MDU RESOURCES GROUP, INC.
NONCONSOLIDATED BALANCE SHEET
DECEMBER 31, 2003 AND DECEMBER 31, 2004

	2003	2004
Assets and Other Debits		
Utility Plant	$881,126,491	$905,354,639
Construction Work in Progress	11,357,572	8,531,701
Less Acc. Provision for Depreciation and Amortization	512,484,759	533,454,668
Net Utility Plant	379,999,304	380,431,672
Gas Stored Underground - Noncurrent	2,361,258	3,022,878
Other Property and Investments		
Nonutility Property	1,036,084	1,511,061
(Less) Accum. Prov. for Depr. And Amort.	353,568	498,029
Investment in Subsidiary Companies	1,278,850,163	1,479,846,408
Other investments	22,254,889	33,381,533
Net Other Property and Investments	1,301,787,568	1,514,240,973
Current and Accrued Assets		
Cash	861,378	1,593,384
Special Deposits	1,200	1,200
Working Fund	15,965	40,596
Temporary Cash Investments	8,529,412	7,142,665
Customer Accounts Receivable	37,004,255	29,563,788
Other Accounts Receivable	3,987,038	4,471,664
(Less) Accum.Prov. For Uncollectible Acct. - Credit	319,419	270,046
Accounts Receivable from Assoc.Companies	17,473,063	20,736,266
Fuel Stock	2,753,765	2,831,449
Plant Materials and Operating Supplies	6,197,652	6,614,811
Merchandise	1,139,740	1,272,501
Stores Expense Undistributed		24,487
Gas Stored Underground - Current	18,438,454	21,773,200
Prepayments	8,839,446	7,074,369
Accured Utility Revenues	27,625,923	42,306,751
Miscellaneous Current and Accrued Assets	117,438	178,863
Total Current and Accrued Assets	132,665,310	145,355,948
Deferred Debits		
Unamortized Debt Expenses	1,533,592	1,466,592
Other Regulatory Assets	4,744,491	3,333,602
Prelim. Survey and Investigation Charges (Electric)	1,127,322	1,424,297
Clearing Accounts	(124,215)	(149,815)
Miscellaneous Deferred Debits	22,910,284	26,759,428
Unamortized Loss on Reaquired Debt	4,518,768	3,531,307
Accumulated Deferred Income Taxes	21,238,378	26,215,669
Unrecovered Purchased Gas Costs	10,518,527	15,533,707
Total Deferred Debits	66,467,147	78,114,787
Total Assets and Other Debits	$1,883,280,587	$2,121,166,258

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED BALANCE SHEET
DECEMBER 31, 2003 AND DECEMBER 31, 2004

	2003	2004
Liabilities and Other Credits		
Proprietary Capital		
Common Stock Issued	$113,716,632	$118,586,065
Preferred Stock Issued	16,200,000	15,000,000
Premium on Capital Stock	761,023,634	866,861,363
(Less) Capital Stock Expense	3,236,160	3,412,569
Retained Earnings	47,203,550	43,802,615
Unappropriated Undistributed Sub Earnings	528,082,638	655,292,626
(Less) Reacquired Capital Stock		3,625,813
Accumulated Other Comprehensive Income	(7,528,653)	(11,491,485)
Total Proprietary Capital	1,455,461,641	1,681,012,802
Long-Term Debt		
Bonds	160,850,000	145,850,000
Other Long-Term Debt	41,500,000	38,100,000
(Less) Unamortized Discount on Long-Term Debt-Debit	36,671	32,226
Total Long-Term Debt	202,313,329	183,917,774
Other Noncurrent Liabilities		
Accumulated Provision for Injuries and Damages	1,017,175	1,046,120
Accumulated Provision for Pensions and Benefits	29,785,661	38,777,977
Accumulated Provision for Rate Refunds	299,228	0
Asset Retirement Obligations	602,589	646,150
Total Other Noncurrent Liabilities	31,704,653	40,470,247
Current and Accrued Liabilities		
Accounts Payable	26,572,779	30,776,542
Accounts Payable to Associated Companies	7,113,407	7,930,615
Customer Deposits	1,584,497	1,845,929
Taxes Accrued	10,323,491	9,081,392
Interest Accrued	2,307,669	2,047,469
Dividends Declared	19,458,320	21,449,171
Tax Collections Payable	1,662,094	1,618,279
Miscellaneous Current and Accrued Liabilities	10,665,144	22,696,729
Total Current and Accrued Assets	79,687,401	97,446,126
Deferred Credits		
Customer Advances for Construction	1,284,167	1,702,239
Accumulated Deferred Investment Tax Credit	2,461,954	1,869,757
Other Deferred Credits	16,816,218	21,674,170
Other Regulatory Liabilities	15,633,652	12,186,926
Accumulated Deferred Income Taxes	77,917,572	80,886,217
Total Deferred Credits	114,113,563	118,319,309
Total Liabilities and Equity	$1,883,280,587	$2,121,166,258

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STATEMENT A

NOTES TO THE FINANCIAL STATEMENTS

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Note 1
Summary of Significant Accounting Policies

Basis of presentation

The consolidated financial statements of the 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, 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, independent power production, and other are nonregulated. For further descriptions of the Company's businesses, see Note 13. The statements also include the ownership interests in the assets, liabilities and expenses of two jointly owned electric generating facilities.

The Company uses the equity method of accounting for certain investments. For more information on the Company's equity method investments, see Note 2.

The Company's regulated businesses are subject to various state and federal agency regulations. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the 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 SFAS No. 71, "Accounting for the Effects of Certain Types 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.

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, 2004 and 2003, was $6.8 million and $8.1 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 was $24.9 million and $19.6 million at December 31, 2004 and 2003, respectively. The remainder of natural gas in underground storage was included in other assets and was $43.3 million and $42.6 million at December 31, 2004 and 2003, respectively.

Inventories

Inventories, other than natural gas in underground storage for the Company's regulated operations, consisted primarily of aggregates held for resale of $71.0 million and $54.7 million, materials and supplies of $31.0 million and $27.2 million, and other inventories of $17.0 million and $12.6 million, as of December 31, 2004 and 2003, 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. Leased mineral rights at the Company's construction materials and mining business were reclassified from other intangible assets, net, to property, plant and equipment, as discussed in new accounting standards in this note. 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 this note, 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 $6.2 million, $7.4 million and $7.6 million in 2004, 2003 and 2002, 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, 2004 and 2003, was as follows:

	2004	2003	Estimated Depreciable Life in Years
	(Dollars in thousands, as applicable)		
Regulated:			
Electric:			
Electric generation, distribution and transmission plant	**$ 650,902**	$ 639,893	4-50
Natural gas distribution:			
Natural gas distribution plant	**264,496**	252,591	4-40
Pipeline and energy services:			
Natural gas transmission, gathering and storage facilities	**358,853**	340,841	8-104
Nonregulated:			
Utility services:			
Land	**2,533**	2,505	---
Buildings and improvements	**10,257**	10,123	3-40
Machinery, vehicles and equipment	**63,586**	58,843	2-10
Other	**6,224**	5,400	3-10
Pipeline and energy services:			
Natural gas gathering and other facilities	**132,067**	119,613	3-20
Energy services	**1,480**	1,339	3-15
Natural gas and oil production:			
Natural gas and oil properties	**973,604**	862,839	*
Other	**9,021**	8,518	3-7
Construction materials and mining:			
Land	**91,610**	89,545	---
Buildings and improvements	**51,309**	48,907	3-40
Machinery, vehicles and equipment	**658,355**	569,295	1-23
Construction in progress	**16,545**	14,392	---
Aggregate reserves	**372,649**	358,260	**
Independent power production:			
Electric generation	**154,631**	153,944	10-30
Construction in progress	**93,953**	29,805	---
Land	**375**	375	---
Other	**1,643**	3	3-7
Other:			
Land	**3,044**	1,626	---
Other	**14,291**	15,381	3-20
Less accumulated depreciation, depletion and amortization	**1,358,723**	1,187,105	
Net property, plant and equipment	**$2,572,705**	$2,396,933	

* *Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of $.98, $.89, and $.80 for the years ended December 31, 2004, 2003 and 2002, respectively. Includes natural gas and oil production properties accounted for under the full-cost method, of which $69.0 million and $104.3 million were excluded from amortization at December 31, 2004 and 2003, respectively.*

** *Depleted 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 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. In the third quarter of 2004, the Company recognized a $2.1 million ($1.3 million after tax) adjustment reflecting the reduction in value of certain gathering facilities in the Gulf Coast region at the pipeline and energy services segment. No impairment losses were recorded in 2003 and 2002. 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. 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 the third quarter of 2004, the Company recognized a goodwill impairment at the pipeline and energy services segment. For more information on the goodwill impairment and 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 SEC, and the cost 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, 2004 and 2003, 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, 2004, 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, 2004, in total and by year in which such costs were incurred:

		Year Costs Incurred			
	Total	2004	2003	2002	2001 and prior
			(In thousands)		
Acquisition	$34,169	$ 6,708	$ 481	$15,493	$ 11,487
Development	22,582	16,259	4,559	1,764	---
Exploration	5,228	4,681	547	---	---
Capitalized interest	7,005	2,252	1,839	2,914	---
Total costs not subject to amortization	$68,984	$29,900	$7,426	$20,171	$ 11,487

Costs not subject to amortization as of December 31, 2004, 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 and an enhanced recovery development project in the Cedar Creek Anticline in southeastern Montana. The Company expects that the majority of these costs will be evaluated within the next 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 and, where applicable, revenues are recognized under Emerging Issues Task Force Issue No. 91-6, "Revenue Recognition of Long-Term Power Sales Contracts," ratably over the terms of the related contract. 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. If a loss is anticipated on a contract, the loss is immediately recognized. Costs in excess of billings on uncompleted contracts of $31.9 million and $31.8 million at December 31, 2004 and 2003, respectively, represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs on uncompleted contracts of $32.2 million and $20.4 million at December 31, 2004 and 2003, respectively, represent billings in excess of revenues recognized and were 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 $40.9 million and $34.3 million at December 31, 2004 and 2003, 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 that natural gas and oil price derivative instruments and interest rate derivative instruments not exceed a period of 24 months and foreign currency derivative instruments not exceed a 12-month period. 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.

Asset retirement obligations

In 2003, the Company adopted SFAS No. 143, which requires the Company 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 Company 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, the Company either settles the obligation for the recorded amount or incurs a gain or loss. For more information on asset retirement obligations, see Note 8.

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 $15.5 million and $10.5 million at December 31, 2004 and 2003, respectively, which is included in prepayments and other current assets.

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 above the primary automobile and general liability policies 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 for claims incurred but not reported.

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 10.

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, 2004, 2003 and 2002, 36,000 shares, 209,805 shares and 3,674,925 shares, respectively, with an average exercise price of $25.70, $24.56 and $20.08, 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, 2004, 2003 and 2002, 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 years ended December 31, 2004 and 2003, was $18,000 and $41,000, respectively (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 Accounting Principles Board (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.

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, 2004, 2003 and 2002, 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:

	2004	2003	2002
	(In thousands, except per share amounts)		
Earnings on common stock, as reported	**$206,382**	$ 174,607	$147,688
Stock-based compensation expense included in reported earnings, net of related tax effects	**18**	41	---
Total stock-based compensation expense determined under fair value method for all awards, net of related tax effects	**(62)**	(2,139)	(2,862)
Pro forma earnings on common stock	**$206,338**	$ 172,509	$144,826
Earnings per common share -- basic -- as reported:			
Earnings before cumulative effect of accounting change	**$ 1.77**	$ 1.64	$ 1.39
Cumulative effect of accounting change	**---**	(.07)	---
Earnings per common share -- basic	**$ 1.77**	$ 1.57	$ 1.39
Earnings per common share -- basic -- pro forma:			
Earnings before cumulative effect of accounting change	**$ 1.77**	$ 1.62	$ 1.36
Cumulative effect of accounting change	**---**	(.07)	---
Earnings per common share -- basic	**$ 1.77**	$ 1.55	$ 1.36
Earnings per common share -- diluted -- as reported:			
Earnings before cumulative effect of accounting change	**$ 1.76**	$ 1.62	$ 1.38
Cumulative effect of accounting change	**---**	(.07)	---
Earnings per common share -- diluted	**$ 1.76**	$ 1.55	$ 1.38

Earnings per common share -- diluted -- pro forma:			
Earnings before cumulative effect of accounting change	**$ 1.76**	$ 1.60	$ 1.36
Cumulative effect of accounting change	**---**	(.07)	---
Earnings per common share -- diluted	**$ 1.76**	$ 1.53	$ 1.36

For more information on the Company's stock-based compensation, see Note 11.

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 the electric power sales contract 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,	**2004**	2003	2002
		(In thousands)	
Interest, net of amount capitalized	**$50,236**	$47,474	$37,788
Income taxes	**$50,487**	$31,737	$60,988

Reclassifications

Certain 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

FIN 46 (revised) --

In December 2003, the FASB issued FIN 46 (revised), which replaced 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.

The Company evaluated the provisions of FIN 46 (revised) and determined that the Company does not have any controlling financial interests in any variable interest entities and, therefore, is not required to consolidate any variable interest entities in its financial statements. The adoption of FIN 46 (revised) did not have an effect on the Company's financial position or results of operations.

FSP Nos. FAS 106-1 and FAS 106-2 --

In January 2004, the FASB issued FSP No. FAS 106-1. FSP 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 2003 Medicare Act.

In May 2004, the FASB issued FSP No. FAS 106-2. FSP No. FAS 106-2 requires (a) that the effects of the federal subsidy be considered an actuarial gain and recognized in the same manner as other actuarial gains and losses and (b) certain disclosures for employers that sponsor postretirement health care plans that provide prescription drug benefits.

The Company provides prescription drug benefits to certain eligible employees. The Company elected the one-time deferral of accounting for the effects of the 2003 Medicare Act in the quarter ended March 31, 2004, the first period in which the plan's accounting for the effects of the 2003 Medicare Act normally would have been reflected in the Company's financial statements.

During the second quarter of 2004, the Company adopted FSP No. FAS 106-2 retroactive to the beginning of the year. The Company and its actuarial advisors determined that benefits provided to certain participants are expected to be at least actuarially equivalent to Medicare Part D (the federal prescription drug benefit), and, accordingly, the Company expects to be entitled to a federal subsidy. The expected federal subsidy reduced the APBO at January 1, 2004, by approximately $3.2 million, and net periodic benefit cost for 2004 by approximately $285,000 (as compared with the amount calculated without considering the effects of the subsidy). In addition, the Company expects a reduction in future participation in the postretirement plans, which further reduced the APBO at January 1, 2004, by approximately $12.7 million and net periodic benefit cost for 2004 by approximately $1.3 million.

FSP Nos. FAS 141-1 and FAS 142-1 --

In April 2004, the FASB issued FSP Nos. FAS 141-1 and FAS 142-1. FSP Nos. FAS 141-1 and FAS 142-1 amend SFAS No. 141, "Business Combinations," and SFAS No. 142 to clarify that certain mineral rights held by mining entities that are not within the scope of SFAS No. 19 be classified as tangible assets rather than intangible assets. The Company adopted FSP Nos. FAS 141-1 and FAS 142-1 in the second quarter of 2004. FSP Nos. FAS 141-1 and FAS 142-1 required reclassification of the Company's leasehold rights at its construction materials and mining operations from other intangible assets, net, to property, plant and equipment, as well as changes to Notes to Consolidated Financial Statements. FSP Nos. FAS 141-1 and FAS 142-1 affected the asset classification in the consolidated balance sheet and associated footnote disclosure only, so the reclassifications did not affect the Company's stockholders' equity, cash flows or results of operations.

FSP No. FAS 142-2 --

In September 2004, the FASB Staff issued FSP No. FAS 142-2. FSP No. FAS 142-2 indicates that the exception in SFAS No. 142 does not change the accounting prescribed in SFAS No. 19 including the balance sheet classification of drilling and mineral rights of oil and gas producing entities and, as a result, the contractual mineral rights should continue to be classified as part of property, plant and equipment. FSP No. FAS 142-2 did not have an effect on the Company's financial position, results of operations or cash flows.

SAB No. 106 --

In September 2004, the SEC issued SAB No. 106 which is an interpretation regarding the application of SFAS No. 143 by oil and gas producing companies following the full-cost accounting method. SAB No. 106 clarifies that the future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet should be excluded from the computation of the present value of estimated future net revenues for purposes of the full-cost ceiling calculation. SAB No. 106 also states that a company is expected to disclose in the financial statement footnotes and MD&A how the company's calculation of the ceiling test and depreciation, depletion and amortization are affected by the adoption of SFAS No. 143. SAB No. 106 shall be applied to all entities subject to SAB No. 106 as of the beginning of the first quarter after October 4, 2004. The adoption of SAB No. 106 is not expected to have a material effect on the Company's financial position or results of operations.

SFAS No. 123 (revised) --

In December 2004, the FASB issued SFAS No. 123 (revised). SFAS No. 123 (revised) revises SFAS No. 123 and requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. SFAS No. 123 (revised) requires a company to record compensation expense for all awards granted after the date of adoption of SFAS No. 123 (revised) and for the unvested portion of previously granted awards that remain outstanding at the date of adoption. SFAS No. 123 (revised) is effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. The Company is evaluating the effects of the adoption of SFAS No. 123 (revised).

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 (losses) on derivative instruments qualifying as hedges, minimum pension liability adjustments and foreign currency translation adjustments. For more information on derivative instruments, see Note 5.

The components of other comprehensive income (loss), and their related tax effects for the years ended December 31, 2004, 2003 and 2002, were as follows:

	2004	2003	2002
		(In thousands)	
Other comprehensive income (loss):			
Net unrealized gain (loss) on derivative instruments qualifying as hedges:			
Net unrealized loss on derivative instruments arising during the period, net of tax of $2,734, $2,132 and $2,903 in 2004, 2003 and 2002, respectively	**$(4,367)**	$ (3,335)	$ (4,541)
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $2,132, $2,903 and $1,448 in 2004, 2003 and 2002, respectively	**(3,335)**	(4,541)	2,218
Net unrealized gain (loss) on derivative instruments qualifying as hedges	**(1,032)**	1,206	(6,759)
Minimum pension liability adjustment, net of tax of $2,406, $38 and $2,876 in 2004, 2003 and 2002, respectively	**(3,782)**	21	(4,464)
Foreign currency translation adjustment	**852**	1,048	(799)
Total other comprehensive income (loss)	**$(3,962)**	$ 2,275	$(12,022)

The after-tax components of accumulated other comprehensive loss as of December 31, 2004, 2003 and 2002, were as follows:

	Net Unrealized Loss on Derivative Instruments Qualifying as Hedges	Minimum Pension Liability Adjustment	Foreign Currency Translation Adjustment	Total Accumulated Other Comprehensive Loss
		(In thousands)		
Balance at December 31, 2002	$(4,541)	$(4,464)	$ (799)	$ (9,804)
Balance at December 31, 2003	$(3,335)	$(4,443)	$ 249	$ (7,529)
Balance at December 31, 2004	**$(4,367)**	**$(8,225)**	**$1,101**	**$(11,491)**

Note 2
Equity Method Investments

The Company has a number of equity method investments including MPX, Carib Power and Hartwell. The Company assesses its equity method investments for impairment whenever events or changes in circumstances indicate that such carrying values may not be recoverable. None of the Company's equity method investments have been impaired and, accordingly, no impairment losses have been recorded in the accompanying consolidated financial statements or related equity method investment balances.

MDU Brasil has a 49 percent interest in MPX, which was formed in August 2001 when MDU Brasil entered into a joint venture agreement with a Brazilian firm. MPX, through a wholly owned subsidiary, owns and operates the Termoceara Generating Facility in the Brazilian state of Ceara. Petrobras, the Brazilian state-controlled energy company, entered into a contract to purchase all of the capacity and market all of energy from the Termoceara Generating Facility. The first phase of the electric power sales contract with Petrobras for 110 megawatts expires in November 2007 and the portion of the contract for the remaining 110 megawatts expires in May 2008. Petrobras also is under contract to supply natural gas to the Termoceara Generating Facility during the term of the electric power sales contract. This natural gas supply contract is renewable by a wholly owned subsidiary of MPX for an additional 13 years.

During 2004, Petrobras initiated discussions with a number of owners of thermoelectric plants, including MPX, regarding a possible renegotiation of their related power purchase agreements or buyout of the generating plants. On January 13, 2005, Petrobras obtained a Brazilian court order permitting it to cease making monthly capacity payments to MPX and to instead deposit the payments into a court account until the matter is resolved. On February 2, 2005, the court revoked its January 13, 2005, order and stated that MPX could withdraw the amounts deposited by Petrobras. This decision was upheld on appeal on February 17, 2005. Under the existing contract, Petrobras agreed to jointly market all of the facility's energy, and in the event that the facility's revenues are insufficient to cover its costs during certain periods, to make certain monthly contingency payments. Petrobras has stated that, because of structural changes in the Brazilian electric power markets since the contract was signed in 2001, the contingency payments had become permanent payment obligations entitling Petrobras to renegotiate the contract. The contract contains a dispute resolution provision which creates a 30-day period for accelerated negotiations. In the event that the parties do not reach agreement during the 30-day period, the dispute would be resolved in arbitration.

The Termoceara Generating Facility generates electricity based upon economic dispatch and available gas supplies. Under current conditions, including, in particular, existing constraints in the region's gas supply infrastructure, the Company does not expect the facility to generate a significant amount of energy at least through 2006.

The functional currency for the Termoceara Generating Facility is the Brazilian Real. The electric power sales contract 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. The Company's 49 percent share of the gain (loss) from the change in fair value of the embedded derivative in the electric power sales contract and the Company's 49 percent share of the foreign currency gain (loss) resulting from an increase (decrease) in value of the Brazilian Real versus the U.S. dollar for the years ended December 31, were as follows:

	2004	2003	2002
		(In thousands)	
Company's 49 percent share of the gain (loss) from the change in fair value of the embedded derivative in the electric power sales contract (after tax)	**$2,451**	$(11,282)	$13,592
Company's 49 percent share of the foreign currency gain (loss) resulting from the change in value of the Brazilian Real versus the U.S. dollar (after tax)	**$1,871**	$ 2,757	$(9,392)

Centennial has unconditionally guaranteed a portion of certain bank borrowings of MPX. For more information on this guarantee, see Note 18.

On February 26, 2004, Centennial International acquired 49.99 percent of Carib Power. Carib Power, through a wholly owned subsidiary, owns a 225-megawatt natural gas-fired electric generating facility located in Trinidad and Tobago. The Trinity Generating Facility sells its output to the T&TEC, the governmental entity responsible for the transmission, distribution and administration of electrical power to the national electrical grid of Trinidad and Tobago. The power purchase agreement expires in September 2029. T&TEC also is under contract to supply natural gas to the Trinity Generating

Facility during the term of the power purchase contract. The functional currency for the Trinity Generating Facility is the U.S. dollar.

On September 28, 2004, Centennial Resources, through wholly owned subsidiaries, acquired a 50-percent ownership interest in a 310-megawatt natural gas-fired electric generating facility. This facility is located in Hartwell, Georgia. The Hartwell Generating Facility sells its output under a power purchase agreement with Oglethorpe that expires in May 2019. American National Power, a wholly owned subsidiary of International Power of the United Kingdom, holds the remaining 50-percent ownership interest and is the operating partner for the facility.

At December 31, 2004, MPX, Carib Power and Hartwell had total assets of $334.2 million and long-term debt of $224.9 million. The Company's investment in the Termoceara, Trinity and Hartwell Generating Facilities was approximately $65.7 million, including undistributed earnings of $26.6 million at December 31, 2004. The Company's investment in the Termoceara Generating Facility was approximately $25.2 million, including undistributed earnings of $4.6 million at December 31, 2003.

Note 3
Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December 31, 2004, were as follows:

	Balance as of January 1, 2004	Goodwill Acquired During the Year*	Goodwill Impaired During the Year	Balance as of December 31, 2004
	(In thousands)			
Electric	$ ---	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---	---
Utility services	62,604	28	---	62,632
Pipeline and energy services	9,494	---	(4,030)	5,464
Natural gas and oil production	---	---	---	---
Construction materials and mining	120,198	254	---	120,452
Independent power production	7,131	4,064	---	11,195
Other	---	---	---	---
Total	$199,427	$ 4,346	$ (4,030)	$ 199,743

* Includes purchase price adjustments related to acquisitions acquired in a prior period.

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

	Balance as of January 1, 2003	Goodwill Acquired During the Year*	Balance as of December 31, 2003
	(In thousands)		
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
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	7,131	---	7,131
Other	---	---	---
Total	$190,999	$8,428	$199,427

* Includes purchase price adjustments related to acquisitions acquired in a prior period.

Innovatum, which specializes in cable and pipeline magnetization and location, developed a hand-held locating device that can detect both magnetic and plastic materials, including unexploded ordnance. Innovatum was working with, and had demonstrated the device to, a Department of Defense contractor and had also met with individuals from the Department of Defense, to discuss the possibility of using the hand-held locating device in their operations. In the third quarter of 2004, after communications with the Department of Defense, and delays in further testing resulting from a Department of Defense request to enhance the hand-held locating device, Innovatum decreased its expected future cash flows from the hand-held locating device. This decrease, coupled with the continued downturn in the telecommunications and energy industries, resulted in a revised earnings forecast for Innovatum, and as a result, a goodwill impairment loss of $4.0 million (before and after tax), which was included in asset impairments, was recognized in the third quarter of 2004. Innovatum, a reporting unit for goodwill impairment testing, is part of the pipeline and energy services segment. The fair value of Innovatum was estimated using the expected present value of future cash flows.

As discussed in Note 1, the Company reclassified its leasehold rights at its construction materials and mining operations from other intangible assets, net, to property, plant and equipment.

Other intangible assets at December 31, 2004 and 2003 were as follows:

	2004	2003
	(In thousands)	
Amortizable intangible assets:		
Acquired contracts	**$ 15,041**	$ 12,656
Accumulated amortization	**(5,013)**	(1,944)
	10,028	10,712
Noncompete agreements	**10,575**	12,075
Accumulated amortization	**(8,186)**	(9,690)
	2,389	2,385
Other	**9,535**	5,078
Accumulated amortization	**(534)**	(321)
	9,001	4,757
Unamortizable intangible assets	**851**	960
Total	**$ 22,269**	$18,814

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, 2004, 2003 and 2002, was $3.8 million, $2.2 million and $757,000, respectively. Estimated amortization expense for amortizable intangible assets is $2.8 million in 2005, $2.0 million in 2006, 2007 and 2008, $1.9 million in 2009 and $10.7 million thereafter.

Note 4
Regulatory Assets and Liabilities

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

	2004	2003
	(In thousands)	
Regulatory assets:		
Deferred income taxes	**$ 39,212**	$ 37,072
Natural gas costs recoverable through rate adjustments	**15,534**	10,519
Plant costs	**12,838**	2,697
Long-term debt refinancing costs	**3,531**	4,519
Postretirement benefit costs	**507**	562
Other	**7,225**	7,159
Total regulatory assets	**78,847**	62,528
Regulatory liabilities:		
Plant removal and decommissioning costs	**78,525**	76,176
Liabilities for regulatory matters	**18,853**	11,970
Taxes refundable to customers	**15,660**	18,973
Deferred income taxes	**15,192**	10,663
Other	**3,676**	658
Total regulatory liabilities	**131,906**	118,440
Net regulatory position	**$ (53,059)**	$ (55,912)

As of December 31, 2004, a large portion of the Company's regulatory assets, other than certain deferred income taxes, was being reflected in rates charged to customers and is being recovered over the next one to 18 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

Derivative instruments (including certain derivative instruments embedded in other contracts) are required to be recorded on the balance sheet as either an asset or liability measured at its fair value. Changes in the derivative instrument's fair value are 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.

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; if the derivative instrument expires or is sold, terminated or exercised; 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, 2004, Fidelity held derivative instruments designated as cash flow hedging instruments.

Hedging activities

Fidelity 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 its 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, 2004, 2003 and 2002, the amount of hedge ineffectiveness, which was included in operating revenues, was immaterial. For the years ended December 31, 2004, 2003 and 2002, Fidelity 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, 2004, the maximum term of Fidelity's swap and collar agreements, in which Fidelity is hedging its exposure to the variability in future cash flows for forecasted transactions, is 12 months. Fidelity estimates that over the next 12 months, net losses of approximately $4.4 million will be reclassified from accumulated other comprehensive loss into earnings, subject to changes in natural gas and oil market prices, as the hedged transactions affect earnings.

Note 6
Fair Value of Other Financial Instruments

The estimated fair value of the Company's long-term debt is based on quoted market prices of the same or similar issues. The estimated fair values of the Company's natural gas and oil price swap and collar agreements were included in current liabilites at December 31, 2004 and 2003. The estimated fair values of the Company's natural gas and oil price swap and collar agreements 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 and natural gas and oil price swap and collar agreements at December 31 was as follows:

	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(In thousands)		
Long-term debt	**$945,487**	**$ 992,172**	$967,096	$1,012,547
Natural gas and oil price swap and collar agreements	**$ (7,101)**	**$ (7,101)**	$ (5,467)	$ (5,467)

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
Long-term Debt and Indenture Provisions

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

	2004	2003
	(In thousands)	
First mortgage bonds and notes:		
Pollution Control Refunding Revenue Bonds, Series 1992, 6.65%, due June 1, 2022	**$ 20,850**	$ 20,850
Secured Medium-Term Notes, Series A, at a weighted average rate of 7.75%, due on dates ranging from April 1, 2007 to April 1, 2012	**95,000**	110,000
Senior Note, 5.98%, due December 15, 2033	**30,000**	30,000
Total first mortgage bonds and notes	**145,850**	160,850
Senior notes at a weighted average rate of 6.23%, due on dates ranging from January 18, 2005 to July 1, 2019	**728,500**	718,000
Commercial paper at a weighted average rate of 2.28%, supported by revolving credit agreements	**63,000**	72,500
Term credit agreements at a weighted average rate of 6.68%, due on dates ranging from January 25, 2005 to December 1, 2013	**8,172**	14,286
Pollution control note obligation, 6.20%, paid in 2004	**---**	1,500
Discount	**(35)**	(40)
Total long-term debt	**945,487**	967,096
Less current maturities	**72,046**	27,646
Net long-term debt	**$873,441**	$939,450

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2004, aggregate $72.0 million in 2005; $138.8 million in 2006; $132.9 million in 2007; $161.3 million in 2008; $86.9 million in 2009 and $353.6 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, 2004.

MDU Resources Group, Inc.

The Company has a revolving credit agreement with various banks totaling $90 million at December 31, 2004. There were no amounts outstanding under the credit agreement at December 31, 2004 and 2003. The credit agreement supports the Company's $75 million commercial paper program. Under the Company's commercial paper program, $37.0 million and $40.0 million were outstanding at December 31, 2004 and 2003, respectively, which was classified as long-term debt. The commercial paper borrowings classified as long-term debt are intended to be refinanced on a long-term basis through continued commercial paper borrowings and as further supported by the credit agreement, which expires on July 18, 2006.

In order to borrow under the Company's credit agreement, the Company 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, 2004.

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

The Company's 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 fund $1.43 of unfunded property or use $1.00 of refunded bonds for each dollar of indebtedness incurred under the Indenture and, in some cases, to certify to the trustee 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 tests, as of December 31, 2004, the Company could have issued approximately $343 million of additional first mortgage bonds.

Approximately $419.7 million of the Company's net electric and natural gas distribution properties at December 31, 2004, 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 has three revolving credit agreements with various banks and institutions that support $335 million of Centennial's $350 million commercial paper program. There were no outstanding borrowings under the Centennial credit agreements at December 31, 2004 or 2003. Under the Centennial commercial paper program, $26.0 million and $32.5 million were outstanding at December 31, 2004 and 2003, 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. One of these credit agreements is for $300 million and expires on August 17, 2007, and another agreement is for $25 million and expires on April 30, 2007. Centennial intends to negotiate the extension or replacement of these agreements prior to their maturities. The third agreement is an uncommitted line for $10 million, which was effective on January 25, 2005, and may be terminated by the bank at any time.

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, 2004 and 2003. The ability to request additional borrowings under this master shelf agreement expires on February 28, 2005. The Company is in discussion regarding potential renewal of this facility. 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, 2004.

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 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 was outstanding at December 31, 2004 and 2003. The ability to request additional borrowings under this master shelf agreement expires on December 20, 2005.

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, 2004.

Note 8
Asset Retirement Obligations

The Company adopted SFAS No. 143 on January 1, 2003. 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, which is included in other liabilities, for the years ended December 31 was as follows:

	2004	2003
	(In thousands)	
Balance at beginning of year	**$34,633**	$29,997
Liabilities incurred	**3,718**	2,405
Liabilities acquired	**178**	1,803
Liabilities settled	**(2,286)**	(1,555)
Accretion expense	**1,931**	1,906
Revisions in estimates	**(824)**	77
Balance at end of year	**$37,350**	$34,633

The fair value of assets that are legally restricted for purposes of settling asset retirement obligations at December 31, 2004 and 2003, was $5.2 million and $5.1 million, respectively.

Note 9
Preferred Stocks

Preferred stocks at December 31 were as follows:

	2004	2003
	(Dollars in thousands)	
Authorized:		
Preferred --		
500,000 shares, cumulative, par value $100, issuable in series		
Preferred stock A --		
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Preference --		
500,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Outstanding:		
4.50% Series -- 100,000 shares	**$10,000**	$ 10,000
4.70% Series -- 50,000 shares	**5,000**	5,000
Total preferred stocks	**$15,000**	$ 15,000

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 10
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.

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, 2002, 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, 2004, there were 12.1 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

In 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 11
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, 2004, 2003 and 2002, 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, 2004, 2003 and 2002, and changes during the years then ended were as follows:

	2004		2003		2002	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance at beginning of year	**4,182,456**	**$19.09**	4,861,268	$18.58	5,208,311	$18.60
Granted	**---**	**---**	27,015	17.29	160,605	19.15
Forfeited	**(382,942)**	**19.64**	(188,486)	20.05	(453,840)	19.77
Exercised	**(1,237,830)**	**18.49**	(517,341)	13.88	(53,808)	12.20
Balance at end of year	**2,561,684**	**19.29**	4,182,456	19.09	4,861,268	18.58
Exercisable at end of year	**1,700,223**	**$18.73**	611,404	$15.06	1,135,050	$14.56

Summarized information about stock options outstanding and exercisable as of December 31, 2004, was as follows:

	Options Outstanding			Options Exercisable	
Range of Exercisable Prices	Number Outstanding	Remaining Contractual Life in Years	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$ 8.22 - 13.00	11,076	2.3	$ 10.69	11,076	$ 10.69
13.01 - 17.00	374,050	3.4	14.20	371,404	14.19
17.01 - 21.00	1,977,433	6.2	19.77	1,243,108	19.78
21.01 - 25.70	199,125	6.2	24.55	74,635	24.97
Balance at end of year	2,561,684	5.8	19.29	1,700,223	18.73

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:

	2004	2003	2002
Weighted average fair value of options at grant date	---	$4.67	$5.38
Weighted average risk-free interest rate	---	3.91%	5.14%
Weighted average expected price volatility	---	32.28%	30.80%
Weighted average expected dividend yield	---	3.43%	3.43%
Expected life in years	---	7	7

In addition, prior to 2002 the Company granted restricted stock awards under a long-term incentive plan and deferred compensation agreements. The restricted stock awards granted vest to the participants at various times ranging from one year 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 Company also has granted stock awards totaling 35,205 shares, 31,855 shares and 21,390 shares in 2004, 2003 and 2002, respectively, under a nonemployee director stock compensation plan. The weighted average grant date fair value of the stock grants was $23.61, $21.40 and $19.20, in 2004, 2003 and 2002, 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 $3.4 million, $4.8 million and $5.2 million in 2004, 2003 and 2002, respectively.

In 2004 and 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	59,224
February 2003	2003-2005	54,180
February 2004	2004-2006	189,337

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 years ended December 31, 2004 and 2003, was $2.5 million and $879,000, respectively.

The Company is authorized to grant options, restricted stock and stock for up to 14.7 million shares of common stock and has granted options, restricted stock and stock on 5.8 million shares through December 31, 2004.

Note 12
Income Taxes

The components of income before income taxes for each of the years ended December 31 were as follows:

	2004	2003	2002
		(In thousands)	
United States	**$ 280,764**	$ 278,143	$ 233,536
Foreign	**20,277**	3,342	1,138
Income before income taxes	**$ 301,041**	$ 281,485	$ 234,674

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

	2004	2003	2002
		(In thousands)	
Current:			
Federal	**$ 47,625**	$ 26,313	$ 46,389
State	**12,231**	7,408	9,082
Foreign	**955**	264	---
	60,811	33,985	55,471
Deferred:			
Income taxes --			
Federal	**28,556**	55,660	26,373
State	**5,422**	9,861	4,632
Foreign	**(223)**	(338)	338
Investment tax credit	**(592)**	(596)	(584)
	33,163	64,587	30,759
Total income tax expense	**$ 93,974**	$ 98,572	$ 86,230

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

	2004	2003
	(In thousands)	
Deferred tax assets:		
Regulatory matters	**$ 39,212**	$ 37,072
Accrued pension costs	**18,754**	12,122
Asset retirement obligations	**12,197**	7,017
Deferred compensation	**9,938**	9,090
Bad debts	**2,266**	3,188
Deferred investment tax credit	**724**	954
Other	**29,237**	21,269
Total deferred tax assets	**112,328**	90,712
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	**450,237**	406,589
Basis differences on natural gas and oil producing properties	**124,788**	105,826
Regulatory matters	**15,192**	10,663
Other	**13,826**	9,309
Total deferred tax liabilities	**604,043**	532,387
Net deferred income tax liability	**$(491,715)**	$(441,675)

As of December 31, 2004 and 2003, 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, 2003, to December 31, 2004, to deferred income tax expense:

	2004
	(In thousands)
Change in net deferred income tax liability from the preceding table	**$ 50,040**
Deferred taxes associated with acquisitions	**(16,189)**
Other	**(688)**
Deferred income tax expense for the period	**$ 33,163**

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,	**2004**		2003		2002	
	Amount	%	Amount	%	Amount	%
		(Dollars in thousands)				
Computed tax at federal statutory rate	**$105,364**	**35.0**	$98,520	35.0	$82,136	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit	**11,468**	**3.8**	11,857	4.2	10,279	4.4
Audit resolution	**(8,818)**	**(2.9)**	---	---	---	---
Foreign operations	**(5,648)**	**(1.9)**	(832)	(.3)	177	---
Depletion allowance	**(3,418)**	**(1.2)**	(3,117)	(1.1)	(2,200)	(.9)
Renewable electricity production credit	**(3,404)**	**(1.1)**	(3,395)	(1.2)	---	---
Other items	**(1,570)**	**(.5)**	(4,461)	(1.6)	(4,162)	(1.8)
Total income tax expense	**$93,974**	**31.2**	$98,572	35.0	$86,230	36.7

In 2004, the Company resolved federal and related state income tax matters for the 1998 through 2000 tax years. The Company reflected the effects of this tax resolution and, in addition, reversed liabilities that had previously been provided and were deemed to be no longer required, which resulted in a benefit of $8.3 million (after tax), including interest.

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. The cumulative undistributed earnings at December 31, 2004, were approximately $22 million. The amount of unrecognized deferred tax liability associated with the undistributed earnings was approximately $5 million.

The Company has evaluated the repatriation provisions of the American Jobs Creation Act of 2004 (Act), which was enacted on October 22, 2004. The provisions of the Act permit corporations to elect an 85-percent deduction for certain qualifying dividends received during 2005 from controlled foreign corporations. The deduction is only available to the extent that the dividend is in excess of an historical base-period average and if the dividend is invested in the United States pursuant to a qualifying domestic investment plan. At this time, the Company does not anticipate that it will be receiving dividends qualifying for this election during 2005.

Note 13
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. Prior to the fourth quarter of 2004, the Company reported 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. The independent power production and other operations did not individually meet the criteria to be considered a reportable segment. In the fourth quarter of 2004, the Company separated independent power production as a reportable business segment due to the significance of its operations. The Company's operations are now conducted through seven reportable segments and all prior period information has been restated to reflect this change.

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 investments in natural gas-fired electric generating facilities in Brazil and Trinidad and Tobago, 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, development 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 segment owns, builds and operates electric generating facilities in the United States and has investments in domestic and international natural resource-based projects. Electric capacity and energy produced at its power plants are sold primarily under mid- and long-term contracts to nonaffiliated entities.

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:

	2004	2003	2002
		(In thousands)	
External operating revenues:			
Electric	**$ 178,803**	$ 178,562	$ 162,616
Natural gas distribution	**316,120**	274,608	186,569
Pipeline and energy services	**281,913**	187,892	110,224
	776,836	641,062	459,409
Utility services	**425,250**	434,177	458,660
Natural gas and oil production	**152,486**	140,281	148,158
Construction materials and mining	**1,321,626**	1,104,408	962,312
Independent power production	**43,059**	32,261	2,998
Other	**---**	---	---
	1,942,421	1,711,127	1,572,128
Total external operating revenues	**$2,719,257**	$2,352,189	$2,031,537
Intersegment operating revenues:			
Electric	**$ ---**	$ ---	$ ---
Natural gas distribution	**---**	---	---
Utility services	**1,571**	---	---
Pipeline and energy services	**75,316**	64,300	55,034
Natural gas and oil production	**190,354**	124,077	55,437
Construction materials and mining	**535**	---	---
Independent power production	**---**	---	---
Other	**4,423**	2,728	3,778
Intersegment eliminations	**(272,199)**	(191,105)	(114,249)
Total intersegment operating revenues	**$ ---**	$ ---	$ ---
Depreciation, depletion and amortization:			
Electric	**$ 20,199**	$ 20,150	$ 19,537
Natural gas distribution	**9,329**	10,044	9,940
Utility services	**11,113**	10,353	9,871
Pipeline and energy services	**17,804**	15,016	14,846
Natural gas and oil production	**70,823**	61,019	48,714
Construction materials and mining	**69,644**	63,601	54,334
Independent power production	**9,587**	7,860	444
Other	**271**	294	275
Total depreciation, depletion			

and amortization	$ 208,770	$ 188,337	$ 157,961
Interest expense:			
Electric	$ 9,116	$ 8,013	$ 7,621
Natural gas distribution	4,292	3,936	4,364
Utility services	3,442	3,668	3,568
Pipeline and energy services	9,262	7,952	7,670
Natural gas and oil production	7,552	4,767	2,464
Construction materials and mining	20,646	18,747	18,422
Independent power production	4,354	5,850	1,100
Other	(70)	15	22
Intersegment eliminations	(1,157)	(154)	(216)
Total interest expense	$ 57,437	$ 52,794	$ 45,015
Income taxes:			
Electric	$ 4,303	$ 9,862	$ 9,501
Natural gas distribution	(3,883)	1,823	(1,325)
Utility services	(3,345)	3,905	4,781
Pipeline and energy services	7,445	11,188	12,462
Natural gas and oil production	61,261	42,993	30,604
Construction materials and mining	26,674	28,168	29,415
Independent power production	1,249	257	406
Other	270	376	386
Total income taxes	$ 93,974	$ 98,572	$ 86,230
Cumulative effect of accounting change (Note 8):			
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	---	---	---
Other	---	---	---
Total cumulative effect of accounting change	$ ---	$ (7,589)	$ ---
Earnings on common stock:			
Electric	$ 12,790	$ 16,950	$ 15,780
Natural gas distribution	2,182	3,869	3,587
Utility services	(5,650)	6,170	6,371
Pipeline and energy services	8,944	18,158	19,097
Natural gas and oil production	110,779	63,027	53,192
Construction materials and mining	50,707	54,412	48,702
Independent power production	26,309	11,415	307
Other	321	606	652
Total earnings on common stock	$ 206,382	$ 174,607	$ 147,688

Capital expenditures:			
Electric	**$ 18,767**	$ 28,537	$ 27,795
Natural gas distribution	**17,384**	15,672	11,044
Utility services	**8,470**	7,820	17,242
Pipeline and energy services	**38,282**	93,004	21,449
Natural gas and oil production	**111,506**	101,698	136,424
Construction materials and mining	**133,080**	128,487	106,893
Independent power production	**76,246**	110,963	89,621
Other	**4,215**	1,895	6,127
Net proceeds from sale or disposition of property	**(20,518)**	(14,439)	(16,217)
Total net capital expenditures	**$ 387,432**	$ 473,637	$ 400,378
Identifiable assets:			
Electric*	**$ 323,819**	$ 327,899	$ 322,475
Natural gas distribution*	**252,582**	234,948	208,502
Utility services	**230,955**	221,824	230,888
Pipeline and energy services	**447,302**	405,904	312,858
Natural gas and oil production	**685,610**	602,389	554,420
Construction materials and mining	**1,345,547**	1,248,607	1,137,697
Independent power production	**349,752**	241,918	130,867
Other**	**97,954**	97,103	99,214
Total identifiable assets	**$3,733,521**	$3,380,592	$2,996,921
Property, plant and equipment:			
Electric*	**$ 650,902**	$ 639,893	$ 619,230
Natural gas distribution*	**264,496**	252,591	244,930
Utility services	**82,600**	76,871	70,660
Pipeline and energy services	**492,400**	461,793	372,420
Natural gas and oil production	**982,625**	871,357	755,788
Construction materials and mining	**1,190,468**	1,080,399	976,751
Independent power production	**250,602**	184,127	79,373
Other	**17,335**	17,007	15,152
Less accumulated depreciation, depletion and amortization	**1,358,723**	1,187,105	1,026,932
Net property, plant and equipment	**$2,572,705**	$2,396,933	$2,107,372

* *Includes allocations of common utility property.*

** *Includes assets not directly assignable to a business (i.e., cash and cash equivalents, certain accounts receivable and other miscellaneous current and deferred assets).*

Excluding the asset impairments at the pipeline and energy services segment of $5.3 million (after tax), 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, independent power production, and other are all from nonregulated operations. Capital expenditures for 2004, 2003 and 2002, related to acquisitions, in the preceding table included the following noncash transactions: issuance of the Company's equity securities of $33.1 million, $42.4 million and $47.2 million in 2004, 2003 and 2002, respectively.

Note 14
Acquisitions

In 2004, the Company acquired a number of businesses, none of which was individually material, including construction materials and mining businesses in Hawaii, Idaho, Iowa and Minnesota and an independent power production operating and development company in Colorado. The total purchase consideration for these businesses and adjustments with respect to certain other acquisitions acquired prior to 2004, consisting of the Company's common stock and cash, was $70.3 million.

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 generating facility in California. The total purchase consideration for these businesses and adjustments with respect to certain other acquisitions acquired in 2002, consisting of 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 April 2000, Fidelity 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 the Seller's Option Interest from Preston for an amount as specified in the agreement. In July 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 2004. 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 15
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. As discussed in Note 1, the Company recognized the effects of the 2003 Medicare Act during the second quarter of 2004. The net periodic benefit cost for 2004 reflects the effects of the 2003 Medicare Act. 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 2004	2003	Other Postretirement Benefits 2004	2003
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$261,335**	$224,766	**$ 88,381**	$ 74,917
Service cost	**7,667**	5,897	**1,826**	1,857
Interest cost	**15,903**	15,211	**4,312**	5,281
Plan participants' contributions	**---**	---	**1,133**	977
Amendments	**---**	210	**(773)**	754
Actuarial (gain) loss	**12,240**	27,701	**(14,951)**	10,338
Benefits paid	**(12,389)**	(12,450)	**(4,437)**	(5,743)
Benefit obligation at end of year	**284,756**	261,335	**75,491**	88,381
Change in plan assets:				
Fair value of plan assets at beginning of year	**223,043**	189,143	**47,234**	40,889
Actual gain on plan assets	**27,264**	43,087	**2,920**	6,148
Employer contribution	**1,604**	3,263	**4,127**	4,963
Plan participants' contributions	**---**	---	**1,134**	977
Benefits paid	**(12,389)**	(12,450)	**(4,437)**	(5,743)
Fair value of plan assets at end of year	**239,522**	223,043	**50,978**	47,234
Funded status - under	**(45,234)**	(38,292)	**(24,513)**	(41,147)
Unrecognized actuarial (gain) loss	**46,293**	41,422	**(1,832)**	11,862
Unrecognized prior service cost	**7,435**	8,556	**---**	706
Unrecognized net transition obligation (asset)	**(47)**	(297)	**16,999**	19,362
Prepaid (accrued) benefit cost	**$ 8,447**	$ 11,389	**$ (9,346)**	$ (9,217)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Prepaid benefit cost	**$ 19,020**	$ 19,671	**$ 572**	$ 614
Accrued benefit liability	**(10,573)**	(8,282)	**(9,918)**	(9,831)
Net amount recognized	**$ 8,447**	$ 11,389	**$ (9,346)**	$ (9,217)

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 $227.3 million and $212.0 million at December 31, 2004 and 2003, 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, 2004 and 2003, were as follows:

	2004	2003
	(In thousands)	
Projected benefit obligation	$ 174,983	$ 38,845
Accumulated benefit obligation	$ 136,012	$ 28,840
Fair value of plan assets	$ 132,280	$ 24,508

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

	Pension Benefits			Other Postretirement Benefits		
Years ended December 31,	2004	2003	2002	2004	2003	2002
			(In thousands)			
Components of net periodic benefit cost:						
Service cost	$ 7,667	$ 5,897	$ 5,135	$ 1,826	$ 1,857	$ 1,460
Interest cost	15,903	15,211	14,877	4,312	5,281	4,915
Expected return on assets	(20,375)	(20,730)	(21,110)	(3,943)	(3,933)	(3,843)
Amortization of prior service cost	1,121	1,156	1,148	144	48	---
Recognized net actuarial (gain) loss	480	(417)	(1,855)	(233)	(255)	(566)
Amortization of net transition obligation (asset)	(250)	(950)	(947)	2,151	2,151	2,151
Net periodic benefit cost (income)	4,546	167	(2,752)	4,257	5,149	4,117
Less amount capitalized	409	14	(352)	440	601	404
Net periodic benefit cost (income)	$ 4,137	$ 153	$ (2,400)	$ 3,817	$ 4,548	$ 3,713

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

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
Discount rate	5.75%	6.00%	5.75%	6.00%
Rate of compensation increase	4.70%	4.70%	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	
	2004	2003	2004	2003
Discount rate	6.00%	6.75%	6.00%	6.75%
Expected return on plan assets	8.50%	8.50%	7.50%	7.50%
Rate of compensation increase	4.70%	4.50%	4.50%	4.50%

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:

	2004	2003
Health care trend rate assumed for next year	**6.0%-9.5%**	6.0%-9.5%
Health care cost trend rate - ultimate	**5.0%-6.0%**	5.0%-6.0%
Year in which ultimate trend rate achieved	**1999-2013**	1999-2012

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, 2004:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 218	$ (872)
Effect on postretirement benefit obligation	$ 3,176	$ (8,489)

The Company's defined benefit pension plans' asset allocation at December 31, 2004 and 2003, and weighted average targeted asset allocations at December 31, 2004, were as follows:

Asset Category	Percentage of Plan Assets 2004	2003	Weighted Average Targeted Asset Allocation Percentage 2004
Equity securities	**74%**	72%	**70%**
Fixed income securities	**24**	25	**30***
Other	**2**	3	---
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, 2004 and 2003, and weighted average targeted asset allocation at December 31, 2004, were as follows:

Asset Category	Percentage of Plan Assets 2004	2003	Weighted Average Targeted Asset Allocation Percentage 2004
Equity securities	**70%**	66%	**70%**
Fixed income securities	**28**	30	**30***
Other	**2**	4	---
Total	**100%**	100%	**100%**

**Includes target for both fixed income securities and other.*

The Company expects to contribute approximately $900,000 to its defined benefit pension plans and approximately $3.8 million to its postretirement benefit plans in 2005.

The following benefit payments, which reflect future service, as appropriate, are expected to be paid:

Years	Pension Benefits	Other Postretirement Benefits
	(In thousands)	
2005	$ 12,403	$ 5,908
2006	12,726	5,666
2007	13,248	5,941
2008	13,830	6,204
2009	14,720	6,493
2010-2014	89,922	38,302

The following Medicare Part D subsidies are expected: none in 2005; $436,000 in 2006; $439,000 in 2007; $440,000 in 2008; $438,000 in 2009 and $2.2 million during the years 2010 through 2014.

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 $28.2 million, $27.2 million and $27.8 million in 2004, 2003 and 2002, respectively.

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has an unfunded, nonqualified benefit plan for executive officers and certain key management employees that generally provides for defined benefit payments at age 65 following the employee's retirement or to their beneficiaries upon death for a 15-year period. Investments, at December 31, 2004, consisted of cash equivalents and life insurance carried on plan participants, which is payable to the Company upon the employee's death. The Company's net periodic benefit cost for this plan was $7.5 million, $5.3 million and $5.1 million in 2004, 2003 and 2002, respectively. The total projected obligation for this plan was $65.3 million and $51.1 million at December 31, 2004 and 2003, respectively. The accumulated benefit obligation for this plan was $52.3 million and $40.7 million at December 31, 2004 and 2003, respectively. The additional minimum liability relating to this plan was $14.3 million and $8.2 million at December 31, 2004 and 2003, respectively. The Company has a related intangible asset recognized as of December 31, 2004 and 2003, of $851,000 and $1.0 million, respectively. A discount rate of 5.75 percent and 6.0 percent at December 31, 2004 and 2003, respectively, and a rate of compensation increase of 4.75 percent at both December 31, 2004 and 2003, were used to determine benefit obligations.

A discount rate of 6.00 percent and 6.75 percent at December 31, 2004 and 2003, respectively, and a rate of compensation increase of 4.75 percent and 4.50 percent at December 31, 2004 and 2003, respectively, were used to determine net periodic benefit cost. The increase in minimum liability included in other comprehensive income was $3.8 million in 2004 and $2.6 million in 2003.

The amount of benefit payments for the unfunded, nonqualified benefit plan, as appropriate, are expected to aggregate $2.5 million in 2005; $2.6 million in 2006; $3.1 million in 2007; $3.2 million in 2008; $3.3 million in 2009 and $20.0 million for the years 2010 through 2014.

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were $13.8 million in 2004, $9.8 million in 2003 and $9.6 million in 2002. The costs incurred in each year reflect additional participants as a result of business acquisitions.

Note 16
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:

	2004	2003
	(In thousands)	
Big Stone Station:		
Utility plant in service	**$ 52,157**	$ 52,154
Less accumulated depreciation	**36,488**	34,993
	$ 15,669	$ 17,161
Coyote Station:		
Utility plant in service	**$124,388**	$124,086
Less accumulated depreciation	**74,671**	72,850
	$ 49,717	$ 51,236

Note 17
Regulatory Matters and Revenues Subject To Refund

On September 7, 2004, Great Plains filed an application with the MPUC for a natural gas rate increase. Great Plains had requested a total of $1.4 million annually or 4.0 percent above current rates. Great Plains also requested an interim increase of $1.4 million annually. On November 23, 2004, the MPUC issued an Order setting interim rates of $1.4 million annually effective with service rendered on or after January 10, 2005, subject to refund. A final order from the MPUC is expected in late 2005.

On June 7, 2004, Montana-Dakota filed an application with the SDPUC for a natural gas rate increase for the Black Hills service area. Montana-Dakota requested a total of $1.3 million annually or 2.2 percent above current rates. On November 15, 2004, Montana-Dakota and the SDPUC Staff filed a Settlement Stipulation with the SDPUC agreeing to an increase of $670,000 annually, or 1.4 percent. On November 30, 2004, the SDPUC approved the Settlement Stipulation effective with service rendered on or after December 1, 2004.

On April 1, 2004, Montana-Dakota filed an application with the MTPSC for a natural gas rate increase. Montana-Dakota requested a total of $1.5 million annually or 1.8 percent above current rates. On January 14, 2005, Montana-Dakota and the Montana Consumer Counsel filed a Stipulation with the MTPSC agreeing to an increase of $125,000 annually to be effective with service rendered on or after February 1, 2005. On January 25, 2005, the MTPSC passed a Motion approving the Stipulation.

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 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. In July 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. In August 2003, Williston Basin requested 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 May 11, 2004, the FERC issued an Order on Rehearing. The Order on Rehearing denied rehearing on all of the issues addressed by Williston Basin in its August 2003 request for rehearing except for the issue of the proper rate to utilize for transmission system negative salvage expenses. In addition, the FERC remanded the issues regarding certain service and annual demand quantity restrictions to an ALJ for resolution. On June 14, 2004, Williston Basin requested clarification of a few of the issues addressed in the Order on Rehearing including determinations associated with cost of service and cost allocation, as discussed in the FERC's Order on Rehearing. On June 14, 2004, Williston Basin also made its filing to comply with the requirements of the various FERC orders in this proceeding. Williston Basin is awaiting a decision from the FERC on Williston Basin's compliance filing and clarification request but is unable to predict the timing of the FERC's decision. Williston Basin participated in a hearing before the ALJ in early January 2005, regarding the matters remanded to the ALJ by the FERC in its Order on Rehearing and an order on these matters is expected in 2005.

A liability has 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 the liability is adequate based on its assessment of the ultimate outcome of the proceeding.

Note 18
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, Grynberg filed suit under the Federal False Claims Act 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.

On June 4, 2004, following preliminary discovery, Williston Basin and Montana-Dakota joined with other defendants and filed a Motion to Dismiss on the grounds that the information upon which Grynberg based his complaint was publicly disclosed prior to the filing of his complaint and further, that he is not the original source of such information. The Motion to Dismiss is additionally based on the grounds that Grynberg disclosed the filing of the complaint prior to the entry of a court order allowing such disclosure and that Grynberg failed to provide adequate information to the government prior to filing suit.

In the event the Motion to Dismiss is not granted, it is expected that further discovery will follow. Williston Basin and Montana-Dakota believe Grynberg will not prevail in the suit or recover damages from Williston Basin and/or Montana-Dakota because insufficient facts exist to support the allegations. Williston Basin and Montana-Dakota believe Grynberg's claims are without merit and intend to vigorously contest this suit.

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.

Fidelity has been named as a defendant in, and/or certain of its operations are or have been the subject of, more than a dozen 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 November 2004 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. Portions of 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, the National Environmental Policy Act, the Federal Land Management Policy Act, the National Historic Preservation Act and the Montana Environmental Policy Act. The cases involving alleged violations of the Federal Clean Water Act have been resolved without a finding that Fidelity is in violation of the Federal Clean Water Act. There presently are no claims pending for penalties, fines or damages under the Federal Clean Water Act. The suits that remain extant include a variety of claims that state and federal government agencies violated various environmental laws that impose procedural requirements and the lawsuits seek injunctive relief, invalidation of various permits and unspecified damages. Fidelity is unable to quantify the damages sought in any of these cases, and will be unable to do so until after completion of discovery in these separate cases. 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 Health Department in September 2003 that the North Dakota Health 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 North Dakota Health 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 in October 2003, in the Burleigh County District Court in Bismarck, North Dakota. Proceedings have been stayed pending discussions with the EPA, the North Dakota Health Department and the other electric generators.

In a related matter, the state of North Dakota and the EPA entered into a MOU on February 24, 2004, establishing the principles to be used by the state of North Dakota in completing dispersion modeling of air quality in Theodore Roosevelt National Park and other "Class I" areas in North Dakota and Montana. In April 2004, the Dakota Resource Council filed a petition for review of the MOU with the United States Eighth Circuit Court of Appeals. The petition was dismissed, without prejudice, in June 2004 upon stipulation of the EPA, the Dakota Resource Council and the state of North Dakota. The Company cannot predict the outcome of the North Dakota Health 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, MBI 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 DEQ are being recorded, and initially paid, through an administrative consent order by the LWG, a group of 10 entities, which 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, 2004, were $14.7 million in 2005, $10.5 million in 2006, $6.6 million in 2007, $5.1 million in 2008, $3.5 million in 2009 and $25.2 million thereafter. Rent expense was $30.6 million, $27.2 million and $26.9 million for the years ended December 31, 2004, 2003 and 2002, 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 20 years. The commitments under these contracts as of December 31, 2004, were $223.6 million in 2005, $105.7 million in 2006, $65.4 million in 2007, $50.5 million in 2008, $46.9 million in 2009 and $236.4 million thereafter. Amounts purchased under various commitments for the years ended December 31, 2004, 2003 and 2002, were approximately $318.3 million, $204.6 million and $152.1 million, respectively. These commitments are not reflected in the Company's consolidated financial statements.

In addition to the above obligations, the Company has certain purchase obligations for natural gas connected to its gathering system. These purchases and the resale of the natural gas are at market-based prices. These obligations continue as long as natural gas is produced. However, if the purchase and resale of natural gas become uneconomical, the purchase commitments can be canceled by the Company with 60 days notice. These purchase obligations are currently estimated at approximately $10 million annually.

Guarantees

Centennial has unconditionally guaranteed a portion of certain bank borrowings of MPX in connection with the Company's equity method investment in the Termoceara Generating Facility, 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, 2004, the aggregate amount of borrowings outstanding subject to these guarantees was $34.9 million and the scheduled repayment of these borrowings is $11.0 million in 2005, $10.7 million in 2006 and 2007 and $2.5 million in 2008. The individual investor (who through EBX owns 51 percent of MPX) has also guaranteed these loans. In the event MPX defaults under its obligation, Centennial and the individual investor would be required to make payments under their guarantees, which are joint and several obligations. 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 has guaranteed certain of Fidelity's natural gas and oil price swap and collar agreement obligations. Fidelity's obligations at December 31, 2004, were $4.9 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, 2004, expire in 2005; however, Fidelity 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, 2004, the amount outstanding was reflected on the Consolidated Balance Sheets. In the event Fidelity 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. These guarantees are related to natural gas transportation and sales agreements, electric power supply agreements, insurance policies and certain other guarantees. At December 31, 2004, the fixed maximum amounts guaranteed under these agreements aggregated $88.8 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $40.1 million in 2005; $4.7 million in 2006; $2.1 million in 2007; $300,000 in 2008; $900,000 in 2009; $22.0 million in 2010; $12.0 million in 2012; $2.2 million in 2028; $500,000, which is subject to expiration 30 days after the receipt of written notice and $4.0 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $561,000 and was reflected on the Consolidated Balance Sheets at December 31, 2004. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

Fidelity and WBI Holdings have outstanding guarantees to Williston Basin. These guarantees are related to natural gas transportation and storage agreements that guarantee the performance of Prairielands Energy Marketing, Inc. (Prairielands), an indirect wholly owned subsidiary of the Company. At December 31, 2004, 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 $1.7 million, which was not reflected on the Consolidated Balance Sheet at December 31, 2004, because these intercompany transactions are eliminated in consolidation.

In addition, Centennial has issued guarantees to third parties related to the Company's routine purchase of maintenance items 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, 2004.

As of December 31, 2004, Centennial was contingently liable for the performance of certain of its subsidiaries under approximately $375 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 is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. The surety bonds were not reflected on the Consolidated Balance Sheets.

Note 19
Related Party Transactions

In 2004, Bitter Creek entered into two natural gas gathering agreements with Nance Petroleum Corporation (Nance Petroleum), a wholly owned subsidiary of St. Mary Land & Exploration Company (St. Mary). Robert L. Nance, an executive officer and shareholder of St. Mary, is also a member of the Board of Directors of the Company. The natural gas gathering agreements with Nance Petroleum were effective upon completion of certain high and low pressure gathering facilities, which occurred in mid-December 2004. Bitter Creek's capital expenditures related to the completion of the gathering lines and the expansion of its gathering facilities to accommodate the natural gas gathering agreements were $7.6 million in 2004 and are estimated for the next three years to be $2.5 million in 2005, $2.2 million in 2006 and $3.3 million in 2007. The natural gas gathering agreements are each for a term of 15 years and month-to-month thereafter. Bitter Creek's revenues from these contracts were $37,000 in 2004 and estimated revenues from these contracts for the next three years are $1.9 million in 2005, $3.8 million in 2006 and $5.8 million in 2007. The amount due from Nance Petroleum at December 31, 2004, was $37,000.

MDU RESOURCES GROUP, INC.
SUPPLEMENTARY FINANCIAL INFORMATION

Quarterly Data (Unaudited)

The following unaudited information shows selected items by quarter for the years 2004 and 2003:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
2004				
Operating revenues	$515,459	$653,301	$804,598	$745,899
Operating expenses	471,436	568,570	690,022	668,511
Operating income	44,023	84,731	114,576	77,388
Net income	23,580	58,630	71,719	53,138
Earnings per common share:				
Basic	.20	.50	.61	.45
Diluted	.20	.50	.60	.45
Weighted average common shares outstanding:				
Basic	114,658	116,559	117,109	117,582
Diluted	115,709	117,567	118,278	118,596

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
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

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:

	2004	2003	2002
		(In thousands)	
Subject to amortization	**$904,620**	$758,500	$603,151
Not subject to amortization	**68,984**	104,339	145,692
Total capitalized costs	**973,604**	862,839	748,843
Less accumulated depreciation, depletion and amortization	**373,932**	305,349	239,964
Net capitalized costs	**$599,672**	$557,490	$508,879

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

Years ended December 31,	**2004***	2003*	2002
		(In thousands)	
Acquisitions	**$ 11,219**	$ 3,027	$ 31,439
Exploration	**21,781**	19,193	5,325
Development**	**77,940**	77,583	94,943
Total capital expenditures	**$110,940**	$99,803	$131,707

* *Excludes net 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 8, of $100,000 and $14.7 million for the years ended December 31, 2004 and 2003, respectively.*

***Includes expenditures for proved undeveloped reserves of $30.3 million, $23.3 million and $10.1 million for the years ended December 31, 2004, 2003 and 2002, 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,	**2004**	2003	2002*
		(In thousands)	
Revenues:			
Sales to affiliates	**$190,354**	$124,077	$ 55,437
Sales to external customers	**149,660**	140,034	145,170
Production costs	**67,125**	67,292	52,520
Depreciation, depletion and amortization**	**69,946**	60,072	48,064
Pretax income	**202,943**	136,747	100,023
Income tax expense	**73,137**	51,925	36,886
Results of operations for producing activities before cumulative effect of accounting change	**129,806**	84,822	63,137
Cumulative effect of accounting change	---	(7,740)	---
Results of operations for producing activities	**$129,806**	$ 77,082	$ 63,137

* *Includes the compromise agreement as discussed in Note 18.*

***Includes $1.4 million of accretion of discount for asset retirement obligations for each of the years ended December 31, 2004 and 2003, in accordance with SFAS No. 143, as discussed in Note 8.*

The following table summarizes the Company's estimated quantities of proved natural gas and oil reserves at December 31, 2004, 2003 and 2002, 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.

	2004		2003		2002	
	Natural Gas	Oil	Natural Gas	Oil	Natural Gas	Oil
			(In thousands of Mcf/barrels)			
Proved developed and undeveloped reserves:						
Balance at beginning of year	**411,700**	**18,900**	372,500	17,500	324,100	17,500
Production	**(59,700)**	**(1,800)**	(54,700)	(1,900)	(48,200)	(2,000)
Extensions and discoveries	**100,700**	**500**	113,300	3,300	80,100	2,200
Purchases of proved reserves	**100**	**---**	900	---	1,200	100
Sales of reserves in place	**---**	**---**	---	(100)	(4,400)	(300)
Revisions of previous estimates	**400**	**(500)**	(20,300)	100	19,700	---
Balance at end of year	**453,200**	**17,100**	411,700	18,900	372,500	17,500

Proved developed reserves:		
January 1, 2002	291,300	17,100
December 31, 2002	331,300	14,800
December 31, 2003	342,800	15,000
December 31, 2004	**376,400**	**16,400**

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:

	2004	2003	2002
		(In thousands)	
Future cash inflows	**$2,848,800**	$2,547,400	$1,726,000
Future production costs	**803,600**	651,300	513,200
Future development costs	**62,800**	67,100	61,200
Future net cash flows before income taxes	**1,982,400**	1,829,000	1,151,600
Future income tax expense	**645,300**	601,000	324,000
Future net cash flows	**1,337,100**	1,228,000	827,600
10% annual discount for estimated timing of cash flows	**515,600**	491,200	321,300
Discounted future net cash flows relating to proved natural gas and oil reserves	**$ 821,500**	$ 736,800	$ 506,300

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

	2004	2003	2002
		(In thousands)	
Beginning of year	**$ 736,800**	$ 506,300	$ 262,000
Net revenues from production	**(291,600)**	(220,000)	(112,900)
Change in net realization	**32,800**	318,600	296,100
Extensions, discoveries and improved recovery, net of future production-related costs	**240,200**	245,800	117,000
Purchases of proved reserves	**300**	2,800	3,700
Sales of reserves in place	**---**	(600)	(8,900)
Changes in estimated future development costs	**(5,300)**	(4,000)	(1,100)
Development costs incurred during the current year	**39,800**	35,300	19,400
Accretion of discount	**97,100**	62,400	27,300
Net change in income taxes	**(36,400)**	(172,000)	(124,700)
Revisions of previous estimates	**9,600**	(35,500)	30,000
Other	**(1,800)**	(2,300)	(1,600)
Net change	**84,700**	230,500	244,300
End of year	**$ 821,500**	$ 736,800	$ 506,300

The estimated discounted future cash inflows from estimated future production of proved reserves were computed using year-end natural gas 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 as of December 31, 2004, are $37.9 million in 2005, $7.6 million in 2006 and none in 2007. 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.