,435	556,280	0		
Labor Expense								
Other Gas Supply	16,999	11,578	4,785	70	431	135		
Distribution	548,999	330,253	189,780	2,507	19,565	6,894		
Customer Accounts	237,000	205,026	31,559	8	380	27		
Customer Service & Information	16,001	13,841	2,131	1	26	2		
Sales	46,000	39,794	6,125	2	74	5		
Administrative & General	206,000	140,304	57,983	840	5,230	1,643		
Total Labor Expense	1,070,999	740,796	292,363	3,428	25,706	8,706		
Benefits Expense	1,325,002	902,441	372,953	5,405	33,638	10,565		
Insurance Expense	(45,000)	(30,649)	(12,666)	(184)	(1,143)	(358)		
Advertising Expense	(35,000)	(30,278)	(4,661)	(1)	(56)	(4)		
Postage Expense	(1,000)	(865)	(133)	0	(2)	0		
Industry Dues	(4,001)	(2,724)	(1,126)	(17)	(102)	(32)		
Rate Case Expense	82,000	55,849	23,081	334	2,082	654		
Uncollectible Accounts	75,000	64,881	9,987	3	120	9		
Vehicles & Work Equipment	315,999	215,224	88,945	1,288	8,022	2,520		
Energy Share	10,999	6,081	3,981	423	438	76		

**MONTANA-DAKOTA UTILITIES
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
PROJECTED CHANGES IN OPERATING INCOME**

Projected Changes in Operating Income	Total		Firm		Small		Large	
	North Dakota	Residential	General	Air Force	Interruptible	Interruptible	Interruptible	Interruptible
Telephone	6,001	4,087	1,689	25	152	48		
All Other O&M	53,001	36,098	14,918	216	1,346	423		
Total Other O&M	2,854,000	1,960,941	789,331	10,920	70,201	22,607		
Depreciation Expense	(379,294)	(234,180)	(126,729)	(1,450)	(11,779)	(5,156)		
Taxes Other than Income								
Ad Valorem Tax	42,741	26,389	14,280	164	1,327	581		
Other Taxes - Payroll, Franchise, Other	79,160	53,916	22,282	322	2,009	631		
Total Taxes Other than Income	121,901	80,305	36,562	486	3,336	1,212		
Deferred Income Taxes								
Unrecovered Purchased Gas Cost	(2,252,365)	(1,214,781)	(856,352)	(110,153)	(71,079)	0		
Other	131,096	80,941	43,801	501	4,071	1,782		
Closing Filing and Out of Period & Fed/State	(525,108)	(324,208)	(175,448)	(2,007)	(16,307)	(7,138)		
Total Deferred Income Tax	(2,646,377)	(1,458,048)	(987,999)	(111,659)	(83,315)	(5,356)		

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
PROJECTED FEDERAL STATE INCOME TAXES

	Projected						
	Federal & State Income Taxes	Total North Dakota	Residential	Firm General	Air Force	Small Interruptible	Large Interruptible
Projected Operating Revenues		120,495,896	67,066,143	44,159,576	4,988,428	3,894,766	386,983
Projected Operating Expenses							
Cost of Gas		99,473,000	53,653,000	37,819,000	4,860,000	3,141,000	0
Other O&M Expense		17,546,697	11,967,948	4,924,935	70,841	443,213	139,760
Total Operation & Maint. Exp.		117,019,697	65,620,948	42,743,935	4,930,841	3,584,213	139,760
Projected Depreciation		2,614,999	1,606,629	886,116	7,287	84,559	30,408
Projected Taxes Other		1,420,998	925,163	435,245	5,623	39,871	15,096
Total Projected Operating Expense		121,055,694	68,152,740	44,065,296	4,943,751	3,708,643	185,264
Projected Operating Income Before Taxes		(559,798)	(1,086,597)	94,280	44,677	186,123	201,719
Adjustment to Interest Expense		(200,869)	(122,898)	(67,424)	(993)	(6,492)	(3,062)
Per Books Interest Expense		975,870	597,063	327,562	4,825	31,541	14,879
Projected Interest Expense		775,001	474,165	260,138	3,832	25,049	11,817
Adjustment to Dividend Deduction		(397)	(245)	(133)	(2)	(12)	(5)
Per Books Dividend Deduction		15,397	9,507	5,144	59	478	209
Projected Dividend Deduction		15,000	9,262	5,011	57	466	204
Other		(639,382)	(394,763)	(213,628)	(2,443)	(19,856)	(8,692)
Purchased Gas Cost Adjustment		(5,685,019)	(3,066,135)	(2,161,452)	(278,027)	(179,405)	0
Per Books Other Tax Deductions		4,311,400	2,288,704	1,660,796	231,977	136,293	(6,370)
Projected Other Tax Deductions		(2,013,001)	(1,172,194)	(714,284)	(48,493)	(62,968)	(15,062)
Projected Taxable Income		663,202	(397,830)	543,415	89,281	223,576	204,760
Projected Federal & State Income Taxes		262,296	(157,342)	214,921	35,310	88,424	80,983

**MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
PROJECTED CHANGES IN RATE BASE**

Projected Changes in Rate Base	Total		Firm		Small		Large	
	North Dakota	Residential	General	Air Force	Interruptible	Interruptible	Interruptible	Interruptible
Plant in Service								
Distribution Plant	5,101,175	3,149,531	1,704,391	19,496	158,412	69,345		
General Plant	(62,653)	(38,683)	(20,934)	(239)	(1,945)	(852)		
Common Plant	278,754	172,106	93,137	1,065	8,657	3,789		
Total Plant	5,317,276	3,282,954	1,776,594	20,322	165,124	72,282		
Accumulated Reserve								
Distribution Plant	3,742,354	2,310,578	1,250,385	14,303	116,215	50,873		
General Plant	(71,022)	(43,851)	(23,730)	(271)	(2,205)	(965)		
Common Plant	236,898	146,264	79,152	905	7,357	3,220		
Acquisition Adjustment	20,081	12,399	6,709	77	623	273		
Total Accumulated Res	3,928,311	2,425,390	1,312,516	15,014	121,990	53,401		
Elimination of CWIP in Service	(427,154)	(263,730)	(142,720)	(1,632)	(13,265)	(5,807)		
Additions to Rate Base:								
Materials & Supplies	82,320	50,826	27,505	314	2,556	1,119		
Fuel Stocks	(2,621)	(1,002)	(1,619)	0	0	0		
Prepayments	140,323	86,637	46,884	537	4,358	1,907		
Gas IRP - Other	(44,484)	(23,626)	(16,655)	(2,550)	(1,653)	0		
Rate Case Expense	0	0	0	0	0	0		
Total Additions	175,538	112,835	56,115	(1,699)	5,261	3,026		
Deductions to Rate Base:								
Accumulated Deferred Income Taxes	(235,481)	(145,389)	(78,678)	(900)	(7,313)	(3,201)		
Accumulated Investment Tax Credits	(60,809)	(37,544)	(20,317)	(233)	(1,889)	(826)		
Customer Advances	(43,101)	(37,352)	(5,749)	0	0	0		
Total Adjustments	(339,391)	(220,285)	(104,744)	(1,133)	(9,202)	(4,027)		
Total Rate Base	1,476,740	926,954	482,217	3,110	44,332	20,127		

**MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
OPERATING REVENUES
TWELVE MONTHS ENDED DECEMBER 31, 2003**

Per Books Operating Revenues	Total		Firm		Small		Large	
	North Dakota	Residential	General	Air Force	Interruptible	Interruptible	Interruptible	Interruptible
Residential	55,219,376	55,219,376	0	0	0	0	0	0
Firm General	36,194,291	0	36,194,291	0	0	0	0	0
Air Force	3,854,651	0	0	3,854,651	0	0	0	0
Small Interruptible	3,989,645	0	0	0	3,989,645	0	0	0
Large Interruptible	692,093	0	0	0	0	0	692,093	0
Unbilled Revenue	2,733,101	1,509,956	989,720	105,404	109,096	18,925	18,925	0
Total Gas Sales and Transport Revenue	102,683,157	56,729,332	37,184,011	3,960,055	4,098,741	711,018	711,018	0
Other Operating Revenue								
Miscellaneous								
Reconnect Fees	15,602	13,521	2,081	0	0	0	0	0
NSF Check Fees	4,483	3,885	598	0	0	0	0	0
Work for Contractors, Municipal & Others	18,389	11,251	6,173	91	594	280	280	0
Rent From Gas Property	301,708	184,593	101,271	1,492	9,752	4,600	4,600	0
Other Gas Revenues								
Miscellaneous	58,264	39,683	16,400	237	1,479	465	465	0
Transport and Penalty Revenue - Net	7,300	4,033	2,644	282	291	50	50	0
Total Other Operating Revenue	405,746	256,966	129,167	2,102	12,116	5,395	5,395	0
Total Gas Operating Revenues	103,088,903	56,986,298	37,313,178	3,962,157	4,110,857	716,413	716,413	0

**MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
OPERATION & MAINTENANCE EXPENSES
TWELVE MONTHS ENDED DECEMBER 31, 2003**

Per Books Operation and Maintenance Expenses	Total		Firm		Small Interruptible	Large Interruptible
	North Dakota	Residential	General	Air Force		
Cost of Purchased Gas	81,904,699	44,174,131	31,140,283	4,005,565	2,584,720	0
Production Expenses						
Other Gas Supply Expenses	209,668	111,359	78,502	12,018	7,789	0
Total Production Expense	209,668	111,359	78,502	12,018	7,789	0
Distribution Expenses						
Operation						
Load Dispatch	72,026	32,119	22,642	3,466	5,016	8,783
Mains and Services	988,154	623,881	322,767	2,468	27,243	11,795
Measuring Stations - General	37,387	24,103	11,509	411	815	549
Measuring Stations - Industrial	28,956	4,596	4,233	7,390	896	11,841
Measuring Stations - City Gate	5,228	3,072	1,674	17	395	70
Meters & House Regulators	660,887	389,146	240,484	0	27,430	3,827
Customer Installations	895,890	532,342	327,417	0	36,131	0
Other Gas Distribution	1,475,119	889,153	511,955	5,799	52,380	15,832
Rents	22,228	13,398	7,715	87	789	239
Supervision & Engineering	561,859	338,670	194,999	2,209	19,951	6,030
Total Operation Expense	4,747,734	2,850,480	1,645,395	21,847	171,046	58,966
Maintenance						
Structures & Improvements	2,484	1,149	607	191	39	498
Mains	107,432	69,776	33,319	389	2,358	1,590
Measuring Stations - General	21,043	13,566	6,478	231	459	309
Measuring Stations - Industrial	2,943	467	430	751	91	1,204
Measuring Stations - City Gate	225	132	72	1	17	3
Services	100,102	59,150	36,380	0	4,015	557
Meters & House Regulators	99,851	58,795	36,334	0	4,144	578
Other Equipment	186,077	113,289	63,418	770	6,220	2,380
Supervision & Engineering	289,934	176,522	98,814	1,199	9,691	3,708
Total Maintenance Expense	810,091	492,846	275,862	3,532	27,034	10,827
Total Distribution Expenses	5,557,825	3,343,326	1,921,247	25,379	198,080	69,793

**MONTANA-DAKOTA UTILITIES CO.
 GAS UTILITY - NORTH DAKOTA
 EMBEDDED CLASS COST OF SERVICE STUDY
 OPERATION & MAINTENANCE EXPENSES
 TWELVE MONTHS ENDED DECEMBER 31, 2003**

Per Books Operation and Maintenance Expenses	Total		Residential	Firm General	Air Force	Small		Large
	North Dakota					Interruptible	Interruptible	
Customer Accounts	262,999		227,517	35,021	9	422	30	
Meter Reading	572,434		338,250	208,041	0	22,958	3,185	
Customer Records & Collection	1,591,194		1,376,519	211,882	55	2,554	184	
Uncollectible Accounts	178,014		153,997	23,704	6	286	21	
Miscellaneous Customer Accounts	158,552		137,162	21,113	5	254	18	
Customer Service & Information	166,788		144,286	22,209	6	268	19	
Sales Expenses	496,319		429,358	66,090	17	797	57	
Administration & General Expenses	5,498,904		3,745,233	1,547,795	22,426	139,604	43,846	
Total Gas O&M Expenses	96,597,396		54,181,138	35,275,887	4,065,486	2,957,732	117,153	
O&M Excl. Gas Cost and A&G	9,193,793		6,261,774	2,587,809	37,495	233,408	73,307	
O&M Excl. Cost of Gas	14,692,697		10,007,007	4,135,604	59,921	373,012	117,153	

**MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
DEPRECIATION EXPENSE
TWELVE MONTHS ENDED DECEMBER 31, 2003**

Per Books Depreciation Expense	Total		Firm		Small		Large	
	North Dakota	Residential	General	Air Force	Interruptible	Interruptible	Interruptible	Interruptible
Distribution Plant								
Mains	956,848	621,464	296,764	3,460	21,005	14,155		
Structures	4,426	2,048	1,081	340	69	888		
Meas. & Reg. Sta. General	14,607	9,418	4,497	160	318	214		
Meas. & Reg. Sta. - City Gate	5,233	3,075	1,675	17	396	70		
Services	923,707	545,816	335,705	0	37,046	5,140		
Meters	355,481	210,053	129,193	0	14,257	1,978		
Service Regulators	42,596	24,432	15,640	0	2,206	318		
Measuring & Reg. Eqpt. - Indust.	8,466	1,345	1,237	2,160	262	3,462		
Other Property on Cust. Prem.	8,586	5,577	2,663	31	188	127		
Catholic Protection & Other Equipment	37,456	24,328	11,617	135	822	554		
Land Rights	966	628	300	3	21	14		
Total Distribution Plant	2,358,372	1,448,184	800,372	6,306	76,590	26,920		
General Plant	167,927	103,680	56,108	642	5,214	2,283		
Common Plant	437,096	269,868	146,041	1,671	13,574	5,942		
Acquisition Adjustment	29,835	18,420	9,969	114	927	405		
Gas Plant Leased to Others	1,063	657	355	4	33	14		
Total Depreciation Expense	2,994,293	1,840,809	1,012,845	8,737	96,338	35,564		

**MONTANA-DAKOTA UTILITIES CO.
 GAS UTILITY - NORTH DAKOTA
 EMBEDDED CLASS COST OF SERVICE STUDY
 TAXES OTHER THAN INCOME TAXES
 TWELVE MONTHS ENDED DECEMBER 31, 2003**

	Per Books						
	Taxes Other Than Income		Total North Dakota	Residential	Firm General	Air Force	Small Interruptible
Ad Valorem Taxes		627,261	387,278	209,579	2,398	19,479	8,527
Other Taxes - Payroll, Franchise, Other		671,836	457,580	189,104	2,739	17,056	5,357
Total Taxes Other Than Income		1,299,097	844,858	398,683	5,137	36,535	13,884

**MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
INCOME TAXES
TWELVE MONTHS ENDED DECEMBER 31, 2003**

	Per Books		Firm				Small	Large
	North Dakota	Total	Residential	General	Air Force	Interruptible	Interruptible	
Income Taxes								
Operating Revenue	103,088,903	56,986,298	37,313,178	3,962,157	4,110,857	716,413		
Operation & Maintenance Expense	96,597,396	54,181,138	35,275,887	4,065,486	2,957,732	117,153		
Depreciation Expense	2,994,293	1,840,809	1,012,845	8,737	96,338	35,564		
Taxes Other Than Income	1,299,097	844,858	398,683	5,137	36,535	13,884		
Total Operating Expense	100,890,786	56,866,805	36,687,415	4,079,360	3,090,605	166,601		
Interest Expense	975,870	597,063	327,562	4,825	31,541	14,879		
Total Expenses	101,866,656	57,463,868	37,014,977	4,084,185	3,122,146	181,480		
Taxable Income Before Adjustments	1,222,247	(477,570)	298,201	(122,028)	988,711	534,933		
Tax Deductions								
Purchased Gas Cost Adjustment	4,780,019	2,578,035	1,817,370	233,768	150,846	0		
Other	(468,619)	(289,331)	(156,574)	(1,791)	(14,553)	(6,370)		
Preferred Dividend Paid Deduction	15,397	9,507	5,144	59	478	209		
Total Deductions & Adjustments	4,326,797	2,298,211	1,665,940	232,036	136,771	(6,161)		
Taxable Income (Before State Income Tax)	(3,104,550)	(2,775,781)	(1,367,739)	(354,064)	851,940	541,094		
Less: State Income Tax	(367,349)	(328,444)	(161,839)	(41,895)	100,805	64,024		
Federal Taxable Income	(2,737,201)	(2,447,337)	(1,205,900)	(312,169)	751,135	477,070		
Federal Income Tax @ Current Rate	(958,021)	(856,568)	(422,065)	(109,260)	262,897	166,975		
Plus: State Income Tax	(367,349)	(328,444)	(161,839)	(41,895)	100,805	64,024		
Plus: Credits & Adjustments	(3,010)	(1,599)	(1,159)	(161)	(95)	4		
Federal and State Income Taxes	(1,328,380)	(1,186,611)	(585,063)	(151,316)	363,607	231,003		
Rounding & Prior Year Adjustments	(133,496)	(82,422)	(44,603)	(510)	(4,146)	(1,815)		
Federal Income Tax Computed	(1,461,876)	(1,269,033)	(629,666)	(151,826)	359,461	229,188		

**MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
DEFERRED INCOME TAXES
TWELVE MONTHS ENDED DECEMBER 31, 2003**

Per Books Deferred Income Taxes	Total		Firm		Small		Large	
	North Dakota	Residential	General	Air Force	Interruptible	Interruptible	Interruptible	Interruptible
Unrecovered Purchased Gas Costs	1,893,367	1,021,160	719,860	92,596	59,751	0		
Other	(261,097)	(161,204)	(87,237)	(998)	(8,109)	(3,549)		
Closing Filing and Out of Period & Fed/State I	141,108	87,122	47,147	539	4,382	1,918		
Total Gas Charges	1,773,378	947,078	679,770	92,137	56,024	(1,631)		
Accumulated Balance 12/31/03	(3,909,479)	(2,413,763)	(1,306,224)	(14,942)	(121,405)	(53,145)		

**MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
PLANT IN SERVICE
TWELVE MONTHS ENDED DECEMBER 31, 2003**

	Per Books Plant in Service	Total		Residential	Firm		Air Force	Small		Large
		North Dakota			General			Interruptible	Interruptible	
Distribution Plant										
Mains		28,329,510	18,399,790	8,786,321	102,443	621,891	419,065			
Structures & Improvements		180,116	83,313	44,002	13,870	2,816	36,115			
Meas. & Reg. Sta. Eqpt. - General		580,270	374,090	178,636	6,380	12,644	8,520			
Meas. & Reg. Sta. Eqpt. - City Gate		174,002	102,244	55,711	569	13,149	2,329			
Service Regulators		1,747,785	1,002,510	641,743	0	90,496	13,036			
Indust. Meas. & Reg. Sta. Eqpt.		370,108	58,747	54,109	94,453	11,456	151,343			
Services		12,695,388	7,501,681	4,613,910	0	509,157	70,640			
Meters		12,834,046	7,583,614	4,664,303	0	514,718	71,411			
CNG Refueling Station		114,888	74,618	35,632	416	2,522	1,700			
Catholic Protection & Other Equipment		783,420	508,825	242,976	2,833	17,198	11,588			
Land & Land Rights		90,918	59,050	28,198	329	1,996	1,345			
Total Distribution Plant		57,900,451	35,748,482	19,345,541	221,293	1,798,043	787,092			
General Plant		6,934,655	4,281,545	2,316,988	26,504	215,349	94,269			
Common Plant		7,612,246	4,699,899	2,543,382	29,094	236,391	103,480			
Gas Plant Leased to Others		11,375	7,023	3,800	43	354	155			
Acquisition Adjustment		97,266	60,054	32,498	372	3,020	1,322			
Total Gas Plant in Service		72,555,993	44,797,003	24,242,209	277,306	2,253,157	986,318			

**MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
ACCUMULATED RESERVE FOR DEPRECIATION
TWELVE MONTHS ENDED DECEMBER 31, 2003**

Per Books Accumulated Reserve for Depreciation	Total		Firm		Air Force	Small		Large
	North Dakota	Residential	General	Residential		Interruptible	Interruptible	
Distribution Plant								
Mains	22,155,470	14,389,800	6,871,460	80,116	486,358	327,736		
Structures & Improvements	107,685	49,810	26,307	8,293	1,683	21,592		
Meas. & Reg. Sta. Equip. - General	276,760	178,421	85,201	3,043	6,031	4,064		
Meas. & Reg. Sta. Equip. - City Gate	55,517	32,622	17,775	181	4,196	743		
Services	13,516,593	7,986,930	4,912,362	0	542,092	75,209		
Meters	4,831,017	2,854,639	1,755,746	0	193,751	26,881		
Service Regulators	696,947	399,761	255,902	0	36,086	5,198		
Indust. Meas. & Reg. Sta. Eqpt.	166,819	26,480	24,388	42,573	5,163	68,215		
Other Property on Customer Prem.	98,083	63,705	30,421	354	2,153	1,450		
Other Equipment	310,040	201,369	96,158	1,121	6,806	4,586		
Catholic Protection & Other Equipment	232,929	151,285	72,242	843	5,113	3,446		
Land Rights	32,553	21,143	10,096	117	715	482		
Total Distribution Reserve	42,480,413	26,355,965	14,158,058	136,641	1,290,147	539,602		
General Plant	3,498,025	2,159,726	1,168,751	13,369	108,628	47,551		
Common Plant	3,645,102	2,250,532	1,217,892	13,932	113,195	49,551		
Acquisition Adjustment	14,919	9,211	4,984	57	464	203		
Gas Plant Leased to Others	5,228	3,227	1,747	20	163	71		
Total Accumulated Reserve for Depreciation	49,643,687	30,778,661	16,551,432	164,019	1,512,597	636,978		

**MONTANA-DAKOTA UTILITIES CO.
 GAS UTILITY - NORTH DAKOTA
 EMBEDDED CLASS COST OF SERVICE STUDY
 CONSTRUCTION WORK IN PROGRESS
 TWELVE MONTHS ENDED DECEMBER 31, 2003**

Per Books CWIP in Service Pending Classification	Total					
	North Dakota	Residential	Firm General	Air Force	Small Interruptible	Large Interruptible
CWIP in Service Pending Classification	427,154	263,730	142,720	1,632	13,265	5,807
Total Construction Work in Progress in Service Pending Classification	427,154	263,730	142,720	1,632	13,265	5,807

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
WORKING CAPITAL
TWELVE MONTHS ENDED DECEMBER 31, 2003

	Per Books		Residential	Firm General	Air Force	Small		Large
	Working Capital					Interruption		
	Total North Dakota							
Materials & Supplies	392,679	242,445	131,201	1,501	12,194	5,338		
Prepaid Insurance	49,678	30,670	16,599	190	1,543	676		
Unamortized Gas IRP Costs - Other	44,484	23,626	16,655	2,550	1,653	0		
Fuel Stocks	24,621	9,414	15,207	0	0	0		

**MONTANA-DAKOTA UTILITIES CO.
 GAS UTILITY - NORTH DAKOTA
 EMBEDDED CLASS COST OF SERVICE STUDY
 RATE BASE REPORT
 TWELVE MONTHS ENDED DECEMBER 31, 2003**

Per Books Rate Base	Total		Firm		Air Force	Small		Large
	North Dakota	Residential	General	Interruptible		Interruptible	Interruptible	
Gas Plant in Service	72,555,993	44,797,003	24,242,209	277,306	277,306	2,253,157	986,318	
Less: Accumulated Depreciation	49,643,687	30,778,661	16,551,432	164,019	164,019	1,512,597	636,978	
Net Gas Plant in Service	22,912,306	14,018,342	7,690,777	113,287	113,287	740,560	349,340	
CWIP in Service	427,154	263,730	142,720	1,632	1,632	13,265	5,807	
Total Plant	23,339,460	14,282,072	7,833,497	114,919	114,919	753,825	355,147	
Additions								
Materials & Supplies	392,679	242,445	131,201	1,501	1,501	12,194	5,338	
Fuel Stock	24,621	9,414	15,207	0	0	0	0	
Gas IRP Costs - Other	44,484	23,626	16,655	2,550	2,550	1,653	0	
Prepayments	49,678	30,670	16,599	190	190	1,543	676	
Total Additions	511,462	306,155	179,662	4,241	4,241	15,390	6,014	
Total Before Deductions	23,850,922	14,588,227	8,013,159	119,160	119,160	769,215	361,161	
Deductions								
Accumulated Deferred Income Tax	(3,909,479)	(2,413,763)	(1,306,224)	(14,942)	(14,942)	(121,405)	(53,145)	
Investment Tax Credit Balance	(206,808)	(127,686)	(69,098)	(790)	(790)	(6,422)	(2,812)	
Customer Advances For Constr.	(297,101)	(124,573)	(147,742)	0	0	(24,786)	0	
Total Deductions	(4,413,388)	(2,666,022)	(1,523,064)	(15,732)	(15,732)	(152,613)	(55,957)	
Total Rate Base	19,437,534	11,922,205	6,490,095	103,428	103,428	616,602	305,204	

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

Case No. _____
Statement M
Schedule M-2
Page 1 of 6

<u>LINE ITEM</u>		<u>ALLOCATION FACTOR</u>	
<u>PLANT IN SERVICE:</u>			
114.2	Acquisition Adjustment - Propane	97,266	15 Distribution Plant
374	Land & Land Rights	90,918	13 Distribution Mains
375	Structures & Improvements	128,275	13 Distribution Mains
		13,406	Direct to Air Force Customer
		4,218	Direct to Firm General Customer
		34,218	Direct to Large Int. Customer
376	Mains	8,498,853	9 Average Customers @ Distribution
		19,830,656	5 1-Day Peak @ Distribution
378	Meas. & Reg. Sta. Equip. - General	575,973	13 Distribution Mains
		4,297	Direct to Air Force Customer
379	Meas. & Reg. Sta. Equip. - City Gate	157,422	13 Distribution Mains
		6,887	Direct to Firm General Customer
		9,693	Direct to Small Int. Customer
380	Services	12,695,388	12 Wtd Customers @ Distrib
381	Meters	12,834,046	12 Wtd Customers @ Distrib
383	Service Regulators	1,696,586	12 Wtd Customers @ Distrib
		25,149	Direct to Firm General Customer
		22,453	Direct to Small Int. Customer
		3,596	Direct to Large Int. Customer
385	Indust. Meas. & Reg. Sta. Equip.	90,450	13 Distribution Mains
		94,126	Direct to Air Force Customer
		26,056	Direct to Firm General Customer
		9,471	Direct to Small Int. Customer
		150,005	Direct to Large Int. Customer
386	Other Property on Customer Premise	114,887	13 Distribution Mains
386.3	Gas Plant Leased to Others	11,374	15 Distribution Plant
387	Cathodic Protection & Other Equipment	783,421	13 Distribution Mains
389	Total General Plant	6,934,654	15 Distribution Plant
389	Total Common Plant	7,612,246	15 Distribution Plant
<u>ACCUMULATED RESERVE FOR DEPRECIATION REPORT:</u>			
374	Land Rights	32,553	13 Distribution Mains
	Total General Plant	3,498,025	15 Distribution Plant
	Total Common Plant	3,645,103	15 Distribution Plant
375	Structures & Improvements	107,686	17 Structures & Improvements
376	Mains	22,155,472	13 Distribution Mains
378	Meas. & Reg. Sta. Equip. - General	276,760	18 Meas. & Reg. Sta. Eqpt.- General
379	Meas. & Reg. Sta. Equip. - City Gate	55,518	19 Meas. & Reg. Eqpt.- City Gate
380	Services	13,516,594	12 Wtd Customers @ Distrib.
381	Meters	4,831,017	12 Wtd Customers @ Distrib.
383	Service Regulators	696,947	20 Service Regulators
385	Indust. Meas. & Reg. Sta. Equip.	166,819	21 Ind. Meas. & Reg. Sta. Eqpt.
386.1	Misc. Property on Customer's Premises	972	13 Distribution Mains
386.2	Other Property on Customer's Premises	97,113	13 Distribution Mains
386.3	Gas Plant Leased to Others	5,229	15 Distribution Plant
387	Cathodic Protection & Other Equipment	232,929	13 Distribution Mains
387	Other Distribution Equipment	310,041	13 Distribution Mains
	Acquisition Adjustment	14,919	15 Distribution Plant
<u>CONSTRUCTION WORK IN PROGRESS REPORT:</u>			
	CWIP in Service pending Classification	427,154	15 Distribution Plant

**MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003**

Case No. _____
Statement M
Schedule M-2
Page 2 of 6

LINE ITEM			ALLOCATION FACTOR
<u>OPERATING REVENUE REPORT:</u>			
Residential	9,543,219		Direct to Residential Demand
	37,896,288		Direct to Residential Energy
	7,779,869		Direct to Residential Customer
Firm General	6,727,432		Direct to Firm General Demand
	26,014,652		Direct to Firm General Energy
	3,452,207		Direct to Firm General Customer
Air Force	268,100		Direct to Air Force Demand
	3,571,311		Direct to Air Force Energy
	15,240		Direct to Air Force Customer
Small Interruptible	162,374		Direct to Small Int. Demand
	3,630,471		Direct to Small Int. Energy
	196,800		Direct to Small Int. Customer
Large Interruptible	0		Direct to Large Int. Demand
	606,293		Direct to Large Int. Energy
	85,800		Direct to Large Int. Customer
Unbilled Revenue	2,733,102	26	Sales Revenue
Other Operating Revenue			
Reconnect Fees	15,602	11	Average Res. & Firm General Cust.
NSF Check Fees	4,483	11	Average Res. & Firm General Cust.
Miscellaneous	18,389	24	Net Gas Plant in Service
Rent From Gas Property	301,707	24	Net Gas Plant in Service
Other Gas Revenues			
Miscellaneous Revenues	58,265	31	O&M Excl. Cost of Gas
Transport & Sales Penalty Revenue - Net	7,300	23	Sales & Transportation Rev.
<u>OPERATION & MAINTENANCE EXPENSE REPORT:</u>			
Cost of Purchased Gas	9,543,219		Direct to Residential Demand
	34,630,912		Direct to Residential Energy
	6,727,432		Direct to Firm General Demand
	24,412,851		Direct to Firm General Energy
	268,100		Direct to Air Force Demand
	3,737,465		Direct to Air Force Energy
	162,374		Direct to Small Int. Demand
	2,422,346		Direct to Small Int. Energy
	0		Direct to Large Int. Demand
	0		Direct to Large Int. Energy
813 Other Gas Supply Expenses	209,668	3	Dk Sales
870 Operation Supervision & Maintenance	561,859	27	All Other Dist. Operation Exp.
871 Load Dispatch	72,026	1	Dk Throughput
874 Mains & Services	988,155	22	Mains & Services
875 Measuring Stations - General	37,387	18	Meas. & Reg. Sta. Eqpt.- General
876 Measuring Stations - Industrial	28,955	21	Ind. Meas. & Reg. Sta. Eqpt.
877 Measuring Stations - City Gate	5,227	19	Meas. & Reg. Eqpt.- City Gate
878 Meters & House Regulators	660,887	16	Meters & Regulators
879 Customer Installations	895,890	10	Wtd Customers Excl. AF, LI
880 Other Gas Distribution	1,475,119	27	All Other Dist. Operation Exp.
881 Rents	22,228	27	All Other Dist. Operation Exp.
885 Maintenance Supervision & Engineering	289,936	28	All Other Dist. Maintenance Exp.
886 Structures & Improvements	2,484	17	Structures & Improvements

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

LINE ITEM		ALLOCATION FACTOR		
887	Mains	107,431	13	Distribution Mains
889	Measuring Stations - General	21,043	18	Meas. & Reg. Sta. Eqpt.- General
890	Measuring Stations - Industrial	2,943	21	Ind. Meas. & Reg. Sta. Eqpt.
891	Measuring Stations - City Gate	224	19	Meas. & Reg. Eqpt.- City Gate
892	Services	100,102	12	Weighted Customers @ Distribution
893	Meters & House Regulators	99,852	16	Meters & Regulators
894	Other Equipment	186,076	28	All Other Dist. Maintenance Exp.
901	Customer Accounts	262,999	8	Average Customers
902	Meter Reading	572,434	43	Total Weighted Customers
903	Customer Records & Collection	1,591,194	8	Average Customers
904	Uncollectible Accounts	178,014	8	Average Customers
905	Miscellaneous Customer Accounts	158,553	8	Average Customers
907	Customer Service & Info.	166,788	8	Average Customers
911	Sales Expenses	496,319	8	Average Customers
920	Administration & General	5,498,904	30	O&M Excl. Gas Cost and A&G

DEPRECIATION EXPENSE REPORT:

374	Land Rights	967	13	Distribution Mains
	Total General Plant	167,928	15	Distribution Plant
	Total Common Plant	437,094	15	Distribution Plant
375	Structures	4,425	17	Structures & Improvements
376	Mains	956,848	13	Distribution Mains
378	Meas. & Reg. Sta. - General	14,607	18	Meas. & Reg. Sta. Eqpt.- General
379	Meas. & Reg. Sta. - City Gate	5,232	19	Meas. & Reg. Eqpt.- City Gate
380	Services	923,707	12	Weighted Customers @ Distribution
381	Meters	355,481	12	Weighted Customers @ Distribution
383	Service Regulators	42,596	20	Service Regulators
385	Measuring & Reg. Equip. - Indust.	8,464	21	Ind. Meas. & Reg. Sta. Eqpt.
386	Other Property on Customer's Premises	8,587	13	Distribution Mains
386.3	Gas Plant Leased to Others	1,063	15	Distribution Plant
387	Cathodic Protection & Other Equipment	37,457	13	Distribution Mains
406	Acquisition Adjustment	29,837	15	Distribution Plant

TAXES OTHER THAN INCOME REPORT:

	Ad Valorem Taxes	627,260	15	Distribution Plant
	Other Taxes - Payroll, Franchise, Other	671,837	31	O&M Excl Cost of Gas

DEFERRED INCOME TAXES REPORT:

	Unrecovered Purchased Gas Costs	1,893,366	33	Total Gas Costs
	Other	(261,097)	25	Total Gas Plant in Service
	Closing Filing and Out of Period & Fed/State FAS	141,108	25	Total Gas Plant in Service
	Accumulated Balance 12/31/03	(3,909,480)	25	Total Gas Plant in Service

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

LINE ITEM	ALLOCATION FACTOR		
<u>INCOME TAXES REPORT:</u>			
Interest Charges	975,871	24	Net Gas Plant in Service
Deductions			
Purchased Gas Cost Adjustment	4,780,020	33	Total Gas Costs
Other	(468,618)	25	Total Gas Plant in Service
Preferred Dividend Paid Deduction	15,397	25	Total Gas Plant in Service
State Income Tax	(367,346)	35	Taxable Income
Rounding & Prior Year Adjustments	(133,496)	25	Total Gas Plant in Service
Taxable Income @ Federal Tax Rate	35.00%		Direct Input
Credits & Adjustments	(3,011)	40	Total Tax Deductions & Adjustments
<u>WORKING CAPITAL REPORT:</u>			
Materials & Supplies	392,679	15	Distribution Plant
Fuel Stocks	24,621	42	DK Sales - Propane Dk only
Prepayments	49,678	25	Total Gas Plant in Service
Unamortized Gas IRP Costs-Other	44,484	3	DK Sales
<u>RATE BASE REPORT:</u>			
Investment Tax Credit Balance	(206,807)	25	Total Gas Plant in Service
Customer Advances for Const.	(143,748)	11	Average Res. & Firm General Cust.
	(128,567)		Direct to Firm General Customer
	(24,786)		Direct to Small Interruptible
<u>COST OF SERVICE BY COMPONENT REPORT:</u>			
Operating Income for Proposed Return	9.887%		
<u>Related Taxes for Increase</u>			
Inverse Tax Rate for Federal & State Income	60.450%		
Effective Federal Tax Rate	35.000%		
Combined Federal and State Tax	39.550%		
<u>Billing Units @ Customer</u>			
Dk Throughput			
	8,152,728		Direct to Residential Energy
	5,747,216		Direct to Firm General Energy
	879,865		Direct to Air Force Energy
	1,273,347		Direct to Small Int. Energy
	2,229,392		Direct to Large Int. Energy
<u>Bills</u>			
	899,028		Direct to Residential Customer
	138,384		Direct to Firm General Customer
	36		Direct to Air Force Customer
	1,662		Direct to Small Int. Customer
	120		Direct to Large Int. Customer

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

Case No. _____
Statement M
Schedule M-2
Page 5 of 6

LINE ITEM			ALLOCATION FACTOR
ADJUSTMENTS TO OPERATING INCOME:			
Revenue:			
Projected 2005 @ Current Rates			
Residential	2,047,120		Direct to Residential Demand
	9,392,374		Direct to Residential Energy
	150,307		Direct to Residential Customer
Firm General	1,443,104		Direct to Firm General Demand
	6,355,675		Direct to Firm General Energy
	37,339		Direct to Firm General Customer
Air Force	57,511		Direct to Air Force Demand
	1,074,164		Direct to Air Force Energy
	0		Direct to Air Force Customer
Small Interruptible	34,830		Direct to Small Int Demand
	(146,026)		Direct to Small Int Energy
	4,200		Direct to Small Int Customer
Large Interruptible	0		Direct to Large Int Demand
	(311,705)		Direct to Large Int Energy
	1,200		Direct to Large Int Customer
Unbilled Revenues	(2,733,102)	26	Sales Revenue
Cost of Gas			
Current Cost of Purchased Gas	2,047,120		Direct to Residential Demand
	7,431,749		Direct to Residential Energy
	1,443,104		Direct to Firm General Demand
	5,235,613		Direct to Firm General Energy
	56,311		Direct to Air Force Demand
	798,124		Direct to Air Force Energy
	34,830		Direct to Small Int Demand
	521,450		Direct to Small Int Energy
	0		Direct to Large Int Demand
	0		Direct to Large Int Energy
Other O&M Expense			
Labor Expense			
Other Gas Supply	17,000	30	O&M Excl. Cost of Gas and A&G
Distribution	549,000	39	Distribution O&M
Customer Accounts	237,000	38	Customer Expense Accounts O&M
Customer Service & Information	16,000	8	Average Customers
Sales	46,000	8	Average Customers
Administrative & General	206,000	30	O&M Excl. Cost of Gas and A&G
Benefits Expense	1,325,000	30	O&M Excl. Cost of Gas and A&G
Insurance Expense	(45,000)	30	O&M Excl. Cost of Gas and A&G
Advertising Expense	(35,000)	8	Average Customers
Postage Expense	(1,000)	8	Average Customers
Industry Dues	(4,000)	30	O&M Excl. Cost of Gas and A&G
Rate Case Expense	82,000	30	O&M Excl. Cost of Gas and A&G
Uncollectible Accounts	75,000	8	Average Customers
Vehicles & Work Equipment	316,000	30	O&M Excl. Cost of Gas and A&G
Energy Share	11,000	41	Total Operating Revenue
Telephone	6,000	30	O&M Excl. Cost of Gas and A&G
All Other O&M	53,000	31	O&M Excl Cost of Gas
Depreciation Expense	(379,293)	15	Distribution Plant

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

Case No. _____
Statement M
Schedule M-2
Page 6 of 6

LINE ITEM	ALLOCATION FACTOR		
Taxes Other Than Income			
Ad Valorem Taxes	42,740	15	Distribution Plant
Other Taxes - Payroll, Franchise, Other	79,163	31	O&M Excl Cost of Gas
Current Income Taxes			
Interest Expense	(200,871)	24	Net Gas Plant in Service
Deductions:			
Purchased Gas Cost Adjustment	(5,685,020)	33	Total Gas Costs
Other	(639,382)	25	Total Gas Plant in Service
Preferred Dividend Paid Deduction	(397)	25	Total Gas Plant in Service
Deferred Income Taxes			
Unrecovered Purchased Gas Cost	(2,252,366)	33	Total Gas Costs
Other	131,097	25	Total Gas Plant in Service
Closing Filing and Out of Period & Fed/State FAS	(525,108)	25	Total Gas Plant in Service
<u>ADJUSTMENTS TO RATE BASE:</u>			
Plant in Service			
Distribution Plant	5,101,174	15	Distribution Plant
General Plant	(62,654)	15	Distribution Plant
Common Plant	278,754	15	Distribution Plant
Accumulated Reserve			
Distribution Plant	3,742,355	15	Distribution Plant
General Plant	(71,025)	15	Distribution Plant
Common Plant	236,898	15	Distribution Plant
Acquisition Adjustment	20,082	15	Distribution Plant
CWIP in Service Pending Reclassification	(427,154)	15	Distribution Plant
Additions to Rate Base:			
Materials & Supplies	82,321	15	Distributin Plant
Fuel Stocks	(2,621)	42	DK Sales - Propane Dk only
Prepayments	140,322	25	Total Gas Plant in Service
Gas IRP - Other	(44,484)	3	DK Sales
Rate Case Expense	0	30	O&M Excl. Cost of Gas and A&G
Deductions to Rate Base:			
Accumulated Deferred Income taxes	(235,480)	25	Total Gas Plant in Service
Accumulated Investment Tax Credits	(60,807)	25	Total Gas Plant in Service
Customer Advances	(43,101)	11	Average Res & Firm General Customers

MONTANA-DAKOTA UTILITIES CO.
 GAS UTILITY - NORTH DAKOTA
 EMBEDDED CLASS COST OF SERVICE STUDY
 ALLOCATION FACTOR REPORT
 TWELVE MONTHS ENDED DECEMBER 31, 2003

	Total North Dakota		Residential		Firm General	
	Demand	Energy	Demand	Energy	Demand	Energy
1. Dk Throughput	18,282,548 100.000000%	8,152,728 44.592953%	0.000000%	0.000000%	0.000000%	5,747,216 31.435531%
2. 1-Day Peak Sales	116,554 100.000000%	61,580 52.833881%	0.000000%	0.000000%	42,735 36.665408%	0.000000%
3. Dk Sales	15,350,072 100.000000%	8,152,728 53.111985%	0.000000%	0.000000%	0.000000%	5,747,216 37.440971%
4. Dk Throughput @ Distribution	15,803,294 100.000000%	7,992,053 50.572071%	0.000000%	0.000000%	0.000000%	5,614,958 35.530301%
5. 1-Day Peak @ Distribution	109,779 100.000000%	61,149 55.701911%	0.000000%	0.000000%	42,380 38.604833%	0.000000%
8. Average Customers	86,603 100.000000%	0.000000%	0.000000%	0.000000%	74,919 86.508550%	11,532 13.315936%
9. Average Customers @ Distribution	85,054 100.000000%	0.000000%	0.000000%	0.000000%	73,594 86.526207%	11,316 13.304489%
10. Weighted Customers Excl. AF, LI	123,853 100.000000%	0.000000%	0.000000%	0.000000%	73,594 59.420442%	45,264 36.546551%
11. Average Res. & Firm General Cust.	86,451 100.000000%	0.000000%	0.000000%	0.000000%	74,919 86.660652%	11,532 13.339348%
12. Weighted Customers @ Distribution	124,546 100.000000%	0.000000%	0.000000%	0.000000%	73,594 59.089815%	45,264 36.343198%
13. Distribution Mains	28,329,510 100.000000%	11,046,055 38.991336%	0.000000%	0.000000%	7,353,735 25.957865%	0 0.000000%
					7,655,592 27.023383%	1,130,729 3.991347%

MONTANA-DAKOTA UTILITIES CO.
 GAS UTILITY - NORTH DAKOTA
 EMBEDDED CLASS COST OF SERVICE STUDY
 ALLOCATION FACTOR REPORT
 TWELVE MONTHS ENDED DECEMBER 31, 2003

	Air Force		Small Interruptible	
	Demand	Energy	Demand	Energy
1. Dk Throughput	0.000000%	879,865 4.812595%	0.000000%	1,273,347 6.964822%
2. 1-Day Peak Sales	2,643 2.267618%	0.000000%	3,488 2.992604%	0.000000%
3. Dk Sales	0.000000%	879,865 5.731993%	0.000000%	570,263 3.715051%
4. Dk Throughput @ Distribution	0.000000%	121,578 0.769321%	0.000000%	1,229,569 7.780460%
5. 1-Day Peak @ Distribution	566 0.515581%	0.000000%	3,368 3.067982%	0.000000%
8. Average Customers	0.000000%	0.000000%	3 0.003464%	139 0.160503%
9. Average Customers @ Distribution	0.000000%	0.000000%	2 0.002351%	135 0.158723%
10. Weighted Customers Excl. AF, LI	0.000000%	0.000000%	0 0.000000%	4,995 4.033007%
11. Average Res. & Firm General Cust.	0.000000%	0.000000%	0.000000%	0.000000%
12. Weighted Customers @ Distribution	0.000000%	0.000000%	0 0.000000%	4,995 4.010566%
13. Distribution Mains	102,243 0.360906%	0 0.000000%	200 0.000706%	0 0.000000%
			608,401 2.147587%	13,490 0.047618%

MONTANA-DAKOTA UTILITIES CO.
 GAS UTILITY - NORTH DAKOTA
 EMBEDDED CLASS COST OF SERVICE STUDY
 ALLOCATION FACTOR REPORT
 TWELVE MONTHS ENDED DECEMBER 31, 2003

	Large Interruptible		
	Demand	Energy	Customer
1. Dk Throughput	0.000000%	2,229,392 12.194099%	0.000000%
2. 1-Day Peak Sales	6,108 5.240489%	0.000000%	0.000000%
3. Dk Sales	0.000000%	0 0.000000%	0.000000%
4. Dk Throughput @ Distribution	0.000000%	845,136 5.347847%	0.000000%
5. 1-Day Peak @ Distribution	2,316 2.109693%	0.000000%	0.000000%
8. Average Customers	0.000000%	0.000000%	10 0.011547%
9. Average Customers @ Distribution	0.000000%	0.000000%	7 0.008230%
10. Weighted Customers Excl. AF, LI	0.000000%	0.000000%	0 0.000000%
11. Average Res. & Firm General Cust.	0.000000%	0.000000%	0.000000%
12. Weighted Customers @ Distribution	0.000000%	0.000000%	693 0.556421%
13. Distribution Mains	418,366 1.476785%	0 0.000000%	699 0.002467%

MONTANA-DAKOTA UTILITIES CO.
 GAS UTILITY - NORTH DAKOTA
 EMBEDDED CLASS COST OF SERVICE STUDY
 ALLOCATION FACTOR REPORT
 TWELVE MONTHS ENDED DECEMBER 31, 2003

	Total North Dakota	Residential		Firm General			
		Demand	Energy	Demand	Energy	Customer	
15. Distribution Plant	57,900,451 100.000000%	11,803,012 20.385009%	0 0.000000%	23,945,470 41.356277%	8,180,209 14.128057%	0 0.000000%	11,165,332 19.283670%
16. Meters & Regulators	14,581,831 100.000000%	0 0.000000%	0 0.000000%	8,586,124 58.882345%	0 0.000000%	0 0.000000%	5,306,046 36.388064%
17. Structures & Improvements	180,116 100.000000%	50,016 27.768770%	0 0.000000%	33,297 18.486420%	34,664 19.245375%	0 0.000000%	9,338 5.184437%
18. Meas. & Reg. Sta. Eqpt.- General	580,270 100.000000%	224,580 38.702674%	0 0.000000%	149,510 25.765592%	155,647 26.823203%	0 0.000000%	22,989 3.961776%
19. Meas. & Reg. Eqpt.- City Gate	174,002 100.000000%	61,381 35.276028%	0 0.000000%	40,863 23.484213%	42,541 24.448570%	0 0.000000%	13,170 7.568879%
20. Service Regulators	1,747,785 100.000000%	0 0.000000%	0 0.000000%	1,002,510 57.358886%	0 0.000000%	0 0.000000%	641,743 36.717502%
21. Ind. Meas. & Reg. Sta. Eqpt.	370,108 100.000000%	35,268 9.529109%	0 0.000000%	23,479 6.343826%	24,443 6.604288%	0 0.000000%	29,666 8.015498%
22. Mains & Services	41,024,898 100.000000%	11,046,055 26.925247%	0 0.000000%	14,855,416 36.210732%	7,655,592 18.660843%	0 0.000000%	5,744,639 14.002811%
23. Sales & Transportation Rev.	102,683,157 100.000000%	9,804,175 9.547988%	38,932,550 37.915224%	7,992,607 7.783757%	6,911,391 6.730793%	26,726,014 26.027651%	3,546,606 3.453932%
24. Net Gas Plant in Service	22,912,306 100.000000%	4,256,456 18.577161%	0 0.000000%	9,761,886 42.605428%	2,949,982 12.875099%	0 0.000000%	4,740,795 20.691043%
25. Total Gas Plant in Service	72,555,993 100.000000%	14,790,546 20.385009%	0 0.000000%	30,006,457 41.356276%	10,250,752 14.128057%	0 0.000000%	13,991,457 19.283668%
26. Sales & Transport Revenue (excluding unbilled revenue)	99,950,056 100.000000%	9,543,219 9.547987%	37,896,288 37.915224%	7,779,869 7.783757%	6,727,432 6.730794%	26,014,652 26.027651%	3,452,207 3.453932%

MONTANA-DAKOTA UTILITIES CO.
 GAS UTILITY - NORTH DAKOTA
 EMBEDDED CLASS COST OF SERVICE STUDY
 ALLOCATION FACTOR REPORT
 TWELVE MONTHS ENDED DECEMBER 31, 2003

	Air Force				Small Interruptible				
	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
15. Distribution Plant	109,249 0.188684%	0 0.000000%	112,044 0.193511%	650,094 1.122779%	0 0.000000%	0 0.000000%	1,147,949 1.982625%		
16. Meters & Regulators	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	605,214 4.150466%		
17. Structures & Improvements	463 0.257057%	0 0.000000%	13,407 7.443536%	2,755 1.529570%	0 0.000000%	0 0.000000%	61 0.033867%		
18. Meas. & Reg. Sta. Eqpt.- General	2,079 0.358281%	0 0.000000%	4,301 0.741207%	12,370 2.131766%	0 0.000000%	0 0.000000%	274 0.047219%		
19. Meas. & Reg. Eqpt.- City Gate	568 0.326433%	0 0.000000%	1 0.000576%	3,381 1.943081%	0 0.000000%	0 0.000000%	9,768 5.613729%		
20. Service Regulators	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	90,496 5.177754%		
21. Ind. Meas. & Reg. Sta. Eqpt.	326 0.088082%	0 0.000000%	94,127 25.432306%	1,942 0.524712%	0 0.000000%	0 0.000000%	9,514 2.570601%		
22. Mains & Services	102,243 0.249222%	0 0.000000%	200 0.000488%	608,401 1.483004%	0 0.000000%	0 0.000000%	522,647 1.273975%		
23. Sales & Transportation Rev.	275,431 0.268234%	3,668,967 3.573095%	15,657 0.015248%	166,814 0.162455%	3,729,745 3.632285%	202,182 0.196899%			
24. Net Gas Plant in Service	39,398 0.171951%	0 0.000000%	73,889 0.322486%	234,442 1.023214%	0 0.000000%	0 0.000000%	506,118 2.208935%		
25. Total Gas Plant in Service	136,902 0.188685%	0 0.000000%	140,404 0.193511%	814,644 1.122780%	0 0.000000%	0 0.000000%	1,438,513 1.982625%		
26. Sales & Transport Revenue (excluding unbilled revenue)	268,100 0.268234%	3,571,311 3.573096%	15,240 0.015248%	162,374 0.162455%	3,630,471 3.632285%	196,800 0.196898%			

MONTANA-DAKOTA UTILITIES CO.
 GAS UTILITY - NORTH DAKOTA
 EMBEDDED CLASS COST OF SERVICE STUDY
 ALLOCATION FACTOR REPORT
 TWELVE MONTHS ENDED DECEMBER 31, 2003

	Large Interruptible		
	Demand	Energy	Customer
15. Distribution Plant	447,036 0.772077%	0 0.000000%	340,056 0.587311%
16. Meters & Regulators	0 0.000000%	0 0.000000%	84,447 0.579125%
17. Structures & Improvements	1,894 1.051545%	0 0.000000%	34,221 18.999423%
18. Meas. & Reg. Sta. Eqpt.- General	8,506 1.465869%	0 0.000000%	14 0.002413%
19. Meas. & Reg. Eqpt.- City Gate	2,325 1.336192%	0 0.000000%	4 0.002299%
20. Service Regulators	0 0.000000%	0 0.000000%	13,036 0.745858%
21. Ind. Meas. & Reg. Sta. Eqpt.	1,336 0.360976%	0 0.000000%	150,007 40.530602%
22. Mains & Services	418,366 1.019786%	0 0.000000%	71,339 0.173892%
23. Sales & Transportation Rev.	0 0.000000%	622,872 0.606596%	88,146 0.085843%
24. Net Gas Plant in Service	161,214 0.703613%	0 0.000000%	188,126 0.821070%
25. Total Gas Plant in Service	560,188 0.772077%	0 0.000000%	426,130 0.587312%
26. Sales & Transport Revenue (excluding unbilled revenue)	0 0.000000%	606,293 0.606596%	85,800 0.085843%

MONTANA-DAKOTA UTILITIES CO.
 GAS UTILITY - NORTH DAKOTA
 EMBEDDED CLASS COST OF SERVICE STUDY
 ALLOCATION FACTOR REPORT
 TWELVE MONTHS ENDED DECEMBER 31, 2003

	Total North Dakota	Residential		Firm General			
		Demand	Energy	Demand	Energy	Customer	
27. All Other Dist. Operation Exp.	2,616,502 100.000000%	285,136 10.897603%	0 0.000000%	1,292,004 49.379057%	197,616 7.552679%	0 0.000000%	710,468 27.153352%
28. All Other Dist. Maintenance Exp.	331,596 100.000000%	50,392 15.196806%	0 0.000000%	151,494 45.686317%	34,924 10.532093%	0 0.000000%	78,089 23.549440%
30. O&M Excl. Gas Cost and A&G	9,193,793 100.000000%	632,961 6.884657%	143,478 1.560596%	5,485,335 59.663457%	438,677 4.771447%	101,144 1.100134%	2,047,988 22.275768%
31. O&M Excl. Cost of Gas	14,692,697 100.000000%	1,011,542 6.884657%	229,294 1.560598%	8,766,171 59.663460%	701,054 4.771445%	161,639 1.100132%	3,272,911 22.275767%
33. Total Cost of Gas	81,904,699 100.000000%	9,543,219 11.651614%	34,630,912 42.281959%	0 0.000000%	6,727,432 8.213731%	24,412,851 29.806411%	0 0.000000%
35. Taxable Income	(3,104,550) 100.000000%	(2,036,971) 65.612439%	2,044,450 -65.853343%	(2,783,260) 89.650996%	(1,415,243) 45.586091%	721,922 -23.253676%	(674,418) 21.723535%
38. Customer Account Expense O&M	262,999 100.000000%	0 0.000000%	0 0.000000%	227,517 86.508694%	0 0.000000%	0 0.000000%	35,021 13.316020%
39. Distribution O&M	5,557,825 100.000000%	632,961 11.388645%	32,119 0.577906%	2,678,246 48.188742%	438,677 7.892962%	22,642 0.407390%	1,459,928 26.267974%
40. Total Tax Deductions & Adjustments	4,326,797 100.000000%	464,560 10.736811%	2,021,086 46.710903%	(187,435) -4.331957%	328,586 7.594209%	1,424,752 32.928561%	(87,398) -2.019924%
41. Total Operating Revenues	103,088,903 100.000000%	9,868,348 9.572659%	38,936,227 37.769561%	8,181,723 7.936570%	6,955,876 6.747454%	26,728,555 25.927674%	3,628,747 3.520017%
42. Dk Sales - Propane	50,774 100.000000%	0 0.000000%	19,414 38.236105%	0 0.000000%	0 0.000000%	31,360 61.763895%	0 0.000000%
43. Total Weighted Customers	124,546 100.000000%	0 0.000000%	0 0.000000%	73,594 59.089815%	0 0.000000%	0 0.000000%	45,264 36.343198%

MONTANA-DAKOTA UTILITIES CO.
 GAS UTILITY - NORTH DAKOTA
 EMBEDDED CLASS COST OF SERVICE STUDY
 ALLOCATION FACTOR REPORT
 TWELVE MONTHS ENDED DECEMBER 31, 2003

	Air Force		Small Interruptible			
	Demand	Energy	Customer	Demand	Energy	Customer
27. All Other Dist. Operation Exp.	2,640 0.100898%	0 0.000000%	7,646 0.292222%	15,705 0.600229%	0 0.000000%	77,205 2.950695%
28. All Other Dist. Maintenance Exp.	467 0.140834%	0 0.000000%	905 0.272922%	2,775 0.836862%	0 0.000000%	8,309 2.505760%
30. O&M Excl. Gas Cost and A&G	5,860 0.063739%	15,484 0.168418%	16,151 0.175673%	34,860 0.379169%	12,805 0.139279%	185,743 2.020309%
31. O&M Excl. Cost of Gas	9,365 0.063739%	24,745 0.168417%	25,811 0.175672%	55,710 0.379168%	20,464 0.139280%	296,838 2.020310%
33. Total Cost of Gas	268,100 0.327332%	3,737,465 4.563188%	0 0.000000%	162,374 0.198247%	2,422,346 2.957518%	0 0.000000%
35. Taxable Income	(24,417) 0.786491%	(312,136) 10.054146%	(17,511) 0.564043%	(100,947) 3.251582%	1,144,975 -36.880546%	(192,088) 6.187306%
38. Customer Account Expense O&M	0 0.000000%	0 0.000000%	9 0.003422%	0 0.000000%	0 0.000000%	422 0.160457%
39. Distribution O&M	5,860 0.105437%	3,466 0.062363%	16,053 0.288836%	34,860 0.627224%	5,016 0.090251%	158,204 2.846509%
40. Total Tax Deductions & Adjustments	14,792 0.341870%	218,121 5.041166%	(877) -0.020269%	4,387 0.101391%	141,370 3.267313%	(8,986) -0.207682%
41. Total Operating Revenues	276,039 0.267768%	3,669,326 3.559380%	16,792 0.016289%	170,322 0.165219%	3,730,091 3.618324%	210,444 0.204138%
42. Dk Sales - Propane	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
43. Total Weighted Customers	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	4,995 4.010566%

MONTANA-DAKOTA UTILITIES CO.
 GAS UTILITY - NORTH DAKOTA
 EMBEDDED CLASS COST OF SERVICE STUDY
 ALLOCATION FACTOR REPORT
 TWELVE MONTHS ENDED DECEMBER 31, 2003

	Large Interruptible		
	Demand	Energy	Customer
27. All Other Dist. Operation Exp.	10,800	0	17,282
	0.412765%	0.000000%	0.660500%
28. All Other Dist. Maintenance Exp.	1,909	0	2,332
	0.575701%	0.000000%	0.703265%
30. O&M Excl. Gas Cost and A&G	23,975	8,783	40,549
	0.260774%	0.095532%	0.441048%
31. O&M Excl. Cost of Gas	38,315	14,036	64,802
	0.260776%	0.095530%	0.441049%
33. Total Cost of Gas	0	0	0
	0.000000%	0.000000%	0.000000%
35. Taxable Income	(65,970)	608,294	(1,230)
	2.124946%	-19.593629%	0.039619%
38. Customer Account Expense O&M	0	0	30
	0.000000%	0.000000%	0.011407%
39. Distribution O&M	23,975	8,783	37,035
	0.431374%	0.158029%	0.666358%
40. Total Tax Deductions & Adjustments	(3,499)	0	(2,662)
	-0.080868%	0.000000%	-0.061524%
41. Total Operating Revenues	2,404	622,972	91,037
	0.002332%	0.604306%	0.088309%
42. Dk Sales - Propane	0.000000%	0.000000%	0.000000%
43. Total Weighted Customers	0	0	693
	0.000000%	0.000000%	0.556421%

MONTANA-DAKOTA UTILITIES CO.
INCOME STATEMENT
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)

	2003	Projected	
		2004	2005
Operating Revenues			
Sales	\$101,924	\$119,376	\$119,307
Transportation	759	783	783
Other	406	406	406
Total Revenues	<u>103,089</u>	<u>120,565</u>	<u>120,496</u>
Operating Expenses			
Operation and Maintenance			
Cost of Gas	81,905	99,630	99,473
Other O&M	14,693	16,579	17,546
Total O&M	<u>96,598</u>	<u>116,209</u>	<u>117,019</u>
Depreciation	2,994	2,537	2,615
Taxes Other Than Income	1,299	1,362	1,421
Current Income Taxes	(1,462)	405	263
Deferred Income Taxes	1,773	(620)	(873)
Total Expenses	<u>101,202</u>	<u>119,893</u>	<u>120,445</u>
Operating Income	<u>\$1,887</u>	<u>\$672</u>	<u>\$51</u>
Average Rate Base	<u>\$19,438</u>	<u>\$20,170</u>	<u>\$20,914</u>
Rate of Return	<u>9.708%</u>	<u>3.332%</u>	<u>0.244%</u>

**MONTANA-DAKOTA UTILITIES CO.
SALES AND TRANSPORTATION REVENUE
GAS UTILITY - NORTH DAKOTA
PROJECTED 2004-2005
(000s)**

	Projected 2004		Projected 2005	
	Dk	Revenue	Dk	Revenue
<u>Sales</u>				
Residential	8,150	\$66,711	8,153	\$66,810
Firm General	5,774	44,198	5,747	44,030
Air Force				
Firm	37	252	37	252
Interruptible	843	4,734	843	4,734
Total Air Force	880	4,986	880	4,986
Small Interruptible	570	3,481	570	3,481
Large Interruptible	0	0	0	0
Total Sales	15,374	\$119,376	15,350	\$119,307
<u>Transportation</u>				
Small Interruptible	703	\$401	703	\$401
Large Interruptible	2,230	382	2,230	382
Total Transportation	2,933	\$783	2,933	\$783
Total Throughput	18,307	\$120,159	18,283	\$120,090

MONTANA-DAKOTA UTILITIES CO.
MISCELLANEOUS REVENUES
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)

	2003	Projected	
		2004	2005
Miscellaneous Service Revenue	<u>\$38</u>	<u>\$38</u>	<u>\$38</u>
Rent from Property	302	302	302
Other Revenue	<u>66</u>	<u>66</u>	<u>66</u>
Total Misc. Revenues	<u>\$406</u>	<u>\$406</u>	<u>\$406</u>

MONTANA-DAKOTA UTILITIES CO.
OPERATION & MAINTENANCE EXPENSE
GAS UTILITY - NORTH DAKOTA
PROJECTED 2004
(000S)

Function	Total	Cost of Gas	Labor	Benefits	Insurance	Contract Labor	Materials	Vehicles & Work Equip.	Postage	Telephone
Cost of Gas	\$99,630	\$99,630								
Other Gas Supply	218		\$147							
Distribution	6,104		4,680			\$426	(\$63)	\$415	\$11	\$90
Customer Accounting	2,997		2,024			60	2	71	244	27
Customer Service & Info	179		136					6		1
Sales	492		395			1		14	3	6
Administrative and General	6,589		1,761	\$2,400	\$426	319	22	12	60	104
Total Other O&M	16,579	0	9,143	2,400	426	806	(39)	518	318	228
Total O&M	\$116,209	\$99,630	\$9,143	\$2,400	\$426	\$806	(\$39)	\$518	\$318	\$228

MONTANA-DAKOTA UTILITIES CO.
OPERATION & MAINTENANCE EXPENSE
GAS UTILITY - NORTH DAKOTA
PROJECTED 2004
(000S)

Function	Office Supplies	Company Consumption	Uncollectible Accounts	Computer Rental	Industry Dues	Advertising	Energy Share	Rate Case Expense	Depreciation Study Expense	All Other O&M
Cost of Gas										\$0
Other Gas Supply										71
Distribution	\$21	\$96								428
Customer Accounting	34	37	252	\$60						186
Customer Service & Info	1					\$27				8
Sales	4	6								63
Administrative and General	118	31		36	39	111	\$11	\$125	\$5	1,009
Total Other O&M	178	170	252	96	39	138	11	125	5	1,765
Total O&M	\$178	\$170	\$252	\$96	\$39	\$138	\$11	\$125	\$5	\$1,765

MONTANA-DAKOTA UTILITIES CO.
 OPERATION & MAINTENANCE EXPENSE
 GAS UTILITY - NORTH DAKOTA
 PROJECTED 2005
 (000S)

Function	Total	Cost of Gas		Labor	Benefits	Insurance	Contract Labor	Materials	Vehicles & Work Equip.	Postage	Telephone
		Gas									
Cost of Gas	\$99,473	\$99,473									
Other Gas Supply	228		\$155								
Distribution	6,414		4,930				\$437	(\$64)	\$451	\$11	\$92
Customer Accounting	3,131		2,132				62	2	79	250	28
Customer Service & Info	186		143						6		1
Sales	516		416				1		15	3	6
Administrative and General	7,071		1,855		2,733	437	327	23	12	62	107
Total Other O&M	17,546	0	9,631		2,733	437	827	(39)	563	326	234
Total O&M	\$117,019	\$99,473	\$9,631		\$2,733	\$437	\$827	(\$39)	\$563	\$326	\$234

**MONTANA-DAKOTA UTILITIES CO.
OPERATION & MAINTENANCE EXPENSE
GAS UTILITY - NORTH DAKOTA
PROJECTED 2005
(000S)**

Function	Office Supplies	Company Consumption	Uncollectible Accounts	Computer Rental	Industry Dues	Advertising	Energy Share	Rate Case Expense	Depreciation Study Expense	All Other O&M
Cost of Gas										\$0
Other Gas Supply										73
Distribution	\$22	\$96								439
Customer Accounting	35	37	252	\$63						191
Customer Service & Info	1					\$27				8
Sales	4	6								65
Administrative and General	121	31		38	39	111	\$11	\$125	\$5	1,034
Total Other O&M	183	170	252	101	39	138	11	125	5	1,810
Total O&M	\$183	\$170	\$252	\$101	\$39	\$138	\$11	\$125	\$5	\$1,810

MONTANA-DAKOTA UTILITIES CO.
PROJECTED COST OF GAS
GAS UTILITY - NORTH DAKOTA
(000s)

	Projected Dk Sales	Dk Adjusted for Distribution Losses 1/	Commodity Charge 2/	Projected Cost of Gas
Projected 2004				
Residential	8,150	8,187	\$6.551	\$53,633
Firm General Service	5,774	5,800	6.551	37,996
Air Force				
Firm	37	37	6.551	242
Interruptible Contract	759	759	5.480	4,159
Total Air Force	<u>796</u>	<u>796</u>		<u>4,401</u>
Small Interruptible	654	657	5.480	3,600
Large Interruptible	<u>0</u>	<u>0</u>	5.480	<u>0</u>
Total	<u>15,374</u>	<u>15,440</u>		<u>\$99,630</u>
Projected 2005				
Residential	8,153	8,190	\$6.551	\$53,653
Firm General Service	5,747	5,773	6.551	37,819
Air Force				
Firm	37	37	6.551	242
Interruptible Contract	759	759	5.480	4,159
Total Air Force	<u>796</u>	<u>796</u>		<u>4,401</u>
Small Interruptible	654	657	5.480	3,600
Large Interruptible	<u>0</u>	<u>0</u>	5.480	<u>0</u>
Total	<u>15,350</u>	<u>15,416</u>		<u>\$99,473</u>

1/ Distribution loss factor of .45%.

2/ Exhibit B, Purchased Gas Cost Adjustment effective February 1, 2004.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
LABOR EXPENSE
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)

	2003	Projected	
		2004 1/	2005 2/
Gas Supply	\$138	\$147	\$155
Distribution	4,381	4,680	4,930
Customer Acct.	1,895	2,024	2,132
Customer Service & Info	127	136	143
Sales	370	395	416
A&G	1,649	1,761	1,855
Total	<u>\$8,560</u>	<u>\$9,143</u>	<u>\$9,631</u>

1/ Reflects average 6.82% increase.

2/ Reflects projected 5.35% increase.

MONTANA-DAKOTA UTILITIES CO.
BENEFITS EXPENSE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)

	2003	Projected 1/	
		2004	2005
Medical/Dental	\$754	\$929	\$1,003
Pension expense	(201)	295	546
Post-retirement	579	619	635
401-K	214	231	237
Workers compensation	62	66	69
SISP	0	260	243
Total	<u>\$1,408</u>	<u>\$2,400</u>	<u>\$2,733</u>

1/ Each benefit adjusted individually.

MONTANA-DAKOTA UTILITIES CO.
INSURANCE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)

	2003	Projected	
		2004 1/	2005 2/
A&G	<u>\$482</u>	<u>\$426</u>	<u>\$437</u>

1/ Reflects a decrease of 11.62%.

2/ Reflects an increase of 2.50%.

MONTANA-DAKOTA UTILITIES CO.
CONTRACT LABOR AND CONSULTING SERVICES
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)

	2003	Projected	
		2004	2005 3/
Distribution 1/	\$333	\$426	\$437
Customer Accounting 2/	67	60	62
Sales 2/	1	1	1
A&G 2/	359	319	327
Total Contract Labor	<u>\$760</u>	<u>\$806</u>	<u>\$827</u>

- 1/ Reflects an increase of 27.89% in 2004.
2/ Reflects a decrease of 11.05% in 2004.
3/ Reflects and increase of 2.50%.

MONTANA-DAKOTA UTILITIES CO.
MATERIALS, REIMBURSEMENTS, AND CAPITAL INSTALLATION CREDITS
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)

2003				
	Total	Materials	Capital Installation Credits	Reimburse- ments
Distribution	\$3	\$286	(\$206)	(77)
Customer Accounting	2	2	0	0
A&G	26	26	0	0
Total	\$31	\$314	(\$206)	(\$77)

2004				
	Total	Materials 1/	Capital Installation Credits 2/	Reimburse- ments 3/
Distribution	(\$63)	\$244	(\$215)	(\$92)
Customer Accounting	2	2	0	0
A&G	22	22	0	0
Total	(\$39)	\$268	(\$215)	(\$92)

2005 4/				
	Total	Materials	Capital Installation Credits	Reimburse- ments
Distribution	(\$64)	\$250	(\$220)	(\$94)
Customer Accounting	2	2	0	0
A&G	23	23	0	0
Total	(\$39)	\$275	(\$220)	(\$94)

- 1/ Reflects a decrease of 14.80%.
- 2/ Reflects an increase of 4.18%.
- 3/ Reflects an increase of 18.87%.
- 4/ Reflects an increase of 2.50%.

**MONTANA-DAKOTA UTILITIES CO.
VEHICLES AND WORK EQUIPMENT
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)**

	2003	Projected 1/	
		2004	2005
Gas Supply	\$0	\$0	\$0
Distribution	199	415	451
Customer Accounting	33	71	79
Customer Service & Info	3	6	6
Sales	7	14	15
A&G	5	12	12
Total Company Vehicles	<u>\$247</u>	<u>\$518</u>	<u>\$563</u>

1/ Based on depreciation expense.

MONTANA-DAKOTA UTILITIES CO.
POSTAGE EXPENSE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)

	2003	Projected	
		2004 1/	2005 2/
Distribution	\$11	\$11	\$11
Customer Accounting	251	244	250
Sales	3	3	3
A&G	62	60	62
Total Postage	<u>\$327</u>	<u>\$318</u>	<u>\$326</u>

1/ Reflects a decrease of 2.93%

2/ Reflects an increase of 2.50%

MONTANA-DAKOTA UTILITIES CO.
TELEPHONE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)

	2003	Projected	
		2004 1/	2005 2/
Distribution	\$90	\$90	\$92
Customer Accounting	27	27	28
Customer Service & Info	1	1	1
Sales	6	6	6
A&G	104	104	107
Total Telephone	<u>\$228</u>	<u>\$228</u>	<u>\$234</u>

1/ Reflects an increase of .35%.
2/ Reflects an increase of 2.50%

MONTANA-DAKOTA UTILITIES CO.
OFFICE SUPPLIES
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)

	2003	Projected	
		2004 1/	2005 2/
Distribution	\$25	\$21	\$22
Customer Accounting	40	34	35
Customer Service	1	1	1
Sales	5	4	4
A&G	138	118	121
Total Office Supplies	<u>\$209</u>	<u>\$178</u>	<u>\$183</u>

1/ Reflects a decrease of 14.66%

2/ Reflects an increase of 2.50%

**MONTANA-DAKOTA UTILITIES CO.
COMPANY CONSUMPTION
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)**

	Total	2003	
		Electric	Gas
Distribution	\$88	\$36	\$52
Customer Accounting	34	16	18
Sales	6	3	3
A&G	30	20	10
Total Company Consumption	<u>\$158</u>	<u>\$75</u>	<u>\$83</u>

	Total	2004	
		Electric 1/	Gas 2/
Distribution	\$96	\$36	\$60
Customer Accounting	37	16	21
Sales	6	3	3
A&G	31	20	11
Total Company Consumption	<u>\$170</u>	<u>\$75</u>	<u>\$95</u>

	Total	2005	
		Electric	Gas
Distribution	\$96	\$36	\$60
Customer Accounting	37	16	21
Sales	6	3	3
A&G	31	20	11
Total Company Consumption	<u>\$170</u>	<u>\$75</u>	<u>\$95</u>

1/ Reflects an increase of 1.18%.
2/ Reflects an increase of 14.92%.

MONTANA-DAKOTA UTILITIES CO.
UNCOLLECTIBLE ACCOUNTS
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)

		Projected 1/	
	2003	2004	2005
Customer Accounting	<u>\$177</u>	<u>\$252</u>	<u>\$252</u>

1/ Based on 5 year average of write-offs to revenues.

**MONTANA-DAKOTA UTILITIES CO.
COMPUTER RENTAL
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)**

	2003	Projected 1/	
		2004	2005
Customer Accounting	\$51	\$60	\$63
A&G	30	36	38
Total Computer Rental	<u>\$81</u>	<u>\$96</u>	<u>\$101</u>

1/ Increase reflects cost of adding new GIS server.

**MONTANA-DAKOTA UTILITIES CO.
INDUSTRY DUES
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005**

	2003	Projected	
		2004	2005
Air Force Association - Minot	\$75	\$75	\$75
American Gas Association 1/	16,483	16,447	16,447
Belfield Area Chamber of Commerce	21	21	21
Bismarck-Mandan Area Chamber of Commerce	3,026	3,026	3,026
Bismarck-Mandan Board of Realtors	3,109	3,109	3,109
Bismarck-Mandan Homebuilders Association	168	168	168
Bowman Chamber	32	32	32
Carrington Chamber of Commerce	110	110	110
Cavalier Area Chamber of Commerce	150	150	150
Cavalier Retail Committee	210	210	210
Central North American Trade Corridor Assoc.	2,500	2,500	2,500
Devils Lake Area Chamber of Commerce	662	662	662
Dickinson Area Chamber of Commerce	184	184	184
Divide County Economic Development	77	77	77
Downtown Business Association	314	314	314
Economic Development Association of ND	268	268	268
Forward Devils Lake Corporation	500	500	500
Garrison Chamber of Commerce	450	450	450
Grafton Area Chamber of Commerce	199	199	199
Hebron Business Club	8	8	8
Hettinger Area Chamber of Commerce	28	28	28
Jamestown Area Chamber of Commerce	700	700	700
Langdon Chamber of Commerce	135	135	135
Linton Chamber of Commerce	4	4	4
Linton Industrial Development Corporation	2	2	2
Mid-America Economic Development Council	130	130	130
Main Street/Downtown Jamestown	150	150	150
Mercer County Economic Development Corporation	870	870	870
Midwest Energy Association	4,054	4,054	4,054
Minot Area Chamber of Commerce	40	40	40
Minot Association of Builders	260	260	260
Minot Builders Exchange	125	125	125
Minot Convention and Visitors Bureau	250	250	250
NARUC	548	548	548
New England Commercial Club	8	8	8
New Rockford Area Chamber of Commerce	60	60	60
North Dakota Irrigation Caucus	469	469	469
Park River Commercial Club	75	75	75
Ray Association	34	34	34
Richardton Business Association	42	42	42
Stanley Commercial Club	170	170	170

**MONTANA-DAKOTA UTILITIES CO.
INDUSTRY DUES
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005**

	2003	Projected	
		2004	2005
Stark Development Corporation	105	105	105
Tioga Area Economic Development Corporation	9	9	9
Tioga Chamber of Commerce	34	34	34
Turtle Lake Commercial Club	75	75	75
Underwood Area Civic Club	50	50	50
United Telecom Council	660	660	660
Valley City Area Chamber of Commerce	375	375	375
Walhalla Chamber of Commerce	75	75	75
Washburn Civic Club	75	75	75
Washburn Area Economic Development	150	150	150
Watford City Area Chamber of Commerce	130	130	130
Watford City Economic Development	40	40	40
Williston Area Chamber of Commerce	252	252	252
Other	4,229	0	0
Total	<u>\$42,959</u>	<u>38,694</u>	<u>38,694</u>

1/ Reflects 2004 dues, adjusted to eliminate 2.28% for lobbying.

MONTANA-DAKOTA UTILITIES CO.
ADVERTISING EXPENSE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)

	2003	Projected	
		2004	2005
Informational	\$27	\$27	\$27
Promotional	35		
Institutional	111	111	111
Total	<u>\$173</u>	<u>\$138</u>	<u>\$138</u>

MONTANA-DAKOTA UTILITIES CO.
ENERGY SHARE OF NORTH DAKOTA
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)

	2003	Projected	
		2004	2005
A&G	<u>\$0</u>	<u>\$11</u>	<u>\$11</u>

MONTANA-DAKOTA UTILITIES CO.
RATE CASE EXPENSE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)

	2003	Projected 1/	
		2004	2005
A&G	\$43	\$125	\$125

1/ Reflects three year amortization of rate case expense plus rate case expense from Case No. PU-399-02-183 not included in amortization.

**MONTANA-DAKOTA UTILITIES CO.
DEPRECIATION STUDY EXPENSE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)**

	2003	Projected 1/	
		2004	2005
A&G	<u>\$0</u>	<u>\$5</u>	<u>\$5</u>

1/ Reflects 5 year amortization of depreciation study expenses.

MONTANA-DAKOTA UTILITIES CO.
OTHER O&M EXPENSE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)

	2003	Projected	
		2004	2005 1/
Other Gas Supply	\$71	\$71	\$73
Distribution	428	428	439
Customer Accounting	186	186	191
Customer Service & Information	8	8	8
Sales	63	63	65
A&G	1,009	1,009	1,034
Total Other O&M	<u>\$1,765</u>	<u>\$1,765</u>	<u>\$1,810</u>

1/ Reflects an increase of 2.5%.

MONTANA-DAKOTA UTILITIES CO.
 OTHER O&M
 GAS UTILITY - NORTH DAKOTA
 TWELVE MONTHS ENDING DECEMBER 31, 2003
 (000s)

Function	Per Books	Cost of Gas	Labor	Benefits	Insurance	Contract Labor	Materials	Vehicles & Work Equip.	Postage	Telephone
Cost of Gas	\$81,905	(\$81,905)								
Other Gas Supply	209		(\$138)							
Distribution	5,558		(4,381)			(\$333)	(\$3)	(\$199)	(\$11)	(\$90)
Customer Accounting	2,763		(1,895)			(67)	(2)	(33)	(251)	(27)
Customer Service & Info	167		(127)					(3)		(1)
Sales	496		(370)			(1)		(7)	(3)	(6)
Administrative and General	5,499		(1,649)	(1,408)	(482)	(359)	(26)	(5)	(62)	(104)
Total Other O&M	14,692	0	(8,560)	(1,408)	(482)	(760)	(31)	(247)	(327)	(228)
Total O&M	\$96,597	(\$81,905)	(\$8,560)	(\$1,408)	(\$482)	(\$760)	(\$31)	(\$247)	(\$327)	(\$228)

MONTANA-DAKOTA UTILITIES CO.
 OTHER O&M
 GAS UTILITY - NORTH DAKOTA
 TWELVE MONTHS ENDING DECEMBER 31, 2003
 (000s)

Function	Office Supplies	Company Consumption	Uncollectible Accounts	Computer Rental	Industry Dues	Advertising	Rate Case Expense	All Other O&M
Cost of Gas								\$0
Other Gas Supply								71
Distribution	(\$25)	(\$88)						428
Customer Accounting	(40)	(34)	(177)	(\$51)				186
Customer Service & Info	(1)					(\$27)		8
Sales	(5)	(6)				(35)		63
Administrative and General	(138)	(30)		(30)	(43)	(111)	(43)	1,009
Total Other O&M	(209)	(158)	(177)	(81)	(43)	(173)	(43)	1,765
Total O&M	(\$209)	(\$158)	(\$177)	(\$81)	(\$43)	(\$173)	(\$43)	\$1,765

**MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
DEPRECIATION EXPENSE
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)**

	2003	Projected	
		2004	2005
Distribution	\$2,359	\$1,870	1,947
General	166	179	168
Intangible Plant - General	2	3	3
Common	236	272	263
Intangible Plant - Common	201	210	231
Acquisition Adjustment	30	3	3
Total	<u>\$2,994</u>	<u>\$2,537</u>	<u>\$2,615</u>

MONTANA-DAKOTA UTILITIES CO.
TAXES OTHER THAN INCOME
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)

<u>Type of Tax</u>	<u>2003</u>	<u>Projected</u>	
		<u>2004</u>	<u>2005</u>
Ad Valorem			
Distribution	\$512	\$535	\$557
General	55	52	54
Common	58	58	56
Intangible	3	3	3
Total Ad Valorem Taxes	<u>\$628</u>	<u>\$648</u>	<u>\$670</u>
O&M Related Taxes - Other			
FICA	602	677	714
Federal Unemployment	9		
State Unemployment	23		
Franchise	12	12	12
Delaware Franchise	25	25	25
Total O&M Related Taxes	<u>671</u>	<u>714</u>	<u>\$751</u>
 Total Taxes Other Than Income	 <u>\$1,299</u>	 <u>\$1,362</u>	 <u>\$1,421</u>

**MONTANA-DAKOTA UTILITIES CO.
AD VALOREM TAXES
GAS UTILITY - NORTH DAKOTA
PROJECTED 2004-2005
(000s)**

Function	Effective Tax Rate	Projected 2004		Projected 2005	
		Plant Balance	Ad Valorem Tax	Plant Balance	Ad Valorem Tax
Distribution 1/	0.8846%	\$60,507	\$535	\$63,013	\$557
General	0.8026%	6,498	52	6,692	54
General Intangible	0.1287%	180	0	180	0
Common	1.0391%	5,558	58	5,409	56
Common Intangible	0.1287%	2,256	3	2,482	3
Total Ad Valorem Taxes		<u>\$74,999</u>	<u>\$648</u>	<u>\$77,776</u>	<u>\$670</u>

1/ Includes gas plant leased to others.

**MONTANA-DAKOTA UTILITIES CO.
AD VALOREM TAXES
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003**

<u>Function</u>	<u>Average Plant Balance @ 12/31/03</u>	<u>Ad Valorem Tax @ 12/31/03</u>	<u>Effective Tax Rate</u>
Distribution 1/	\$57,911,823	\$512,281	0.8846%
General	6,753,671	54,208	0.8026%
Common	5,573,420	57,915	1.0391%
Intangible 2/	<u>2,219,808</u>	<u>2,856</u>	0.1287%
Total	<u><u>\$72,458,722</u></u>	<u><u>\$627,260</u></u>	

1/ Includes gas plant leased to others.

2/ General and common intangible.

**MONTANA-DAKOTA UTILITIES CO.
PAYROLL TAXES
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)**

	2003	Projected	
		2004 1/	2005 1/
FICA	\$602		
Federal Unemployment	9		
State Unemployment	23		
Total	<u>\$634</u>	<u>\$677</u>	<u>\$714</u>

1/ Calculated based on 2003 ratio of payroll taxes to labor.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
CALCULATION OF CURRENT INCOME TAXES
PROJECTED 2004-2005
(000s)

	Projected	
	2004	2005
Operating Revenues		
Sales Revenues	\$119,376	\$119,307
Transportation Revenues	783	783
Other Revenues	406	406
Total Operating Revenues	120,565	120,496
Operating Expenses		
Operation and Maintenance		
Cost of Gas	99,630	99,473
Other O&M	16,579	17,546
Total O&M	116,209	117,019
Depreciation Expense	2,537	2,615
Taxes other Than Income	1,362	1,421
Total Operating Expenses	120,108	121,055
Operating Income before Taxes	457	(559)
Deductions and Adjustments to Book Income:		
Interest Expense	793	775
Preferred Dividend Paid	15	15
Other Tax Deductions	(1,376)	(2,013)
Total Adjustments to Taxable Income	(568)	(1,223)
Taxable Income	1,025	664
Federal & State Income Taxes @ 39.55%	\$405	\$263

**MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
INTEREST EXPENSE ANNUALIZATION
PROJECTED 2004-2005
(000s)**

	Projected	
	2004	2005
Rate Base	\$20,170	\$20,914
Long Term Debt Ratio	45.589%	43.535%
Long Term Debt Cost	8.624%	8.518%
Weighted Cost of Debt	3.932%	3.708%
Interest Expense	<u>\$793</u>	<u>\$775</u>

MONTANA-DAKOTA UTILITIES CO.
INCOME TAX DEDUCTIONS
GAS UTILITY - NORTH DAKOTA
PROJECTED 2004-2005
(000s)

	Projected	
	2004	2005
<u>1900 Account M-1's</u>		
Pension Expense	(183)	(141)
BOD Retirement	(93)	(93)
 <u>2820 Account M-1's</u>		
Liberalized Depreciation and Other Property Timing Differences	337	(739)
 <u>2830 Account M-1's</u>		
Purchased Gas Cost Adjustment	(1,282)	(905)
Amortization of Loss on Bond Retirements	(114)	(94)
 <u>Permanent M-1's</u>		
Meals & Entertainment	(41)	(41)
Total M-1 Deductions	<u>(\$1,376)</u>	<u>(\$2,013)</u>

MONTANA-DAKOTA UTILITIES CO.
DEFERRED INCOME TAXES
GAS UTILITY - NORTH DAKOTA
PROJECTED 2004-2005
(000s)

	Projected	
	2004	2005
Gas Utility - Rate Base Deductions:		
Depreciation, Retirements and Other Timing Differences Required to be Normalized	\$42	(\$384)
Total Rate Base Deductions	42	(384)
Gas Utility - Current Timing Differences:		
Pension Expense	(154)	(130)
Unrecovered Purchased Gas Cost	(508)	(359)
Total Current Timing Differences	(662)	(489)
 Total	 (\$620)	 (\$873)

MONTANA-DAKOTA UTILITIES CO.
AVERAGE RATE BASE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)

	2003	Projected	
		2004	2005
Gas Plant in Service	\$72,556	\$75,096	\$77,873
Accumulated Reserve for Depreciation	49,644	51,343	53,572
Net Gas Plant in Service	22,912	23,753	24,301
CWIP in Service Pending Reclassification	427		
Total Gas Plant in Service	23,339	23,753	24,301
Additions			
Materials and Supplies	393	475	475
Fuel Stock	25	22	22
Prepayments	50	181	190
Other	44	4	0
Total Additions	512	682	687
Total Before Deductions	\$23,851	\$24,435	\$24,988
Deductions			
Accumulated Deferred Income Taxes	\$3,909	\$3,845	\$3,674
Accumulated Investment Tax Credits	207	166	146
Customer Advances	297	254	254
Total Deductions	4,413	4,265	4,074
Total Rate Base	\$19,438	\$20,170	\$20,914

**MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)**

	<u>2003 1/</u>	<u>Projected 2004</u>	<u>Average 2004</u>	<u>Projected 2005</u>	<u>Average 2005</u>
Distribution	\$59,417	\$61,596	\$60,507	\$64,429	\$63,013
General	6,574	6,783	6,678	6,961	6,872
Common	7,698	7,929	7,814	7,854	7,891
Acquisition Adjustment	<u>97</u>	<u>97</u>	<u>97</u>	<u>97</u>	<u>97</u>
Total	<u><u>\$73,786</u></u>	<u><u>\$76,405</u></u>	<u><u>\$75,096</u></u>	<u><u>\$79,341</u></u>	<u><u>\$77,873</u></u>

1/ Includes CWIP in Service.

MONTANA-DAKOTA UTILITIES CO.
 PLANT IN SERVICE
 TWELVE MONTHS ENDING DECEMBER 31, 2003
 PROJECTED 2004-2005
 (000s)

	2003 1/ \$59,417	2004			Average	2005			Average
		Additions \$2,304	Retirements (\$125)	Balance \$61,596	2004 \$60,507	Additions \$2,962	Retirements (\$129)	Balance \$64,429	2005 \$63,013
Distribution 2/									
<u>General</u>									
Other	2,592	49	(206)	2,435	2,514	26	(193)	2,268	2,351
Transportation	2,307	516	(183)	2,640	2,473	336	(209)	2,767	2,703
Work Equipment	1,456	66	(115)	1,407	1,431	259	(112)	1,554	1,481
Tools	39	85	(3)	121	80	81	(10)	192	157
Intangible	180	0	0	180	180	0	0	180	180
Total General	6,574	716	(507)	6,783	6,678	702	(524)	6,961	6,872
<u>Common</u>									
Other	4,279	227	(350)	4,156	4,218	187	(340)	4,003	4,079
Transportation	1,337	87	(109)	1,315	1,325	90	(108)	1,297	1,306
Work Equipment	15	0	(1)	14	15	21	(1)	34	24
Intangible	2,067	383	(6)	2,444	2,256	83	(7)	2,520	2,482
Total Common	7,698	697	(466)	7,929	7,814	381	(456)	7,854	7,891
Acquisition Adjustment	97			97	97			97	97
Total Gas Plant in Service	\$73,786	\$3,717	(\$1,098)	\$76,405	\$75,096	\$4,045	(\$1,109)	\$79,341	\$77,873

1/ Includes CWIP in Service by function.
 2/ Includes gas plant leased to others.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF ACCUMULATED RESERVE FOR DEPRECIATION
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004- 2005
(000s)

	<u>2003</u>	<u>Projected 2004</u>	<u>Average 2004</u>	<u>Projected 2005</u>	<u>Average 2005</u>
Distribution	\$43,576	\$45,320	\$44,448	\$47,136	\$46,228
General	3,056	3,302	3,179	3,552	3,427
Common	3,589	3,780	3,684	3,984	3,882
Acquisition Adjustment	<u>30</u>	<u>33</u>	<u>32</u>	<u>36</u>	<u>35</u>
Total	<u>\$50,251</u>	<u>\$52,435</u>	<u>\$51,343</u>	<u>\$54,708</u>	<u>\$53,572</u>

MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED RESERVE FOR DEPRECIATION
GAS UTILITY - NORTH DAKOTA
PROJECTED 2004
(000s)

	2003	2004				2004	
	Acc. Reserve for Depr.	Average Plant In Service	Depreciation/ Amortization Rate 1/	Depreciation/ Amortization Expense	Retirements/ Removal	Ending Balance	2004 Average Balance
Distribution 2/	\$43,576	\$60,507	3.09%	\$1,870	(\$126)	\$45,320	\$44,448
General							
Other	975	2,514	7.14%	179	(156)	998	986
Transportation	1,049	2,473	20.82%	515	(168)	1,396	1,222
Work Equipment	810	1,431	0.44%	6	(130)	686	748
Tools	45	80	5.56%	4	(7)	42	44
Intangible	177	180	1.52%	3	0	180	179
Total General	3,056	6,678		707	(461)	3,302	3,179
Common							
Other	2,154	4,218	6.46%	272	(366)	2,060	2,107
Transportation	312	1,325	10.22%	135	(53)	394	353
Work Equipment	2	15	2.69%	0	0	2	2
Intangible	1,121	2,256	9.32%	210	(7)	1,324	1,222
Total Common	3,589	7,814		617	(426)	3,780	3,684
Acquisition Adjustment	30	97	3/	3	0	33	32
Total Gas Plant in Service	\$50,251	\$75,096		\$3,197	(\$1,013)	\$52,435	\$51,343
Depreciation Expense				\$2,537			

1/ Composite depreciation rates by function.

2/ Includes gas plant leased to others.

3/ Amortized over 34.5 years.

MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED RESERVE FOR DEPRECIATION
GAS UTILITY - NORTH DAKOTA
PROJECTED 2005
(000s)

	2004	Average Plant In Service	Depreciation/ Amortization Rate 1/	Depreciation/ Amortization Expense	Retirements/ Removal	Ending Balance	2005 Average Balance
Distribution 2/	\$45,320	\$63,013	3.09%	\$1,947	(\$131)	\$47,136	\$46,228
General							
Other	998	2,351	7.14%	168	(160)	1,006	1,002
Transportation	1,396	2,703	20.82%	563	(223)	1,736	1,565
Work Equipment	686	1,481	0.44%	7	(110)	583	635
Tools	42	157	5.56%	9	(7)	44	43
Intangible	180	180	1.52%	3	0	183	182
Total General	3,302	6,872		750	(500)	3,552	3,427
Common							
Other	2,060	4,079	6.46%	263	(350)	1,973	2,016
Transportation	394	1,306	10.22%	134	(67)	461	428
Work Equipment	2	24	2.69%	1	0	3	3
Intangible	1,324	2,482	9.32%	231	(8)	1,547	1,435
Total Common	3,780	7,891		629	(425)	3,984	3,882
Acquisition Adjustment	33	97	3/	3	0	36	35
Total Gas Plant in Service	\$52,435	\$77,873		\$3,329	(\$1,056)	\$54,708	\$53,572
Depreciation Expense				\$2,615			

1/ Composite depreciation rates by function.
2/ Includes gas plant leased to others.
3/ Amortized over 34.5 years.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF WORKING CAPITAL AND
CUSTOMER ADVANCES FOR CONSTRUCTION
GAS UTILITY - NORTH DAKOTA
PROJECTED 2004-2005
(000s)

<u>Working Capital</u>	Average	
	<u>2004</u>	<u>2005</u>
Materials and Supplies	\$475	\$475
Fuel Stocks	22	22
Prepayments	181	190
Gas IRP	<u>4</u>	<u>0</u>
Total Working Capital	<u>\$682</u>	<u>\$687</u>
Customer Advances for Construction	<u>\$254</u>	<u>\$254</u>

**MONTANA-DAKOTA UTILITIES CO.
MATERIALS AND SUPPLIES
GAS UTILITY - NORTH DAKOTA
PROJECTED 2004-2005
(000s)**

	<u>2003</u>	<u>2004</u>	<u>2005</u>
December 2002	\$376		
January 2003	371		
February	408		
March	504		
April	545		
May	500		
June	534		
July	540		
August	507		
September	488		
October	509		
November	483		
December	409		
13 Month Average	<u>\$475</u>	<u>\$475</u>	<u>\$475</u>

MONTANA-DAKOTA UTILITIES CO.
FUEL STOCKS
GAS UTILITY - NORTH DAKOTA
PROJECTED 2004-2005
(000S)

	<u>2003</u>	<u>2004</u>	<u>2005</u>
December 2002	\$24		
January 2003	24		
February	24		
March	13		
April	22		
May	23		
June	17		
July	19		
August	19		
September	21		
October	21		
November	34		
December	26		
13 Month Average	<u>\$22</u>	<u>\$22</u>	<u>\$22</u>

MONTANA-DAKOTA UTILITIES CO.
PREPAYMENTS
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)

	<u>2003</u>	<u>2004</u>	<u>2005</u>
December 2002	\$33	\$66	\$91
January 2003	10	345	363
February	164	313	329
March	144	287	301
April	231	255	267
May	203	224	234
June	190	191	200
July	166	164	170
August	133	131	136
September	110	98	101
October	99	66	67
November	110	124	125
December	66	91	90
13 Month Average	<u>\$128</u>	<u>\$181</u>	<u>\$190</u>

**MONTANA-DAKOTA UTILITIES CO.
GAS INTEGRATED RESOURCE PLAN
GAS UTILITY - NORTH DAKOTA
PROJECTED 2004-2005
(000s)**

	<u>2003</u>	<u>2004</u>	<u>2005</u>
December 2002	\$71	\$18	
January 2003	67	14	
February	62	9	
March	58	5	
April	53	0	
May	49	0	
June	44	0	
July	40	0	
August	36	0	
September	31	0	
October	27	0	
November	22	0	
December	18	0	
13 Month Average Balance	<u>\$44</u>	<u>\$4</u>	<u>\$0</u>

MONTANA-DAKOTA UTILITIES CO.
CUSTOMER ADVANCES FOR CONSTRUCTION
GAS UTILITY - NORTH DAKOTA
PROJECTED 2004-2005
(000s)

	<u>2003</u>	<u>2004</u>	<u>2005</u>
December 2002	\$287		
January 2003	239		
February	191		
March	192		
April	224		
May	224		
June	240		
July	241		
August	241		
September	289		
October	311		
November	312		
December	307		
13 Month Average	<u>\$254</u>	<u>\$254</u>	<u>\$254</u>

MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED DEFERRED INCOME TAXES
ACCUMULATED INVESTMENT TAX CREDITS
GAS UTILITY - NORTH DAKOTA
PROJECTED 2004-2005
(000s)

	2003	Projected 2004			Projected 2005		
		Changes	Balance	Average	Changes	Balance	Average
<u>Accumulated Deferred Income Taxes</u>							
Liberalized Depreciation	\$3,716						
Contribution in Aid of Construction	(157)						
Customer Advances	(109)						
Normalization	374						
Balance	<u>\$3,824</u>	<u>\$42</u>	<u>\$3,866</u>	<u>\$3,845</u>	<u>(\$384)</u>	<u>\$3,482</u>	<u>\$3,674</u>
<u>Accumulated Investment Tax Credits</u>							
Balance	<u>\$178</u>	<u>(\$24)</u>	<u>\$154</u>	<u>\$166</u>	<u>(\$16)</u>	<u>\$138</u>	<u>\$146</u>