MDU RESOURCES GROUP INC
Form 10-Q
November 03, 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 September 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 October 27, 2006: 180,881,227 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
Alusa	Tecnica de Engenharia Eletrica - Alusa
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
Brascan	Brascan Brasil Ltda.
Brazilian Transmission Lines	Company’s equity method investment in companies owning ECTE, ENTE and ERTE
Brush Generating Facility	213 MW of natural gas-fired electric generating facilities located near Brush, Colorado
Carib Power	Carib Power Management LLC
Cascade	Cascade Natural Gas Corporation
CBNG	Coalbed natural gas
CELESC	Centrais Elétricas de Santa Catarina S.A.
CEM	Colorado Energy Management, LLC, a direct wholly owned subsidiary of Centennial Resources
CEMIG	Companhia Energética de Minas Gerais - CEMIG
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 International	Centennial Energy Resources International, Inc., a direct wholly owned subsidiary of Centennial Resources
Centennial Power	Centennial Power, Inc., a direct wholly owned subsidiary of Centennial Resources
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
Clean Water Act	Federal Clean Water Act
Colorado Federal District Court	U.S. District Court for the District of Colorado
Company	MDU Resources Group, Inc.
D.C. Appeals Court	U.S. Court of Appeals for the District of Columbia Circuit
dk	Decatherm
DRC	Dakota Resource Council
ECTE	Empresa Catarinense de Transmissão de Energia S.A.
EITF	Emerging Issues Task Force
EITF No. 04-6	Accounting for Stripping Costs in the Mining Industry
EIS	Environmental Impact Statement

Elk Basin Storage Reservoir	Natural gas storage reservoir located in Montana and Wyoming owned by Williston Basin
ENTE	Empresa Norte de Transmissão de Energia S.A.
EPA	U.S. Environmental Protection Agency
ERTE	Empresa Regional de Transmissão de Energia S.A.
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
Hardin Generating Facility	116-MW coal-fired electric generating facility near Hardin, Montana
Hart-Scott-Rodino Act	Hart-Scott-Rodino Antitrust Improvements Act
Hartwell	Hartwell Energy Limited Partnership
Hobbs Power	Hobbs Power Funding, LLC, an indirect subsidiary of ArcLight Energy Partners Fund III, L.P.
Howell	Howell Petroleum Corporation
Innovatum	Innovatum Inc., an indirect wholly owned subsidiary of WBI Holdings
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
kW	Kilowatts
kWh	Kilowatt-hour
LPP	Lea Power Partners, LLC, a direct wholly owned subsidiary of Centennial Power
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 Brasil	MDU Brasil Ltda., an indirect wholly owned subsidiary of Centennial International
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. 142	Goodwill and Other Intangible Assets
SFAS No. 144	Accounting for the Impairment of Disposal of Long-Lived Assets
SFAS No. 148	Accounting for Stock-Based Compensation - Transition and Disclosure - an amendment of SFAS No. 123
SFAS No. 158	Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans
SIP	State Implementation Plan
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)
TRWUA	Tongue River Water Users' Association
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 16.

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 4.

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PART I -- FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	Three Months Ended September 30,	Nine Months Ended September 30,

	2006	2005	2006	2005
	(In thousands, except per share amounts)			
Operating revenues:				
Electric, natural gas distribution and pipeline and energy services	$ 171,954	$ 185,419	$ 633,590	$ 621,357
Construction services, natural gas and oil production, construction materials and mining, independent power production and other	1,018,682	880,758	2,344,981	1,817,744
	1,190,636	1,066,177	2,978,571	2,439,101
Operating expenses:				
Fuel and purchased power	20,727	16,286	53,973	47,019
Purchased natural gas sold	28,648	33,235	194,969	193,407
Operation and maintenance:				
Electric, natural gas distribution and pipeline and energy services	40,012	38,310	120,112	114,799
Construction services, natural gas and oil production, construction materials and mining, independent power production and other	812,899	735,045	1,906,366	1,501,835
Depreciation, depletion and amortization	71,312	60,504	203,675	164,798
Taxes, other than income	32,476	32,894	98,629	88,099
	1,006,074	916,274	2,577,724	2,109,957
Operating income	184,562	149,903	400,847	329,144
Earnings from equity method investments	2,829	1,800	8,931	18,518
Other income	4,502	1,762	9,809	4,418
Interest expense	20,240	14,091	53,402	40,282
Income before income taxes	171,653	139,374	366,185	311,798
Income taxes	61,555	51,851	130,801	109,152
Income from continuing operations	110,098	87,523	235,384	202,646
Loss from discontinued operations, net of tax (Note 3)	(1,611)	(300)	(2,208)	(830)
Net income	108,487	87,223	233,176	201,816
Dividends on preferred stocks	171	171	514	513
Earnings on common stock	$ 108,316	$ 87,052	$ 232,662	$ 201,303
Earnings per common share - basic:				

Earnings before discontinued operations	$	.61	$	.49	$	1.30	$	1.14
Discontinued operations, net of tax		(.01)		---		(.01)		(.01)
Earnings per common share - basic	$	.60	$	.49	$	1.29	$	1.13
Earnings per common share - diluted:								
Earnings before discontinued operations	$	.61	$	.48	$	1.30	$	1.13
Discontinued operations, net of tax		(.01)		---		(.01)		(.01)
Earnings per common share - diluted	$	.60	$	.48	$	1.29	$	1.12
Dividends per common share	$	.1350	$	.1267	$	.3884	$	.3667
Weighted average common shares outstanding -- basic		180,291		179,429		181,010		177,907
Weighted average common shares outstanding -- diluted		181,307		180,584		181,010		178,953

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

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

	September 30, 2006	September 30, 2005	December 31, 2005
	(In thousands, except shares and per share amounts)		
ASSETS			
Current assets:			
Cash and cash equivalents	$ 70,205	$ 98,392	$ 107,435
Receivables, net	721,770	632,207	603,959
Inventories	226,398	193,934	172,201
Deferred income taxes	8,698	3,416	9,062
Prepayments and other current assets	80,545	42,100	40,539
	1,107,616	970,049	933,196
Investments	155,989	100,954	98,217
Property, plant and equipment	5,044,720	4,397,510	4,594,355
Less accumulated depreciation, depletion and amortization	1,713,860	1,490,465	1,544,462
	3,330,860	2,907,045	3,049,893
Deferred charges and other assets:			
Goodwill	237,839	214,939	230,865
Other intangible assets, net	29,850	28,487	19,059
Other	104,402	90,256	92,332
	372,091	333,682	342,256
	$ 4,966,556	$ 4,311,730	$ 4,423,562
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Long-term debt due within one year	$ 98,980	$ 86,802	$ 101,758
Accounts payable	319,415	300,509	269,021
Taxes payable	46,633	75,263	50,533
Dividends payable	24,569	22,935	22,951
Other accrued liabilities	166,582	255,355	184,665
	656,179	740,864	628,928
Long-term debt	1,307,050	1,047,245	1,104,752
Deferred credits and other liabilities:			
Deferred income taxes	587,001	473,419	526,176
Other liabilities	295,496	264,188	272,084
	882,497	737,607	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 181,279,379 at September 30, 2006, 120,191,877 at September 30, 2005 and 120,262,786 at December 31, 2005	181,279	120,192	120,263
Other paid-in capital	872,973	901,302	909,006
Retained earnings	1,046,933	834,567	884,795

Accumulated other comprehensive income (loss)	8,271	(81,421)	(33,816)
Treasury stock at cost - 538,921 shares at September 30, 2006, 359,281 shares at September 30, 2005 and December 31, 2005	(3,626)	(3,626)	(3,626)
Total common stockholders’ equity	2,105,830	1,771,014	1,876,622
Total stockholders’ equity	2,120,830	1,786,014	1,891,622
	$ 4,966,556	$ 4,311,730	$ 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)

	Nine Months Ended September 30, 2006	2005
	(In thousands)	
Operating activities:		
Net income	$ 233,176	$ 201,816
Loss from discontinued operations, net of tax	2,208	830
Income from continuing operations	235,384	202,646
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	203,675	164,798
Earnings, net of distributions, from equity method investments	(3,164)	(14,235)
Deferred income taxes	28,945	11,747
Changes in current assets and liabilities, net of acquisitions:		
Receivables	(102,271)	(163,007)
Inventories	(51,059)	(47,781)
Other current assets	(13,814)	(1,544)
Accounts payable	65,283	88,358
Other current liabilities	12,220	49,585
Other noncurrent changes	13,740	13,421
Net cash provided by continuing operations	388,939	303,988
Net cash used in discontinued operations	(297)	(232)
Net cash provided by operating activities	388,642	303,756
Investing activities:		
Capital expenditures	(398,079)	(341,532)
Acquisitions, net of cash acquired	(124,240)	(162,774)
Net proceeds from sale or disposition of property	19,342	31,643
Investments	(55,956)	(1,863)
Proceeds from sale of equity method investment	---	38,166
Net cash used in continuing operations	(558,933)	(436,360)
Net cash used in discontinued operations	(24)	(77)
Net cash used in investing activities	(558,957)	(436,437)
Financing activities:		
Issuance of long-term debt	394,504	292,228
Repayment of long-term debt	(206,437)	(104,038)
Proceeds from issuance of common stock	13,255	7,858
Dividends paid	(68,881)	(64,616)
Tax benefit on stock-based compensation	2,050	---
Net cash provided by continuing operations	134,491	131,432
Net cash provided by discontinued operations	248	264
Net cash provided by financing activities	134,739	131,696
Effect of exchange rate changes on cash and cash equivalents	(1,654)	---
Decrease in cash and cash equivalents	(37,230)	(985)
Cash and cash equivalents -- beginning of year	107,435	99,377
Cash and cash equivalents -- end of period	$ 70,205	$ 98,392

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

MDU RESOURCES GROUP, INC.
NOTES TO CONSOLIDATED
FINANCIAL STATEMENTS

September 30, 2006 and 2005
(Unaudited)

1. **Basis of presentation**

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. **Discontinued operations**

Innovatum, a component of the pipeline and energy services segment, specializes in cable and pipeline magnetization and location. During the third quarter of 2006, the Company initiated a plan to sell Innovatum within the next year because the Company has determined that Innovatum is a non-strategic asset. The Company does not expect to have any involvement in the operations of Innovatum after the sale.

In accordance with SFAS No. 144, the Consolidated Statements of Income, Consolidated Statements of Cash Flows, and related Notes to Consolidated Financial Statements for current and prior periods have been restated to present the results of operations of Innovatum as a discontinued operation. In addition, the assets and liabilities of Innovatum have been treated as held for sale and, as a result, no depreciation, depletion and amortization expense will be recorded. The Company recorded a loss of $4.3 million (before tax) during the third quarter of 2006 to write down goodwill (see Note 14), with the remaining assets of Innovatum recorded at net realizable value less estimated selling costs. The loss on the write-down has been excluded from continuing operations and recorded in discontinued operations, net of tax, in the Consolidated Statements of Income.

Operating results related to Innovatum were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(In thousands)			
Operating revenues	$ 654	$ 685	$ 1,796	$ 2,228
Loss from discontinued operations	(4,743)	(435)	(5,606)	(1,207)
Income tax benefit	3,132	135	3,398	377
Net loss from discontinued operations	$ (1,611)	$ (300)	$ (2,208)	$ (830)

The income tax benefit for the three and nine months ended September 30, 2006, is larger than the customary relationship between the income tax benefit and the loss before tax due to an estimated capital loss tax benefit (which reflects the effect of the $4.0 million and $4.3 million goodwill impairments in 2004 and 2006, respectively) the

Company will realize from the sale of the Innovatum stock.

The carrying amounts of the major assets and liabilities related to Innovatum are as follows:

	September 30, 2006	September 30, 2005	December 31, 2005
		(In thousands)	
Inventories	$ 1,164	$ 1,144	$ 988
Other current assets	126	147	863
Net property, plant and equipment	234	416	361
Goodwill	---	4,305	4,305
Deferred charges and other assets	3,491	487	478
Total assets	$ 5,015	$ 6,499	$ 6,995
Current liabilities	$ 28	$ 203	$ 36
Long-term debt	4,013	10,118	3,765
Deferred credits	188	265	209
Total liabilities	$ 4,229	$ 10,586	$ 4,010

4. **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.

5. **Allowance for doubtful accounts**

The Company's allowance for doubtful accounts as of September 30, 2006 and 2005, and December 31, 2005, was $6.0 million, $8.6 million and $8.0 million, respectively.

6. **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 $43.8 million, $45.0 million and $24.7 million at September 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 September 30, 2006 and 2005, and December 31, 2005, respectively.

7. **Inventories**

Inventories, other than natural gas in underground storage for the Company’s regulated operations, consisted primarily of aggregates held for resale of $92.1 million, $79.5 million and $78.1 million; materials and supplies of $62.6 million, $47.3 million and $48.7 million; and other inventories of $27.9 million, $22.1 million and $20.7 million, as of September 30, 2006 and 2005, and December 31, 2005, respectively. These inventories were stated at the lower of average cost or market value.

8. **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 nine months ended September 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.

9. **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 nine months ended September 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 nine months ended September 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 September 30, 2005		Nine Months Ended September 30, 2005	
	(In thousands, except per share amounts)			
Earnings on common stock, as reported	$	87,052	$	201,303
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		50		(75)
Pro forma earnings on common stock	$	87,102	$	201,232
Earnings per common share - basic - as reported	$	.49	$	1.13
Earnings per common share - basic - pro forma	$	.49	$	1.13
Earnings per common share - diluted - as reported	$	.48	$	1.12
Earnings per common share - diluted - pro forma	$	.48	$	1.12

Total stock-based compensation expense for the three and nine months ended September 30, 2006, was $848,000 and $3.0 million, net of income taxes of $542,000 and $1.9 million, respectively, including $140,000 and $282,000, net of income taxes of $90,000 and $180,000, respectively, related to stock option awards.

As of September 30, 2006, total remaining unrecognized compensation expense related to stock-based compensation was approximately $5.8 million (before income taxes) which will be amortized over a weighted-average period of 1.8 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 September 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 nine months ended September 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	(89,873)		13.05	
Exercised	(263,746)		12.35	
Outstanding at end of period	2,433,354		13.06	4.1
Exercisable at end of period	1,352,328	$	12.61	3.9

Summarized information about stock options outstanding and exercisable as of September 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	10,124	0.8	$ 7.28	$ 152	10,124	$ 7.28	$ 152
8.01 - 11.00	290,565	1.7	9.60	3,702	287,673	9.60	3,666
11.01 - 14.00	1,877,924	4.4	13.18	17,202	962,831	13.19	8,809
14.01 - 17.13	254,741	4.5	16.32	1,534	91,700	16.54	532
Balance at end of period	2,433,354	4.1	$ 13.06	$ 22,590	1,352,328	$ 12.61	$ 13,159

The aggregate intrinsic value in the preceding table represents the total intrinsic value (before income taxes), based on the Company's stock price on September 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 $584,000 and $3.3 million from the exercise of stock options for the three and nine months ended September 30, 2006, respectively. The aggregate intrinsic value of options exercised during the three and nine months ended September 30, 2006, was $629,000 and $3.0 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 the 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 nine months ended September 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	(21,541)		13.22
Nonvested at end of period	32,117	$	13.22

The fair value of restricted stock awards that vested during the nine months ended September 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 nine months ended September 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 compensation expense is based on the grant-date fair value.

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

Grant Date	Performance Period	Target Grant of Shares
February 2004	2004-2006	278,600
February 2005	2005-2007	258,256
February 2006	2006-2008	203,343

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. The fair value of performance share awards that vested during the nine months ended September 30, 2006, was $2.2 million.

A summary of the status of the performance share awards for the nine months ended September 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	(29,776)		18.76
Nonvested at end of period	740,199	$	18.72

10. **Cash flow information**

Cash expenditures for interest and income taxes were as follows:

		Nine Months Ended September 30,		
		2006		2005
		(In thousands)		
Interest, net of amount capitalized	$	48,957	$	33,059
Income taxes	$	105,264	$	60,578

11. **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 9.

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.

SFAS No. 158 In September 2006, the FASB issued SFAS No. 158. SFAS No. 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its balance sheet and recognize changes in that funded status in the year in which the changes occur through comprehensive income. The standard also requires an employer to measure the funded status of the plan as of the date of its year-end balance sheet. SFAS No. 158 is effective for the Company as of December 31, 2006. The Company is evaluating the effects of the adoption of SFAS No. 158.

12. **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 15.

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

	Three Months Ended September 30, 2006	2005
	(In thousands)	
Net income	$ 108,487	$ 87,223
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 $8,709 and $39,038 in 2006 and 2005, respectively	13,912	(62,360)
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $2,654 and $3,353 in 2006 and 2005, respectively	4,240	(5,356)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	9,672	(57,004)
Foreign currency translation adjustment	(401)	(70)
	9,271	(57,074)
Comprehensive income	$ 117,758	$ 30,149

	Nine Months Ended September 30, 2006	2005
	(In thousands)	
Net income	$ 233,176	$ 201,816
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 $15,840 and $44,991 in 2006 and 2005, respectively	25,304	(71,869)
Less: Reclassification adjustment for loss on derivative instruments included in net income, net of tax of $12,121 and $1,895 in 2006 and 2005, respectively	(19,361)	(3,028)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	44,665	(68,841)
Foreign currency translation adjustment	(2,578)	(1,089)
	42,087	(69,930)
Comprehensive income	$ 275,263	$ 131,886

13. **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.

On August 16, 2006, MDU Brasil acquired ownership interests in companies owning three electric energy transmission lines. The interests involve the ENTE (13.3-percent ownership interest), ERTE (13.3-percent ownership interest) and ECTE (25-percent ownership interest) electric energy transmission lines, which are located primarily in northeastern and southern Brazil. The contracts provide for revenues denominated in the Brazilian Real, annual inflation adjustments and change in tax law adjustments and have between 24 and 26 years remaining under the contracts. Alusa, Brascan, and CEMIG hold the remaining ownership interests, with CELESC also having an ownership interest in ECTE. Alusa is the operating partner for the transmission lines.

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 September 30, 2006 and 2005, and December 31, 2005, the Company's equity method investments had total assets of $576.6 million, $244.3 million and $231.9 million, respectively, and long-term debt of $324.3 million, $159.6 million and $154.8 million, respectively. The Company's investment in its equity method investments was approximately $99.2 million, $44.0 million and $41.8 million, including undistributed earnings of $6.6 million, $2.5 million and $3.5 million, at September 30, 2006 and 2005, and December 31, 2005, respectively.

14. **<u>Goodwill and other intangible assets</u>**

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

Nine Months Ended September 30, 2006	Balance as of January 1, 2006	Goodwill Acquired During the Year*	Goodwill Impaired During the Year	Balance as of September 30, 2006
		(In thousands)		
Electric	$ ---	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---	---
Construction services	80,970	5,956	---	86,926
Pipeline and energy services	5,464	---	(4,305)	1,159
Natural gas and oil production	---	---	---	---
Construction materials and mining	133,264	5,323	---	138,587
Independent power production	11,167	---	---	11,167
Other	---	---	---	---
Total	$ 230,865	$ 11,279	$ (4,305)	$ 237,839

Nine Months Ended September 30, 2005	Balance as of January 1, 2005	Goodwill Acquired During the Year*	Balance as of September 30, 2005
		(In thousands)	
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	3,122	123,574
Independent power production	11,195	(28)	11,167
Other	---	---	---
Total	$ 199,743	$ 15,196	$ 214,939

Year Ended	Balance as of January 1,	Goodwill Acquired During	Balance as of December 31,

December 31, 2005	2005	the Year*	2005
		(In thousands)	
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.

During the third quarter of 2006, the Company initiated a plan to sell Innovatum which is a reporting unit for goodwill impairment testing and part of the pipeline and energy services segment. In accordance with SFAS No. 142, the Company was required to test Innovatum for impairment at the time that the Company committed to the plan to sell. The fair value of Innovatum was estimated using the expected proceeds from the sale which is estimated to be the current book value of the assets of Innovatum other than its goodwill. As a result, a goodwill impairment loss of $4.3 million (before tax) was recognized in the third quarter of 2006. For more information on Innovatum, see Note 3.

Other intangible assets were as follows:

	September 30, 2006	September 30, 2005	December 31, 2005
		(In thousands)	
Amortizable intangible assets:			
Acquired contracts	$ 20,651	$ 18,707	$ 18,065
Accumulated amortization	(9,958)	(7,640)	(9,458)
	10,693	11,067	8,607
Noncompete agreements	12,886	11,784	11,784
Accumulated amortization	(9,104)	(8,434)	(8,557)
	3,782	3,350	3,227
Other	17,208	14,699	7,914
Accumulated amortization	(2,357)	(1,480)	(1,213)
	14,851	13,219	6,701
Unamortizable intangible assets	524	851	524
Total	$ 29,850	$ 28,487	$ 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 nine months ended September 30, 2006, was $1.5 million and $4.3 million, respectively. Amortization expense for the three and nine months ended September 30, 2005, and for the year ended December 31, 2005, was $1.8 million, $3.9 million and $5.5 million, respectively. Estimated amortization expense for amortizable intangible assets is $5.6 million in 2006, $6.2 million in 2007, $5.2 million in 2008, $4.2 million in 2009, $3.6 million in 2010 and $8.8 million thereafter.

15. **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. As of September 30, 2006, the Company had no outstanding foreign currency or interest rate hedges. 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 qualified for hedge accounting, as discussed below. At September 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 a 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 nine months ended September 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 qualified for hedge accounting. The oil hedges became ineffective as the physical price received no longer correlated to the hedge price due to the widening of regional basis differentials on the price of the physical production received. The ineffectiveness related to these collar agreements resulted in a gain of approximately $841,000 (before tax) for the three months ended September 30, 2006, and a loss of approximately $138,000 (before tax) for the nine months ended September 30, 2006. The ineffectiveness related to these collar agreements was recorded in operation and maintenance expense. The amount of hedge ineffectiveness on Fidelity’s remaining hedges was immaterial for the three and nine months ended September 30, 2006.

For the three and nine months ended September 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 September 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 15 months. The Company estimates that over the next 12 months net gains of approximately $15.9 million (after tax) will be reclassified from accumulated other comprehensive income into earnings, subject to changes in natural gas and oil market prices, as the hedged transactions affect earnings.

16. **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.

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 domestic and international investments including transmission and 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 insurer 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 of 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 September 30, 2006	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 53,204	$ ---	$ 5,698
Natural gas distribution	31,378	---	(2,347)
Pipeline and energy services	87,372	16,434	7,141
	171,954	16,434	10,492
Construction services	262,188	139	8,300
Natural gas and oil production	71,885	50,607	35,012
Construction materials and mining	667,651	---	52,520

Independent power production	16,958	---	1,714
Other	---	1,773	278
	1,018,682	52,519	97,824
Intersegment eliminations	---	(68,953)	---
Total	$ 1,190,636	$ ---	$ 108,316

Three Months Ended September 30, 2005	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 50,195	$ ---	$ 6,169
Natural gas distribution	34,014	---	(3,016)
Pipeline and energy services	101,210	17,086	5,282
	185,419	17,086	8,435
Construction services	207,259	162	5,131
Natural gas and oil production	48,867	67,517	35,450
Construction materials and mining	610,499	---	34,120
Independent power production	14,133	---	3,730
Other	---	1,580	186
	880,758	69,259	78,617
Intersegment eliminations	---	(86,345)	---
Total	$ 1,066,177	$ ---	$ 87,052

Nine Months Ended September 30, 2006	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 139,109	$ ---	$ 10,003
Natural gas distribution	229,497	---	446
Pipeline and energy services	264,984	67,808	17,290
	633,590	67,808	27,739
Construction services	728,936	385	23,377
Natural gas and oil production	189,890	175,104	107,249
Construction materials and mining	1,386,214	---	68,957
Independent power production	39,941	---	4,560
Other	---	5,861	780
	2,344,981	181,350	204,923
Intersegment eliminations	---	(249,158)	---
Total	$ 2,978,571	$ ---	$ 232,662

Nine Months Ended September 30, 2005	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 135,566	$ ---	$ 11,057
Natural gas distribution	233,679	---	523
Pipeline and energy services	252,112	58,889	17,245
	621,357	58,889	28,825

Construction services	457,879	294	10,748
Natural gas and oil production	130,664	170,542	94,204
Construction materials and mining	1,191,601	7	44,005
Independent power production	37,600	---	23,069
Other	---	4,315	452
	1,817,744	175,158	172,478
Intersegment eliminations	---	(234,047)	---
Total	$ 2,439,101	$ ---	$ 201,303

The pipeline and energy services segment recognized a loss from discontinued operations, net of tax, of $1.6 million and $2.2 million for the three and nine months ended September 30, 2006, respectively, and $300,000 and $830,000 for the three and nine months ended September 30, 2005, respectively. Excluding the loss from discontinued operations at pipeline and energy services, 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.

17. **Acquisitions**

During the first nine 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 California and 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 $131.0 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.

18. **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 September 30,	Pension Benefits 2006	Pension Benefits 2005	Other Postretirement Benefits 2006	Other Postretirement Benefits 2005
	(In thousands)			
Components of net periodic benefit cost (income):				
Service cost	$ 3,197	$ 2,084	$ 782	$ 211
Interest cost	5,861	4,155	1,107	666
Expected return on assets	(7,983)	(4,987)	(1,643)	(979)
Amortization of prior service cost	233	256	14	34
Recognized net actuarial (gain) loss	569	346	(18)	(364)
	---	(11)	704	531

Amortization of net transition obligation (asset)				
Net periodic benefit cost	1,877	1,843	946	99
Less amount capitalized	179	190	80	123
Net periodic benefit cost (income)	$ 1,698	$ 1,653	$ 866	$ (24)

Nine Months Ended September 30,	Pension Benefits 2006	2005	Other Postretirement Benefits 2006	2005
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	$ 7,799	$ 6,252	$ 1,725	$ 1,242
Interest cost	14,009	12,463	2,964	2,802
Expected return on assets	(17,419)	(14,960)	(3,494)	(3,004)
Amortization of prior service cost	746	768	37	34
Recognized net actuarial (gain) loss	1,587	1,038	(187)	(441)
Amortization of net transition obligation (asset)	(2)	(33)	1,766	1,594
Net periodic benefit cost	6,720	5,528	2,811	2,227
Less amount capitalized	560	547	205	329
Net periodic benefit cost	$ 6,160	$ 4,981	$ 2,606	$ 1,898

In addition to the qualified plan defined pension benefits reflected in the table, the Company 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 an 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 nine months ended September 30, 2006, was $1.8 million and $5.7 million, respectively. The Company's net periodic benefit cost for this plan for the three and nine months ended September 30, 2005, was $1.6 million and $4.9 million, respectively.

19. **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 was submitted on August 11, 2006, for MNPUC approval and is still pending action. 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. Oral argument was held on October 20, 2006 regarding those matters. 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.

20. **Contingencies**

Litigation

Royalties Case In June 1997, Grynberg, acting on behalf of the United States, filed suit under the Federal False Claims Act against Williston Basin and Montana-Dakota. He also filed more than 70 similar suits against natural gas transmission companies and producers, gatherers and processors of natural gas. Grynberg 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.

On October 20, 2006, the Wyoming Federal District Court adopted and modified the Special Master's Written Report and ordered that the actions against Williston Basin and Montana-Dakota be dismissed. It is expected that Grynberg will appeal the decision to the U.S. Tenth Circuit Court of Appeals.

In the event the Wyoming Federal District Court's decision is overturned and Grynberg's actions are reinstated, 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 CBNG 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 TRWUA and the Northern Cheyenne Tribe. Portions of three 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. 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 CBNG in Montana should be enjoined until the BLM completes a SEIS. The Montana Federal District Court, in February 2005, entered a ruling finding that the 2003 EIS was inadequate. The Montana Federal District Court later entered an order that would have allowed limited CBNG development in the Powder River Basin in Montana pending the BLM's preparation of a SEIS. The plaintiffs appealed the decision to the Ninth Circuit because the Montana Federal District Court declined to enter an injunction enjoining all development pending completion of the SEIS. The Montana Federal District Court also declined to enter an injunction pending the appeal. In 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 CBNG development projects in the Powder River Basin in Montana. That court also enjoined Fidelity from drilling any additional federally permitted wells associated with its Montana Coal Creek Project and from constructing infrastructure to produce and transport CBNG 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 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 of the NPRC lawsuit 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.

In May 2005, the NPRC and other petitioners 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 CBNG operations, treatment of such water in the event re-injection is not feasible and amend the non-degradation policy in connection with CBNG 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 CBNG 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 CBNG 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. Fidelity, the NPRC and the TRWUA have been allowed 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 CBNG produced water and that, if its permits are set aside, Fidelity's CBNG 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 the District Court of 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 certain parameters contained in water produced in connection with CBNG operations. Fidelity's motion for intervention was granted on August 1, 2006.

Similarly, industry members have filed two lawsuits, and the State of Wyoming has filed one lawsuit, in Wyoming Federal District Court. These lawsuits challenge the EPA's failure to timely disapprove the 2006 rules. All three Wyoming lawsuits were consolidated on September 22, 2006.

Fidelity will continue to vigorously defend 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 CBNG operations and/or the future development of this resource in the affected regions.

Electric Operations Montana-Dakota joined with two electric generators in appealing a September 2003 finding by the ND Health Department that it 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 were stayed pending conclusion of the periodic review of sulfur dioxide emissions in the state.

In September 2005, the ND Health Department issued its final periodic review decision based on its August 2005 final air quality modeling report. The ND Health Department concluded there are no violations of the sulfur dioxide increment in North Dakota. In March 2006, the DRC filed a complaint in Colorado Federal District Court seeking to force the EPA to declare that the increment had been violated based on earlier modeling conducted by the EPA. The EPA is defending against the DRC claim and it has filed a motion to dismiss the case. The Colorado Federal District Court has not yet ruled on the motion.

Montana-Dakota expects the EPA to initiate a rulemaking proceeding to formally approve the conclusions contained in the September 2005 ND Health Department decision and the August 2005 final report. Once concluded, this rulemaking should result in a revision to the North Dakota SIP that, in turn, should allow for the dismissal of the case in Burleigh County District Court referenced above.

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 the Elk Basin Storage Reservoir. Based on relevant information, including reservoir and well pressure data, Williston Basin believes that the 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 the Elk Basin Storage Reservoir. Williston Basin is seeking not only to recover damages for the gas that has been diverted, but to prevent further loss of gas from the Elk

Basin 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 the Elk Basin 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.

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 September 30, 2006, were immaterial. 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 September 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 September 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 September 30, 2006, the fixed maximum amounts guaranteed under these agreements aggregated $180.1 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $1.0 million in 2006; $102.1 million in 2007; $4.7 million in 2008; $2.7 million in 2009; $30.1 million in 2010; $23.0 million in 2011; $12.0 million in 2012; $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 September 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 September 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 September 30, 2006, the fixed maximum amounts guaranteed under these letters of credit aggregated $42.5 million. In 2006 and 2007, $5.8 million and $36.7 million, respectively, of letters of credit are scheduled to expire. There were no amounts outstanding under the above letters of credit at September 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 September 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 $1.6 million, which was not reflected on the Consolidated Balance Sheet at September 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 September 30, 2006.

In the normal course of business, Centennial has purchased surety bonds related to construction contracts and reclamation obligations of its subsidiaries. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds 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. As of September 30, 2006, approximately $544 million of surety bonds were outstanding which were not reflected on the Consolidated Balance Sheet.

21. **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, was also a member of the Board of Directors of the Company until his retirement on August 17, 2006. The natural gas gathering agreements with Nance Petroleum were effective upon completion of certain high and low pressure gathering facilities, which occurred in mid-December 2004. Bitter Creek's capital expenditures related to the completion of the gathering lines and the expansion of its gathering facilities to accommodate the natural gas gathering agreements were $11,000 and $39,000 for the three and nine months ended September 30, 2006, and were $245,000 and $2.3 million for the three and nine months ended September 30, 2005, respectively, and are estimated for the next three years to be $41,000 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 $420,000 and $1.2 million for the three and nine months ended September 30, 2006, respectively, and were $316,000 and $855,000 for the three and nine months ended September 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 September 30, 2006, was $139,000.

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 September 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.

22. **Pending acquisition**

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. On October 27, 2006, shareholders of Cascade approved the merger agreement. 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.

23. **Subsequent event**

On October 20, 2006, Centennial Power sold 100 percent of its membership interest in the recently formed LPP to Hobbs Power. LPP was formed to develop a 550-MW combined-cycle generating facility to be built near Hobbs, New Mexico. The facility will consist of two combustion turbine generators, two heat-recovery boilers and one steam turbine generator. Southwestern Public Service Company, a subsidiary of Xcel Energy, has signed a 25-year power purchase agreement for the entire capacity and output of the Hobbs facility. CEM is currently in negotiations to construct and operate the new facility. Onsite construction is expected to begin by the spring of 2007 with power coming online by the summer of 2008. Because of expected continuing involvement by certain subsidiaries of Centennial Resources, revenues associated with the sale of LPP to Hobbs Power are currently expected to be recognized over the period of construction of the new facility.

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 operational and 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; and incremental expansion of pipeline capacity to allow customers access to more liquid and potentially higher-priced markets.

Challenges Energy price volatility; natural gas basis differentials; regulatory requirements; recruitment and retention of a skilled workforce; and increased competition from other natural gas pipeline and gathering companies.

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, auxiliary equipment and industry-related field services; and increased competition from many of the larger natural gas and oil companies.

Construction Materials and Mining
Strategy Focus on high growth strategic markets located near major transportation corridors and desirable mid-sized metropolitan areas; enhance profitability through cost containment, margin discipline and 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, asphalt cement, ready-mix concrete and related products), complementing and expanding on the Company's expertise. Ongoing efforts to increase margin are being pursued through the implementation of a variety of continuous improvement programs, including corporate purchasing of equipment, parts and commodities (asphalt cement, diesel fuel, cement, etc.), negotiation of contract price escalation provisions and the utilization of national purchasing accounts. A critical element of the Company's long term strategy for this business is the acquisition and development of reserves deemed strategic to Company operations. Ownership of, and access to aggregate reserves, is key to the vertical integration strategy.

Challenges Price volatility with respect to, and availability of, raw materials such as asphalt cement, diesel fuel and cement; recruitment and retention of a skilled workforce; fixed price construction contracts are particularly vulnerable to volatility of these energy and material prices. Some of our markets are likely to be affected by the slowdown in housing, which should be partially mitigated by increased commercial spending.

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 foreign currency fluctuation 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 September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(Dollars in millions, where applicable)			
Electric	$ 5.7	$ 6.2	$ 10.0	$ 11.1

Natural gas distribution		(2.3)		(3.0)		.4		.5
Construction services		8.3		5.1		23.4		10.7
Pipeline and energy services		7.1		5.3		17.3		17.2
Natural gas and oil production		35.0		35.5		107.2		94.2
Construction materials and mining		52.5		34.1		69.0		44.0
Independent power production		1.7		3.7		4.6		23.1
Other		.3		.2		.8		.5
Earnings on common stock	$	108.3	$	87.1	$	232.7	$	201.3
Earnings per common share - basic	$	.60	$	.49	$	1.29	$	1.13
Earnings per common share - diluted	$	.60	$	.48	$	1.29	$	1.12
Return on average common equity for the 12 months ended						15.7%		15.0%

Three Months Ended September 30, 2006 and 2005 Consolidated earnings for the quarter ended September 30, 2006, increased $21.2 million from the comparable period largely due to:

- Higher earnings from construction due to increased volumes and margins, earnings from companies acquired since the comparable prior period and higher earnings from aggregate and asphalt due to higher margins at the construction materials and mining business
- Higher earnings from increased outside and inside construction workloads and margins at the construction services business

Nine Months Ended September 30, 2006 and 2005 Consolidated earnings for the nine months ended September 30, 2006, increased $31.4 million from the comparable period largely due to:

- Higher earnings from construction materials and mining business, as previously discussed
- Higher average realized natural gas and oil prices of 9 percent and 26 percent, respectively, and increased natural gas and oil production of 5 percent and 18 percent, respectively at the natural gas and oil production business
- Higher earnings from increased outside and inside construction workloads and margins, and earnings from companies acquired since the comparable prior period at the construction services business
- Higher transportation, storage and gathering volumes, largely offset by the 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 19.

Partially offsetting the increase were decreased earnings from equity method investments, which largely reflect 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.

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

Electric

		Three Months Ended September 30,				Nine Months Ended September 30,		
		2006		2005		2006		2005
		(Dollars in millions, where applicable)						
Operating revenues	$	53.2	$	50.2	$	139.1	$	135.5
Operating expenses:								
Fuel and purchased power		19.1		16.3		51.2		47.0
Operation and maintenance		16.3		15.0		46.0		43.7

Depreciation, depletion and amortization		5.4		5.2		15.9		15.5
Taxes, other than income		2.1		2.1		6.4		6.5
		42.9		38.6		119.5		112.7
Operating income		10.3		11.6		19.6		22.8
Earnings	$	5.7	$	6.2	$	10.0	$	11.1
Retail sales (million kWh)		652.1		626.3		1,828.1		1,785.5
Sales for resale (million kWh)		172.3		169.1		423.9		482.4
Average cost of fuel and purchased power per kWh	$	.022	$	.019	$	.022	$	.019

Three Months Ended September 30, 2006 and 2005 Electric earnings decreased $500,000 due to higher operation and maintenance expense of $800,000 (after tax), including costs related to a scheduled maintenance outage at an electric generating station. This decrease was partially offset by higher retail sales margins, largely due to increased volumes of 4 percent.

Nine Months Ended September 30, 2006 and 2005 Electric earnings decreased $1.1 million due to:

- Higher operation and maintenance expense of $1.4 million (after tax), primarily the result of scheduled maintenance outages at electric generating stations
- Decreased sales for resale margins due to lower average rates of 13 percent and decreased volumes of 12 percent largely due to plant availability

Partially offsetting the decrease were:

- Lower interest expense of $600,000 (after tax), resulting from lower average interest rates due to the repurchase and redemption of certain higher cost long-term debt
- Higher retail sales margins, largely due to increased volumes of 2 percent

Natural Gas Distribution

		Three Months Ended September 30,				Nine Months Ended September 30,		
		2006		2005		2006		2005
		(Dollars in millions, where applicable)						
Operating revenues:								
Sales	$	30.5	$	33.0	$	226.6	$	230.2
Transportation and other		0.9		1.0		2.9		3.5
		31.4		34.0		229.5		233.7
Operating expenses:								
Purchased natural gas sold		20.7		23.2		182.5		185.3
Operation and maintenance		11.0		11.3		35.7		34.5
Depreciation, depletion and amortization		2.5		2.4		7.3		7.2
Taxes, other than income		1.4		1.3		4.5		4.3
		35.6		38.2		230.0		231.3
Operating income (loss)		(4.2)		(4.2)		(.5)		2.4
Earnings (loss)	$	(2.3)	$	(3.0)	$	.4	$	.5
Volumes (MMdk):								
Sales		3.1		3.0		21.9		24.1
Transportation		2.6		2.9		9.8		9.9
Total throughput		5.7		5.9		31.7		34.0

Degree days (% of normal)*		94%		50%		83%		92%
Average cost of natural gas, including transportation, per dk	$	6.67	$	7.78	$	8.32	$	7.68

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

Three Months Ended September 30, 2006 and 2005 The natural gas distribution business experienced a seasonal loss of $2.3 million in the third quarter compared to a loss of $3.0 million in the third quarter of 2005. The increase in earnings of $700,000 was largely due to higher nonregulated earnings from energy-related services.

Nine Months Ended September 30, 2006 and 2005 Earnings at the natural gas distribution business decreased $100,000 due to:

· Lower retail sales margin due to lower sales volumes of 9 percent, resulting from 10 percent warmer weather than last year, partially offset by higher weather-normalized revenues in certain jurisdictions
· Higher operation and maintenance expense of $800,000 (after tax), largely due to higher payroll-related costs from an early retirement program

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

Construction Services

	Three Months Ended September 30,				Nine Months Ended September 30,			
		2006		2005		2006		2005
				(In millions)				
Operating revenues	$	262.3	$	207.4	$	729.3	$	458.2
Operating expenses:								
Operation and maintenance		236.8		188.8		656.2		412.4
Depreciation, depletion and amortization		3.6		3.9		11.0		9.7
Taxes, other than income		6.6		5.0		19.5		15.2
		247.0		197.7		686.7		437.3
Operating income		15.3		9.7		42.6		20.9
Earnings	$	8.3	$	5.1	$	23.4	$	10.7

Three Months Ended September 30, 2006 and 2005 Construction services earnings increased $3.2 million compared to the third quarter of the comparable period due to:

· Higher outside construction workloads and margins of $2.2 million (after tax), largely in the Southwest region
· Higher inside construction workloads and margins of $900,000 (after tax), largely in the Southwest region
· Increased equipment sales and rentals

Partially offsetting this increase were higher general and administrative expenses of $600,000 (after tax), primarily payroll related.

Nine Months Ended September 30, 2006 and 2005 Construction services earnings increased $12.7 million compared to the nine months of the comparable period due to:

· Earnings from acquisitions made since the comparable prior period, which contributed approximately 40 percent of the earnings increase
· Higher inside construction workloads and margins of $4.6 million (after tax) in the Central, Southwest and Northwest regions

· Higher outside construction workloads and margins of $2.8 million (after tax), largely in the Southwest region, partially offset by decreased workloads and margins in the Northwest region
· Increased equipment sales and rentals

Partially offsetting this increase were higher general and administrative expenses of $1.7 million (after tax), primarily payroll related.

Pipeline and Energy Services

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	(Dollars in millions)			
Operating revenues:				
Pipeline	$ 27.7	$ 21.5	$ 74.5	$ 63.7
Energy services	76.1	96.8	258.3	247.3
	103.8	118.3	332.8	311.0
Operating expenses:				
Purchased natural gas sold	69.0	89.3	236.1	226.1
Operation and maintenance	12.8	11.9	38.4	36.7
Depreciation, depletion and amortization	4.9	4.6	14.9	7.7
Taxes, other than income	2.5	2.1	7.6	6.1
	89.2	107.9	297.0	276.6
Operating income	14.6	10.4	35.8	34.4
Earnings	$ 7.1	$ 5.3	$ 17.3	$ 17.2
Transportation volumes (MMdk):				
Montana-Dakota	7.5	7.7	22.6	23.1
Other	29.3	19.7	75.4	53.1
	36.8	27.4	98.0	76.2
Gathering volumes (MMdk)	21.9	20.6	64.8	60.2

Three Months Ended September 30, 2006 and 2005 Pipeline and energy services experienced an increase in earnings of $1.8 million due to:

· Higher transportation, storage and gathering volumes ($3.1 million after tax)
· Higher gathering and storage rates ($1.1 million after tax)

Partially offsetting this increase were:

· Higher operation and maintenance expense, primarily related to the natural gas storage litigation. For more information, see Note 20.
· An increased loss from discontinued operations of $1.3 million (after tax) related to Innovatum. For more information, see Notes 3 and 14.

Nine Months Ended September 30, 2006 and 2005 Pipeline and energy services experienced an increase in earnings of $100,000 due to:

· Higher transportation, storage and gathering volumes ($6.4 million after tax)
· Higher gathering rates ($2.7 million after tax)

Partially offsetting this increase were:

· 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 19.
· Higher operation and maintenance expense, primarily due to the natural gas storage litigation, as previously discussed
· An increased loss from discontinued operations of $1.4 million (after tax) related to Innovatum, as previously discussed
· Higher taxes, other than income of $900,000 (after tax), primarily due to property taxes

Natural Gas and Oil Production

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(Dollars in millions, where applicable)			
Operating revenues:				
Natural gas	$ 89.1	$ 94.3	$ 281.7	$ 247.2
Oil	31.6	20.5	78.0	52.3
Other	1.8	1.6	5.3	1.7
	122.5	116.4	365.0	301.2
Operating expenses:				
Purchased natural gas sold	1.5	1.5	5.2	1.7
Operation and maintenance:				
Lease operating costs	14.0	10.9	38.3	28.6
Gathering and transportation	4.5	3.8	13.9	9.5
Other	7.2	9.5	23.9	21.4
Depreciation, depletion and amortization	27.7	22.3	78.1	60.6
Taxes, other than income:				
Production and property taxes	8.5	9.3	26.4	22.7
Other	.2	.1	.7	.4
	63.6	57.4	186.5	144.9
Operating income	58.9	59.0	178.5	156.3
Earnings	$ 35.0	$ 35.5	$ 107.2	$ 94.2
Production:				
Natural gas (MMcf)	15,603	15,015	46,207	44,069
Oil (MBbls)	554	477	1,475	1,250
Average realized prices (including hedges):				
Natural gas (per Mcf)	$ 5.71	$ 6.28	$ 6.10	$ 5.61
Oil (per barrel)	$ 57.01	$ 42.95	$ 52.90	$ 41.88
Average realized prices (excluding hedges):				
Natural gas (per Mcf)	$ 5.13	$ 6.87	$ 5.72	$ 5.88
Oil (per barrel)	$ 57.69	$ 50.72	$ 53.99	$ 47.83
Production costs, including taxes, per net equivalent Mcf:				
Lease operating costs	$ .74	$ .61	$ .70	$ .55
Gathering and transportation	.23	.21	.25	.19
Production and property taxes	.45	.52	.48	.44
	$ 1.42	$ 1.34	$ 1.43	$ 1.18

Three Months Ended September 30, 2006 and 2005 The natural gas and oil production business experienced a $500,000 decrease in earnings due to:

- Lower average realized natural gas prices of 9 percent
- Higher depreciation, depletion and amortization of $3.4 million (after tax) due to higher depletion rates and increased production
- Higher lease operating expense of $1.9 million (after tax), largely CBNG and acquisition-related

Partially offsetting the decrease were:

- 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
- Higher average realized oil prices of 33 percent
- Decreased general and administrative expense of $900,000 (after tax), primarily lower outside service costs

Nine Months Ended September 30, 2006 and 2005 The natural gas and oil production business experienced a $13.0 million increase in earnings due to:

- Higher average realized natural gas prices of 9 percent and higher average realized oil prices of 26 percent
- Increased natural gas production of 5 percent and oil production of 18 percent, as previously discussed

Partially offsetting the increase were:

- Higher depreciation, depletion and amortization of $10.8 million (after tax) due to higher depletion rates and increased production
- Higher lease operating expenses of $6.0 million (after tax), as previously discussed
- Increased gathering and transportation expense of $2.7 million (after tax), largely higher gathering rates
- Increased general and administrative expense of $1.7 million (after tax), including higher payroll-related and office expenses
- Higher interest expense of $1.1 million (after tax), primarily due to higher average debt balances

Construction Materials and Mining

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(Dollars in millions)			
Operating revenues	$ 667.6	$ 610.5	$ 1,386.2	$ 1,191.6
Operating expenses:				
Operation and maintenance	546.9	518.3	1,167.1	1,018.8
Depreciation, depletion and amortization	22.6	19.8	64.8	57.0
Taxes, other than income	10.0	12.3	30.3	30.7
	579.5	550.4	1,262.2	1,106.5
Operating income	88.1	60.1	124.0	85.1
Earnings	$ 52.5	$ 34.1	$ 69.0	$ 44.0
Sales (000's):				
Aggregates (tons)	14,961	17,518	34,386	34,447
Asphalt (tons)	3,669	4,331	6,358	6,831
Ready-mixed concrete (cubic yards)	1,420	1,463	3,391	3,347

Three Months Ended September 30, 2006 and 2005 Earnings at the construction materials and mining business increased $18.4 million due to:

· Higher earnings of $9.3 million (after tax) from construction, largely due to increased volumes and margins, the result of strong markets and favorable weather
· Earnings from companies acquired since the comparable prior period, which contributed approximately 29 percent of the earnings increase
· Increased earnings from aggregate and asphalt operations of $5.0 million (after tax), largely due to higher margins, partially offset by lower volumes

Partially offsetting the increase in earnings were:

· Higher depreciation, depletion and amortization of $900,000 (after tax), primarily due to higher plant and equipment balances
· Lower earnings of $900,000 (after tax) from ready-mixed concrete operations, largely due to lower volumes

Nine Months Ended September 30, 2006 and 2005 Earnings at the construction materials and mining business increased $25.0 million due to:

· Higher earnings of $15.0 million (after tax) from construction, as previously discussed
· Increased earnings from aggregate operations of $5.6 million (after tax), largely due to higher margins
· Increased earnings from asphalt and ready-mixed concrete operations of $3.8 million (after tax) due to higher margins, partially offset by lower volumes from existing operations
· Earnings from companies acquired since the comparable period, which contributed approximately 19 percent of the earnings increase

Partially offsetting the increase in earnings were:

· Higher depreciation, depletion and amortization of $2.9 million (after tax), as previously discussed
· Increased general and administrative expense of $2.0 million (after tax), primarily payroll-related

Independent Power Production

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(Dollars in millions)			
Operating revenues	$ 17.0	$ 14.1	$ 39.9	$ 37.6
Operating expenses:				
Fuel and purchased power	1.7	---	3.0	---
Operation and maintenance	8.5	8.0	22.8	21.7
Depreciation, depletion and amortization	4.3	2.2	10.9	6.9
Taxes, other than income	1.1	.7	3.1	2.1
	15.6	10.9	39.8	30.7
Operating income	1.4	3.2	.1	6.9
Earnings	$ 1.7	$ 3.7	$ 4.6	$ 23.1
Net generation capacity (kW)*	437,600	279,600	437,600	279,600
Electricity produced and sold (thousand kWh)*	300,951	89,646	592,226	217,658

* Excludes equity method investments.

Three Months Ended September 30, 2006 and 2005 Earnings at the independent power production business decreased $2.0 million largely due to:

· Lower margins of $2.0 million (after tax) related to domestic electric generating facilities primarily due to lower capacity revenues
· Higher interest expense of $1.9 million (after tax) largely due to debt related to the Hardin Generating Facility which was placed in commercial operation in March 2006

Partially offsetting the decrease in earnings were:

· Higher earnings from equity method investments of $700,000 (after tax), due to the acquisition of the Brazilian Transmission Lines in August 2006
· Earnings from an acquisition of a domestic electric generating facility made since the comparable prior period

Nine Months Ended September 30, 2006 and 2005 Earnings at the independent power production business decreased $18.5 million largely due to:

· Decreased earnings from equity method investments of $11.8 million, which largely 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 acquisition of the Brazilian Transmission Lines in August 2006 and increased earnings at the Trinity Generating Facility partially resulting from a one-time benefit due to a tax rate deduction
· Lower margins of $4.0 million (after tax) related to domestic electric generating facilities, as previously discussed
· Higher interest expense of $3.7 million (after tax), as previously discussed

Partially offsetting the decrease in earnings were earnings from an acquisition of a domestic electric generating facility made since the comparable prior period.

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 September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
		(In millions)		
Other:				
Operating revenues	$ 1.8	$ 1.6	$ 5.9	$ 4.3
Operation and maintenance	1.2	1.4	4.3	3.7
Depreciation, depletion and amortization	.3	.1	.8	.2
Taxes, other than income	.1	---	.1	.1
Intersegment transactions:				
Operating revenues	$ 69.0	$ 86.3	$ 249.1	$ 234.0
Fuel and purchased power	.1	---	.2	---
Purchased natural gas sold	62.6	80.8	228.8	219.7
Operation and maintenance	6.3	5.5	20.1	14.3

For further information on intersegment eliminations, see Note 16.

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 $1.50 to $1.65, an increase from prior guidance of $1.47 to $1.60.

- The Company's long-term compound annual growth goal on earnings per share is in the range of 7 to 10 percent.

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 in late 2011 or early 2012. A major commitment decision on the project will be made in mid-year 2007.

- This business continues to pursue growth opportunities 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

- As discussed in Note 22, 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 by mid-year 2007.

- The Company is awaiting approval by the MNPUC of its compliance filing reflecting a natural gas rate increase of $481,000 annually, or 1.3 percent, stemming from a general rate case filing made in September 2004. For further information, see Note 19.

- 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 will be significantly higher than 2005 record levels.

- The Company expects higher margins in 2006 as compared to 2005 levels.

- Work backlog as of September 30, 2006, was approximately $505 million compared to $406 million at September 30, 2005.

Pipeline and energy services

· Firm capacity for the Grasslands Pipeline increased from 90,000 Mcf per day to 97,000 Mcf per day effective November 1, 2006, with possible expansion to 200,000 Mcf per day. Based on anticipated demand, additional incremental expansions are forecasted over the next few years beginning in 2008.

· In 2006, total gathering and transportation throughput is expected to increase approximately 15 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 be within this range.

· The Company expects to drill more than 350 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.

· The Company's 2006 earnings guidance reflects estimated November-December NYMEX prices for natural gas in the range of $6.25 to $6.75 per Mcf, Ventura prices in the range of $5.75 to $6.25 and CIG prices in the range of $4.75 to $5.25. Also reflected are the actual natural gas index prices for October, which were lower than the November-December estimates. For the first nine months of 2006, more than three-fourths of this segment's natural gas production was priced at non-NYMEX prices, the majority of which was at Ventura pricing.

· Estimates of NYMEX crude oil prices for October-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 20 percent to 25 percent of its estimated oil production for the last three months of 2006. For 2007, the Company has hedged approximately 25 percent to 30 percent of its estimated natural gas production. The hedges that are in place as of October 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	10/06 - 12/06	460,000	$6.00-$7.60
Natural Gas	Ventura	10/06 - 12/06	920,000	$6.655
Natural Gas	Ventura	10/06 - 12/06	460,000	$6.75-$7.71
Natural Gas	Ventura	10/06 - 12/06	460,000	$6.75-$7.77
Natural Gas	Ventura	10/06 - 12/06	460,000	$7.00-$8.85
Natural Gas	NYMEX	10/06 - 12/06	460,000	$7.75-$8.50
Natural Gas	Ventura	10/06 - 12/06	460,000	$7.76
Natural Gas	CIG	10/06 - 12/06	460,000	$6.50-$6.98
Natural Gas	CIG	10/06 - 12/06	460,000	$7.00-$8.87
Natural Gas	Ventura	10/06 - 12/06	230,000	$8.50-$10.00
Natural Gas	Ventura	10/06 - 12/06	230,000	$8.50-$10.15
Natural Gas	Ventura	10/06 - 10/06	155,000	$9.25-$12.88
Natural Gas	Ventura	10/06 - 10/06	155,000	$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
Natural Gas	Ventura	1/07 - 12/07	3,650,000	$7.67
Crude Oil	NYMEX	10/06 - 12/06	46,000	$43.00-$54.15
Crude Oil	NYMEX	10/06 - 12/06	36,800	$60.00-$69.20
Crude Oil	NYMEX	10/06 - 12/06	23,000	$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

· 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, asphalt cement, ready-mixed concrete and related products), complementing and expanding on the Company's expertise. Ongoing efforts to increase margin are being pursued through the implementation of a variety of continuous improvement programs, including corporate purchasing of equipment, parts and commodities (asphalt cement, diesel fuel, cement, etc.), negotiation of contract price escalation provisions and the utilization of national purchasing accounts. Ownership of, and access to aggregate reserves, is key to the vertical integration strategy.

· The Company's overall margin is expected to improve in 2006 as compared to 2005 because of strong markets and demand for construction materials and services, favorable weather, and continued operational improvements in Texas.

· Work backlog as of September 30, 2006, of approximately $594 million, includes a higher expected average margin than the backlog of $597 million at September 30, 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 beginning in May 2007.

· This segment continues to evaluate opportunities for domestic and international investments, utilizing the Company's disciplined approach for acquisitions.

NEW ACCOUNTING STANDARDS

For information regarding new accounting standards, see Note 11, 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 nine months of 2006 increased $84.9 million from the comparable 2005 period, the result of:

- Higher depreciation, depletion, and amortization expense of $38.9 million, largely at the natural gas and oil production business, as previously discussed
- Increased net income of $31.4 million, largely increased earnings at the construction materials and mining, natural gas and oil production and construction services businesses
- Higher deferred income taxes of $17.2 million due to increased property, plant, and equipment balances at the natural gas and oil production business; natural gas costs recoverable through rate adjustments at the natural gas distribution business; and costs associated with the repurchase of certain first mortgage bonds at the electric and natural gas distribution businesses
- Decreased earnings, net of distributions, from equity method investments of $11.1 million, primarily the result of the sale of the Termoceara Generating Facility

Partially offsetting the increase in cash flows from operating activities were higher working capital requirements of $15.3 million.

Investing activities Cash flows used in investing activities in the first nine months of 2006 increased $122.5 million compared to the comparable 2005 period, the result of:

- Increased capital expenditures 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 offset by lower capital expenditures related to the Hardin Generating Facility
- Lower proceeds from sale of equity method investment due to the absence in 2006 of the 2005 sale of the Termoceara Generating Facility
- Increased investments largely due to the acquisition of the Brazilian Transmission Lines in 2006

Partially offsetting this increase was a decrease in cash flows used for acquisitions of $38.5 million, largely at the natural gas and oil production business.

Financing activities Cash flows provided by financing activities in the first nine months of 2006 increased $3.0 million compared to the comparable 2005 period, the result of an increase in the issuance of long-term debt and common stock, partially offset by an increase in the repayment of long-term debt and dividends paid.

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 18.

Capital expenditures

Net capital expenditures for the first nine months of 2006 were $487.1 million and are estimated to be approximately $620 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 24 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 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 September 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 September 30, 2006. The credit agreement supports the Company's $100 million commercial paper program. Under the Company's commercial paper program, $12.0 million was outstanding at September 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). In August 2006, the Company borrowed $100 million through the issuance of unsecured notes. The funds were 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.

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 September 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 September 30, 2006, the Company could have issued approximately $452 million of additional first mortgage bonds.

The Company's coverage of fixed charges including preferred dividends was 6.2 times and 6.1 times for the 12 months ended September 30, 2006 and December 31, 2005, respectively. Additionally, the Company's first mortgage bond interest coverage was 25.0 times and 10.2 times for the 12 months ended September 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 61 percent and 63 percent at September 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 September 30, 2006, the Company repurchased $68.0 million of first mortgage bonds. As of September 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 September 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. The Company has not issued any stock under the Sales Agency Financing Agreement through September 30, 2006.

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 September 30, 2006. Under the Centennial commercial paper program, $292.5 million was outstanding at September 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 September 30, 2006, $42.5 million of letters of credit were outstanding, as discussed in Note 20, 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, $489.5 million was outstanding at September 30, 2006. On October 16, 2006, Centennial borrowed an additional $50.0 million under this agreement. 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.

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 September 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 September 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 September 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 September 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 September 30, of each year listed in the table below) were as follows:

	2007	2008	2009	2010	2011	Thereafter	Total
				(In millions)			
Long-term debt	$ 99.0	$ 131.9	$ 87.3	$ 314.7	$ 79.3	$ 693.8	$ 1,406.0
Estimated interest payments*	75.6	69.9	62.5	58.2	40.7	218.2	525.1
Operating leases	15.9	12.5	10.5	9.6	8.4	35.6	92.5
Purchase commitments	205.2	101.4	66.5	63.0	58.5	245.4	740.0
	$ 395.7	$ 315.7	$ 226.8	$ 445.5	$ 186.9	$ 1,193.0	$ 2,763.6

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

<u>ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK</u>

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 12 and 15.

The following table summarizes derivative instruments entered into by Fidelity as of September 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	1,380	$2,218
Natural gas swap agreements maturing in 2007	$7.70	5,475	$6,362

		Weighted Average Floor/Ceiling Price (Per MMBtu)	Forward Notional Volume (In MMBtu's)	Fair Value
Natural gas collar agreements maturing in 2006	$	7.24/$8.72	4,600	$10,027
Natural gas collar agreements maturing in 2007	$	7.87/$10.74	10,123	$12,787

		Weighted Average Floor/Ceiling Price (Per barrel)	Forward Notional Volume (In barrels)	Fair Value
Oil collar agreements maturing in 2006	$	52.61/$64.31	106	$(464)

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 20, 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 CBNG 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 CBNG development activities. These proceedings have caused delays in CBNG drilling activity, and the ultimate outcome of the actions could have a material negative effect on existing CBNG operations and/or the future development of its CBNG 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 CBNG 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 negative effect on Fidelity's existing CBNG operations and/or the future development of its CBNG 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 CBNG operations. The amended policy includes additional limitations on factors deemed harmful, thereby restricting water discharges even further than previous standards. Due in part to this amended policy, in May 2006, the Northern Cheyenne Tribe 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 CBNG operations. If these permits are set aside, Fidelity's CBNG 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, if the Company is unable to integrate the Cascade operations effectively, its future financial position or results of operations may be adversely affected.

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 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 nonaffiliated natural gas producer that has been conducting drilling and production operations that 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 materially and 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 the Elk Basin Storage Reservoir. Based on relevant information, including reservoir and well pressure data, Williston Basin believes that Elk Basin Storage Reservoir pressures have decreased and that the storage reservoir has lost gas as a result of Anadarko's and Howell's drilling and production activities. In related litigation, Howell 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 has answered Howell's complaint and has asserted counterclaims. If Williston Basin is unable to obtain timely relief through the courts or regulatory process, its present and future gas storage operations could be materially and 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 July 1, 2006 and September 30, 2006, the Company issued 320,697 shares 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 this 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.

ITEM 6. EXHIBITS

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

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: November 3, 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

EXHIBIT INDEX

Exhibit No.

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