MDU RESOURCES GROUP INC
Form 10-Q
August 04, 2006

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

X QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For The Quarterly Period Ended June 30, 2006

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Transition Period from _____________ to ______________

Commission file number 1-3480

MDU Resources Group, Inc.
(Exact name of registrant as specified in its charter)

Delaware	**41-0423660**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

1200 West Century Avenue
P.O. Box 5650
Bismarck, North Dakota 58506-5650
(Address of principal executive offices)
(Zip Code)

(701) 530-1000
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act (Check one):

Large accelerated filer x Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x.

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of July 31, 2006: 180,136,624 shares.

DEFINITIONS

The following abbreviations and acronyms used in this Form 10-Q are defined below:

Abbreviation or Acronym	
2005 Annual Report	Company's Annual Report on Form 10-K for the year ended December 31, 2005
ALJ	Administrative Law Judge
Anadarko	Anadarko Petroleum Corporation
APB	Accounting Principles Board
APB Opinion No. 25	Accounting for Stock-Based Compensation
APB Opinion No. 28	Interim Financial Reporting
Badger Hills Project	Tongue River-Badger Hills Project
Bbl	Barrel
BER	Montana Board of Environmental Review
Bitter Creek	Bitter Creek Pipelines, LLC, an indirect wholly owned subsidiary of WBI Holdings
BLM	Bureau of Land Management
Carib Power	Carib Power Management LLC
Cascade	Cascade Natural Gas Corporation
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
Clean Water Act	Federal Clean Water Act
Company	MDU Resources Group, Inc.
D.C. Appeals Court	U.S. Court of Appeals for the District of Columbia Circuit
dk	Decatherm
EITF	Emerging Issues Task Force
EITF No. 04-6	Accounting for Stripping Costs in the Mining Industry
EPA	U.S. Environmental Protection Agency
Exchange Act	Securities Exchange Act of 1934
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings
FIN	FASB Interpretation No.
FIN 48	Accounting for Uncertainty in Income Taxes
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company

Grynberg	Jack J. Grynberg
Hart-Scott-Rodino Act	Hart-Scott-Rodino Antitrust Improvements Act
Hartwell	Hartwell Energy Limited Partnership
Hartwell Generating Facility	310-MW natural gas-fired electric generating facility near Hartwell, Georgia (50 percent ownership)
Howell	Howell Petroleum Corporation
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
kW	Kilowatts
kWh	Kilowatt-hour
LWG	Lower Willamette Group
MBbls	Thousands of barrels of oil or other liquid hydrocarbons
MBI	Morse Bros., Inc., an indirect wholly owned subsidiary of Knife River
Mcf	Thousand cubic feet
MDU Construction Services	MDU Construction Services Group, Inc., formerly Utility Services, Inc. (name change was effective December 23, 2005), a direct wholly owned subsidiary of Centennial
MMBtu	Million Btu
MMcf	Million cubic feet
MMdk	Million decatherms
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
Montana DEQ	Montana State Department of Environmental Quality
Montana Federal District Court	U.S. District Court for the District of Montana
MNPUC	Minnesota Public Utilities Commission
MPX	MPX Termoceara Ltda.
MW	Megawatt
Nance Petroleum	Nance Petroleum Corporation, a wholly owned subsidiary of St. Mary
ND Health Department	North Dakota Department of Health
NEPA	National Environmental Policy Act
NHPA	National Historic Preservation Act
Ninth Circuit	U.S. Ninth Circuit Court of Appeals
NPRC	Northern Plains Resource Council
Order on Rehearing	Order on Rehearing and Compliance and Remanding Certain Issues for Hearing
Oregon DEQ	Oregon State Department of Environmental Quality
Prairielands	Prairielands Energy Marketing, Inc., an indirect wholly owned subsidiary of WBI Holdings
SEIS	Supplemental Environmental Impact Statement
SFAS	Statement of Financial Accounting Standards
SFAS No. 87	Employers' Accounting for Pensions
SFAS No. 109	Accounting for Income Taxes
SFAS No. 123	Accounting for Stock-Based Compensation
SFAS No. 123 (revised)	Share-Based Payment (revised 2004)
SFAS No. 148	Accounting for Stock-Based Compensation - Transition and Disclosure - an amendment of SFAS No. 123
St. Mary	St. Mary Land & Exploration Company
Termoceara Generating Facility	220-MW natural gas-fired electric generating facility in the Brazilian state of Ceara (49 percent ownership)

Trinity Generating Facility	225-MW natural gas-fired electric generating facility in Trinidad and Tobago (49.99 percent ownership)
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
Williston Basin	Williston Basin Interstate Pipeline Company, an indirect wholly owned subsidiary of WBI Holdings
Wyoming Federal District Court	U.S. District Court for the District of Wyoming

INTRODUCTION

The Company is a diversified natural resource company, which was incorporated under the laws of the state of Delaware in 1924. Its principal executive offices are at 1200 West Century Avenue, P.O. Box 5650, Bismarck, North Dakota 58506-5650, telephone (701) 530-1000.

Montana-Dakota, through the electric and natural gas distribution segments, generates, transmits and distributes electricity and distributes natural gas in Montana, North Dakota, South Dakota and Wyoming. Great Plains distributes natural gas in western Minnesota and southeastern North Dakota. These operations also supply related value-added products and services.

The Company, through its wholly owned subsidiary, Centennial, owns WBI Holdings (comprised of the pipeline and energy services and the natural gas and oil production segments), Knife River (construction materials and mining segment), MDU Construction Services (construction services segment), Centennial Resources (independent power production segment) and Centennial Capital (reflected in the Other category). For more information on the Company's business segments, see Note 15.

On May 11, 2006, the Company's Board of Directors approved a three-for-two common stock split. For more information on the common stock split, see Note 3.

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PART I -- FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

MDU RESOURCES GROUP, INC.
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(In thousands, except per share amounts)			
Operating revenues:				
Electric, natural gas distribution and pipeline and energy services	$ 171,221	$ 182,109	$ 462,782	$ 437,481
Construction services, natural gas and oil production, construction materials and mining, independent power production and other	802,562	588,063	1,326,295	936,986
	973,783	770,172	1,789,077	1,374,467
Operating expenses:				
Fuel and purchased power	16,872	14,547	33,246	30,733
Purchased natural gas sold	39,361	46,673	166,321	160,172
Operation and maintenance:				
Electric, natural gas distribution and pipeline and energy services	43,719	39,482	81,883	78,467
Construction services, natural gas and oil production, construction materials and mining, independent power production and other	647,190	475,784	1,093,466	766,788

Depreciation, depletion and amortization	69,105	51,588	132,482	104,427
Taxes, other than income	33,137	28,574	66,179	55,243
	849,384	656,648	1,573,577	1,195,830
Operating income	124,399	113,524	215,500	178,637
Earnings from equity method investments	2,900	15,404	6,102	16,718
Other income	2,912	1,505	5,310	2,656
Interest expense	19,159	13,342	33,243	26,359
Income before income taxes	111,052	117,091	193,669	171,652
Income taxes	39,610	36,918	68,980	57,059
Net income	71,442	80,173	124,689	114,593
Dividends on preferred stocks	171	171	343	342
Earnings on common stock	$ 71,271	$ 80,002	$ 124,346	$ 114,251
Earnings per common share -- basic	$ .40	$ .45	$ .69	$ .65
Earnings per common share -- diluted	$ .39	$ .45	$ .69	$ .64
Dividends per common share	$ .1267	$ .1200	$ .2534	$ .2400
Weighted average common shares outstanding -- basic	179,911	177,522	179,867	177,133
Weighted average common shares outstanding -- diluted	181,107	178,556	181,050	178,150

The accompanying notes are an integral part of these consolidated financial statements.

MDU RESOURCES GROUP, INC.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2006	June 30, 2005	December 31, 2005
		(In thousands, except shares and per share amounts)	
ASSETS			
Current assets:			
Cash and cash equivalents	$ 116,698	$ 57,711	$ 107,435
Receivables, net	651,192	546,722	603,959
Inventories	207,746	158,886	172,201
Deferred income taxes	11,637	6,840	9,062
Prepayments and other current assets	93,203	56,859	40,539
	1,080,476	827,018	933,196
Investments	106,226	98,563	98,217

Property, plant and equipment	4,925,546	4,273,670	4,594,355
Less accumulated depreciation, depletion and amortization	1,654,465	1,440,732	1,544,462
	3,271,081	2,832,938	3,049,893
Deferred charges and other assets:			
Goodwill	242,955	214,972	230,865
Other intangible assets, net	25,550	30,297	19,059
Other	103,141	91,953	92,332
	371,646	337,222	342,256
	$ 4,829,429	$ 4,095,741	$ 4,423,562
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Long-term debt due within one year	$ 159,168	$ 26,866	$ 101,758
Accounts payable	294,951	212,888	269,021
Taxes payable	31,919	26,300	50,533
Dividends payable	22,967	21,685	22,951
Other accrued liabilities	157,438	164,225	184,665
	666,443	451,964	628,928
Long-term debt	1,299,175	1,119,719	1,104,752
Deferred credits and other liabilities:			
Deferred income taxes	571,427	505,651	526,176
Other liabilities	281,934	244,018	272,084
	853,361	749,669	798,260
Commitments and contingencies			
Stockholders' equity:			
Preferred stocks	15,000	15,000	15,000
Common stockholders' equity:			
Common stock			
Shares issued -- $1.00 par value 180,515,943 at June 30, 2006, 120,093,303 at June 30, 2005 and 120,262,786 at December 31, 2005	180,516	120,093	120,263
Other paid-in capital	856,366	898,373	909,006
Retained earnings	963,194	770,361	884,795
Accumulated other comprehensive loss	(1,000)	(24,347)	(33,816)
Treasury stock at cost - 538,921 shares at June 30, 2006, 359,281 shares at December 31, 2005 and 412,906 shares at June 30, 2005	(3,626)	(5,091)	(3,626)
Total common stockholders' equity	1,995,450	1,759,389	1,876,622
Total stockholders' equity	2,010,450	1,774,389	1,891,622
	$ 4,829,429	$ 4,095,741	$ 4,423,562

The accompanying notes are an integral part of these consolidated financial statements.

MDU RESOURCES GROUP, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30, 2006		Six Months Ended June 30, 2005	
	(In thousands)			
Operating activities:				
Net income	$	124,689	$	114,593
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion and amortization		132,482		104,427
Earnings, net of distributions, from equity method investments		(3,107)		(14,619)
Deferred income taxes		17,492		5,120
Changes in current assets and liabilities, net of acquisitions:				
Receivables		(32,863)		(34,399)
Inventories		(33,249)		(12,963)
Other current assets		(39,617)		(16,463)
Accounts payable		30,461		20,545
Other current liabilities		(11,356)		(12,193)
Other noncurrent changes		6,537		9,282
Net cash provided by operating activities		191,469		163,330
Investing activities:				
Capital expenditures		(266,251)		(216,912)
Acquisitions, net of cash acquired		(121,735)		(162,274)
Net proceeds from sale or disposition of property		14,885		11,355
Investments		(5,208)		657
Net cash used in investing activities		(378,309)		(367,174)
Financing activities:				
Issuance of long-term debt		335,653		324,727
Repayment of long-term debt		(97,158)		(123,734)
Proceeds from issuance of common stock		2,709		4,116
Dividends paid		(45,914)		(42,931)
Tax benefit on stock-based compensation		3,167		---
Net cash provided by financing activities		198,457		162,178
Effect of exchange rate changes on cash and cash equivalents		(2,354)		---
Increase (decrease) in cash and cash equivalents		9,263		(41,666)
Cash and cash equivalents -- beginning of year		107,435		99,377
Cash and cash equivalents -- end of period	$	116,698	$	57,711

The accompanying notes are an integral part of these consolidated financial statements.

MDU RESOURCES GROUP, INC.
NOTES TO CONSOLIDATED
FINANCIAL STATEMENTS

June 30, 2006 and 2005
(Unaudited)

1. **<u>Basis of presentation</u>**

The accompanying consolidated interim financial statements were prepared in conformity with the basis of presentation reflected in the consolidated financial statements included in the Company's 2005 Annual Report, and the standards of accounting measurement set forth in APB Opinion No. 28 and any amendments thereto adopted by the FASB. Interim financial statements do not include all disclosures provided in annual financial statements and, accordingly, these financial statements should be read in conjunction with those appearing in the 2005 Annual Report. The information is unaudited but includes all adjustments that are, in the opinion of management, necessary for a fair presentation of the accompanying consolidated interim financial statements.

2. **Seasonality of operations**

Some of the Company's operations are highly seasonal and revenues from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Accordingly, the interim results for particular businesses, and for the Company as a whole, may not be indicative of results for the full fiscal year.

3. **Common stock split**

On May 11, 2006, 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 July 26, 2006, to common stockholders of record on July 12, 2006. Certain common stock information appearing in the accompanying consolidated financial statements has been restated in accordance with accounting principles generally accepted in the United States of America to give retroactive effect to the stock split. Additionally, preference share purchase rights have been appropriately adjusted to reflect the effects of the split.

4. **Allowance for doubtful accounts**

The Company's allowance for doubtful accounts as of June 30, 2006 and 2005, and December 31, 2005, was $7.3 million, $7.4 million and $8.0 million, respectively.

5. **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 $19.4 million, $7.2 million and $24.7 million at June 30, 2006 and 2005, and December 31, 2005, respectively. The remainder of natural gas in underground storage was included in other assets and was $43.2 million, $43.3 million, and $43.2 million at June 30, 2006 and 2005, and December 31, 2005, respectively.

6. **Inventories**

Inventories, other than natural gas in underground storage for the Company’s regulated operations, consisted primarily of aggregates held for resale of $93.1 million, $84.2 million and $78.1 million; materials and supplies of $71.3 million, $45.8 million and $48.7 million; and other inventories of $23.9 million, $21.7 million and $20.7 million, as of June 30, 2006 and 2005, and December 31, 2005, respectively. These inventories were stated at the lower of average cost or market value.

7. **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 applicable period. 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 applicable period, plus the effect of outstanding stock options, restricted stock grants and performance share awards. For the three and six months ended June 30, 2006 and 2005, there were no shares excluded from the calculation of diluted earnings per share. Common stock outstanding includes issued shares less shares held in treasury.

8. **Stock-based compensation**

On January 1, 2006, the Company adopted SFAS No. 123 (revised). This accounting standard revises SFAS No. 123 and requires entities to recognize compensation expense in an amount equal to the grant-date fair value of share-based payments granted to employees. SFAS No. 123 (revised) was adopted using the modified prospective method, recognizing compensation expense for all awards granted after the date of adoption of the standard and for the unvested portion of previously granted awards that remain outstanding at the date of adoption. In accordance with the modified prospective method, the Company's consolidated financial statements for prior periods have not been restated to reflect, and do not include, the impact of SFAS No. 123 (revised).

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 accounted for stock options granted prior to January 1, 2003, under APB Opinion No. 25. No compensation expense had 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. Compensation expense recognized for stock option awards granted on or after January 1, 2003, for the six months ended June 30, 2005, was $4,000, net of income taxes of $3,000.

The Company adopted SFAS No. 123 effective January 1, 2003, for newly granted stock options only. The following table illustrates the effect on earnings and earnings per common share for the three and six months ended June 30, 2005, 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:

	Three Months Ended June 30, 2005		Six Months Ended June 30, 2005	
	(In thousands, except per share amounts)			
Earnings on common stock, as reported	$	80,002	$	114,251
Stock-based compensation expense included in reported earnings, net of related tax effects		---		4
Total stock-based compensation expense determined under fair value method for all awards, net of related tax effects		(88)		(125)
Pro forma earnings on common stock	$	79,914	$	114,130
Earnings per common share - basic - as reported	$	.45	$	.65
Earnings per common share - basic - pro forma	$	.45	$	.64
Earnings per common share - diluted - as reported	$	.45	$	.64
Earnings per common share - diluted - pro forma	$	.45	$	.64

Total stock-based compensation expense for the three and six months ended June 30, 2006, was $1.4 million and $2.2 million, net of income taxes of $900,000 and $1.4 million, respectively, including $71,000 and $142,000, net of income taxes of $45,000 and $90,000, respectively, related to stock option awards.

As of June 30, 2006, total remaining unrecognized compensation expense related to stock-based compensation was approximately $7.2 million (before income taxes) which will be amortized over a weighted-average period of 1.9 years.

The Company is authorized to grant options, restricted stock and stock for up to 17.1 million shares of common stock and has granted options, restricted stock and stock on 6.7 million shares through June 30, 2006.

The Company generally issues new shares of common stock to satisfy stock option exercises, restricted stock, stock and performance share awards.

Stock Options

The Company has stock option plans for directors, key employees and employees. The Company has not granted stock options since 2003. 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 the date of grant and three years after the date of grant, respectively, and expire 10 years after the date of grant.

The fair value of each option outstanding was estimated on the date of grant using the Black-Scholes option pricing model.

A summary of the status of the stock option plans for the six months ended June 30, 2006, was as follows:

	Shares		Weighted Average Exercise Price	Weighted Average Remaining Contractual Life In Years
Outstanding at beginning of period	2,786,973	$	12.99	
Granted	---		---	
Forfeited	(68,553)		13.00	
Exercised	(213,233)		12.58	
Outstanding at end of period	2,505,187		13.02	4.3
Exercisable at end of period	1,408,377	$	12.57	4.1

Summarized information about stock options outstanding and exercisable as of June 30, 2006, was as follows:

	Options Outstanding				Options Exercisable		
Range of Exercisable Prices	Number Out-standing	Remaining Contractual Life in Years	Weighted Average Exercise Price	Aggregate Intrinsic Value (000's)	Number Exer-cisable	Weighted Average Exercise Price	Aggregate Intrinsic Value (000's)
$ 7.28 - 8.00	10,125	1.0	$ 7.28	$ 173	10,125	$ 7.28	$ 173
8.01 - 11.00	315,024	1.9	9.58	4,672	312,132	9.58	4,629
11.01 - 14.00	1,925,293	4.7	13.18	21,621	994,417	13.19	11,156
14.01 - 17.13	254,745	4.7	16.32	2,061	91,703	16.54	722
Balance at end of period	2,505,187	4.3	$ 13.02	$ 28,527	1,408,377	$ 12.57	$ 16,680

The aggregate intrinsic value in the preceding table represents the total intrinsic value (before income taxes), based on the Company's stock price on June 30, 2006, which would have been received by the option holders had all option holders exercised their options as of that date.

The Company received cash of $1.0 million and $2.7 million from the exercise of stock options for the three and six months ended June 30, 2006, respectively. The aggregate intrinsic value of options exercised during the three and six months ended June 30, 2006, was $800,000 and $2.3 million, respectively.

Restricted Stock Awards

Prior to 2002, the Company granted restricted stock awards under a long-term incentive plan. The restricted stock awards granted vest 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 grant-date fair value is the market price of the Company's stock on the grant date.

A summary of the status of the restricted stock awards for the six months ended June 30, 2006, was as follows:

	Number of Shares		Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	130,764	$	10.63
Granted	---		---
Vested	(77,106)		8.82
Forfeited	(5,942)		13.22
Nonvested at end of period	47,716	$	13.22

The fair value of restricted stock awards that vested during the six months ended June 30, 2006, was $1.8 million.

Stock Awards

Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. There were 40,500 shares with a fair value of $1.0 million issued under this plan during the six months ended June 30, 2006.

Performance Share Awards

Since 2003, key employees of the Company have been awarded performance share awards each year. Entitlement to performance shares is based on the Company's total shareholder return over designated performance periods as measured against a selected peer group. The grant-date fair value is the market price of the Company's stock on the grant date.

Target grants of performance shares outstanding at June 30, 2006, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2004	2004-2006	278,596
February 2005	2005-2007	283,512
February 2006	2006-2008	205,801

Participants may earn additional performance shares if the Company's total shareholder return exceeds that of the selected peer group. Compensation expense assumes that the target payout will be achieved and is adjusted for subsequent changes in the expected outcome of performance-related conditions until the vesting date. As a result, the final value may vary according to the number of shares of Company stock that are ultimately granted based on the performance criteria. The fair value of performance share awards that vested during the six months ended June 30, 2006, was $2.2 million.

A summary of the status of the performance share awards for the six months ended June 30, 2006, was as follows:

	Number of Shares		Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	634,275	$	16.31
Granted	216,970		22.91
Additional performance shares earned	14,522		11.14
Vested	(95,792)		11.14
Forfeited	(2,066)		18.37

Nonvested at end of period	767,909	$ 18.72

9. **Cash flow information**

Cash expenditures for interest and income taxes were as follows:

	Six Months Ended June 30,	
	2006	2005
	(In thousands)	
Interest, net of amount capitalized	$27,988	$23,184
Income taxes	$78,382	$54,650

10. **New accounting standards**

SFAS No. 123 (revised) In December 2004, the FASB issued SFAS No. 123 (revised). This accounting standard revises SFAS No. 123 and requires entities to recognize compensation expense in an amount equal to the grant-date fair value of share-based payments granted to employees. SFAS No. 123 (revised) was effective for the Company on January 1, 2006. As of the required effective date, the Company applied SFAS No. 123 (revised) using the modified prospective method, recognizing 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. The Company used the Black-Scholes option-pricing model to calculate the fair value of stock options. For more information on the adoption of SFAS No. 123 (revised), see Note 8.

EITF No. 04-6 In March 2005, the FASB ratified EITF No. 04-6. EITF No. 04-6 requires that stripping costs during the production phase of a mine be treated as a variable inventory production cost when incurred. EITF No. 04-6 was effective for the Company on January 1, 2006. The adoption of EITF No. 04-6 did not have a material effect on the Company’s financial position or results of operations.

FIN 48 In July 2006, the FASB issued FIN 48. FIN 48 clarifies the application of SFAS No. 109 by defining a criterion that an individual tax position must meet for any part of the benefit of that position to be recognized in an enterprise’s financial statements. The criterion allows for recognition in the financial statements of a tax position when it is more likely than not that the position will be sustained upon examination. FIN 48 is effective for the Company on January 1, 2007. The Company is evaluating the effects of the adoption of FIN 48.

11. **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 and foreign currency translation adjustments. For more information on derivative instruments, see Note 14.

Comprehensive income, and the components of other comprehensive income (loss) and related tax effects, were as follows:

	Three Months Ended June 30,	
	2006	2005
	(In thousands)	
Net income	$71,442	$80,173
Other comprehensive income:		
Net unrealized gain on derivative instruments qualifying as hedges:		
Net unrealized gain on derivative instruments arising during the period, net of tax of $4,051 and $1,225 in 2006	6,471	1,957

and 2005, respectively		
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $1,033 and $4,522 in 2006 and 2005, respectively	1,650	(7,223)
Net unrealized gain on derivative instruments qualifying as hedges	4,821	9,180
Foreign currency translation adjustment	(2,176)	(925)
	2,645	8,255
Comprehensive income	$74,087	$88,428

	Six Months Ended June 30,	
	2006	2005
	(In thousands)	
Net income	$ 124,689	$ 114,593
Other comprehensive income (loss):		
Net unrealized gain (loss) on derivative instruments qualifying as hedges:		
Net unrealized gain (loss) on derivative instruments arising during the period, net of tax of $17,652 and $8,467 in 2006 and 2005, respectively	28,197	(13,525)
Less: Reclassification adjustment for loss on derivative instruments included in net income, net of tax of $4,254 and $1,057 in 2006 and 2005, respectively	(6,796)	(1,688)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	34,993	(11,837)
Foreign currency translation adjustment	(2,177)	(1,019)
	32,816	(12,856)
Comprehensive income	$ 157,505	$ 101,737

12. **Equity method investments**

The Company has equity method investments including a 49.99-percent ownership interest in Carib Power and a 50-percent ownership interest in Hartwell. Carib Power, through a wholly owned subsidiary, owns a 225-MW natural gas-fired electric generating facility in Trinidad and Tobago. Hartwell owns a 310-MW natural gas-fired electric generating facility near Hartwell, Georgia. The Company assesses its equity method investments for impairment whenever events or changes in circumstances indicate that the related 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.

In June 2005, the Company completed the sale of its 49 percent interest in MPX to Petrobras, the Brazilian state-controlled energy company. The Company realized a gain of $15.6 million from the sale in the second quarter of 2005. In 2005, the Termoceara Generating Facility was accounted for as an asset held for sale and, as a result, no depreciation, depletion and amortization expense was recorded in 2005.

At June 30, 2006 and 2005, and December 31, 2005, the Company’s equity method investments, including Carib Power and Hartwell, had total assets of $228.9 million, $243.6 million and $231.9 million, respectively, and long-term debt of $149.5 million, $159.6 million and $154.8 million, respectively. The Company’s investment in its equity method investments, including the Trinity and Hartwell Generating Facilities, was approximately $50.1 million, $43.4 million and $41.8 million, including undistributed earnings of $6.5 million, $2.6 million and $3.5 million, at June 30, 2006 and 2005, and December 31, 2005, respectively.

13. **Goodwill and other intangible assets**

The changes in the carrying amount of goodwill were as follows:

Six Months Ended June 30, 2006	Balance as of January 1, 2006	Goodwill Acquired During the Year* (In thousands)	Balance as of June 30, 2006
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Construction services	80,970	5,981	86,951
Pipeline and energy services	5,464	---	5,464
Natural gas and oil production	---	---	---
Construction materials and mining	133,264	6,109	139,373
Independent power production	11,167	---	11,167
Other	---	---	---
Total	$ 230,865	$ 12,090	$ 242,955

Six Months Ended June 30, 2005	Balance as of January 1, 2005	Goodwill Acquired During the Year* (In thousands)	Balance as of June 30, 2005
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Construction services	62,632	12,102	74,734
Pipeline and energy services	5,464	---	5,464
Natural gas and oil production	---	---	---
Construction materials and mining	120,452	3,155	123,607
Independent power production	11,195	(28)	11,167
Other	---	---	---
Total	$ 199,743	$ 15,229	$ 214,972

Year Ended December 31, 2005	Balance as of January 1, 2005	Goodwill Acquired During the Year* (In thousands)	Balance as of December 31, 2005
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Construction services	62,632	18,338	80,970
Pipeline and energy services	5,464	---	5,464
Natural gas and oil production	---	---	---
Construction materials and mining	120,452	12,812	133,264
Independent power production	11,195	(28)	11,167
Other	---	---	---
Total	$ 199,743	$ 31,122	$ 230,865

* Includes purchase price adjustments that were not material related to acquisitions in a prior period.

Other intangible assets were as follows:

	June 30, 2006	June 30, 2005	December 31, 2005
		(In thousands)	
Amortizable intangible assets:			
Acquired contracts	$ 20,650	$ 18,707	$ 18,065
Accumulated amortization	(9,196)	(6,519)	(9,458)
	11,454	12,188	8,607
Noncompete agreements	11,984	11,784	11,784
Accumulated amortization	(8,900)	(8,310)	(8,557)
	3,084	3,474	3,227
Other	12,358	14,698	7,914
Accumulated amortization	(1,870)	(914)	(1,213)
	10,488	13,784	6,701
Unamortizable intangible assets	524	851	524
Total	$ 25,550	$ 30,297	$ 19,059

The unamortizable intangible assets were recognized in accordance with SFAS No. 87, 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 three and six months ended June 30, 2006, was $1.6 million and $2.8 million, respectively. Amortization expense for the three and six months ended June 30, 2005, and for the year ended December 31, 2005, was $1.2 million, $2.1 million and $5.5 million, respectively. Estimated amortization expense for amortizable intangible assets is $5.4 million in 2006, $5.7 million in 2007, $4.7 million in 2008, $3.7 million in 2009, $3.1 million in 2010 and $5.2 million thereafter.

14. **Derivative instruments**

From time to time, the Company utilizes 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 following information should be read in conjunction with Notes 1 and 5 in the Company's Notes to Consolidated Financial Statements in the 2005 Annual Report.

Historically, Fidelity has held derivative instruments designated as cash flow hedging instruments. However, in the second quarter of 2006, the oil collar agreements became ineffective and no longer qualify for hedge accounting, as discussed below. At June 30, 2006, Fidelity held derivative instruments designated as cash flow hedging instruments as well as derivative instruments that did not qualify for hedge accounting.

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.

The fair value of the hedging instruments must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or liability. Changes in the fair value attributable to the effective portion of hedging instruments, net of tax, are recorded in stockholders' equity as a component of accumulated other comprehensive income (loss). At the date the natural gas or oil production quantities are settled, 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. The proceeds the Company receives for its natural gas and oil production are also generally based on market prices.

For the three and six months ended June 30, 2005, the amount of hedge ineffectiveness was immaterial. However, in the second quarter of 2006, the oil collar agreements became ineffective and no longer qualify for hedge accounting. The amount of ineffectiveness for the three and six months ended June 30, 2006, related to these collar agreements was approximately $979,000 (before tax) and was recorded in operation and maintenance expense. The amount of hedge ineffectiveness on Fidelity's remaining hedges was immaterial for the three and six months ended June 30, 2006.

For the three and six months ended June 30, 2006 and 2005, Fidelity did not exclude any components of the derivative instruments' gain or loss from the assessment of hedge effectiveness. Gains and losses must be reclassified into earnings as a result of the discontinuance of cash flow hedges if it is probable that the original forecasted transactions will not occur. There were no such 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 June 30, 2006, 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 18 months. The Company estimates that over the next 12 months net gains of approximately $7.5 million (after tax) will be reclassified from accumulated other comprehensive income (loss) into earnings, subject to changes in natural gas and oil market prices, as the hedged transactions affect earnings.

15. **Business segment data**

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The 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 resource-based projects.

The electric segment generates, transmits and distributes electricity in Montana, North Dakota, South Dakota, and Wyoming. The natural gas distribution segment distributes natural gas in those states as well as in western Minnesota. These operations also supply related value-added products and services.

The construction services segment specializes in electrical line construction; pipeline construction; inside electrical wiring, cabling and mechanical services; 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 and Mid-Continent regions 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 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 primarily are sold under mid- and long-term contracts to nonaffiliated entities.

The Other category includes the activities of Centennial Capital which insures various types of risks as a captive insurer for certain of the Company’s subsidiaries. The function of the captive is to fund the deductible layers of the insured companies’ general liability and automobile liability coverages. Centennial Capital also owns certain real and personal property.

The information below follows the same accounting policies as described in Note 1 in the Company’s Notes to Consolidated Financial Statements in the 2005 Annual Report. Information on the Company’s businesses was as follows:

Three Months Ended June 30, 2006	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 40,875	$ ---	$ 509
Natural gas distribution	45,845	---	(2,530)
Pipeline and energy services	84,501	18,568	5,580
	171,221	18,568	3,559
Construction services	243,062	136	9,679
Natural gas and oil production	62,906	51,206	30,979
Construction materials and mining	484,878	---	25,311
Independent power production	11,716	---	1,504
Other	---	2,318	239
	802,562	53,660	67,712
Intersegment eliminations	---	(72,228)	---
Total	$ 973,783	$ ---	$ 71,271

Three Months Ended June 30, 2005	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 41,052	$ ---	$ 1,755
Natural gas distribution	54,691	---	(1,283)
Pipeline and energy services	86,366	15,055	8,737
	182,109	15,055	9,209
Construction services	136,911	(19)	3,659
Natural gas and oil production	43,487	54,255	29,949
Construction materials and mining	394,015	---	18,421
Independent power production	13,650	---	18,582
Other	---	1,367	182
	588,063	55,603	70,793
Intersegment eliminations	---	(70,658)	---
Total	$ 770,172	$ ---	$ 80,002

Six Months Ended June 30, 2006	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock

		(In thousands)	
Electric	$ 85,905	$ ---	$ 4,305
Natural gas distribution	198,124	---	2,793
Pipeline and energy services	178,753	51,374	10,149
	462,782	51,374	17,247
Construction services	466,747	246	15,077
Natural gas and oil production	118,004	124,498	72,237
Construction materials and mining	718,562	---	16,437
Independent power production	22,982	---	2,846
Other	---	4,087	502
	1,326,295	128,831	107,099
Intersegment eliminations	---	(180,205)	---
Total	$ 1,789,077	$ ---	$ 124,346

Six Months Ended June 30, 2005	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 85,371	$ ---	$ 4,888
Natural gas distribution	199,665	---	3,539
Pipeline and energy services	152,445	41,803	11,963
	437,481	41,803	20,390
Construction services	250,621	132	5,617
Natural gas and oil production	81,797	103,025	58,754
Construction materials and mining	581,102	7	9,885
Independent power production	23,466	---	19,339
Other	---	2,735	266
	936,986	105,899	93,861
Intersegment eliminations	---	(147,702)	---
Total	$ 1,374,467	$ ---	$ 114,251

Earnings (loss) from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from construction services, natural gas and oil production, construction materials and mining, independent power production, and other are all from nonregulated operations.

16. **Acquisitions**

During the first six months of 2006, the Company acquired a construction services business in Nevada, natural gas and oil properties in Wyoming, construction materials and mining businesses in Washington, and a natural gas-fired electric generating facility in California at the independent power production segment, none of which was material. The total purchase consideration for these businesses and properties and purchase price adjustments with respect to certain other acquisitions made prior to 2006, consisting of the Company's common stock and cash, was $122.7 million.

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. On certain of the above acquisitions, final fair market values are pending the completion of the review of the relevant assets, liabilities and issues identified as of the acquisition date. The results of operations of the acquired businesses and properties 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.

17. **Employee benefit plans**

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans were as follows:

Three Months Ended June 30,	Pension Benefits 2006	Pension Benefits 2005	Other Postretirement Benefits 2006	Other Postretirement Benefits 2005
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	$ 2,301	$ 2,121	$ 472	$ 546
Interest cost	4,074	4,152	928	1,039
Expected return on assets	(4,718)	(5,063)	(926)	(1,042)
Amortization of prior service cost	257	256	12	---
Recognized net actuarial (gain) loss	509	483	(85)	(38)
Amortization of net transition obligation (asset)	(1)	(11)	531	525
Net periodic benefit cost	2,422	1,938	932	1,030
Less amount capitalized	225	185	79	115
Net periodic benefit cost	$ 2,197	$ 1,753	$ 853	$ 915

Six Months Ended June 30,	Pension Benefits 2006	Pension Benefits 2005	Other Postretirement Benefits 2006	Other Postretirement Benefits 2005
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	$ 4,602	$ 4,168	$ 943	$ 1,031
Interest cost	8,148	8,308	1,857	2,136
Expected return on assets	(9,436)	(9,973)	(1,851)	(2,025)
Amortization of prior service cost	513	512	23	---
Recognized net actuarial (gain) loss	1,018	692	(169)	(77)
Amortization of net transition obligation (asset)	(2)	(22)	1,062	1,063
Net periodic benefit cost	4,843	3,685	1,865	2,128
Less amount capitalized	381	357	125	206
Net periodic benefit cost	$ 4,462	$ 3,328	$ 1,740	$ 1,922

In addition to the qualified plan defined pension benefits reflected in the table, 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. The Company's net periodic benefit cost for this plan for the three and six months ended June 30, 2006, was $1.9 million and $3.9 million, respectively. The Company’s net periodic benefit cost for this plan for the three and six months ended June 30, 2005, was $1.4 million and $3.3 million, respectively.

18. **Regulatory matters and revenues subject to refund**

In September 2004, Great Plains filed a natural gas rate application with the MNPUC requesting a revenue increase of $1.4 million annually, or approximately 4 percent. An interim increase of $1.4 million annually was effective January

10, 2005, subject to refund. The final order in the amount of $481,000 annually, or 1.3 percent, was issued on May 1, 2006. A compliance filing will be submitted in August 2006 for MNPUC approval. Great Plains has adequately provided a liability for the revenue subject to refund.

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 April 2005, the FERC issued its Order on Compliance Filing and Motion for Refunds. In this Order, the FERC approved Williston Basin's refund rates and established rates to be effective April 19, 2005. Williston Basin made its compliance filing complying with the requirements of this Order regarding rates and issued refunds totaling approximately $18.5 million to its customers in May 2005. As a result of the Order, Williston Basin recorded a $5.0 million (after tax) benefit in the second quarter of 2005 from the resolution of the rate proceeding which included the reversal of a portion of the liability it had previously established for this regulatory proceeding. In June 2005, Williston Basin appealed to the D.C. Appeals Court certain issues addressed by the FERC's Order on Initial Decision dated July 2003 and its Order on Rehearing dated May 2004 concerning determinations associated with cost of service and volumes used in allocating costs and designing rates. Those matters are pending resolution by the D.C. Appeals Court. A provision has been established for certain issues pending before the D.C. Appeals Court. The Company believes that the provision is adequate based on its assessment of the ultimate outcome of the proceeding.

In May 2004, the FERC remanded issues regarding certain service and annual demand quantity restrictions to an ALJ for resolution. In November 2005, the FERC issued an Order on Initial Decision affirming the ALJ's Initial Decision regarding the service and annual demand quantity restrictions. On April 20, 2006, the FERC issued an Order on Rehearing denying Williston Basin's Request for Rehearing of the FERC's November 2005 Order. On April 25, 2006, Williston Basin appealed to the D.C. Appeals Court certain issues addressed by the FERC's Order on Initial Decision dated November 2005 and its Order on Rehearing issued April 20, 2006, concerning the service and annual demand quantity restrictions. Those matters are pending resolution by the D.C. Appeals Court.

19. **Contingencies**

Litigation

Royalties Case In June 1997, Grynberg filed suit under the Federal False Claims Act against Williston Basin and Montana-Dakota. Grynberg also filed more than 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. All cases were consolidated in Wyoming Federal District Court.

In June 2004, following preliminary discovery, Williston Basin and Montana-Dakota joined with other defendants and filed a Motion to Dismiss on the ground 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 was heard in March 2005 by the Special Master appointed by the Wyoming Federal District Court. The Special Master, in his Written Report dated May 2005, recommended that the lawsuit be dismissed against certain defendants, including Williston Basin and Montana-Dakota. A hearing on the adoption of the Written Report was held in December 2005, before the Wyoming Federal District Court.

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.

Coalbed Natural Gas Operations 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 April 2006 by a number of environmental organizations, including the NPRC 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 the Wyoming Federal District Court. The lawsuits involve allegations that Fidelity and/or various government agencies are in violation of state and/or federal law, including the Clean Water Act, the NEPA, the Federal Land Management Policy Act, the NHPA, the Montana State Constitution, the Montana Environmental Policy Act and the Montana Water Quality 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.

In suits filed in the Montana Federal District Court, the NPRC and the Northern Cheyenne Tribe asserted that further development by Fidelity and others of coalbed natural gas in Montana should be enjoined until the BLM completes a SEIS. The Montana Federal District Court, in February 2005, entered a ruling requiring the BLM to complete a SEIS. The Montana Federal District Court later entered an order that would have allowed limited coalbed natural gas development in the Powder River Basin in Montana pending the BLM's preparation of the SEIS. The plaintiffs appealed the decision to the Ninth Circuit. The Montana Federal District Court declined to enter an injunction requested by the NPRC and the Northern Cheyenne Tribe that would have enjoined development pending the appeal. In late May 2005, the Ninth Circuit granted the request of the NPRC and the Northern Cheyenne Tribe and, pending further order from the Ninth Circuit, enjoined the BLM from approving any new coalbed natural gas development projects in the Powder River Basin in Montana. That court also enjoined Fidelity from drilling any additional federally permitted wells in its Montana Coal Creek Project and from constructing infrastructure to produce and transport coalbed natural gas from the Coal Creek Project's existing federal wells. The matter has been fully briefed and argued before the Ninth Circuit and the parties are awaiting a decision of the court.

In related actions in the Montana Federal District Court, the NPRC and the Northern Cheyenne Tribe asserted, among other things, that the actions of the BLM in approving Fidelity's applications for permits and the plan of development for the Badger Hills Project in Montana did not comply with applicable Federal laws, including the NHPA and the NEPA. The NPRC also asserted that the Environmental Assessment that supported the BLM's prior approval of the Badger Hills Project was invalid. In June 2005, the Montana Federal District Court issued orders in these cases enjoining operations on Fidelity's Badger Hills Project pending the BLM's consultation with the Northern Cheyenne Tribe as to satisfaction of the applicable requirements of NHPA and a further environmental analysis under NEPA. Fidelity has sought and obtained stays of the injunctive relief from the Montana Federal District Court and production from Fidelity’s Badger Hills Project continues. In September 2005, the Montana Federal District Court entered an Order based on a stipulation between the parties to the NPRC action that production from existing wells in Fidelity’s Badger Hills Project may continue pending preparation of a revised environmental analysis. In November 2005, the Montana Federal District Court entered an Order based on a stipulation between the parties to the Northern Cheyenne Tribe action that production from existing wells in Fidelity’s Badger Hills Project may continue pending preparation of a revised environmental analysis. In December 2005, Fidelity filed a Notice of Appeal to the Ninth Circuit in connection with the Montana Federal District Court’s decision insofar as it found the BLM’s approval of Fidelity’s applications did not comply with applicable law.

The NPRC filed a petition with the BER and the BER initiated related rulemaking proceedings to create rules that would, if promulgated, require re-injection of water produced in connection with coalbed natural gas operations and treatment of such water in the event re-injection is not feasible and amend the non-degradation policy in connection with coalbed natural gas development to include additional limitations on factors deemed harmful, thereby restricting discharges even further than under the previous standards. On March 23, 2006, the BER issued its decision on the NPRC’s rulemaking petition. The BER rejected the proposed requirement of re-injection of water produced in connection with coalbed natural gas and deferred action on the proposed treatment requirement. The BER adopted the proposed amendment to the non-degradation policy. While it is possible the BER's ruling could have an adverse impact on Fidelity's operations, Fidelity believes that two five-year water discharge permits issued by the Montana DEQ in February 2006 should, assuming normal operating conditions, allow Fidelity to continue its existing coalbed natural gas operations at least through the expiration of the permits in March 2011. However, these permits are now being challenged in Montana state court by the Northern Cheyenne Tribe. Specifically, on April 3, 2006, the Northern Cheyenne Tribe filed a complaint in the District Court of Big Horn County against the Montana DEQ seeking to set aside the two permits. The Northern Cheyenne Tribe asserted that the Montana DEQ issued the permits in violation of various federal and state environmental laws. In particular, the Northern Cheyenne Tribe claimed the agency violated the Clean Water Act and the Montana Water Quality Act by failing to include in the permits conditions requiring application of the best practicable control technology currently available and by ignoring the BER's recently adopted amendment to the non-degradation policy. In addition, the Northern Cheyenne Tribe claimed that the actions of the Montana DEQ violated the Montana State Constitution's guarantee of a clean and healthful environment, that the Montana DEQ's related environmental assessment was invalid, that the Montana DEQ was required but failed to prepare an environmental impact statement and that it failed to consider other alternatives to the issuance of the permits. Both Fidelity and the NPRC have filed motions to intervene in this proceeding. Fidelity has asserted that the Northern Cheyenne Tribe's complaint should be dismissed with prejudice, that Fidelity's discharge of water pursuant to its two permits is its primary means for managing coalbed natural gas produced water and that, if its permits are set aside, Fidelity's coalbed natural gas operations in Montana could be significantly and adversely affected.

In a related proceeding, on July 25, 2006, Fidelity filed a motion to intervene in a lawsuit filed in Montana state court in Big Horn County by other producers. The lawsuit challenges the BER's 2006 rulemaking, which amended the nondegradation policy, as well as the BER's 2003 rulemaking procedure which first set numeric limits for water produced in connection with coalbed natural gas operations.

Fidelity will continue vigorously defending its interests in all coalbed-related lawsuits and related actions in which it is involved, including the Ninth Circuit injunction and the proceedings challenging its water permits. In those cases where damage claims have been asserted, Fidelity is unable to quantify the damages sought and will be unable to do so until after the completion of discovery. 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 this resource in the affected regions.

Electric Operations Montana-Dakota has joined with two electric generators in appealing a finding by the ND Health Department in September 2003 that the ND 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 ND 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 ND Health Department and the other electric generators. The Company cannot predict the outcome of the ND Health Department matter or its ultimate impact on its operations.

Natural Gas Storage Williston Basin filed suit in Montana Federal District Court on January 27, 2006, seeking to recover unspecified damages from Anadarko and its wholly owned subsidiary, Howell, and to enjoin Anadarko's and Howell's present and future operations in and near Williston Basin's Elk Basin Storage Reservoir located in Wyoming and Montana. Based on relevant information, including reservoir and well pressure data, Williston Basin believes that Elk Basin Storage Reservoir pressures have decreased and that quantities of natural gas have been diverted as a result of Anadarko's and Howell's drilling and production activities in areas within and near the boundaries of Williston Basin's Elk Basin Storage Reservoir. Williston Basin is seeking not only to recover damages for the gas that has been diverted, but to prevent further drainage of its storage reservoir. The Montana Federal District Court entered an Order on July 14, 2006, dismissing the case for lack of subject matter jurisdiction. Williston Basin filed a Notice of Appeal to the Ninth Circuit on July 31, 2006. In related litigation, Anadarko filed suit in Wyoming state district court against

Williston Basin asserting that it is entitled to produce any gas that might escape from Williston Basin's storage reservoir. Williston Basin intends to vigorously defend its rights and interests in these proceedings, to assess further avenues for recovery through the regulatory process at the FERC and to pursue the recovery of any and all economic losses it may have suffered. Williston Basin cannot predict the ultimate outcome of this proceeding or estimate the size of any potential recovery.

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

Portland Harbor Site In December 2000, MBI was named by the EPA as a Potentially Responsible Party in connection with the cleanup of a riverbed site adjacent to a commercial property site, acquired by MBI in 1999. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site. Sixty-eight other parties were also named in this administrative action. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. To date, costs of the overall remedial investigation of the harbor site for both the EPA and the Oregon 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 or Georgia-Pacific West, Inc., the seller of the commercial property to MBI. Although the LWG originally estimated the overall remedial investigation and feasibility study would cost approximately $10 million, it is now anticipated, on the basis of costs incurred to date and delays attributable to an additional round of sampling and potential further investigative work, that such cost could increase to a total of $60 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 more years to complete. The development of a proposed plan and record of decision on the harbor site is not anticipated to occur until 2010, after which a cleanup plan will be undertaken.

Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon DEQ and other information available, MBI does not believe it is a Responsible Party. In addition, MBI has notified Georgia-Pacific West, Inc., 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.

Guarantees

In connection with the sale of MPX in June 2005 to Petrobras, an indirect wholly-owned subsidiary of the Company has agreed to indemnify Petrobras for 49 percent of any losses which Petrobras may incur from certain contingent liabilities specified in the purchase agreement. Centennial has agreed to unconditionally guarantee payment of the indemnity obligations to Petrobras for periods ranging from approximately two to five and a half years from the date of sale. The guarantee was required by Petrobras as a condition to closing the sale of MPX.

In addition, WBI Holdings has guaranteed certain of Fidelity's natural gas and oil price swap and collar agreement obligations. Fidelity's obligations at June 30, 2006, were approximately $1.1 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 June 30, 2006, expire in 2006 and 2007; 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. The amount outstanding by Fidelity was reflected on the Consolidated Balance Sheet at June 30, 2006. 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, construction contracts, a conditional purchase agreement and certain other guarantees. At June 30, 2006, the fixed maximum amounts guaranteed under these agreements aggregated $181.9 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $1.4 million in 2006; $102.3 million in 2007; $4.0 million in 2008; $2.7 million in 2009; $30.1 million in 2010; $23.0 million in 2011; $12.0 million in 2012; $1.9 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. A guarantee for an unfixed amount estimated at $250,000 at June 30, 2006, has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $700,000 and was reflected on the Consolidated Balance Sheet at June 30, 2006. 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.

Centennial has outstanding letters of credit to third parties related to insurance policies and other agreements that guarantee the performance of other subsidiaries of the Company. At June 30, 2006, the fixed maximum amounts guaranteed under these letters of credit aggregated $43.4 million. In 2006 and 2007, $12.3 million and $31.1 million, respectively, of letters of credit are scheduled to expire. There were no amounts outstanding under the above letters of credit at June 30, 2006.

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. At June 30, 2006, 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 2008 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 $1.5 million, which was not reflected on the Consolidated Balance Sheet at June 30, 2006, 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 and lease obligations 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 or lease obligations, 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 June 30, 2006.

As of June 30, 2006, Centennial was contingently liable for the performance of certain of its subsidiaries under approximately $558 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 Sheet.

20. **Related party transactions**

In 2004, Bitter Creek entered into two natural gas gathering agreements with Nance Petroleum. 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 was $28,000 for the six months ended June 30, 2006, and were $1.1 million and $2.1 million for the three and six months ended June 30, 2005, respectively, and are estimated for the next three years to be $500,000 in 2006, $3.3 million in 2007 and $2.2 million in 2008. 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 $403,000 and $789,000 for the three and six months ended June 30, 2006, respectively, and were $287,000 and $539,000 for the three and six months ended June 30, 2005, respectively. Estimated revenues from these contracts for the next three years are $1.8 million in 2006, $2.1 million in 2007 and $3.2 million in 2008. The amount due from Nance Petroleum at June 30, 2006, was $136,000.

In 2005, Montana-Dakota entered into agreements to purchase natural gas from Nance Petroleum through March 31, 2006. Montana-Dakota’s expenses under these agreements through March 31, 2006, were $1.9 million. There were no amounts due to Nance Petroleum at June 30, 2006.

In 2005, Fidelity entered into an agreement for the purchase of an ownership interest in a natural gas and oil property with a third party whereunder it became a party to a joint operating agreement in which St. Mary is the operator of the property. St. Mary receives an overhead fee as operator of this property. The Company recorded its proportionate share of capital costs allocable to its ownership interest in the related property, which were not material to Fidelity.

21. **Subsequent event**

On July 8, 2006, the Company entered into a definitive merger agreement to acquire Cascade, subject to approval of Cascade’s shareholders and various regulatory authorities, as well as antitrust clearance under the Hart-Scott-Rodino Act, and the satisfaction of other customary closing conditions. Regulatory approvals are anticipated to be obtained by mid-year 2007. The total value of the transaction, including the assumption of certain indebtedness, is approximately $475 million. Cascade’s natural gas service areas are concentrated in western and south central Washington and south central and eastern Oregon.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

The Company’s strategy is to apply its expertise in energy and transportation infrastructure industries to increase market share, increase profitability and enhance shareholder value through:

- Organic growth as well as a continued disciplined approach to the acquisition of well-managed companies and properties
- The elimination of system-wide cost redundancies through increased focus on integration of operations and standardization and consolidation of various support services and functions across companies within the organization
- The development of projects that are accretive to earnings per share and returns on invested capital

The Company has capabilities to fund its growth and operations through various sources, including internally generated funds, commercial paper facilities and the issuance from time to time of debt securities and the Company’s equity securities. For information on the Company’s net capital expenditures, see Liquidity and Capital Commitments. Net capital expenditures are comprised of (A) capital expenditures plus (B) acquisitions (including the issuance of the Company’s equity securities, less cash acquired) less (C) net proceeds from the sale or disposition of property.

The key strategies for each of the Company’s business segments, and certain related business challenges, are summarized below.

Key Strategies and Challenges

Electric and Natural Gas Distribution

Strategy Provide competitively priced energy to customers while working with them to ensure efficient usage. Both the electric and natural gas distribution segments continually seek opportunities for growth and expansion of their customer base through extensions of existing operations and through selected acquisitions of companies and properties at prices that will provide an opportunity for the Company to earn a competitive return on investment. The natural gas distribution segment also continues to pursue growth by expanding its energy-related services.

Challenges Both segments are subject to extensive regulation in the state jurisdictions where they conduct operations with respect to costs and permitted returns on investment as well as subject to certain operational regulations at the federal level. The ability of these segments to grow through acquisitions is subject to significant competition from other energy providers. In addition, as to the electric business, the ability of this segment to grow its service territory and customer base is affected by significant competition from other energy providers, including rural electric cooperatives.

Construction Services

Strategy Provide a competitive return on investment while operating in a competitive industry by: building new and strengthening existing customer relationships; effectively controlling costs; recruiting, developing and retaining talented employees; focusing business development efforts on project areas that will permit higher margins; and properly managing risk. This segment continuously seeks opportunities to expand through strategic acquisitions.

Challenges This segment operates in highly competitive markets, with many jobs subject to competitive bidding. Maintenance of effective cost controls and retention of key personnel are ongoing challenges.

Pipeline and Energy Services

Strategy Leverage the segment's existing expertise in energy infrastructure, services and technologies to increase market share and profitability through optimization of existing operations, internal growth, and acquisitions of energy-related assets and companies. Incremental and new growth opportunities include: access to new sources of natural gas for storage, gathering and transportation services; expansion of existing gathering and transmission facilities; incremental expansion of the capacity of the Grasslands Pipeline to allow customers access to more liquid and potentially higher-priced markets; and pursuit of new markets for the segment's locating and tracking technology business.

Challenges Energy price volatility; natural gas basis differentials; regulatory requirements; recruitment and retention of a skilled workforce; increased competition from other natural gas pipeline and gathering companies; and establishing and enhancing customer relationships at the location and tracking technology business.

Natural Gas and Oil Production

Strategy Apply new technology and leverage existing exploration and production expertise, with a focus on operated properties, to increase production and reserves from existing leaseholds, and to seek additional reserves and production opportunities in new areas to further diversify the segment's asset base. By optimizing existing operations and taking advantage of new and incremental growth opportunities, this segment's goal is to increase both production and reserves over the long term so as to generate competitive returns on investment.

Challenges Fluctuations in natural gas and oil prices; ongoing environmental litigation and administrative proceedings; timely receipt of necessary permits and approvals; recruitment and retention of a skilled workforce; availability of drilling rigs and industry specialty services; and increased competition from many of the larger natural gas and oil companies.

Construction Materials and Mining

Strategy Focus on high growth regional markets located near major transportation corridors and metropolitan areas; enhance profitability through vertical integration of the segment's operations; and continue growth through acquisitions. Vertical integration allows the segment to manage operations from aggregate mining to final lay-down of concrete and asphalt, with control of and access to adequate quantities of permitted aggregate reserves being significant. A key element of the Company's long-term strategy for this business is to further expand its presence in the higher-margin materials business (rock, sand, gravel and related products), complementing the Company's ongoing efforts to increase margin by building a more profitable backlog of business and carefully managing costs through implementation of a variety of continuous improvement programs, including centralized purchasing and negotiation of contract price escalation provisions and the utilization of national purchasing accounts.

Challenges Price volatility with respect to, and availability of, raw materials such as steel and cement; petroleum price volatility; recruitment and retention of a skilled workforce; and increased competition from national and international construction materials companies. In particular, increases in energy prices can affect the profitability of construction jobs.

Independent Power Production

Strategy Achieve growth through the acquisition, construction and operation of domestic nonregulated electric generation facilities and through international investments in the energy and natural resources sectors. The segment continues to seek projects with mid- to long-term agreements with financially stable customers, while maintaining diversity in customers, geographic markets and fuel source.

Challenges Overall business challenges for this segment include: the risks and uncertainties associated with the construction, startup and operation of power plant facilities; changes in energy market pricing; increased competition from other independent power producers; and fluctuations in the value of foreign currency and political risk in the countries where this segment does business.

For further information on the risks and challenges the Company faces as it pursues its growth strategies and other factors that should be considered for a better understanding of the Company's financial condition, see Part II, Item 1A - Risk Factors, as well as Part I, Item 1A - Risk Factors in the 2005 Annual Report. For further information on each segment's key growth strategies, projections and certain assumptions, see Prospective Information. For information pertinent to various commitments and contingencies, see Notes to Consolidated Financial Statements.

Earnings Overview

The following table summarizes the contribution to consolidated earnings by each of the Company's businesses.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(Dollars in millions, where applicable)			
Electric	$ .5	$ 1.8	$ 4.3	$4.9
Natural gas distribution	(2.5)	(1.3)	2.8	3.5
Construction services	9.7	3.7	15.1	5.6
Pipeline and energy services	5.6	8.7	10.2	12.0
Natural gas and oil production	31.0	29.9	72.2	58.8
Construction materials and mining	25.3	18.4	16.4	9.9
Independent power production	1.5	18.6	2.8	19.3
Other	.2	.2	.5	.3
Earnings on common stock	$ 71.3	$ 80.0	$ 124.3	$114.3
Earnings per common share - basic	$ .40	$ .45	$ .69	$.65
Earnings per common share - diluted	$ .39	$ .45	$ .69	$.64
			15.1%	14.4%

Return on average common equity for the 12 months ended

Three Months Ended June 30, 2006 and 2005 Consolidated earnings for the quarter ended June 30, 2006, decreased $8.7 million from the comparable prior period largely due to:

- Decreased earnings from equity method investments, largely the absence in 2006 of the 2005 $15.6 million benefit from the sale of the Termoceara Generating Facility at the independent power production business
- Absence in 2006 of the benefit from the resolution of a rate proceeding of $5.0 million (after tax) recorded in 2005 at the pipeline and energy services business. For more information, see Note 18.

Partially offsetting the decrease were:

- Higher earnings from construction due to increased volumes and margins and earnings from companies acquired since the comparable prior period at the construction materials and mining business
- Earnings from acquisitions made since the comparable prior period and increased outside construction workloads and inside construction workloads and margins at the construction services business

Six Months Ended June 30, 2006 and 2005 Consolidated earnings for the six months ended June 30, 2006, increased $10.0 million from the comparable prior period largely due to:

- Higher average realized natural gas prices of 20 percent, increased natural gas and oil production of 5 percent and 19 percent, respectively, and higher average realized oil prices of 22 percent at the natural gas and oil production business
- Earnings from acquisitions made since the comparable prior period and higher inside construction workloads and margins at the construction services business
- Higher earnings from construction, as previously discussed, and increased realized ready-mixed concrete volumes and margins at the construction materials and mining business

Partially offsetting the increase were:

- Decreased earnings from equity method investments which reflect the absence in 2006 of the 2005 $15.6 million benefit from the sale of the Termoceara Generating Facility, higher net interest expense largely due to debt related to the Hardin Generating Facility which was placed in commercial operation in March 2006, and lower margins related to domestic electric generating facilities primarily due to lower capacity revenues at the independent power production business
- Absence in 2006 of the benefit from the resolution of a rate proceeding of $5.0 million (after tax) recorded in 2005, as previously discussed, at the pipeline and energy services business

FINANCIAL AND OPERATING DATA

The following tables contain key financial and operating statistics for each of the Company's businesses.

Electric

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(Dollars in millions, where applicable)			
Operating revenues	$ 40.9	$ 41.1	$ 85.9	$ 85.4
Operating expenses:				
Fuel and purchased power	16.0	14.5	32.0	30.7
Operation and maintenance	15.7	14.9	29.7	28.7

Depreciation, depletion and amortization	5.3	5.2	10.6	10.4
Taxes, other than income	2.0	2.1	4.3	4.3
	39.0	36.7	76.6	74.1
Operating income	1.9	4.4	9.3	11.3
Earnings	$ .5	$ 1.8	$ 4.3	$ 4.9
Retail sales (million kWh)	563.0	554.7	1,175.9	1,159.2
Sales for resale (million kWh)	85.3	115.3	251.7	313.3
Average cost of fuel and purchased power per kWh	$ .024	$ .021	$ .022	$ .020

Three Months Ended June 30, 2006 and 2005 Electric earnings decreased $1.3 million due to:

- Higher operation and maintenance expense of $500,000 (after tax), primarily the result of a scheduled maintenance outage at an electric generating station
  - Decreased retail sales margins, largely the result of the timing of increased fuel and purchased power costs
- Decreased sales for resale margins due to lower average rates of 15 percent resulting from lower demand caused by mild weather and decreased volumes of 26 percent due to plant availability

This decrease was partially offset by decreased interest expense of $200,000 (after tax) resulting from lower average interest rates due to the repurchase and redemption of certain long-term debt.

Six Months Ended June 30, 2006 and 2005 Electric earnings decreased $600,000 due to:

- Decreased sales for resale margins due to lower average rates of 16 percent and decreased volumes of 20 percent, both as previously discussed
- Higher operation and maintenance expense of $600,000 (after tax), largely the result of a scheduled maintenance outage at an electric generating station

Partially offsetting the decrease was decreased interest expense of $400,000 (after tax) resulting from lower average interest rates, as previously discussed.

Natural Gas Distribution

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(Dollars in millions, where applicable)			
Operating revenues:				
Sales	$ 44.9	$ 53.6	$ 196.1	$ 197.3
Transportation and other	.9	1.1	2.0	2.4
	45.8	54.7	198.1	199.7
Operating expenses:				
Purchased natural gas sold	33.4	41.6	161.8	162.1
Operation and maintenance	13.0	11.3	24.8	23.2
Depreciation, depletion and amortization	2.4	2.3	4.8	4.8
Taxes, other than income	1.5	1.4	3.0	3.0
	50.3	56.6	194.4	193.1
Operating income (loss)	(4.5)	(1.9)	3.7	6.6
Earnings (loss)	$ (2.5)	$ (1.3)	$ 2.8	$ 3.5
Volumes (MMdk):				

Sales	4.6	5.3	18.8	21.2
Transportation	2.8	3.0	7.2	6.9
Total throughput	7.4	8.3	26.0	28.1
Degree days (% of normal)*	68%	92%	82%	93%
Average cost of natural gas, including transportation, per dk	$ 7.29	$ 7.82	$ 8.59	$ 7.66

* Degree days are a measure of the daily temperature-related demand for energy for heating.

Three Months Ended June 30, 2006 and 2005 The natural gas distribution business experienced a seasonal loss of $2.5 million in the second quarter compared to a loss of $1.3 million in the second quarter of 2005. The decrease in earnings of $1.2 million was largely due to:

- Higher operation and maintenance expense of $1.1 million (after tax), largely due to higher payroll-related costs from an early retirement program
- Lower retail sales margins due to lower sales volumes of 14 percent, resulting from 27 percent warmer weather than last year

Six Months Ended June 30, 2006 and 2005 Earnings at the natural gas distribution business decreased $700,000 due to:

- Higher operation and maintenance expense of $1.0 million (after tax) largely due to higher payroll-related costs from an early retirement program
- Lower retail sales margins due to lower sales volumes of 11 percent, resulting from 12 percent warmer weather than last year, partially offset by higher weather-normalized revenues in certain jurisdictions

Partially offsetting the decrease in earnings were higher nonregulated earnings from energy-related services.

Construction Services

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(In millions)			
Operating revenues	$ 243.2	$ 136.9	$ 467.0	$ 250.8
Operating expenses:				
Operation and maintenance	216.5	122.6	419.3	223.7
Depreciation, depletion and amortization	3.9	3.1	7.4	5.9
Taxes, other than income	5.5	4.3	12.9	10.1
	225.9	130.0	439.6	239.7
Operating income	17.3	6.9	27.4	11.1
Earnings	$ 9.7	$ 3.7	$ 15.1	$ 5.6

Three Months Ended June 30, 2006 and 2005 Construction services earnings increased $6.0 million compared to the second quarter of the comparable prior period due to:

- Earnings from acquisitions made since the comparable prior period, which contributed approximately 59 percent of the earnings increase
- Higher outside construction workloads and margins of $1.4 million (after tax), largely in the Southwest region partially offset by decreased workloads and margins in the Northwest region
- Higher inside construction workloads and margins of $1.1 million (after tax)
- Increased equipment sales and rentals

Six Months Ended June 30, 2006 and 2005 Construction services earnings increased $9.5 million compared to the six months of the comparable prior period due to:

- Earnings from acquisitions made since the comparable prior period, which contributed approximately 60 percent of the earnings increase
- Higher inside construction workloads and margins of $3.4 million (after tax)
- Increased equipment sales and rentals
- Higher outside construction workloads of $600,000 (after tax), largely in the Southwest region partially offset by decreased workloads and margins in the Northwest region

Partially offsetting the increase were higher general and administrative expenses of $1.1 million (after tax), including higher payroll-related expenses and outside services.

Pipeline and Energy Services

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(Dollars in millions)			
Operating revenues:				
Pipeline	$ 26.1	$ 22.5	$ 46.8	$ 42.3
Energy services	77.0	78.9	183.3	151.9
	103.1	101.4	230.1	194.2
Operating expenses:				
Purchased natural gas sold	69.3	71.4	167.1	136.9
Operation and maintenance	15.0	13.3	27.5	26.6
Depreciation, depletion and amortization	5.1	(1.5)	10.1	3.1
Taxes, other than income	2.6	2.0	5.1	4.1
	92.0	85.2	209.8	170.7
Operating income	11.1	16.2	20.3	23.5
Earnings	$ 5.6	$ 8.7	$ 10.2	$ 12.0
Transportation volumes (MMdk):				
Montana-Dakota	7.1	7.7	15.1	15.4
Other	28.0	19.6	46.2	33.5
	35.1	27.3	61.3	48.9
Gathering volumes (MMdk)	21.2	19.7	42.9	39.7

Three Months Ended June 30, 2006 and 2005 Pipeline and energy services experienced a decrease in earnings of $3.1 million due to:

- Absence in 2006 of the benefit from the resolution of a rate proceeding of $5.0 million (after tax) recorded in 2005, which included a reduction to depreciation, depletion and amortization expense. For more information, see Note 18.
- Higher operation and maintenance expense, primarily related to the natural gas storage litigation. For more information, see Note 19.

Partially offsetting this decrease were higher transportation, storage and gathering volumes of $2.6 million (after tax), and higher gathering rates of $1.0 million (after tax).

Six Months Ended June 30, 2006 and 2005 Pipeline and energy services experienced a decrease in earnings of $1.8 million due to:

- Absence in 2006 of the benefit from the resolution of a rate proceeding of $5.0 million (after tax) recorded in 2005, as previously discussed
- Higher operation and maintenance expense, primarily related to the natural gas storage litigation, as previously discussed

Partially offsetting this decrease were higher transportation, storage and gathering volumes of $3.3 million (after tax), and higher gathering rates of $2.1 million (after tax).

Natural Gas and Oil Production

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(Dollars in millions, where applicable)			
Operating revenues:				
Natural gas	$ 87.2	$ 80.3	$ 192.5	$ 152.8
Oil	25.4	17.3	46.5	31.8
Other	1.5	.1	3.5	.2
	114.1	97.7	242.5	184.8
Operating expenses:				
Purchased natural gas sold	1.7	.1	3.7	.2
Operation and maintenance:				
Lease operating costs	12.3	9.8	24.2	17.7
Gathering and transportation	4.7	2.8	9.4	5.6
Other	9.4	6.4	16.8	11.9
Depreciation, depletion and amortization	25.8	21.2	50.3	38.3
Taxes, other than income:				
Production and property taxes	8.0	7.5	18.0	13.5
Other	.4	.1	.5	.3
	62.3	47.9	122.9	87.5
Operating income	51.8	49.8	119.6	97.3
Earnings	$ 31.0	$ 29.9	$ 72.2	$ 58.8
Production:				
Natural gas (MMcf)	15,242	14,627	30,604	29,054
Oil (MBbls)	471	406	921	773
Average realized prices (including hedges):				
Natural gas (per Mcf)	$ 5.72	$ 5.49	$ 6.29	$ 5.26
Oil (per barrel)	$ 54.00	$ 42.60	$ 50.43	$ 41.21
Average realized prices (excluding hedges):				
Natural gas (per Mcf)	$ 5.15	$ 5.71	$ 6.03	$ 5.37
Oil (per barrel)	$ 55.71	$ 47.81	$ 51.77	$ 46.06
Production costs, including taxes, per net equivalent Mcf:				
Lease operating costs	$ .68	$ .57	$ .67	$ .52
Gathering and transportation	.26	.17	.26	.17
Production and property taxes	.45	.44	.50	.40
	$ 1.39	$ 1.18	$ 1.43	$ 1.09

Three Months Ended June 30, 2006 and 2005 The natural gas and oil production business experienced a $1.1 million increase in earnings due to:

- Higher average realized oil prices of 27 percent
- Higher average realized natural gas prices of 4 percent
- Increased oil production of 16 percent and natural gas production of 4 percent, largely due to increased production in the Rocky Mountain region as well as from the May 2005 South Texas and May 2006 Big Horn acquisitions

Partially offsetting the increase were:

- Higher depreciation, depletion and amortization of $2.9 million (after tax) due to higher depletion rates and increased production
- Higher lease operating expenses of $1.6 million (after tax), including acquisitions since the comparable prior period
- Increased general and administrative expense of $1.3 million (after tax), including higher payroll-related expenses and office expenses

Six Months Ended June 30, 2006 and 2005 The natural gas and oil production business experienced a $13.4 million increase in earnings due to:

- Higher average realized natural gas prices of 20 percent
- Increased natural gas production of 5 percent and oil production of 19 percent, as previously discussed
- Higher average realized oil prices of 22 percent

Partially offsetting the increase were:

- Higher depreciation, depletion and amortization of $7.4 million (after tax) due to higher depletion rates and increased production
- Higher lease operating expenses of $4.0 million (after tax), as previously discussed
- Increased general and administrative expense of $2.5 million (after tax), including higher payroll-related expenses, outside service fees and office expenses

Construction Materials and Mining

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	(Dollars in millions)			
Operating revenues	$ 484.9	$ 394.0	$ 718.6	$ 581.1
Operating expenses:				
Operation and maintenance	404.5	330.0	620.2	500.5
Depreciation, depletion and amortization	22.1	19.0	42.2	37.2
Taxes, other than income	11.9	10.5	20.3	18.4
	438.5	359.5	682.7	556.1
Operating income	46.4	34.5	35.9	25.0
Earnings	$ 25.3	$ 18.4	$ 16.4	$ 9.9
Sales (000's):				
Aggregates (tons)	13,341	11,023	19,425	16,929
Asphalt (tons)	2,356	2,139	2,689	2,500
Ready-mixed concrete (cubic yards)	1,260	1,224	1,971	1,884

Three Months Ended June 30, 2006 and 2005 Earnings at the construction materials and mining business increased $6.9 million due to:

- Higher earnings of $5.2 million (after tax) from construction, largely due to increased volumes and margins
- Earnings from companies acquired since the comparable prior period, which contributed approximately 21 percent of the earnings increase
- Increased earnings from aggregate and ready-mixed concrete operations of $2.4 million (after tax), largely due to higher volumes

Partially offsetting the increase in earnings were:

- Increased general and administrative expense of $1.6 million (after tax), largely payroll-related
- Higher depreciation, depletion and amortization of $1.2 million (after tax), primarily due to higher plant and equipment balances and increased aggregate production

Six Months Ended June 30, 2006 and 2005 Earnings at the construction materials and mining business increased $6.5 million due to:

- Higher earnings of $5.7 million (after tax) from construction, as previously discussed
- Higher realized ready-mixed concrete margins and volumes added $3.4 million (after tax) to earnings
- Higher earnings from aggregate operations of $1.8 million (after tax), largely higher volumes

Partially offsetting the increase in earnings were:

- Increased general and administrative expense of $2.7 million (after tax), primarily payroll-related
- Higher depreciation, depletion and amortization of $1.9 million (after tax), as previously discussed
- Higher interest expense of $1.4 million (after tax), largely due to acquisition-related debt and higher interest rates

Independent Power Production

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(Dollars in millions)			
OOperating revenues	$ 11.7	$ 13.7	$ 23.0	$ 23.5
Operating expenses:				
Fuel and purchased power	1.0	---	1.3	---
Operation and maintenance	5.1	7.3	14.3	13.7
Depreciation, depletion and amortization	4.3	2.2	6.6	4.7
Taxes, other than income	1.1	.7	2.0	1.4
	11.5	10.2	24.2	19.8
Operating income (loss)	.2	3.5	(1.2)	3.7
Earnings	$ 1.5	$ 18.6	$ 2.8	$ 19.3
Net generation capacity (kW)*	437,600	279,600	437,600	279,600
Electricity produced and sold (thousand kWh)*	202,778	90,762	291,275	128,012

* Excludes equity method investments.

Three Months Ended June 30, 2006 and 2005 Earnings at the independent power production business decreased $17.1 million largely due to:

- Decreased earnings from equity method investments which reflect the absence in 2006 of the 2005 $15.6 million benefit from the sale of the Termoceara Generating Facility, partially offset by increased earnings from the Trinity Generating Facility
- Higher interest expense of $1.8 million (after tax) largely due to debt related to the Hardin Generating Facility which was placed in commercial operation in March 2006
- Lower margins of $1.4 million (after tax) related to domestic electric generating facilities primarily due to lower capacity revenues

Six Months Ended June 30, 2006 and 2005 Earnings at the independent power production business decreased $16.5 million largely due to:

- Decreased earnings from equity method investments which reflect the absence in 2006 of the 2005 $15.6 million benefit from the sale of the Termoceara Generating Facility, partially offset by increased earnings from the Trinity Generating Facility partially due to a one-time benefit due to a tax rate reduction
- Higher interest expense of $1.8 million (after tax), as previously discussed
- Lower margins of $2.0 million (after tax) related to domestic electric generating facilities primarily due to lower capacity revenues

Other and Intersegment Transactions
Amounts presented in the preceding tables will not agree with the Consolidated Statements of Income due to the Company's other operations and the elimination of intersegment transactions. The amounts relating to these items are as follows:

	Three Months Ended June 30,				Six Months Ended June 30,			
		2006		2005		2006		2005
				(In millions)				
Other:								
Operating revenues	$	2.3	$	1.4	$	4.1	$	2.7
Operation and maintenance		1.8		1.2		3.0		2.4
Depreciation, depletion and amortization		.2		.1		.5		.1
Taxes, other than income		.1		---		.1		.1
Intersegment transactions:								
Operating revenues	$	72.2	$	70.7	$	180.2	$	147.7
Fuel and purchased power		.1		---		.1		---
Purchased natural gas sold		65.0		66.4		166.3		139.0
Operation and maintenance		7.1		4.3		13.8		8.7

For further information on intersegment eliminations, see Note 15.

PROSPECTIVE INFORMATION
The following information includes highlights of the key growth strategies, projections and certain assumptions for the Company and its subsidiaries and other matters for each of the Company's businesses. Many of these highlighted points are forward-looking statements. There is no assurance that the Company's projections, including estimates for growth and increases in revenues and earnings, will in fact be achieved. Please refer to assumptions contained in this section, as well as the various important factors listed in Part II, Item 1A - Risk Factors, as well as Part I, Item 1A - Risk Factors in the 2005 Annual Report. Changes in such assumptions and factors could cause actual future results to differ materially from targeted growth, revenue and earnings projections.

MDU Resources Group, Inc.

· Earnings per common share for 2006, diluted, are projected in the range of $1.47 to $1.60, an increase from prior guidance of $1.43 to $1.57.

· The Company expects the percentage of 2006 earnings per common share, diluted, by quarter to be in the following approximate ranges:

o Third quarter - 30 percent to 35 percent
o Fourth quarter - 20 percent to 25 percent

· The Company's long-term compound annual growth goal on earnings per share is in the range of 7 percent to 10 percent, although the Company has exceeded this level in recent years.

Electric

· The Company is analyzing potential projects for accommodating load growth and replacing an expiring purchased power contract with Company-owned generation. This will add to the Company's base-load capacity and rate base. New generation is projected to be on line by 2011. A decision on the project to be built is anticipated by early 2007.

· As discussed in Note 21, the Company has entered into a definitive merger agreement to acquire Cascade. When the acquisition is completed, it is expected to significantly enhance regulated earnings and cash flows. Regulatory approvals are anticipated to be obtained by mid-year 2007.

· This business continues to pursue growth by expanding energy-related services.

· Montana-Dakota has obtained and holds, or is in the process of renewing, valid and existing franchises authorizing it to conduct its electric operations in all of the municipalities it serves where such franchises are required. Montana-Dakota intends to protect its service area and seek renewal of all expiring franchises.

Natural gas distribution

· In September 2004, a natural gas rate case was filed with the MNPUC requesting a revenue increase of $1.4 million annually, or approximately 4 percent. For further information, see Note 18.

· Montana-Dakota's and Great Plains' retail natural gas rate schedules contain clauses permitting monthly adjustments in rates based upon changes in natural gas commodity, transportation and storage costs. Current regulatory practices allow Montana-Dakota and Great Plains to recover increases or refund decreases in such costs within a period ranging from 24 to 28 months from the time such costs are paid. At June 30, 2006, the Montana Public Service Commission has not issued a final order relative to the three years of monthly gas cost changes that were implemented on an interim basis from May 2003 through May 2005. A final order is expected by late 2006.

· This business continues to pursue growth by expanding energy-related services.

· Montana-Dakota and Great Plains have obtained and hold, or are in the process of renewing, valid and existing franchises authorizing them to conduct their natural gas operations in all of the municipalities they serve where such franchises are required. Montana-Dakota and Great Plains intend to protect their service areas and seek renewal of all expiring franchises.

Construction services

· Revenues in 2006 are expected to be significantly higher than 2005 record levels.

· The Company anticipates margins to strengthen in 2006 as compared to 2005 levels.

· Work backlog as of June 30, 2006, was approximately $523 million, including acquisitions, compared to $358 million at June 30, 2005.

Pipeline and energy services

· Firm capacity for the Grasslands Pipeline is 90,000 Mcf per day with possible expansion to 200,000 Mcf per day. Based on anticipated demand, incremental expansions are forecasted over the next few years beginning as early as 2008.

· In 2006, total gathering and transportation throughput is expected to increase approximately 5 percent to 10 percent over 2005 levels.

Natural gas and oil production

· The Company's long-term compound annual growth goal for production is in the range of 7 percent to 10 percent. In 2006, the Company expects to exceed the upper end of this range.

· The Company is expecting to drill more than 325 wells in 2006. Currently, this segment's net combined natural gas and oil production is approximately 200,000 Mcf equivalent to 210,000 Mcf equivalent per day.

· Estimates of natural gas prices in the Rocky Mountain region for August through December 2006, reflected in the Company's 2006 earnings guidance, are in the range of $5.50 to $6.00 per thousand cubic feet. The Company's estimates for natural gas prices on the NYMEX for August through December, reflected in the Company's 2006 earnings guidance, are in the range of $6.75 to $7.25 per Mcf. During 2005, more than three-fourths of this segment's natural gas production was priced using Rocky Mountain or other non-NYMEX prices.

· Estimates of NYMEX crude oil prices for August through December, reflected in the Company's 2006 earnings guidance, are projected in the range of $60 to $65 per barrel.

· The Company has hedged approximately 30 percent to 35 percent of its estimated natural gas production and 15 percent to 20 percent of its estimated oil production for the last six months of 2006. For 2007, the Company has hedged approximately 20 percent to 25 percent of its estimated natural gas production. The hedges that are in place as of July 27, 2006, are summarized in the following chart:

Commodity	Index*	Period Outstanding	Forward Notional Volume (MMBtu)/(Bbl)	Price Swap or Costless Collar Floor-Ceiling (Per MMBtu/Bbl)
Natural Gas	Ventura	7/06 - 12/06	920,000	$6.00-$7.60
Natural Gas	Ventura	7/06 - 12/06	1,840,000	$6.655
Natural Gas	Ventura	7/06 - 12/06	920,000	$6.75-$7.71
Natural Gas	Ventura	7/06 - 12/06	920,000	$6.75-$7.77
Natural Gas	Ventura	7/06 - 12/06	920,000	$7.00-$8.85
Natural Gas	NYMEX	7/06 - 12/06	920,000	$7.75-$8.50
Natural Gas	Ventura	7/06 - 12/06	920,000	$7.76
Natural Gas	CIG	7/06 - 12/06	920,000	$6.50-$6.98
Natural Gas	CIG	7/06 - 12/06	920,000	$7.00-$8.87
Natural Gas	Ventura	7/06 - 12/06	460,000	$8.50-$10.00
Natural Gas	Ventura	7/06 - 12/06	460,000	$8.50-$10.15
Natural Gas	Ventura	7/06 - 10/06	615,000	$9.25-$12.88
Natural Gas	Ventura	7/06 - 10/06	615,000	$9.25-$12.80
Natural Gas	CIG	11/06 - 12/06	305,000	$7.00-$8.65
Natural Gas	Ventura	1/07 - 12/07	1,825,000	$8.00-$11.91
Natural Gas	Ventura	1/07 - 12/07	912,500	$8.00-$11.80

Natural Gas	Ventura	1/07 - 12/07	912,500	$8.00-$11.75
Natural Gas	Ventura	1/07 - 12/07	1,825,000	$7.50-$10.55
Natural Gas	CIG	1/07 - 12/07	1,825,000	$7.40
Natural Gas	CIG	1/07 - 12/07	1,825,000	$7.405
Natural Gas	Ventura	1/07 - 12/07	1,460,000	$8.25-$10.80
Natural Gas	CIG	1/07 - 12/07	912,500	$7.50-$9.12
Natural Gas	Ventura	1/07 - 12/07	1,825,000	$8.29
Natural Gas	Ventura	11/06 - 3/07	755,000	$8.00-$9.80
Natural Gas	Ventura	1/07 - 12/07	1,825,000	$7.85-$9.70
Crude Oil	NYMEX	7/06 - 12/06	92,000	$43.00-$54.15
Crude Oil	NYMEX	7/06 - 12/06	73,600	$60.00-$69.20
Crude Oil	NYMEX	7/06 - 12/06	46,000	$60.00-$76.80

*Ventura is an index pricing point related to Northern Natural Gas Co.'s system; CIG is an index pricing point related to Colorado Interstate Gas Co.'s system.

Construction materials and mining

· Ready-mixed concrete and aggregate volumes for 2006 are expected to be higher than the record levels achieved in 2005. Asphalt volumes are expected to be slightly lower than 2005 record volumes.

• Work backlog as of June 30, 2006, was approximately $763 million, including acquisitions, compared to $740 million at June 30, 2005.

· A key element of the Company's long-term strategy for this business is to further expand its presence in the higher-margin materials business (rock, sand, gravel and related products), complementing the Company's ongoing efforts to increase margin by building a more profitable backlog of business and carefully managing costs.

· Strong market and product demand, cost containment initiatives and continued operational improvement in Texas are expected to result in improved margins over 2005.

Independent power production

· Earnings at this segment are expected to be minimal in 2006, reflecting primarily the sale of the Company's Brazilian electric generating facility in June 2005, significantly higher interest expense related to the construction of the Hardin Generating Facility and lower revenues because of the bridge contract renewal at the Brush Generating Facility. The bridge contract will be replaced by a more favorably priced 10-year contract in April 2007.

· This segment is focused on redeploying the funds from the June 2005 sale of the Brazilian facility and continues to explore for investment opportunities both domestically and internationally, using the Company's disciplined approach for acquisitions.

NEW ACCOUNTING STANDARDS

For information regarding new accounting standards, see Note 10, which is incorporated by reference.

CRITICAL ACCOUNTING POLICIES INVOLVING SIGNIFICANT ESTIMATES

The Company's critical accounting policies involving significant estimates include impairment testing of long-lived assets and intangibles, impairment testing of natural gas and oil production properties, revenue recognition, purchase accounting, asset retirement obligations, and pension and other postretirement benefits. There were no material changes in the Company's critical accounting policies involving significant estimates from those reported in the 2005 Annual Report. For more information on critical accounting policies involving significant estimates, see Part II, Item 7 in the 2005 Annual Report.

LIQUIDITY AND CAPITAL COMMITMENTS

Cash flows

Operating activities Net income before depreciation, depletion and amortization is a significant contributor to cash flows from operating activities. The changes in cash flows from operating activities generally follow the results of operations as discussed in Financial and Operating Data and also are affected by changes in working capital. Cash flows provided by operating activities in the first six months of 2006 increased $28.1 million from the comparable 2005 period, the result of:

- Higher depreciation, depletion and amortization expense of $28.1 million, largely at the natural gas and oil production business, as previously discussed
- Higher deferred income taxes of $12.4 million, primarily related to natural gas costs recoverable through rate adjustments and costs associated with the repurchase of certain first mortgage bonds at the electric and natural gas distribution businesses, as well as higher property, plant and equipment at the natural gas and oil production business
- Decreased earnings, net of distributions, from equity method investments of $11.5 million, primarily the result of the sale of the Termoceara Generating Facility
- Increased net income of $10.0 million, largely increased earnings at the natural gas and oil production, construction services and construction materials and mining businesses

Partially offsetting the increase in cash flows from operating activities were:

- Increased working capital requirements of $31.2 million, largely at the following businesses:
  - Natural gas distribution, largely due to timing of natural gas costs recoverable/refundable through rate adjustments, lower storage withdrawals and higher natural gas costs
  - Construction materials and mining, due to higher asphalt oil and fuel inventories
  - Higher income tax payments

Investing activities Cash flows used in investing activities in the first six months of 2006 increased $11.1 million compared to the comparable 2005 period, the result of increased capital expenditures primarily at the natural gas and oil production business, largely due to additional exploration and development, and higher ongoing capital expenditures at the construction materials and mining business. Partially offsetting this increase was a decrease in cash flows used for acquisitions largely at the natural gas and oil production segment.

Financing activities Cash flows provided by financing activities in the first six months of 2006 increased $36.3 million compared to the comparable 2005 period, the result of a decrease in the repayment of long-term debt of $26.6 million and an increase in the issuance of long-term debt of $10.9 million.

Defined benefit pension plans

There are no material changes to the Company's qualified noncontributory defined benefit pension plans from those reported in the 2005 Annual Report. For further information, see Note 17.

Capital expenditures

Net capital expenditures for the first six months of 2006 were $362.3 million and are estimated to be approximately $590 million for the year 2006. Estimated capital expenditures include those for:

- Completed acquisitions
- System upgrades
- Routine replacements
- Service extensions
- Routine equipment maintenance and replacements
- Buildings, land and building improvements
- Pipeline and gathering projects
- Further enhancement of natural gas and oil production and reserve growth

· Power generation opportunities, including certain costs for additional electric generating capacity
· Other growth opportunities

Approximately 23 percent of estimated 2006 net capital expenditures are associated with completed acquisitions. The Company continues to evaluate potential future acquisitions and other growth opportunities; however, they are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the estimated 2006 capital expenditures referred to previously. It is anticipated that all of the funds required for capital expenditures will be met from various sources, including internally generated funds; commercial paper credit facilities at Centennial Energy Holdings, Inc. and MDU Resources Group, Inc., as described below; and through the issuance of long-term debt and the Company's equity securities.

Capital resources
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 June 30, 2006.

MDU Resources Group, Inc. The Company has a revolving credit agreement with various banks totaling $125 million (with provision for an increase, at the option of the Company on stated conditions and upon regulatory approval, up to a maximum of $150 million). There were no amounts outstanding under the credit agreement at June 30, 2006. The credit agreement supports the Company's $100 million commercial paper program. Under the Company's commercial paper program, $85.0 million was outstanding at June 30, 2006. The commercial paper borrowings are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings (supported by the credit agreement, which expires in June 2011). The Company plans to borrow up to $100 million through the issuance of unsecured notes later this year. These funds are expected to be used primarily to pay down commercial paper borrowings and for general corporate purposes in connection with the Company's electric and natural gas distribution businesses.

The Company's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Minor fluctuations in the Company's credit ratings have not limited, nor would they be expected to limit, the Company's ability to access the capital markets. In the event of a minor downgrade, the Company may experience a nominal basis point increase in overall interest rates with respect to its cost of borrowings. If the Company were to experience a significant downgrade of its credit ratings, it may need to borrow under its credit agreement.

To the extent the Company needs to borrow under its credit agreement, it would be expected to incur increased annualized interest expense on its variable rate debt of approximately $128,000 (after tax) based on June 30, 2006, variable rate borrowings.

Prior to the maturity of the credit agreement, the Company expects that it will negotiate the extension or replacement of this agreement. If the Company is unable to successfully negotiate an extension of, or replacement for, the credit agreement, or if the fees on this facility became too expensive, which the Company does not currently anticipate, the Company would seek alternative funding. One source of alternative funding might involve the securitization of certain Company assets.

In order to borrow under the Company's credit agreement, the Company must be in compliance with the applicable covenants and certain other conditions, including covenants not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent or (B) the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Also included is a covenant that does not permit the ratio of the Company's earnings before interest, taxes, depreciation and amortization to interest expense (determined with respect to the Company alone, excluding its subsidiaries), for the 12-month period ended each fiscal quarter, to be less than 2.5 to 1. Other covenants include restrictions on the sale of certain assets and on the making of certain investments. The Company was in compliance with these covenants and met the required conditions at June 30, 2006. In the event the Company does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued, as previously described.

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 the Company 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 June 30, 2006, the Company could have issued approximately $441 million of additional first mortgage bonds.

The Company's coverage of fixed charges including preferred dividends was 6.1 times for both the 12 months ended June 30, 2006 and December 31, 2005. Additionally, the Company's first mortgage bond interest coverage was 24.4 times and 10.2 times for the 12 months ended June 30, 2006 and December 31, 2005, respectively. Common stockholders' equity as a percent of total capitalization (net of long-term debt due within one year) was 60 percent and 63 percent at June 30, 2006 and December 31, 2005, respectively.

The Company has repurchased, and may from time to time seek to repurchase, outstanding first mortgage bonds through open market purchases or privately negotiated transactions. The Company will evaluate any such transactions in light of then existing market conditions, taking into account its liquidity and prospects for future access to capital. Between January 1 and June 30, 2006, the Company repurchased $68.0 million of first mortgage bonds. As of June 30, 2006, the Company had $57.0 million of first mortgage bonds outstanding, $30.0 million of which were held by the Indenture trustee for the benefit of the Senior Note holders. At such time as the aggregate principal amount of the Company’s outstanding first mortgage bonds, other than those held by the Indenture trustee, is $20 million or less, the Company would have the ability, subject to satisfying certain specified conditions, to require that any debt issued under its Indenture, dated as of December 15, 2003, as supplemented, from the Company to The Bank of New York, as trustee, become unsecured and rank equally with all of the Company’s other unsecured and unsubordinated debt (as of June 30, 2006, the only such debt outstanding under the Indenture was $30.0 million in aggregate principal amount of the Company’s 5.98% Senior Notes due in 2033).

On July 27, 2006, the Company entered into a Sales Agency Financing Agreement with Wells Fargo Securities, LLC with respect to the issuance and sale of up to 3,000,000 shares of the Company’s common stock, par value $1.00 per share, together with preference share purchase rights appurtenant thereto. The common stock may be offered for sale, from time to time, in accordance with the terms and conditions of the agreement, which terminates on June 30, 2007. Proceeds from the sale of shares of common stock under the agreement are expected to be used for corporate development purposes and other general corporate purposes. The offering is made pursuant to the Company’s shelf registration statement on Form S-3, as amended, which became effective on September 26, 2003, as supplemented by a prospectus supplement, dated July 27, 2006, filed with the Securities and Exchange Commission pursuant to Rule 424(b) under the Securities Act of 1933, as amended.

Centennial Energy Holdings, Inc. Centennial has three revolving credit agreements with various banks and institutions totaling $437.9 million with certain provisions allowing for increased borrowings. These credit agreements support Centennial’s $400 million commercial paper program. There were no outstanding borrowings under the Centennial credit agreements at June 30, 2006. Under the Centennial commercial paper program, $310.5 million was outstanding at June 30, 2006. 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 (supported by Centennial credit agreements). One of these credit agreements is for $400 million, which includes a provision for an increase, at the option of Centennial on stated conditions, up to a maximum of $450 million and expires on August 26, 2010. Another agreement is for $17.9 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 $20 million and may be terminated by the bank at any time. As of June 30, 2006, $43.4 million of letters of credit were outstanding, as discussed in Note 19, of which $25.9 million reduced amounts available under these agreements.

Centennial has an uncommitted long-term master shelf agreement that allows for borrowings of up to $550 million (previously $450 million). Under the terms of the master shelf agreement, $547.5 million was outstanding at June 30, 2006. The ability to request additional borrowings under this master shelf agreement expires on May 8, 2009. To meet potential future financing needs, Centennial may pursue other financing arrangements, including private and/or public financing.

Centennial's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Minor fluctuations in Centennial's credit ratings have not limited, nor would they be expected to limit, Centennial's ability to access the capital markets. In the event of a minor downgrade, Centennial may experience a nominal basis point increase in overall interest rates with respect to its cost of borrowings. If Centennial were to experience a significant downgrade of its credit ratings, it may need to borrow under its committed bank lines.

To the extent Centennial needs to borrow under its committed bank lines, it would be expected to incur increased annualized interest expense on its variable rate debt of approximately $466,000 (after tax) based on June 30, 2006, variable rate borrowings. Based on Centennial's overall interest rate exposure at June 30, 2006, this change would not have a material effect on the Company's results of operations or cash flows.

Prior to the maturity of the Centennial credit agreements, Centennial expects that it will negotiate the extension or replacement of these agreements, which provide credit support to access the capital markets. In the event Centennial was unable to successfully negotiate these agreements, or in the event the fees on such facilities became too expensive, which Centennial does not currently anticipate, it would seek alternative funding. One source of alternative funding might involve the securitization of certain Centennial assets.

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, including covenants not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 65 percent (for the $400 million credit agreement) and 60 percent (for the $17.9 million credit agreement and the master shelf agreement). Also included is a covenant that does not permit the ratio of Centennial's earnings before interest, taxes, depreciation and amortization to interest expense, for the 12-month period ended each fiscal quarter, to be less than 2.5 to 1 (for the $400 million credit agreement), 2.25 to 1 (for the $17.9 million credit agreement) and 1.75 to 1 (for the master shelf agreement). Other covenants include minimum consolidated net worth, limitation on priority debt and restrictions on the sale of certain assets and on the making of certain loans and investments. Centennial and such subsidiaries were in compliance with these covenants and met the required conditions at June 30, 2006. In the event Centennial or such subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued as previously described.

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, $80.0 million was outstanding at June 30, 2006. The ability to request additional borrowings under this master shelf agreement expires on December 20, 2008.

In order to borrow under its uncommitted long-term master shelf agreement, Williston Basin must be in compliance with the applicable covenants and certain other conditions, including covenants not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include limitation on priority debt and some restrictions on the sale of certain assets and the making of certain investments. Williston Basin was in compliance with these covenants and met the required conditions at June 30, 2006. In the event Williston Basin does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

Off balance sheet arrangements

In connection with the sale of MPX in June 2005 to Petrobras, an indirect wholly owned subsidiary of the Company has agreed to indemnify Petrobras for 49 percent of any losses that Petrobras may incur from certain contingent liabilities specified in the purchase agreement. Centennial has agreed to unconditionally guarantee payment of the indemnity obligations to Petrobras for periods ranging from approximately two to five and a half years from the date of sale. The guarantee was required by Petrobras as a condition to closing the sale of MPX.

Contractual obligations and commercial commitments

At June 30, 2006, the Company's contractual obligations related to long-term debt, estimated interest payments, operating leases and purchase commitments (for the twelve months ended June 30, of each year listed in the table below) were as follows:

	2007	2008	2009	2010	2011	Thereafter	Total
				(In millions)			
Long-term debt	$ 159.2	$ 132.0	$ 87.4	$ 22.5	$ 492.4	$ 564.8	$ 1,458.3
Estimated interest payments*	75.9	68.9	61.4	57.3	42.0	129.5	435.0
Operating leases	14.2	10.5	8.9	8.1	6.9	35.7	84.3
Purchase commitments	195.1	113.0	67.8	63.4	60.8	253.4	753.5
	$ 444.4	$ 324.4	$ 225.5	$ 151.3	$ 602.1	$ 983.4	$ 2,731.1

* *Estimated interest payments are calculated based on the applicable rates and payment dates.*

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to the impact of market fluctuations associated with commodity prices and interest rates. The Company has policies and procedures to assist in controlling these market risks and utilizes derivatives to manage a portion of its risk.

Commodity price risk

Fidelity utilizes derivative instruments 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. For more information on derivative instruments and commodity price risk, see Part II, Item 7A in the 2005 Annual Report, and Notes 11 and 14.

The following table summarizes derivative instruments entered into by Fidelity as of June 30, 2006. These agreements call for Fidelity to receive fixed prices and pay variable prices.

	(Notional amount and fair value in thousands)		
	Weighted Average Fixed Price (Per MMBtu)	Forward Notional Volume (In MMBtu's)	Fair Value
Natural gas swap agreements maturing in 2006	$ 7.02	2,760	$ 1,604
Natural gas swap agreements maturing in 2007	$ 7.70	5,475	$ (412)

	Weighted Average Floor/Ceiling Price (Per MMBtu)	Forward Notional Volume (In MMBtu's)	Fair Value
Natural gas collar agreements maturing in 2006	$ 7.34/8.94	$ 8,895	$ 11,693
Natural gas collar agreements maturing in 2007	$ 7.87/11.03	$ 7,848	$ 3,610

	Weighted Average Floor/Ceiling Price (Per barrel)	Forward Notional Volume (In barrels)	Fair Value
Oil collar agreements maturing in 2006	$ 52.61/64.31	212	$ (2,608)

Interest rate risk
There were no material changes to interest rate risk faced by the Company from those reported in the 2005 Annual Report. For more information on interest rate risk, see Part II, Item 7A in the 2005 Annual Report.

ITEM 4. CONTROLS AND PROCEDURES

The following information includes the evaluation of disclosure controls and procedures by the Company's chief executive officer and the chief financial officer, along with any significant changes in internal controls of the Company.

Evaluation of disclosure controls and procedures
The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports it files under the Exchange Act is recorded, processed, summarized and reported within required time periods. The Company's chief executive officer and chief financial officer have evaluated the effectiveness of the Company's disclosure controls and procedures and they have concluded that, as of the end of the period covered by this report, such controls and procedures were effective.

Changes in internal controls
The Company maintains a system of internal accounting controls that is designed to provide reasonable assurance that the Company's transactions are properly authorized, the Company's assets are safeguarded against unauthorized or improper use, and the Company's transactions are properly recorded and reported to permit preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America. There were no changes in the Company's internal control over financial reporting that occurred during the period covered by this report that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II -- OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see Note 19, which is incorporated by reference.

ITEM 1A. RISK FACTORS

This Form 10-Q contains forward-looking statements within the meaning of Section 21E of the Exchange Act. Forward-looking statements are all statements other than statements of historical fact, including without limitation those statements that are identified by the words "anticipates," "estimates," "expects," "intends," "plans," "predicts" and similar expressions.

The Company is including the following factors and cautionary statements in this Form 10-Q to make applicable and to take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of, the Company. Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions (many of which are based, in turn, upon further assumptions) and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Prospective Information. All these subsequent forward-looking statements, whether written or oral and whether made by or on behalf of the Company, also are expressly qualified by these factors and cautionary statements.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including without limitation, management's examination of historical operating trends, data contained in the Company's records and other data available from third parties. Nonetheless, the Company's expectations, beliefs or projections may not be achieved or accomplished.

Any forward-looking statement contained in this document speaks only as of the date on which the statement is made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

There are no material changes in the Company’s risk factors from those reported in Part I, Item 1A - Risk Factors of the 2005 Annual Report other than the risks associated with the ongoing litigation and administrative proceedings in connection with the Company’s coalbed natural gas development activities, and risks related to foreign operations, a pending utility company acquisition, litigation in connection with one of the Company’s storage reservoirs and increases in employee and retiree benefit costs, as discussed below. These factors and the other matters discussed herein are important factors that could cause actual results or outcomes for the Company to differ materially from those discussed in the forward-looking statements included elsewhere in this document.

Environmental and Regulatory Risks

One of the Company’s subsidiaries is subject to ongoing litigation and administrative proceedings in connection with its coalbed natural gas development activities. These proceedings have caused delays in coalbed natural gas drilling activity, and the ultimate outcome of the actions could have a material effect on existing coalbed natural gas operations and/or the future development of its coalbed natural gas properties.

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. 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.

The BER in March 2006 issued a decision in a rulemaking proceeding, initiated by the NPRC, that amends the non-degradation policy applicable to water discharged in connection with coalbed natural gas operations. The amended policy includes additional limitations on factors deemed harmful, thereby restricting water discharges even further than under previous standards. In light of the amended policy, several parties commenced litigation in Montana state court challenging two five-year water discharge permits that the Montana DEQ granted to Fidelity in February 2006 and which are critical to Fidelity's ability to manage water produced under present and future coalbed natural gas operations. If these permits are set aside, Fidelity's coalbed natural gas operations in Montana could be significantly and adversely affected.

Risks Relating to Foreign Operations
The value of the Company's investments in foreign operations may diminish due to political, regulatory and economic conditions and changes in currency exchange rates in countries where the Company does business.

The Company is subject to political, regulatory and economic conditions and changes in currency exchange rates in foreign countries where the Company does business. Significant changes in the political, regulatory or economic environment in these countries could negatively affect the value of the Company's investments located in these countries. Also, since the Company is unable to predict the fluctuations in the foreign currency exchange rates, these fluctuations may have an adverse impact on the Company's results of operations.

Other Risks
The Company's pending acquisition of Cascade may be delayed or may not occur if certain conditions are not satisfied. Upon completion of the acquisition, the Company may not be able to integrate Cascade's operations effectively.

The Company has entered into a definitive merger agreement to acquire Cascade. The total value of the transaction, including the assumption of certain indebtedness, is approximately $475 million. The completion of the acquisition is subject to the approval of Cascade's shareholders and various regulatory authorities, as well as antitrust clearance under the Hart-Scott-Rodino Act, and the satisfaction of other customary closing conditions. The Company's pending acquisition of Cascade may be delayed or may not occur if the Company is unable to timely obtain necessary regulatory approvals, satisfy closing conditions or obtain financing. If the Company is unable to integrate the Cascade operations effectively, its future financial position or results of operations may be adversely affected.

One of the Company's subsidiaries is engaged in litigation with a non-affiliated natural gas producer which has been conducting drilling and production operations which the subsidiary believes is causing diversion and loss of storage gas from one of its storage reservoirs. If the subsidiary is not able to obtain relief through the courts or regulatory process, its storage operations could be adversely affected.

Williston Basin has filed suit in Federal court in Montana seeking to recover unspecified damages from Anadarko and its wholly owned subsidiary, Howell, and to enjoin Anadarko's and Howell's present and future operations in and near Williston Basin's Elk Basin Storage Reservoir located in Wyoming and Montana. Based on relevant information, including reservoir and well pressure data, Williston Basin believes that Elk Basin Storage Reservoir pressures have decreased and that quantities of natural gas have been diverted as a result of Anadarko's and Howell's drilling and production activities. In related litigation, Anadarko filed suit in Wyoming state district court against Williston Basin asserting that it is entitled to produce any gas that might escape from Williston Basin's storage reservoir. If Williston Basin is unable to obtain timely relief through the courts or regulatory process, its present and future gas storage operations could be adversely affected.

Other factors that could impact the Company's businesses.

In addition to those reported in Part I, Item 1A - Risk Factors of the 2005 Annual Report, the following factor may also impact the Company's financial results in future periods:

- Increases in employee and retiree benefit costs

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Between April 1, 2006 and June 30, 2006, the Company issued 1,785 shares (adjusted for the effect of the common stock split, as discussed in Note 3) of Common Stock, $1.00 par value, and the preference share purchase rights appurtenant thereto, as part of the consideration paid by the Company in the acquisition of a business acquired by the Company in a prior period. The Common Stock and preference share purchase rights issued by the Company in this transaction were issued in a private transaction exempt from registration under the Securities Act of 1933 pursuant to Section 4 (2) thereof, Rule 506 promulgated thereunder, or both. The classes of persons to whom these securities were sold were either accredited investors or other persons to whom such securities were permitted to be offered under the applicable exemption.

The following table includes information with respect to the issuer's purchase of equity securities (adjusted for the effect of the common stock split, as discussed in Note 3):

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares (or Units) Purchased	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (2)	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs (2)
April 1 through April 30, 2006	40,831(1)	$24.72		
May 1 through May 31, 2006				
June 1 through June 30, 2006				
Total	40,831			

(1) Represents 331 shares of common stock withheld by the Company to pay taxes in connection with the vesting of shares granted pursuant to a compensation plan and 40,500 shares of common stock purchased on the open market in connection with annual stock grants made to the Company's non-employee directors.

(2) Not applicable. The Company does not currently have in place any publicly announced plans or programs to repurchase equity securities.

ITEM 6. EXHIBITS

2 Agreement and Plan of Merger by and among MDU Resources Group, Inc., Firemoon Acquisition, Inc. and Cascade Natural Gas Corporation dated as of July 8, 2006, filed by Cascade Natural Gas Corporation as Exhibit 2.1 to Form 8-K dated July 10, 2006, in File No. 1-7196. (1)

3 Company Bylaws, as amended

4(a)	Letter Amendment No. 1 to Amended and Restated Master Shelf Agreement, dated May 17, 2006, among Centennial Energy Holdings, Inc., The Prudential Insurance Company of America, and certain investors described in the Letter Amendment
4(b)	First Amendment, dated June 30, 2006, to Credit Agreement, dated June 21, 2005, among MDU Resources Group, Inc., Wells Fargo Bank, National Association, as administrative agent, and certain lenders described in the credit agreement amendment
4(c)	Certificate of Adjustment to Purchase Price and Redemption Price, as amended and restated, pursuant to the Rights Agreement, dated as of November 12, 1998, between MDU Resources Group, Inc. and Wells Fargo Bank, N.A., Rights Agent
10(a)	Directors' Compensation Policy, as amended
10(b)	Supplemental Income Security Plan, as amended and restated effective as of January 1, 2005
12	Computation of Ratio of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividends
31(a)	Certification of Chief Executive Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31(b)	Certification of Chief Financial Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32	Certification of Chief Executive Officer and Chief Financial Officer furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

(1) Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. MDU Resources Group, Inc. hereby undertakes to furnish supplementally copies of any of the omitted schedules upon request by the SEC.

MDU Resources Group, Inc. agrees to furnish to the SEC upon request any instrument with respect to long-term debt that MDU Resources Group, Inc. has not filed as an exhibit pursuant to the exemption provided by Item 601(b)(4)(iii)(A) of Regulation S-K.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

MDU RESOURCES GROUP, INC.

DATE: August 4, 2006	BY:	/s/ Vernon A. Raile Vernon A. Raile Executive Vice President, Treasurer

and Chief Financial Officer

BY: /s/ Doran N. Schwartz
Doran N. Schwartz
Vice President and Chief Accounting Officer

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