MDU RESOURCES GROUP INC
Form 10-Q
November 07, 2012

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

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

For The Quarterly Period Ended September 30, 2012

OR

o 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 (State or other jurisdiction of incorporation or organization)	41-0423660 (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 ý No o.

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o.

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

Large accelerated filer ý Accelerated filer o

Non-accelerated filer o Smaller reporting company o
(Do not check if a smaller reporting company)

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of October 31, 2012: 188,830,529 shares.

DEFINITIONS

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

Abbreviation or Acronym	
2011 Annual Report	Company's Annual Report on Form 10-K for the year ended December 31, 2011
Alusa	Tecnica de Engenharia Electrica - Alusa
ASC	FASB Accounting Standards Codification
BART	Best available retrofit technology
Bbl	Barrel
Bicent	Bicent Power LLC
Big Stone Station	450-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
BLM	Bureau of Land Management
BOE	One barrel of oil equivalent - determined using the ratio of one barrel of crude oil, condensate or natural gas liquids to six Mcf of natural gas
BOPD	Barrels of oil per day
Brazilian Transmission Lines	Company's equity method investment in the company owning ECTE, ENTE and ERTE (ownership interests in ENTE and ERTE were sold in the fourth quarter of 2010 and portions of the ownership interest in ECTE were sold in the third quarter of 2012 and the fourth quarters of 2011 and 2010)
Btu	British thermal unit
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CELESC	Centrais Elétricas de Santa Catarina S.A.
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
CEMIG	Companhia Energética de Minas Gerais
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
Colorado State District Court	Colorado Thirteenth Judicial District Court, Yuma County
Company	MDU Resources Group, Inc.
dk	Decatherm
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
ECTE	Empresa Catarinense de Transmissão de Energia S.A. (5.01 percent ownership interest at September 30, 2012, 2.5, 2.5 and 14.99 percent ownership interests were sold in the third quarter of 2012 and the fourth quarters of 2011 and 2010, respectively)
ENTE	Empresa Norte de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
EPA	U.S. Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
ERTE	Empresa Regional de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings
FIP	Funding improvement plan

GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
Hawaiian Cement	Hawaiian Cement, an indirect wholly owned subsidiary of Knife River
IFRS	International Financial Reporting Standards
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
IP rates	Initial production rates
JTL	JTL Group, Inc., an indirect wholly owned subsidiary of Knife River
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
Knife River - Northwest	Knife River Corporation - Northwest, an indirect wholly owned subsidiary of Knife River
kWh	Kilowatt-hour

LPP	Lea Power Partners, LLC, a former indirect wholly owned subsidiary of Centennial Resources (member interests were sold in October 2006)
LWG	Lower Willamette Group
MBbls	Thousands of barrels
MBOE	Thousands of BOE
Mcf	Thousand cubic feet
MDU Brasil	MDU Brasil Ltda., an indirect wholly owned subsidiary of Centennial Resources
MDU Construction Services	MDU Construction Services Group, Inc., a direct wholly owned subsidiary of Centennial
MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of the Company
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 Department of Environmental Quality
Montana First Judicial District Court	Montana First Judicial District Court, Lewis and Clark County
Montana Seventeenth Judicial District Court	Montana Seventeenth Judicial District Court, Phillips County
MPPAA	Multiemployer Pension Plan Amendments Act of 1980
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
New York Supreme Court	Supreme Court of the State of New York, County of New York
NSPS	New Source Performance Standards
Oil	Includes crude oil, condensate and natural gas liquids
Omimex	Omimex Canada, Ltd.
OPUC	Oregon Public Utility Commission
Oregon DEQ	Oregon State Department of Environmental Quality
Prairielands	Prairielands Energy Marketing, Inc., an indirect wholly owned subsidiary of WBI Holdings
PRP	Potentially Responsible Party
RCRA	Resource Conservation and Recovery Act
ROD	Record of Decision
RP	Rehabilitation plan
SEC	U.S. Securities and Exchange Commission
SEC Defined Prices	The average price of oil and natural gas during the applicable 12-month period, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions
Securities Act	Securities Act of 1933, as amended
SourceGas	SourceGas Distribution LLC
WBI Energy Midstream	WBI Energy Midstream, LLC an indirect wholly owned subsidiary of WBI Holdings (previously Bitter Creek Pipelines, LLC, name changed effective July 1, 2012)
WBI Energy Transmission	WBI Energy Transmission, Inc., an indirect wholly owned subsidiary of WBI Holdings (previously Williston Basin Interstate Pipeline Company, name changed effective July 1, 2012)
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
WI	Working interest

WUTC	Washington Utilities and Transportation Commission

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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. Cascade distributes natural gas in Oregon and Washington. Intermountain distributes natural gas in Idaho. Great Plains distributes natural gas in western Minnesota and southeastern North Dakota. These operations also supply related value-added services.

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

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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,	
	2012	2011	2012	2011
	(In thousands, except per share amounts)			
Operating revenues:				
Electric, natural gas distribution and pipeline and energy services	$184,863	$212,848	$784,399	$964,866
Exploration and production, construction materials and contracting, construction services and other	988,655	939,333	2,209,889	2,019,877
Total operating revenues	1,173,518	1,152,181	2,994,288	2,984,743
Operating expenses:				
Fuel and purchased power	17,634	17,357	51,247	48,784
Purchased natural gas sold	35,199	50,102	279,038	396,326
Operation and maintenance:				
Electric, natural gas distribution and pipeline and energy services	67,830	69,475	188,945	207,465
Exploration and production, construction materials and contracting, construction services and other	793,850	767,519	1,793,347	1,663,927
Depreciation, depletion and amortization	91,850	88,897	260,858	256,861
Taxes, other than income	41,090	39,410	132,017	131,591
Write-down of oil and natural gas properties (Note 5)	160,100	—	160,100	—
Total operating expenses	1,207,553	1,032,760	2,865,552	2,704,954
Operating income (loss)	(34,035)	119,421	128,736	279,789
Earnings from equity method investments	2,388	826	4,025	2,260
Other income	1,702	1,282	4,050	5,090
Interest expense	19,840	19,589	56,929	61,642
Income (loss) before income taxes	(49,785)	101,940	79,882	225,497
Income taxes	(20,253)	37,840	24,516	73,632
Income (loss) from continuing operations	(29,532)	64,100	55,366	151,865
Income (loss) from discontinued operations, net of tax (Note 9)	(139)	(126)	4,867	154
Net income (loss)	(29,671)	63,974	60,233	152,019
Dividends declared on preferred stocks	171	171	514	514
Earnings (loss) on common stock	$(29,842)	$63,803	$59,719	$151,505
Earnings (loss) per common share - basic:				
Earnings (loss) before discontinued operations	$(.16)	$.34	$.29	$.80
Discontinued operations, net of tax	—	—	.03	—
Earnings (loss) per common share - basic	$(.16)	$.34	$.32	$.80
Earnings (loss) per common share - diluted:				

Earnings (loss) before discontinued operations	$(.16)	$.34	$.29	$.80
Discontinued operations, net of tax	—	—	.03	—
Earnings (loss) per common share - diluted	$(.16)	$.34	$.32	$.80
Dividends declared per common share	$.1675	$.1625	$.5025	$.4875
Weighted average common shares outstanding - basic	188,831	188,794	188,824	188,753
Weighted average common shares outstanding - diluted	188,831	188,797	189,029	188,760

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In thousands)			
Net income (loss)	$(29,671)	$63,974	$60,233	$152,019
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 $(5,377) and $19,481 for the three months ended and $4,570 and $19,367 for the nine months ended in 2012 and 2011, respectively	(9,125)	32,547	7,962	31,787
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income (loss), net of tax of $4,570 and $(320) for the three months ended and $4,126 and $45 for the nine months ended in 2012 and 2011, respectively	7,782	(534)	7,029	77
Net unrealized gain (loss) on derivative instruments qualifying as hedges	(16,907)	33,081	933	31,710
Foreign currency translation adjustment, net of tax of $(8) and $(905) for the three months ended and $(273) and $(736) for the nine months ended in 2012 and 2011, respectively	(5)	(1,401)	(440)	(1,140)
Net unrealized gain on available-for-sale investments, net of tax of $21 and $0 for the three months ended and $32 and $56 for the nine months ended in 2012 and 2011, respectively	39	—	60	103
Other comprehensive income (loss)	(16,873)	31,680	553	30,673
Comprehensive income (loss)	$(46,544)	$95,654	$60,786	$182,692

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

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

	September 30, 2012	September 30, 2011	December 31, 2011
(In thousands, except shares and per share amounts)			
ASSETS			
Current assets:			
Cash and cash equivalents	$74,242	$118,702	$162,772
Receivables, net	743,274	641,389	646,251
Inventories	315,767	269,569	274,205
Deferred income taxes	25,345	14,713	40,407
Commodity derivative instruments	19,193	38,794	27,687
Prepayments and other current assets	71,579	48,851	43,316
Total current assets	1,249,400	1,132,018	1,194,638
Investments	102,139	109,249	109,424
Property, plant and equipment	8,129,872	7,506,833	7,646,222
Less accumulated depreciation, depletion and amortization	3,546,927	3,307,433	3,361,208
Net property, plant and equipment	4,582,945	4,199,400	4,285,014
Deferred charges and other assets:			
Goodwill	636,039	634,931	634,931
Other intangible assets, net	18,015	22,248	20,843
Other	314,133	262,107	311,275
Total deferred charges and other assets	968,187	919,286	967,049
Total assets	$6,902,671	$6,359,953	$6,556,125
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Short-term borrowings	$11,000	$—	$—
Long-term debt due within one year	240,564	76,600	139,267
Accounts payable	402,241	305,695	337,228
Taxes payable	54,903	77,190	70,176
Dividends payable	31,800	30,850	31,794
Accrued compensation	48,792	44,100	47,804
Commodity derivative instruments	2,072	3,028	13,164
Other accrued liabilities	233,773	226,986	259,320
Total current liabilities	1,025,145	764,449	898,753
Long-term debt	1,502,413	1,347,014	1,285,411
Deferred credits and other liabilities:			
Deferred income taxes	797,249	746,946	769,166
Other liabilities	834,934	710,465	827,228
Total deferred credits and other liabilities	1,632,183	1,457,411	1,596,394
Commitments and contingencies			
Stockholders' equity:			
Preferred stocks	15,000	15,000	15,000
Common stockholders' equity:			
Common stock			
Authorized - 500,000,000 shares, $1.00 par value			

Shares issued - 189,369,450 at September 30, 2012, 189,332,485 at September 30, 2011 and 189,332,485 at December 31, 2011	189,369	189,332	189,332
Other paid-in capital	1,038,066	1,034,411	1,035,739
Retained earnings	1,550,569	1,556,550	1,586,123
Accumulated other comprehensive loss	(46,448)	(588)	(47,001)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)	(3,626)
Total common stockholders' equity	2,727,930	2,776,079	2,760,567
Total stockholders' equity	2,742,930	2,791,079	2,775,567
Total liabilities and stockholders' equity	$6,902,671	$6,359,953	$6,556,125

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,	
	2012	2011
	(In thousands)	
Operating activities:		
Net income	$60,233	$152,019
Income from discontinued operations, net of tax	4,867	154
Income from continuing operations	55,366	151,865
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	260,858	256,861
Earnings, net of distributions, from equity method investments	(1,086)	(314)
Deferred income taxes	40,310	79,985
Write-down of oil and natural gas properties	160,100	—
Changes in current assets and liabilities, net of acquisitions:		
Receivables	(89,596)	(57,829)
Inventories	(40,386)	(21,004)
Other current assets	(18,512)	2,976
Accounts payable	21,811	(8,037)
Other current liabilities	(32,994)	31,592
Other noncurrent changes	(19,683)	(23,908)
Net cash provided by continuing operations	336,188	412,187
Net cash used in discontinued operations	(6,826)	(572)
Net cash provided by operating activities	329,362	411,615
Investing activities:		
Capital expenditures	(629,776)	(339,461)
Acquisitions, net of cash acquired	(67,253)	(157)
Net proceeds from sale or disposition of property and other	31,090	23,584
Investments	11,188	(9,768)
Proceeds from sale of equity method investment	2,394	—
Net cash used in continuing operations	(652,357)	(325,802)
Net cash provided by discontinued operations	—	—
Net cash used in investing activities	(652,357)	(325,802)
Financing activities:		
Issuance of short-term borrowings	2,900	—
Repayment of short-term borrowings	—	(20,000)
Issuance of long-term debt	400,443	300
Repayment of long-term debt	(73,459)	(83,805)
Proceeds from issuance of common stock	88	5,744
Dividends paid	(95,394)	(92,473)
Excess tax benefit on stock-based compensation	26	1,248
Net cash provided by (used in) continuing operations	234,604	(188,986)
Net cash provided by discontinued operations	—	—
Net cash provided by (used in) financing activities	234,604	(188,986)

Effect of exchange rate changes on cash and cash equivalents	(139)	(199)
Decrease in cash and cash equivalents	(88,530)	(103,372)
Cash and cash equivalents -- beginning of year	162,772	222,074
Cash and cash equivalents -- end of period	$74,242	$118,702

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

MDU RESOURCES GROUP, INC.
NOTES TO CONSOLIDATED
FINANCIAL STATEMENTS

September 30, 2012 and 2011
(Unaudited)

Note 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 2011 Annual Report, and the standards of accounting measurement set forth in the interim reporting guidance in the ASC 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 2011 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 and are of a normal recurring nature. Depreciation, depletion and amortization expense is reported separately on the Consolidated Statements of Income and therefore is excluded from the other line items within operating expenses. Management has also evaluated the impact of events occurring after September 30, 2012, up to the date of issuance of these consolidated interim financial statements.

Note 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.

Note 3 - Accounts receivable and allowance for doubtful accounts
Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts, and costs and estimated earnings in excess of billings on uncompleted contracts. The total balance of receivables past due 90 days or more was $35.1 million, $27.9 million and $29.8 million as of September 30, 2012 and 2011, and December 31, 2011.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts as of September 30, 2012 and 2011, and December 31, 2011, was $10.5 million, $12.1 million and $12.4 million, respectively.

Note 4 - Inventories and natural gas in storage
Inventories, other than natural gas in storage for the Company's regulated operations, were stated at the lower of average cost or market value. Natural gas in storage for the Company's regulated operations is generally carried at average cost, or cost using the last-in, first-out method. The portion of the cost of natural gas in storage expected to be used within one year was included in inventories. Inventories consisted of:

	September 30, 2012	September 30, 2011	December 31, 2011
	(In thousands)		
Aggregates held for resale	$88,632	$80,868	$78,518
Materials and supplies	75,551	64,988	61,611
Asphalt oil	47,084	26,851	32,335
Natural gas in storage (current)	41,091	39,629	36,578
Merchandise for resale	30,827	30,974	32,165

Other	32,582	26,259	32,998
Total	$315,767	$269,569	$274,205

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was included in other assets and was $50.3 million, $47.2 million, and $50.3 million at September 30, 2012 and 2011, and December 31, 2011, respectively.

Note 5 - Oil and natural gas properties
The Company uses the full-cost method of accounting for its oil and natural gas production activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized and amortized on

the units-of-production method based on total proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are generally treated as adjustments to the cost of the properties with no gain or loss recognized.

Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties not subject to amortization, less applicable income taxes. Proved reserves and associated future cash flows are determined based on SEC Defined Prices. If capitalized costs, less accumulated amortization and related deferred income taxes, exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter regardless of subsequent price changes.

The Company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling at September 30, 2012, largely the result of lower SEC Defined Prices, primarily lower natural gas prices. Accordingly, the Company was required to write down its oil and natural gas producing properties. The noncash write-down amounted to $160.1 million ($100.9 million after tax) for the three and nine months ended September 30, 2012.

The Company hedges a portion of its oil and natural gas production and the effects of the cash flow hedges were used in determining the full-cost ceiling. The Company would have recognized an additional write-down of its oil and natural gas properties of $19.5 million ($12.3 million after tax) at September 30, 2012, if the effects of cash flow hedges had not been considered in calculating the full-cost ceiling. For more information on the Company's cash flow hedges, see Note 12.

Note 6 - Earnings (loss) per common share

Basic earnings (loss) per common share were computed by dividing earnings (loss) 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 performance share awards. Diluted loss per common share for the three months ended September 30, 2012, was computed by dividing the loss on common stock by the weighted average number of shares of common stock outstanding during the applicable period. Due to the loss on common stock for the three months ended September 30, 2012, the effect of outstanding performance share awards was excluded from the computation of diluted loss per common share as their effect was antidilutive. Common stock outstanding includes issued shares less shares held in treasury. Net income (loss) was the same for both the basic and diluted earnings (loss) per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings (loss) per share calculation was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In thousands)			
Weighted average common shares outstanding - basic	188,831	188,794	188,824	188,753
Effect of dilutive stock options and performance share awards	—	3	205	7
Weighted average common shares outstanding - diluted	188,831	188,797	189,029	188,760
Shares excluded from the calculation of diluted earnings per share	434	—	—	—

Note 7 - Cash flow information

Cash expenditures for interest and income taxes were as follows:

Nine Months Ended
September 30,

	2012	2011
	(In thousands)	
Interest, net of amount capitalized	$57,956	$63,669
Income taxes paid (refunded), net	$3,210	$(11,331)

Noncash investing transactions were as follows:

	September 30,	
	2012	2011
	(In thousands)	
Property, plant and equipment additions in accounts payable	$68,636	$31,100

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Note 8 - New accounting standards
Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs
In May 2011, the FASB issued guidance on fair value measurement and disclosure requirements. The guidance generally clarifies the application of existing requirements on topics including the concepts of highest and best use and valuation premise and disclosing quantitative information about the unobservable inputs used in the measurement of instruments categorized within Level 3 of the fair value hierarchy. Additionally, the guidance includes changes on topics such as measuring fair value of financial instruments that are managed within a portfolio and additional disclosure for fair value measurements categorized within Level 3 of the fair value hierarchy. This guidance was effective for the Company on January 1, 2012. The guidance requires additional disclosures, but it did not impact the Company's results of operations, financial position or cash flows.

Presentation of Comprehensive Income In June 2011, the FASB issued guidance on the presentation of comprehensive income. This guidance eliminates the option of presenting components of other comprehensive income as part of the statement of stockholders' equity. The guidance allows the Company the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income in either a single continuous statement of comprehensive income or in two separate but consecutive statements. In December 2011, the FASB indefinitely deferred the effective date for the guidance related to the presentation of reclassifications of items out of accumulated other comprehensive income by component in both the statement in which net income is presented and the statement in which other comprehensive income is presented. This guidance, except for the portion that was indefinitely deferred, was effective for the Company on January 1, 2012, and must be applied retrospectively. The guidance requires the Company to present a consolidated statement of comprehensive income as part of its basic financial statements along with other revisions to the disclosures, but it did not impact the Company's results of operations, financial position or cash flows.

Note 9 - Discontinued operations
In 2007, Centennial Resources sold CEM to Bicent. In connection with the sale, Centennial Resources had agreed to indemnify Bicent and its affiliates from certain third party claims arising out of or in connection with Centennial Resources' ownership or operation of CEM prior to the sale. In addition, Centennial had previously guaranteed CEM's obligations under a construction contract. The Company incurs legal expenses and has accrued liabilities related to this matter. In the second quarter of 2012, discontinued operations reflected a net benefit largely related to settlement of certain liabilities and insurance recoveries related to this matter. In the first quarter of 2011, the Company had an income tax benefit related to favorable resolution of certain tax matters. These items are reflected as discontinued operations in the consolidated financial statements and accompanying notes. Discontinued operations are included in the Other category. For more information regarding litigation, see Note 19.

Note 10 - Equity method investments
Investments in companies in which the Company has the ability to exercise significant influence over operating and financial policies are accounted for using the equity method. The Company's equity method investments at September 30, 2012, include ECTE.

In August 2006, MDU Brasil acquired ownership interests in the Brazilian Transmission Lines. The electric transmission lines are primarily in northeastern and southern Brazil. The transmission contracts provide for revenues denominated in the Brazilian Real, annual inflation adjustments and change in tax law adjustments. The functional currency for the Brazilian Transmission Lines is the Brazilian Real.

In 2009, multiple sales agreements were signed for the Company to sell its ownership interest in the Brazilian Transmission Lines. In November 2010, the Company completed the sale of its entire ownership interest in ENTE and ERTE and 59.96 percent of the Company's ownership interest in ECTE. The remaining interest in ECTE is being purchased over a four-year period. In August 2012 and November 2011, the Company completed the sale of one-fourth of the remaining interest in each year. Alusa, CEMIG and CELESC hold the remaining ownership interests in ECTE.

At September 30, 2012 and 2011, and December 31, 2011, the Company's equity method investments had total assets of $110.6 million, $108.0 million and $111.1 million, respectively, and long-term debt of $28.2 million, $39.7 million and $37.1 million, respectively. The Company's investment in its equity method investments was approximately $7.4 million, $10.5 million and $9.2 million, including undistributed earnings of $4.1 million, $2.9 million and $3.7 million, at September 30, 2012 and 2011, and December 31, 2011, respectively.

Note 11 - Goodwill and other intangible assets

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

Nine Months Ended September 30, 2012	Balance as of January 1, 2012*	Goodwill Acquired During the Year**	Balance as of September 30, 2012*
	(In thousands)		
Natural gas distribution	$345,736	$—	$345,736
Pipeline and energy services	9,737	—	9,737
Construction materials and contracting	176,290	—	176,290
Construction services	103,168	1,108	104,276
Total	$634,931	$1,108	$636,039

* Balance is presented net of accumulated impairment of $12.3 million at the pipeline and energy services segment, which occurred in prior periods.

** Includes a purchase price adjustment that was not material related to an acquisition in a prior period.

Nine Months Ended September 30, 2011	Balance as of January 1, 2011*	Goodwill Acquired During the Year**	Balance as of September 30, 2011*
	(In thousands)		
Natural gas distribution	$345,736	$—	$345,736
Pipeline and energy services	9,737	—	9,737
Construction materials and contracting	176,290	—	176,290
Construction services	102,870	298	103,168
Total	$634,633	$298	$634,931

* Balance is presented net of accumulated impairment of $12.3 million at the pipeline and energy services segment, which occurred in prior periods.

** Includes a purchase price adjustment that was not material related to an acquisition in a prior period.

Year Ended December 31, 2011	Balance as of January 1, 2011*	Goodwill Acquired During the Year**	Balance as of December 31, 2011*
	(In thousands)		
Natural gas distribution	$345,736	$—	$345,736
Pipeline and energy services	9,737	—	9,737
Construction materials and contracting	176,290	—	176,290
Construction services	102,870	298	103,168
Total	$634,633	$298	$634,931

* Balance is presented net of accumulated impairment of $12.3 million at the pipeline and energy services segment, which occurred in prior periods.

** Includes a purchase price adjustment that was not material related to an acquisition in a prior period.

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Other amortizable intangible assets were as follows:

	September 30, 2012	September 30, 2011	December 31, 2011
	(In thousands)		
Customer relationships	$21,310	$21,702	$21,702
Accumulated amortization	(11,192)	(9,896)	(10,392)
	10,118	11,806	11,310
Noncompete agreements	7,236	7,685	7,685
Accumulated amortization	(5,198)	(5,222)	(5,371)
	2,038	2,463	2,314
Other	10,979	12,901	11,442
Accumulated amortization	(5,120)	(4,922)	(4,223)
	5,859	7,979	7,219
Total	$18,015	$22,248	$20,843

Amortization expense for amortizable intangible assets for the three and nine months ended September 30, 2012, was $1.0 million and $2.9 million, respectively. Amortization expense for amortizable intangible assets for the three and nine months ended September 30, 2011, was $1.1 million and $3.0 million, respectively. Estimated amortization expense for amortizable intangible assets is $3.8 million in 2012, $3.7 million in 2013, $3.4 million in 2014, $2.6 million in 2015, $2.2 million in 2016 and $5.2 million thereafter.

Note 12 - Derivative instruments

The Company's policy allows the use of derivative instruments as part of an overall energy price, foreign currency and interest rate risk management program to efficiently manage and minimize commodity price, foreign currency and interest rate risk. As of September 30, 2012, the Company had no outstanding foreign currency hedges. The following information should be read in conjunction with Notes 1 and 7 in the Company's Notes to Consolidated Financial Statements in the 2011 Annual Report.

Cascade

At September 30, 2012, Cascade held a natural gas swap agreement, with total forward notional volumes of 31,000 MMBtu, which was not designated as a hedge. Cascade utilizes natural gas swap agreements to manage a portion of its regulated natural gas supply portfolio in order to manage fluctuations in the price of natural gas related to core customers in accordance with authority granted by the WUTC and OPUC. Core customers consist of residential, commercial and smaller industrial customers. The fair value of the derivative instrument 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. Periodic changes in the fair market value of the derivative instruments are recorded on the Consolidated Balance Sheets as a regulatory asset or a regulatory liability, and settlements of these arrangements are expected to be recovered through the purchased gas cost adjustment mechanism. Gains and losses on the settlements of these derivative instruments are recorded as a component of purchased natural gas sold on the Consolidated Statements of Income as they are recovered through the purchased gas cost adjustment mechanism. Under the terms of these arrangements, Cascade will either pay or receive settlement payments based on the difference between the fixed strike price and the monthly index price applicable to each contract. For the three and nine months ended September 30, 2012, the change in the fair market value of the derivative instrument of $175,000 and $384,000, respectively, was recorded as a decrease to regulatory assets. For the three months ended September 30, 2011, the change in the fair market value of the derivative instruments of $414,000 was recorded as an increase to regulatory assets. For the nine months ended September 30, 2011, the change in the fair market value of the derivative instruments of $8.1 million was recorded as a decrease to regulatory assets.

Cascade's derivative instrument contains a cross-default provision that states if the entity fails to make payment with respect to certain of its indebtedness, in excess of specified amounts, the counterparty could require early settlement or termination of such entity's derivative instrument in a liability position. The fair value of Cascade's derivative instrument with a credit-risk-related contingent feature that is in a liability position at September 30, 2012, was $53,000. The aggregate fair value of assets that would have been needed to settle the instrument immediately if the credit-risk-related contingent feature was triggered on September 30, 2012, was $53,000.

Fidelity

At September 30, 2012, Fidelity held oil swap and collar agreements with total forward notional volumes of 3.3 million Bbl, natural gas swap agreements with total forward notional volumes of 8.2 million MMBtu, and natural gas basis swap agreements with total forward notional volumes of 874,000 MMBtu, a majority of which were designated as cash flow hedging instruments. Fidelity utilizes these derivative instruments to manage a portion of the market risk associated with fluctuations in the price of oil and natural gas and basis differentials on its forecasted sales of oil and natural gas production.

Centennial
At September 30, 2012, Centennial held interest rate swap agreements with a total notional amount of $60.0 million, which were designated as cash flow hedging instruments. Centennial entered into these interest rate derivative instruments to manage a portion of its interest rate exposure on the forecasted issuance of long-term debt. Centennial's interest rate swap agreements have mandatory termination dates ranging from October 2012 through June 2013.

Fidelity and Centennial
The fair value of the derivative instruments must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or liability. Changes in the fair value attributable to the effective portion of hedging instruments, net of tax, are recorded in stockholders' equity as a component of accumulated other comprehensive income (loss). To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings.

For the three and nine months ended September 30, 2012, net losses of $500,000 (before tax) and $900,000 (before tax), respectively, of ineffectiveness on oil and natural gas derivatives that qualified for hedge accounting were reclassified into operating revenues and are reflected on the Consolidated Statements of Income. The amount of hedge ineffectiveness was immaterial for the three and nine months ended September 30, 2011. For the three and nine months ended September 30, 2012, a loss of $600,000 (before tax) and a gain of $400,000 (before tax), respectively, and for the three and nine months ended September 30, 2011, gains of $200,000 (before tax) and $300,000 (before tax), respectively, related to derivative instruments that did not qualify for hedge accounting were reported in operating revenues on the Consolidated Statements of Income. There were no components of the derivative instruments' gain or loss excluded 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, and there were no such reclassifications.

Gains and losses on the oil and natural gas derivative instruments are reclassified from accumulated other comprehensive income (loss) into operating revenues on the Consolidated Statements of Income at the date the oil and natural gas quantities are settled. The proceeds received for oil and natural gas production are generally based on market prices. Gains and losses on the interest rate derivatives are reclassified from accumulated other comprehensive income (loss) into interest expense on the Consolidated Statements of Income in the same period the hedged item affects earnings. For more information regarding the gains and losses on derivative instruments qualifying as cash flow hedges that were recognized in other comprehensive income (loss) and the gains and losses reclassified from accumulated other comprehensive income (loss) into earnings, see the Consolidated Statements of Comprehensive Income.

As of September 30, 2012, the maximum term of the derivative instruments, in which the exposure to the variability in future cash flows for forecasted transactions is being hedged, is 15 months.

Based on September 30, 2012, fair values, over the next 12 months net gains of approximately $9.8 million (after tax) are estimated to be reclassified from accumulated other comprehensive income (loss) into earnings, subject to changes in oil and natural gas market prices and interest rates, as the hedged transactions affect earnings.

Certain of Fidelity's and Centennial's derivative instruments contain cross-default provisions that state if Fidelity or any of its affiliates or Centennial fails to make payment with respect to certain indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of derivative instruments in liability positions. The aggregate fair value of Fidelity's and Centennial's derivative instruments with credit-risk-related contingent features that are in a liability position at September 30, 2012, was $9.9 million. The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on September 30, 2012, was $9.9 million.

The location and fair value of the Company's derivative instruments in the Consolidated Balance Sheets were as follows:

Asset Derivatives	Location on Consolidated Balance Sheets	Fair Value at September 30, 2012 (In thousands)	Fair Value at September 30, 2011	Fair Value at December 31, 2011
Designated as hedges:				
Commodity derivatives	Commodity derivative instruments	$18,619	$38,458	$27,687
	Other assets - noncurrent	3,463	15,575	2,768
		22,082	54,033	30,455
Not designated as hedges:				
Commodity derivatives	Commodity derivative instruments	574	336	—
	Other assets - noncurrent	63	—	—
		637	336	—
Total asset derivatives		$22,719	$54,369	$30,455

Liability Derivatives	Location on Consolidated Balance Sheets	Fair Value at September 30, 2012 (In thousands)	Fair Value at September 30, 2011	Fair Value at December 31, 2011
Designated as hedges:				
Commodity derivatives	Commodity derivative instruments	$1,958	$1,723	$12,727
	Other liabilities - noncurrent	83	157	937
Interest rate derivatives	Other accrued liabilities	7,779	—	827
	Other liabilities - noncurrent	—	3,491	3,935
		9,820	5,371	18,426
Not designated as hedges:				
Commodity derivatives	Commodity derivative instruments	114	1,305	437
		114	1,305	437
Total liability derivatives		$9,934	$6,676	$18,863

Note 13 - Fair value measurements

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments to satisfy its obligations under its unfunded, nonqualified benefit plans for executive officers and certain key management employees, and invests in these fixed-income and equity securities for the purpose of earning investment returns and capital appreciation. These investments, which totaled $48.4 million, $33.6 million and $38.4 million, as of September 30, 2012 and 2011, and December 31, 2011, respectively, are classified as Investments on the Consolidated Balance Sheets. The net unrealized gains on these investments were $2.4 million and $4.7 million for the three and nine months ended September 30, 2012, respectively. The net unrealized losses on these investments were $6.7 million and $5.9 million for the three and nine months ended September 30, 2011, respectively. The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income.

The Company did not elect the fair value option, which records gains and losses in income, for its remaining available-for-sale securities, which include auction rate securities, mortgage-backed securities and U.S. Treasury securities. These available-for-sale securities are recorded at fair value and are classified as Investments on the Consolidated Balance Sheets. The Company's auction rate securities approximated cost and, as a result, there were no accumulated unrealized gains or losses recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets related to these investments. In the second quarter of 2012, the Company sold its auction rate securities at cost and did not realize any gains or losses. Unrealized gains or losses on mortgage-backed securities and U.S. Treasury securities are recorded in accumulated other comprehensive income (loss). Details of available-for-sale securities were as follows:

September 30, 2012	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Insurance investment contract	$37,250	$11,134	$—	$48,384
Mortgage-backed securities	8,391	175	(2)	8,564
U.S. Treasury securities	1,758	47	—	1,805
Total	$47,399	$11,356	$(2)	$58,753

December 31, 2011	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Insurance investment contract	$31,884	$6,468	$—	$38,352
Auction rate securities	11,400	—	—	11,400
Mortgage-backed securities	8,206	95	(5)	8,296
U.S. Treasury securities	1,619	37	—	1,656
Total	$53,109	$6,600	$(5)	$59,704

The fair value of the Company's money market funds approximates cost.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs. The Company's assets and liabilities measured at fair value on a recurring basis are as follows:

	Fair Value Measurements at September 30, 2012, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at September 30, 2012
	(In thousands)			
Assets:				
Money market funds	$—	$21,816	$—	$21,816
Available-for-sale securities:				
Insurance investment contract*	—	48,384	—	48,384
Mortgage-backed securities	—	8,564	—	8,564
U.S. Treasury securities	—	1,805	—	1,805
Commodity derivative instruments	—	22,719	—	22,719
Total assets measured at fair value	$—	$103,288	$—	$103,288
Liabilities:				
Commodity derivative instruments	$—	$2,155	$—	$2,155
Interest rate derivative instruments	—	7,779	—	7,779
Total liabilities measured at fair value	$—	$9,934	$—	$9,934

* The insurance investment contract invests approximately 28 percent in common stock of mid-cap companies, 28 percent in common stock of small-cap companies, 29 percent in common stock of large-cap companies and 15 percent in fixed-income and other investments.

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	Fair Value Measurements at September 30, 2011, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at September 30, 2011
	(In thousands)			
Assets:				
Money market funds	$—	$56,194	$—	$56,194
Available-for-sale securities:				
Insurance investment contract*	—	33,591	—	33,591
Auction rate securities	—	11,400	—	11,400
Mortgage-backed securities	—	8,570	—	8,570
U.S. Treasury securities	—	1,444	—	1,444
Commodity derivative instruments	—	54,369	—	54,369
Total assets measured at fair value	$—	$165,568	$—	$165,568
Liabilities:				
Commodity derivative instruments	$—	$3,185	$—	$3,185
Interest rate derivative instruments	—	3,491	—	3,491
Total liabilities measured at fair value	$—	$6,676	$—	$6,676

* The insurance investment contract invests approximately 34 percent in common stock of mid-cap companies, 33 percent in common stock of small-cap companies, 32 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.

	Fair Value Measurements at December 31, 2011, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2011
	(In thousands)			
Assets:				
Money market funds	$—	$97,500	$—	$97,500
Available-for-sale securities:				
Insurance investment contract*	—	38,352	—	38,352
Auction rate securities	—	11,400	—	11,400
Mortgage-backed securities	—	8,296	—	8,296
U.S. Treasury securities	—	1,656	—	1,656
Commodity derivative instruments	—	30,455	—	30,455
Total assets measured at fair value	$—	$187,659	$—	$187,659
Liabilities:				
Commodity derivative instruments	$—	$14,101	$—	$14,101
Interest rate derivative instruments	—	4,762	—	4,762
Total liabilities measured at fair value	$—	$18,863	$—	$18,863

* The insurance investment contract invests approximately 33 percent in common stock of mid-cap companies, 34 percent in common stock of small-cap companies, 32 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.

The estimated fair value of the Company's Level 2 money market funds and available-for-sale securities is determined using the market approach. The Level 2 money market funds consist of investments in short-term unsecured promissory notes and the value is based on comparable market transactions taking into consideration the credit quality of the issuer. The estimated fair value of the Company's Level 2 available-for-sale securities is based on comparable market transactions, other observable inputs or other sources, including pricing from outside sources such as the fund itself.

The estimated fair value of the Company's Level 2 commodity derivative instruments is based upon futures prices, volatility and time to maturity, among other things. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The Company's and the counterparties nonperformance risk is evaluated.

The estimated fair value of the Company's Level 2 interest rate derivative instruments is measured using quoted market prices or pricing models using prevailing market interest rates as of the measurement date. Counterparty statements are utilized to determine the value of the interest rate derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The Company's and the counterparties nonperformance risk is evaluated.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the three and nine months ended September 30, 2012, there were no transfers between Levels 1 and 2.

The Company's long-term debt is not measured at fair value on the Consolidated Balance Sheets and the fair value is being provided for disclosure purposes. The fair value was based on discounted future cash flows using current market interest rates. The estimated fair value of the Company's Level 2 long-term debt was as follows:

	Carrying Amount	Fair Value
	(In thousands)	
Long-term debt at September 30, 2012	$1,742,977	$1,906,673
Long-term debt at September 30, 2011	$1,423,614	$1,568,942
Long-term debt at December 31, 2011	$1,424,678	$1,592,807

The carrying amounts of the Company's remaining financial instruments included in current assets and current liabilities approximate their fair values.

Note 14 - Income taxes

In connection with the income tax examination for the 2007 through 2009 tax years, the Company recorded income tax expense of $2.2 million for unrecognized tax positions in the first quarter of 2012.

In addition, the Company had a reduction of deferred income tax expense of $2.5 million in the first quarter of 2012, due to a deferred income tax rate reduction related to state income tax apportionment.

In the first quarter of 2011, the Company received favorable resolution of certain tax matters relating to the 2004 through 2006 tax years. As a result, the Company recorded an income tax benefit from continuing operations of $4.2 million. This resolution includes the effects of $2.8 million related to the reversal of unrecognized tax benefits that were previously established for the 2004 through 2006 tax years and associated interest of $600,000.

The settlement of federal and state audits is not anticipated within the next twelve months and, as a result, it is not expected that the unrecognized tax benefits will significantly increase or decrease within the next twelve months.

Note 15 - Business segment data

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The vast majority of the Company's operations are located within the United States. The Company also has investments in foreign countries, which largely consist of Centennial Resources' equity method investment in ECTE.

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 Idaho, Minnesota, Oregon and Washington. These operations also supply related value-added services.

The pipeline and energy services segment provides natural gas transportation, underground storage, processing and gathering services, as well as oil gathering, through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. This segment also provides cathodic protection and other energy-related services.

The exploration and production segment is engaged in oil and natural gas acquisition, exploration, development and production activities in the Rocky Mountain and Mid-Continent regions of the United States and in and around the Gulf of Mexico.

The construction materials and contracting segment mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mixed concrete, cement, asphalt, liquid asphalt and other value-added products. It also performs integrated contracting services. This segment operates in the central, southern and western United States and Alaska and Hawaii.

The construction services segment specializes in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization equipment. This segment also provides utility excavation services and inside electrical wiring, cabling and mechanical services, sells and distributes electrical materials, and manufactures and distributes specialty equipment.

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 Other category also includes Centennial Resources' equity method investment in ECTE.

The information below follows the same accounting policies as described in Note 1 of the Company's Notes to Consolidated Financial Statements in the 2011 Annual Report. Information on the Company's businesses was as follows:

Three Months Ended September 30, 2012	External Operating Revenues	Inter-segment Operating Revenues	Earnings (Loss) on Common Stock
	(In thousands)		
Electric	$63,492	$—	$11,000
Natural gas distribution	80,069	—	(8,782)
Pipeline and energy services	41,302	7,046	3,273
	184,863	7,046	5,491
Exploration and production	100,380	8,076	(87,748)
Construction materials and contracting	641,500	8,508	41,889
Construction services	246,358	834	9,863
Other	417	1,948	663
	988,655	19,366	(35,333)
Intersegment eliminations	—	(26,412)	—
Total	$1,173,518	$—	$(29,842)

Three Months Ended September 30, 2011	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
	(In thousands)		
Electric	$61,949	$—	$8,312
Natural gas distribution	92,440	—	(11,183)
Pipeline and energy services	58,459	10,591	5,221
	212,848	10,591	2,350
Exploration and production	96,803	23,956	22,497
Construction materials and contracting	619,134	—	33,103
Construction services	222,822	3,344	5,044
Other	574	2,025	809
	939,333	29,325	61,453

Intersegment eliminations	—	(39,916)	—
Total	$1,152,181	$—	$63,803

Nine Months Ended September 30, 2012	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
	(In thousands)		
Electric	$ 174,410	$ —	$ 22,977
Natural gas distribution	504,805	—	10,314
Pipeline and energy services	105,184	36,393	21,884
	784,399	36,393	55,175
Exploration and production	289,106	25,114	(56,860)
Construction materials and contracting	1,229,731	11,756	24,748
Construction services	688,368	1,078	29,951
Other	2,684	4,303	6,705
	2,209,889	42,251	4,544
Intersegment eliminations	—	(78,644)	—
Total	$ 2,994,288	$ —	$ 59,719

Nine Months Ended September 30, 2011	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
	(In thousands)		
Electric	$ 169,780	$ —	$ 21,642
Natural gas distribution	627,450	—	18,235
Pipeline and energy services	167,636	47,836	16,913
	964,866	47,836	56,790
Exploration and production	262,604	74,889	60,093
Construction materials and contracting	1,138,280	—	16,680
Construction services	617,699	9,940	15,815
Other	1,294	6,614	2,127
	2,019,877	91,443	94,715
Intersegment eliminations	—	(139,279)	—
Total	$ 2,984,743	$ —	$ 151,505

Earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from exploration and production, construction materials and contracting, construction services and other are all from nonregulated operations.

Note 16 - Acquisitions

On May 18, 2012, the Company acquired a 50 percent undivided interest in natural gas and oil midstream assets in western North Dakota. The acquisition includes a natural gas processing plant and a natural gas gathering pipeline system, along with an oil gathering system, an oil storage terminal and an oil pipeline. The total purchase consideration for acquisitions was approximately $67.5 million, including the Company's interest in the above facilities and a purchase price adjustment related to an acquisition made prior to 2012. The Company recognizes its proportionate share of the assets, liabilities, revenues and expenses related to the natural gas and oil midstream assets acquisition. Proforma financial amounts reflecting the effects of the above acquisitions have not been presented, as the acquisitions were not material to the Company's financial position or results of operations.

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Note 17 - Employee benefit plans

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

	Pension Benefits		Other Postretirement Benefits	
Three Months Ended September 30,	2012	2011	2012	2011
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	$349	$35	$437	$361
Interest cost	4,407	4,706	943	1,175
Expected return on assets	(5,865)	(5,679)	(1,222)	(1,263)
Amortization of prior service credit	(22)	(54)	(534)	(669)
Amortization of net actuarial loss	1,887	917	356	430
Amortization of net transition obligation	—	—	531	532
Curtailment gain	(1,023)	—	—	—
Net periodic benefit cost, including amount capitalized	(267)	(75)	511	566
Less amount capitalized	185	323	314	(41)
Net periodic benefit cost	$(452)	$(398)	$197	$607

	Pension Benefits		Other Postretirement Benefits	
Nine Months Ended September 30,	2012	2011	2012	2011
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	$1,044	$1,689	$1,310	$1,083
Interest cost	13,223	14,625	3,124	3,525
Expected return on assets	(17,596)	(17,106)	(3,667)	(3,789)
Amortization of prior service cost (credit)	(64)	33	(1,078)	(2,007)
Amortization of net actuarial loss	5,670	3,509	1,769	688
Amortization of net transition obligation	—	—	1,594	1,594
Curtailment (gain) loss	(1,023)	1,218	—	—
Net periodic benefit cost, including amount capitalized	1,254	3,968	3,052	1,094
Less amount capitalized	615	858	635	(136)
Net periodic benefit cost	$639	$3,110	$2,417	$1,230

Defined pension plan benefits to all nonunion and certain union employees hired after December 31, 2005, were discontinued. Employees that would have been eligible for defined pension plan benefits are eligible to receive additional defined contribution plan benefits. Effective January 1, 2010, all benefit and service accruals for nonunion and certain union plans were frozen. Effective June 30, 2011 and September 30, 2012, all benefit and service accruals for certain additional union employees were frozen. These employees will be eligible to receive additional defined contribution plan benefits.

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 the employee's retirement or to their beneficiaries upon death for a 15-year period. The Company's net periodic benefit cost for this plan for the three and nine months ended September 30, 2012, was $2.0 million and $6.1 million, respectively. The Company's net periodic benefit cost for this plan for the three and nine months ended September 30, 2011, was $2.0 million and $6.0 million, respectively.

Note 18 - Regulatory matters and revenues subject to refund

On September 26, 2012, Montana-Dakota filed an application with the MTPSC for a gas rate increase. Montana-Dakota requested a total increase of $3.5 million annually or approximately 5.9 percent above current rates. The requested increase includes the costs associated with the increased investment in facilities, including ongoing investment in new and replacement distribution facilities, the landfill gas production facility, a region operations building, automated meter reading and a new customer billing system. Montana-Dakota requested an interim increase, subject to refund, of $1.7 million or approximately 2.9 percent to be effective within 30 days.

Note 19 - Contingencies

The Company is party to claims and lawsuits arising out of its business and that of its consolidated subsidiaries. The Company accrues a liability for those contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, where feasible, an estimate of the possible loss. The Company had accrued liabilities of $41.6 million, $40.6 million and $64.1 million for contingencies related to litigation and environmental matters as of September 30, 2012 and 2011, and December 31, 2011, respectively, which includes amounts that may have been accrued for matters discussed in Litigation and Environmental matters within this note.

Litigation

Guarantee Obligation Under a Construction Contract Centennial guaranteed CEM's obligations under a construction contract with LPP for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. Centennial Resources sold CEM in July 2007 to Bicent. In February 2009, Centennial received a Notice and Demand from LPP under the guarantee agreement alleging that CEM did not meet certain of its obligations under the construction contract and demanding that Centennial indemnify LPP against all losses, damages, claims, costs, charges and expenses arising from CEM's alleged failures. In December 2009, LPP submitted a demand for arbitration of its dispute with CEM to the American Arbitration Association seeking compensatory damages of $149.7 million. An arbitration award was issued January 13, 2012, awarding LPP $22.0 million. Centennial subsequently received a demand from LPP for payment of the arbitration award plus interest and attorneys' fees. An accrual related to the guarantee as a result of the arbitration award was recorded in discontinued operations on the Consolidated Statement of Income in the fourth quarter of 2011. CEM filed a petition with the New York Supreme Court to vacate the arbitration award in favor of LPP. On October 19, 2012, Centennial moved to intervene in the New York Supreme Court action to vacate the arbitration award and also filed a complaint with the New York Supreme Court seeking a declaration that LPP is not entitled to indemnification from Centennial under the guaranty for the arbitration award. For more information regarding discontinued operations, see Note 9.

Construction Materials Until the fall of 2011 when it discontinued active mining operations at the pit, JTL operated the Target Range Gravel Pit in Missoula County, Montana under a 1975 reclamation contract pursuant to the Montana Opencut Mining Act. In September 2009, the Montana DEQ sent a letter asserting JTL was in violation of the Montana Opencut Mining Act by conducting mining operations outside a permitted area. JTL filed a complaint in Montana First Judicial District Court in June 2010, seeking a declaratory order that the reclamation contract is a valid permit under the Montana Opencut Mining Act. The Montana DEQ filed an answer and counterclaim to the complaint in August 2011, alleging JTL was in violation of the Montana Opencut Mining Act and requesting imposition of penalties of not more than $3.7 million plus not more than $5,000 per day from the date of the counterclaim. The Company believes the operation of the Target Range Gravel Pit was conducted under a valid permit; however, the imposition of civil penalties is reasonably possible. The Company filed an application for amendment of its opencut mining permit and intends to resolve this matter through settlement or continuation of the Montana First Judicial

District Court litigation.

Natural Gas Gathering Operations In January 2010, SourceGas filed an application with the Colorado State District Court to compel WBI Energy Midstream to arbitrate a dispute regarding operating pressures under a natural gas gathering contract on one of WBI Energy Midstream's pipeline gathering systems in Montana. WBI Energy Midstream resisted the application and sought a declaratory order interpreting the gathering contract. In May 2010, the Colorado State District Court granted the application and ordered WBI Energy Midstream into arbitration. An arbitration hearing was held in August 2010. In October 2010, the arbitration panel issued an award in favor of SourceGas for approximately $26.6 million. As a result, WBI Energy Midstream, which is included in the pipeline and energy services segment, recorded a $26.6 million charge ($16.5 million after tax) in the third quarter of 2010. On April 20, 2011, the Colorado State District Court confirmed the arbitration award as a court judgment. WBI Energy Midstream filed an appeal from the Colorado State District Court's order and judgment to the Colorado Court of Appeals. The Colorado Court of Appeals issued a decision on May 24, 2012, reversing the Colorado State District Court order compelling arbitration, vacating the final award and remanding the case to the Colorado State District Court to determine SourceGas's claims and WBI Energy Midstream's counterclaims. As a result of the Colorado Court of Appeals decision, in the second quarter of 2012, WBI Energy Midstream recorded a net benefit of $24.1 million ($15.0 million after tax), which is largely reflected in operation and maintenance expense on the Consolidated Statements of Income, related to this matter because the incurrence of a loss for the arbitration award is not probable. On August 2, 2012, SourceGas filed a petition for writ of certiorari with the Colorado Supreme Court for review of the Colorado Court of Appeals decision. WBI Energy Midstream anticipates that on remand to the Colorado State District Court, SourceGas will assert claims similar to those asserted in the arbitration proceeding.

In a related matter, Omimex filed a complaint against WBI Energy Midstream in Montana Seventeenth Judicial District Court in July 2010 alleging WBI Energy Midstream breached a separate gathering contract with Omimex as a result of the increased operating pressures demanded by SourceGas on the same natural gas gathering system. In December 2011, Omimex filed an amended complaint alleging WBI Energy Midstream breached obligations to operate its gathering system as a common carrier under United States and Montana law. WBI Energy Midstream removed the action to the United States District Court for the District of Montana. Expert reports submitted by Omimex contend its damages as a result of the increased operating pressures are $16.1 million to $22.6 million. The Company believes the claims asserted by Omimex are without merit and an award is not deemed probable. The Company intends to vigorously defend against the claims.

The Company also is involved in other legal actions in the ordinary course of its business. After taking into account liabilities accrued for the foregoing matters, management believes that the outcomes with respect to the above and other legal proceedings will not have a material effect upon the Company's financial position, results of operations or cash flows.

Environmental matters

Portland Harbor Site In December 2000, Knife River - Northwest was named by the EPA as a PRP in connection with the cleanup of a riverbed site adjacent to a commercial property site acquired by Knife River - Northwest from Georgia-Pacific West, Inc. in 1999. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site. 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 and feasibility study of the harbor site are being recorded, and initially paid, through an administrative consent order by the LWG, a group of several entities, which does not include Knife River - Northwest or Georgia-Pacific West, Inc. Investigative costs are indicated to be in excess of $70 million. It is not possible to estimate the cost of a corrective action plan until the remedial investigation and feasibility study have been completed, the EPA has decided on a strategy and a ROD has been published. Corrective action will be taken after the development of a proposed plan and ROD on the harbor site is issued. Knife River - Northwest also received notice in January 2008 that the Portland Harbor Natural Resource Trustee Council intends to perform an injury assessment to natural resources resulting from the release of hazardous substances at the Harbor Superfund Site. The Portland Harbor Natural Resource Trustee Council indicates the injury determination is appropriate to facilitate early settlement of damages and restoration for natural resource injuries. It is not possible to estimate the costs of natural resource damages until an assessment is completed and allocations are undertaken.

Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon DEQ and other information available, Knife River - Northwest does not believe it is a Responsible Party. In addition, Knife River - Northwest has notified Georgia-Pacific West, Inc., that it intends to seek indemnity for liabilities incurred in relation to the above matters pursuant to the terms of their sale agreement. Knife River - Northwest has entered into an agreement tolling the statute of limitations in connection with the LWG's potential claim for contribution to the costs of the remedial investigation and feasibility study. By letter in March 2009, LWG stated its intent to file suit against Knife River - Northwest and others to recover LWG's investigation costs to the extent Knife River - Northwest cannot demonstrate its non-liability for the contamination or is unwilling to participate in an alternative dispute resolution process that has been established to address the matter. At this time, Knife River - Northwest has agreed to participate in the alternative dispute resolution process.

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

Manufactured Gas Plant Sites There are three claims against Cascade for cleanup of environmental contamination at manufactured gas plant sites operated by Cascade's predecessors.

The first claim is for contamination at a site in Eugene, Oregon which was received in 1995. There are PRPs in addition to Cascade that may be liable for cleanup of the contamination. Some of these PRPs have shared in the investigation costs. It is expected that these and other PRPs will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately $500,000 to $11.0 million. The Oregon DEQ is preparing a staff report which will recommend a cleanup alternative for the site. It is not known at this time what share of the cleanup costs will actually be borne by Cascade; however, Cascade anticipates its proportional share could be approximately 50 percent. Cascade has accrued $1.3 million for remediation of this site.

The second claim is for contamination at a site in Bremerton, Washington which was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants requiring further investigation and cleanup. EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from $340,000 to $6.4 million. Data developed through the assessment and previous investigations indicates the contamination likely derived from multiple, different sources and multiple current and former owners of properties and businesses in the vicinity of the site may be responsible for the contamination. In April 2010, the Washington Department of Ecology issued notice it considered Cascade a PRP for hazardous substances at the site. In May 2012, the EPA added the site to the National Priorities List. Cascade is in discussions with the EPA regarding an administrative settlement agreement and consent order with the intent of reaching consensus on the scope and schedule for a remedial investigation and feasibility study for the site. Cascade has accrued $6.4 million for the remedial investigation and feasibility study and $6.4 million for remediation of this site. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site until the next general rate case. The WUTC approved the petition in September 2010, subject to conditions set forth in the order.

The third claim is for contamination at a site in Bellingham, Washington. Cascade received notice from a party in May 2008 that Cascade may be a PRP, along with other parties, for contamination from a manufactured gas plant owned by Cascade and its predecessor from about 1946 to 1962. The notice indicates that current estimates to complete investigation and cleanup of the site exceed $8.0 million. Other PRPs have reached an agreed order and work plan with the Washington Department of Ecology for completion of a remedial investigation and feasibility study for the site. A report documenting the initial phase of the remedial investigation was completed in June 2011. There is currently not enough information available to estimate the potential liability to Cascade associated with this claim although Cascade believes its proportional share of any liability will be relatively small in comparison to other PRPs. The plant manufactured gas from coal between approximately 1890 and 1946. In 1946, shortly after Cascade's predecessor acquired the plant, it converted the plant to a propane-air gas facility. There are no documented wastes or by-products resulting from the mixing or distribution of propane-air gas.

Cascade has received notices from certain of its insurance carriers that they will participate in defense of Cascade for these contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

Halawa Quarry The State of Hawaii Department of Health issued a Notice of Violation to Hawaiian Cement dated August 31, 2012, alleging violations of Hawaii's Water Pollution statute at Hawaiian Cement's Halawa Quarry by failure to comply with the quarry's National Pollutant Discharge Elimination System permit by failing to design, construct and maintain a facility to contain or treat the volume of all process wastewater and storm water that would result from a 10-year, 24-hour rainfall event. The Notice of Violation also alleges Hawaiian Cement violated the quarry's permit by discharging pollution, including levels of pH and total suspended solids in excess of the permit limits, on three occasions in January, June and December 2011. The Notice of Violation seeks development and implementation of corrective action plans and unspecified administrative penalties. Hawaiian Cement expects to resolve the Notice of Violation through a negotiated settlement with monetary penalties of approximately $100,000 as well as development and implementation of corrective action plans, the final cost of which have not been determined but which are not expected to be material.

Guarantees
Centennial guaranteed CEM's obligations under a construction contract. For more information, see Litigation in this note.

In connection with the sale of the Brazilian Transmission Lines, as discussed in Note 10, Centennial has agreed to guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries who are the sellers in three purchase and sale agreements for periods ranging up to 10 years from the date of sale. The guarantees were required by the buyers as a condition to the sale of the Brazilian Transmission Lines.

WBI Holdings has guaranteed certain of Fidelity's oil and natural gas swap and collar agreement obligations. There is no fixed maximum amount guaranteed in relation to the oil and natural gas swap and collar agreements as the amount of the obligation is dependent upon oil and natural gas commodity prices. The amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the oil and natural gas swap and collar agreements at September 30, 2012, expire in the years ranging from 2012 to 2013; 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 $400,000 and was reflected on the Consolidated Balance Sheet at September 30, 2012. 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 construction contracts, natural gas transportation and sales agreements, gathering contracts and certain other guarantees. At September 30, 2012, the fixed maximum amounts guaranteed under these agreements aggregated $73.3 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $4.3 million in 2012; $52.0 million in 2013; $300,000 in 2014; $100,000 in 2015; $100,000 in 2016; $700,000 in 2018; $300,000 in 2019; $11.5 million, which is subject to expiration on a specified number of days after the receipt of written notice; and $4.0 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $500,000 and was reflected on the Consolidated Balance Sheet at September 30, 2012. 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.

Certain subsidiaries have outstanding letters of credit to third parties related to insurance policies, natural gas transportation agreements and other agreements, some of which are guaranteed by other subsidiaries of the Company. At September 30, 2012, the fixed maximum amounts guaranteed under these letters of credit, aggregated $27.5 million. In 2012 and 2013, $22.2 million and $5.3 million, respectively, of letters of credit are scheduled to expire. There were no amounts outstanding under the above letters of credit at September 30, 2012.

WBI Holdings has an outstanding guarantee to WBI Energy Transmission. This guarantee is related to a natural gas transportation and storage agreement that guarantees the performance of Prairielands. At September 30, 2012, the fixed maximum amount guaranteed under this agreement was $5.0 million and is scheduled to expire in 2014. In the event of Prairielands' default in its payment obligations, WBI Holdings would be required to make payment under its guarantee. The amount outstanding by Prairielands under the above guarantee was $1.1 million. The amount outstanding under this guarantee was not reflected on the Consolidated Balance Sheet at September 30, 2012, because this intercompany transaction was eliminated in consolidation.

In addition, Centennial, Knife River and MDU Construction Services have issued guarantees to third parties related to the routine purchase of maintenance items, materials 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 these obligations, Centennial, Knife River and MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these guarantees were reflected on the Consolidated Balance Sheet at September 30, 2012.

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries, as well as an arbitration award. 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, 2012, approximately $532 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Note 20 - Subsequent events

On October 4, 2012, the Company amended its revolving credit agreement to increase the borrowing limit to $125.0 million and extend the termination date to October 4, 2017.

MDU Energy Capital entered into a private placement facility and on October 22, 2012, issued $25.0 million of Senior Notes under the agreement, with due dates ranging from October 2022 to October 2042 at a weighted average interest rate of 4.1 percent. MDU Energy Capital intends to issue an additional $25.0 million under the private placement facility on May 15, 2013.

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 return on invested capital

The Company has capabilities to fund its growth and operations through various sources, including internally generated funds, commercial paper facilities, revolving credit facilities and the issuance from time to time of debt and equity securities. For more information on the Company's net capital expenditures, see Liquidity and Capital Commitments.

The key strategies for each of the Company's business segments and certain related business challenges are summarized below. For a summary of the Company's business segments, see Note 15.

Key Strategies and Challenges

Electric and Natural Gas Distribution

Strategy Provide competitively priced energy and related services to customers. The electric and natural gas distribution segments continually seek opportunities for growth and expansion of their customer base through extensions of existing operations, including building electric generation, transmission extensions, and through selected acquisitions of companies and properties at prices that will provide stable cash flows and an opportunity for the Company to earn a competitive return on investment.

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 and environmental regulations. The ability of these segments to grow through acquisitions is subject to significant competition. In addition, the ability of both segments to grow service territory and customer base is affected by the economic environment of the markets served and competition from other energy providers and fuels. The construction of any new electric generating facilities, transmission lines and other service facilities are subject to increasing cost and lead time, extensive permitting procedures, and federal and state legislative and regulatory initiatives, which will necessitate increases in electric energy prices. Legislative and regulatory initiatives to increase renewable energy resources and reduce GHG emissions could impact the price and demand for electricity and natural gas.

Pipeline and Energy Services

Strategy Utilize the segment's existing expertise in energy infrastructure and related services 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 energy sources for storage, gathering and transportation services; expansion of existing gathering, transmission and storage facilities; incremental expansion of pipeline capacity; expansion of midstream business to include liquid pipelines and processing activities; and expansion of related energy services.

Challenges Challenges for this segment include: energy price volatility; natural gas basis differentials; environmental and regulatory requirements; recruitment and retention of a skilled workforce; and competition from other pipeline and energy services companies.

Exploration and Production
Strategy Apply technology and utilize 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 both in new and existing areas to further expand the segment's asset base. By optimizing existing operations and taking advantage of new and incremental growth opportunities, this segment is focused on balancing the oil and gas commodity mix to maximize profitability with its goal to add value by increasing both reserves and production over the long term so as to generate competitive returns on investment.

Challenges Volatility in natural gas and oil prices; timely receipt of necessary permits and approvals; environmental and regulatory requirements; recruitment and retention of a skilled workforce; availability of drilling rigs, materials, auxiliary equipment and industry-related field services; inflationary pressure on development and operating costs; and competition from other exploration and production companies are ongoing challenges for this segment.

Construction Materials and Contracting
Strategy Focus on high-growth strategic markets located near major transportation corridors and desirable mid-sized metropolitan areas; strengthen long-term, strategic aggregate reserve position through purchase and/or lease opportunities; enhance profitability through cost containment, margin discipline and vertical integration of the segment's operations; and continue growth through organic and acquisition opportunities. 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 (liquid asphalt, diesel fuel, cement and other materials), and negotiation of contract price escalation provisions. 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 permitted aggregate reserves being significant. A key element of the Company's long-term strategy for this business is to further expand its market presence in the higher-margin materials business (rock, sand, gravel, liquid asphalt, asphalt concrete, ready-mixed concrete and related products), complementing and expanding on the Company's expertise.

Challenges Volatility in the cost of raw materials such as diesel, gasoline, liquid asphalt, cement and steel, continue to be a concern. This business unit expects to continue cost containment efforts, positioning its operations for the resurgence in the private market, while continuing the emphasis on industrial, energy and public works projects.

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; retaining, developing and recruiting talented employees; focusing our efforts on projects that will permit higher margins while properly managing risk.

Challenges This segment operates in highly competitive markets with many jobs subject to competitive bidding. Maintenance of effective operational and cost controls, retention of key personnel, managing through downturns in the economy and effective management of working capital are ongoing challenges.

For more 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 Item 1A - Risk Factors, as well as Part I, Item 1A - Risk Factors in the 2011 Annual Report. For more 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,	
	2012	2011	2012	2011
	(Dollars in millions, where applicable)			
Electric	$11.0	$8.3	$23.0	$21.7
Natural gas distribution	(8.8)	(11.2)	10.3	18.2
Pipeline and energy services	3.3	5.2	21.9	16.9
Exploration and production	(87.8)	22.5	(56.9)	60.1
Construction materials and contracting	41.9	33.1	24.7	16.7
Construction services	9.9	5.1	30.0	15.8
Other	.8	.9	1.9	2.0
Earnings (loss) before discontinued operations	(29.7)	63.9	54.9	151.4
Income (loss) from discontinued operations, net of tax	(.1)	(.1)	4.8	.1
Earnings (loss) on common stock	$(29.8)	$63.8	$59.7	$151.5
Earnings (loss) per common share - basic:				
Earnings (loss) before discontinued operations	$(.16)	$.34	$.29	$.80
Discontinued operations, net of tax	—	—	.03	—
Earnings (loss) per common share - basic	$(.16)	$.34	$.32	$.80
Earnings (loss) per common share - diluted:				
Earnings (loss) before discontinued operations	$(.16)	$.34	$.29	$.80
Discontinued operations, net of tax	—	—	.03	—
Earnings (loss) per common share - diluted	$(.16)	$.34	$.32	$.80
Return on average common equity for the 12 months ended			4.3%	8.9%

Three Months Ended September 30, 2012 and 2011 Consolidated earnings for the quarter ended September 30, 2012, decreased $93.6 million from the comparable prior period largely due to a $100.9 million after-tax noncash write-down of oil and natural gas properties at the exploration and production business.

Partially offsetting this decrease were:

- Increased construction margins, higher liquid asphalt oil margins and volumes, as well as lower selling, general and administrative expense at the construction materials and contracting business
- Higher workloads and margins in the Central and Western regions, higher equipment sales and rental margins, as well as higher margins in the Mountain region, partially offset by higher general and administrative expense at the construction services business

Nine Months Ended September 30, 2012 and 2011 Consolidated earnings for the nine months ended September 30, 2012, decreased $91.8 million from the comparable prior period largely due to:

- A $100.9 million after-tax noncash write-down of oil and natural gas properties, lower average realized natural gas prices, as well as decreased natural gas production, partially offset by increased oil production at the exploration and production business
- Decreased retail sales volumes at the natural gas distribution business

Partially offsetting these decreases were:

- Higher workloads and margins in the Central and Western regions, higher equipment sales and rental margins, as well as higher margins in the Mountain region, partially offset by higher general and administrative expense at the construction services business
- Increased construction margins and lower selling, general and administrative expense, partially offset by higher income taxes at the construction materials and contracting business
- Lower operation and maintenance expense from existing operations largely related to a $15.0 million net benefit related to the natural gas gathering operations litigation, as discussed in Note 19, partially offset by lower natural gas gathering volumes from existing operations at the pipeline and energy services business

FINANCIAL AND OPERATING DATA

Below are key financial and operating data for each of the Company's businesses.

Electric

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(Dollars in millions, where applicable)			
Operating revenues	$63.5	$61.9	$174.4	$169.8
Operating expenses:				
Fuel and purchased power	17.6	17.4	51.2	48.8
Operation and maintenance	17.9	18.1	53.1	52.4
Depreciation, depletion and amortization	8.1	8.1	24.2	24.2
Taxes, other than income	2.6	2.4	7.9	7.5
	46.2	46.0	136.4	132.9
Operating income	17.3	15.9	38.0	36.9
Earnings	$11.0	$8.3	$23.0	$21.7
Retail sales (million kWh)	753.8	718.8	2,189.8	2,128.1
Sales for resale (million kWh)	8.9	35.3	11.8	63.9
Average cost of fuel and purchased power per kWh	$.022	$.022	$.022	$.021

Three Months Ended September 30, 2012 and 2011 Electric earnings increased $2.7 million (32 percent) due to:

- Higher retail sales volumes of 5 percent, primarily to residential and small commercial and industrial customers, reflecting increased demand due to warmer weather than last year, as well as increased customer growth
- Lower operation and maintenance expense of $600,000 (after tax), primarily decreased benefit-related costs, partially offset by increased contract services at certain of the Company's electric generation stations
- Higher other income of $500,000 (after tax), largely higher allowance for funds used during construction

Nine Months Ended September 30, 2012 and 2011 Electric earnings increased $1.3 million (6 percent) due to:

- Higher retail sales volumes of 3 percent, primarily to small commercial and industrial and residential customers, as previously discussed, offset in part by decreased volumes to large commercial and industrial customers
- Lower net interest expense of $800,000 (after tax), including higher capitalized interest
- Higher other income of $600,000 (after tax), as previously discussed

Partially offsetting these increases were higher income taxes of $1.2 million, primarily related to the absence of an income tax benefit related to favorable resolution of certain income tax matters in 2011.

Natural Gas Distribution

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(Dollars in millions, where applicable)			
Operating revenues	$80.1	$92.4	$504.8	$627.5
Operating expenses:				
Purchased natural gas sold	38.0	49.3	300.2	408.8
Operation and maintenance	31.8	34.8	102.9	102.5
Depreciation, depletion and amortization	11.4	11.1	34.0	33.4
Taxes, other than income	7.0	7.3	33.2	35.7
	88.2	102.5	470.3	580.4
Operating income (loss)	(8.1)	(10.1)	34.5	47.1
Earnings (loss)	$(8.8)	$(11.2)	$10.3	$18.2
Volumes (MMdk):				
Sales	8.0	8.4	60.1	69.7
Transportation	30.0	28.0	94.7	87.7
Total throughput	38.0	36.4	154.8	157.4
Degree days (% of normal)*				
Montana-Dakota/Great Plains	38%	54%	75%	110%
Cascade	91%	78%	98%	104%
Intermountain	51%	39%	92%	110%
Average cost of natural gas, including transportation, per dk	$4.73	$5.85	$4.99	$5.87

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

Three Months Ended September 30, 2012 and 2011 The natural gas distribution business recognized a seasonal loss of $8.8 million compared to a loss of $11.2 million in the third quarter of 2011. The decrease in the seasonal loss is largely due to lower operation and maintenance expense, primarily lower benefit-related costs.

Nine Months Ended September 30, 2012 and 2011 Earnings at the natural gas distribution business decreased $7.9 million (43 percent) due to:

- Lower earnings of $7.3 million (after tax) related to decreased retail sales volumes, largely resulting from significantly warmer weather than last year, partially offset by weather normalization adjustments in certain jurisdictions
- Higher income taxes of $1.0 million, primarily related to the absence of a reduction of deferred income taxes associated with benefits in 2011

These decreases were partially offset by higher other income of $600,000 (after tax), primarily related to allowance for funds used during construction.

Pipeline and Energy Services

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(Dollars in millions)			
Operating revenues	$48.3	$69.1	$141.6	$215.5
Operating expenses:				
Purchased natural gas sold	10.8	31.8	35.4	99.8
Operation and maintenance	19.2	16.6	34.8	*52.8
Depreciation, depletion and amortization	7.3	6.4	20.4	19.3
Taxes, other than income	3.5	3.4	10.5	10.3
	40.8	58.2	101.1	182.2
Operating income	7.5	10.9	40.5	33.3
Earnings	$3.3	$5.2	$21.9	*$16.9
Transportation volumes (MMdk)	34.1	29.4	103.0	82.5
Natural gas gathering volumes (MMdk)	10.7	16.4	36.5	50.8
Customer natural gas storage balance (MMdk):				
Beginning of period	40.4	31.7	36.0	58.8
Net injection (withdrawal)	8.8	6.8	13.2	(20.3)
End of period	49.2	38.5	49.2	38.5

* Results reflect a net benefit of $24.1 million ($15.0 million after tax) related to the natural gas gathering operations litigation, largely reflected in operation and maintenance expense, as discussed in Note 19.

Three Months Ended September 30, 2012 and 2011 Pipeline and energy services earnings decreased $1.9 million (37 percent) due to:

- Lower natural gas gathering volumes from existing operations, largely resulting from customers experiencing curtailments, normal production declines, deferral of certain natural gas development activity and the Company's divestments
- Higher operation and maintenance expense from existing operations of $700,000 (after tax), largely due to higher payroll-related and legal costs

Partially offsetting the earnings decrease was higher storage services revenue of $600,000 (after tax), largely higher average storage balances, as well as higher margins of $600,000 (after tax) from energy efficiency-related services.

Results also reflect lower operating revenues and lower purchased natural gas sold, both related to lower natural gas prices and lower natural gas volumes.

Nine Months Ended September 30, 2012 and 2011 Pipeline and energy services earnings increased $5.0 million due to:

- Lower operation and maintenance expense from existing operations largely related to a $15.0 million (after tax) net benefit related to the natural gas gathering operations litigation, as discussed in Note 19, which was partially offset by an impairment of certain natural gas gathering assets of $1.7 million (after tax) due largely to low natural gas prices
- Higher transportation volumes of $800,000 (after tax), largely higher volumes transported to storage

Partially offsetting the earnings increase were:

- Lower earnings of $7.3 million (after tax) due to lower natural gas gathering volumes from existing operations, as previously discussed
- Lower storage services revenue of $1.0 million (after tax), largely lower average storage balances

Results also reflect lower operating revenues and lower purchased natural gas sold, both related to lower natural gas prices and lower natural gas volumes.

Exploration and Production

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(Dollars in millions, where applicable)			
Operating revenues:				
Oil	$85.0	$74.9	$243.6	$201.9
Natural gas	23.5	45.9	70.6	135.6
	108.5	120.8	314.2	337.5
Operating expenses:				
Operation and maintenance:				
Lease operating costs	20.7	19.4	58.2	55.8
Gathering and transportation	4.3	6.9	12.8	18.1
Other	9.6	9.8	28.4	27.3
Depreciation, depletion and amortization	41.4	38.5	112.6	106.0
Taxes, other than income:				
Production and property taxes	9.6	10.0	27.8	30.5
Other	.2	(.7)	.8	(.1)
Write-down of oil and natural gas properties	160.1	—	160.1	—
	245.9	83.9	400.7	237.6
Operating income (loss)	(137.4)	36.9	(86.5)	99.9
Earnings (loss)	$(87.8)	$22.5	$(56.9)	$60.1
Production:				
Oil (MBbls)	1,123	944	3,165	2,567
Natural gas (MMcf)	7,390	11,656	25,676	34,667
Total production (MBOE)	2,354	2,887	7,444	8,345
Average realized prices (including hedges):				
Oil (per Bbl)	$75.69	$79.28	$76.96	$78.64
Natural gas (per Mcf)	$3.17	$3.94	$2.75	$3.91
Average realized prices (excluding hedges):				
Oil (per Bbl)	$73.89	$80.90	$76.45	$83.05
Natural gas (per Mcf)	$2.25	$3.44	$1.88	$3.44
Average depreciation, depletion and amortization rate, per BOE	$16.85	$12.72	$14.44	$12.09
Production costs, including taxes, per BOE:				
Lease operating costs	$8.77	$6.71	$7.81	$6.68
Gathering and transportation	1.84	2.37	1.72	2.17
Production and property taxes	4.07	3.46	3.74	3.66
	$14.68	$12.54	$13.27	$12.51

Three Months Ended September 30, 2012 and 2011 Exploration and production earnings decreased $110.3 million due to:

- A noncash write-down of oil and natural gas properties of $100.9 million (after tax), as discussed in Note 5
- Decreased natural gas production of 37 percent, largely related to a decision to curtail production, normal production declines, deferral of certain natural gas development activity and divestment at existing properties
- Lower average realized natural gas prices of 20 percent
- Lower average realized oil prices of 5 percent
-

Higher depreciation, depletion and amortization expense of $1.9 million (after tax), due to higher depletion rates, partially offset by lower volumes

Partially offsetting these decreases were:

- Increased oil production of 19 percent, largely related to drilling activity in the Bakken area, as well as the Paradox Basin
- Lower gathering and transportation expense of $1.6 million (after tax), largely due to lower gathering costs resulting from lower volumes and lower gathering rates in the coalbed area

Nine Months Ended September 30, 2012 and 2011 Exploration and production earnings decreased $117.0 million due to:

- A noncash write-down of oil and natural gas properties of $100.9 million (after tax), as discussed in Note 5
- Lower average realized natural gas prices of 30 percent
- Decreased natural gas production of 26 percent, as previously discussed
- Higher depreciation, depletion and amortization expense of $4.2 million (after tax), as previously discussed
- Lower average realized oil prices of 2 percent
- Increased lease operating expenses of $1.5 million (after tax), largely due to higher costs in the Bakken area resulting largely from increased production volumes and higher workover costs, partially offset by lower costs at certain natural gas properties where curtailments of production have occured
- Higher general and administrative expense of $1.3 million (after tax), largely due to higher payroll-related costs

Partially offsetting these decreases were:

- Increased oil production of 23 percent, largely related to drilling activity in the Bakken area, the Paradox Basin, as well as at the South Texas properties
- Lower gathering and transportation expense of $3.3 million (after tax), as previously discussed
- Lower production taxes of $1.6 million (after tax), largely resulting from lower revenues excluding hedges

Construction Materials and Contracting

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(Dollars in millions)			
Operating revenues	$650.0	$619.1	$1,241.5	$1,138.2
Operating expenses:				
Operation and maintenance	549.6	530.7	1,103.3	1,011.8
Depreciation, depletion and amortization	20.3	21.6	59.9	64.2
Taxes, other than income	11.0	11.1	29.6	28.6
	580.9	563.4	1,192.8	1,104.6
Operating income	69.1	55.7	48.7	33.6
Earnings	$41.9	$33.1	$24.7	$16.7
Sales (000's):				
Aggregates (tons)	9,009	9,196	17,983	18,502
Asphalt (tons)	3,013	3,462	4,874	5,469
Ready-mixed concrete (cubic yards)	1,105	986	2,410	2,081

Three Months Ended September 30, 2012 and 2011 Earnings at the construction materials and contracting business increased $8.8 million (27 percent) due to:

- Increased construction margins of $4.1 million (after tax) reflecting increased construction activity and margins in the South and North Central regions
- Higher earnings of $2.3 million (after tax) resulting from higher liquid asphalt oil margins and volumes
- Lower selling, general and administrative expense of $2.3 million (after tax), largely lower payroll and benefit-related costs
- Higher earnings of $1.5 million (after tax) resulting from higher ready-mixed concrete volumes and margins

Partially offsetting these increases were:

- Lower earnings of $800,000 (after tax) resulting from lower aggregate margins primarily due to higher costs, as well as lower volumes
- Lower gains of $700,000 (after tax) from the sale of property, plant and equipment

Nine Months Ended September 30, 2012 and 2011 Construction materials and contracting earnings increased $8.0 million (48 percent) due to:

- Increased construction margins of $8.3 million (after tax), largely due to favorable weather in the North Central and Intermountain regions and increased construction activity in the North Central region
- Lower selling, general and administrative expense of $3.6 million (after tax), as previously discussed
- Higher earnings of $3.0 million (after tax) resulting from higher ready-mixed concrete volumes and margins, largely in the North Central region
- Higher earnings of $2.9 million (after tax) resulting from higher liquid asphalt oil margins and volumes

Partially offsetting these increases were:

- Higher income taxes, including the absence of an income tax benefit of $2.0 million related to favorable resolution of certain income tax matters in 2011
- Lower earnings of $3.5 million (after tax) resulting from lower asphalt margins primarily due to higher costs, as well as lower volumes
- Lower earnings of $3.3 million (after tax) resulting from lower aggregate margins and volumes, as previously discussed

Construction Services

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In millions)			
Operating revenues	$247.2	$226.2	$689.4	$627.6
Operating expenses:				
Operation and maintenance	219.9	208.0	606.5	571.2
Depreciation, depletion and amortization	2.8	2.8	8.3	8.5
Taxes, other than income	7.2	5.8	22.1	19.0
	229.9	216.6	636.9	598.7
Operating income	17.3	9.6	52.5	28.9
Earnings	$9.9	$5.1	$30.0	$15.8

Three Months Ended September 30, 2012 and 2011 Construction services earnings increased $4.8 million (96 percent), primarily due to higher workloads and margins in the Central and Western regions, higher equipment sales and rental margins, as well as higher margins in the Mountain region. These increases were partially offset by higher general and administrative expense of $700,000 (after tax).

Nine Months Ended September 30, 2012 and 2011 Construction services earnings increased $14.2 million (89 percent), primarily due to higher workloads and margins in the Central and Western regions, higher equipment sales and rental margins, as well as higher margins in the Mountain region. These increases were partially offset by higher general and administrative expense of $3.3 million (after tax), including higher payroll-related costs.

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,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In millions)			
Other:				
Operating revenues	$2.3	$2.6	$7.0	$7.9
Operation and maintenance	1.5	1.6	4.4	6.5
Depreciation, depletion and amortization	.5	.4	1.5	1.2
Taxes, other than income	—	.1	.1	.1
Intersegment transactions:				
Operating revenues	$26.4	$39.9	$78.6	$139.3
Purchased natural gas sold	13.6	31.0	56.5	112.3
Operation and maintenance	12.8	8.9	22.1	27.0

For more information on intersegment eliminations, see Note 15.

PROSPECTIVE INFORMATION

The following information highlights the key growth strategies, projections and certain assumptions for the Company and its subsidiaries and other matters for certain 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 changes in 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 2011 Annual Report. Changes in such assumptions and factors could cause actual future results to differ materially from the Company's growth and earnings projections.

MDU Resources Group, Inc.

- Earnings per common share for 2012 are projected in the range of $1.05 to $1.20, excluding a third quarter noncash write-down of $100.9 million after tax and a second quarter $15.0 million after-tax benefit from a reversal of an arbitration charge. Including these items, earnings guidance for 2012 is 60 cents to 75 cents per common share.

- Although near-term market conditions are uncertain, the Company's long-term compound annual growth goals on earnings per share from operations are in the range of 7 to 10 percent.

- The Company continually seeks opportunities to expand through strategic acquisitions and organic growth opportunities.

Electric and natural gas distribution

- The Company filed an application with the MTPSC on September 26, 2012, for a natural gas rate increase, as discussed in Note 18.

- The EPA approved the South Dakota Regional Haze Program, which requires the Big Stone Station to install and operate a BART air quality control system to reduce emissions of particulate matter, sulfur dioxide and nitrogen oxides. The Company's share of the cost for the installation is estimated at $125 million and is expected to be completed in 2015. Advance determination of prudence for recovery of costs related to this system in electric rates charged to customers has been approved by the NDPSC.

- The Company plans to construct and operate an 88-MW simple-cycle natural gas turbine and associated facilities, with an estimated project cost of $85 million and a projected in-service date late 2014. It will be located on owned property that is adjacent to the Company's Heskett Generating Station near Mandan, North Dakota. The capacity is necessary to meet the requirements of the Company's integrated electric system customers and will be a partial replacement for third-party contract capacity expiring in 2015. Advance determination of prudence and a Certificate of Public Convenience and Necessity have been received from the NDPSC.

- The Company plans to invest approximately $75 million in 2012 to serve the growing electric and gas customer base associated with the Bakken oil development in western North Dakota and eastern Montana.

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- The Company is analyzing potential projects for accommodating load growth in its industrial and agricultural sectors with company and customer-owned pipeline facilities designed to serve existing facilities currently served by fuel oil or propane, and to serve new customers. The Company is currently engaged in a 30-mile natural gas line project into the Hanford Nuclear Site in Washington.

- Currently the Company is involved with a number of pipeline projects to enhance the reliability and deliverability of its system in the Pacific Northwest and Idaho.

- The Company is pursuing opportunities associated with the potential development of high-voltage transmission lines and system enhancements targeted toward delivery of energy to major market areas.

- On October 10, 2012, the Company entered into a new coal supply agreement that will replace the Coyote coal supply agreement that expires in May 2016, as reported in Items 1 and 2 - Business and Properties - General in the 2011 Annual Report. The new agreement provides for the purchase of coal necessary to supply the coal requirements of the Coyote Station for the period May 2016 through December 2040.

- On August 16, 2012, Cascade filed an application for a decoupling mechanism with the OPUC. The OPUC approved an extension until March 31, 2013, of Cascade's existing decoupling mechanism, which was scheduled to expire in the third quarter of 2012, as reported in Items 1 and 2 - Business and Properties - General in the 2011 Annual Report.

Pipeline and energy services

- The Company along with Calumet Refining, LLC, continues to explore the feasibility of building and operating a 20,000 Bbl per day diesel topping plant in southwestern North Dakota. The facility would process Bakken crude and market the diesel within the Bakken region. Options to purchase land for the plant site were recently exercised. Total project costs are estimated to be approximately $280 million to $300 million with a projected in-service date in 2014.

- In May 2012, the Company purchased a 50 percent undivided interest in Whiting Oil and Gas Corporation's Pronghorn natural gas and oil midstream assets near Belfield, North Dakota in the Bakken area. The Company expects to invest approximately $100 million in 2012 including the purchase price. The Belfield natural gas processing plant has an inlet processing capacity of 35 MMcf per day.

- The Company expects average natural gas storage balances for the remainder of the year to be slightly higher than last year. The curtailment and/or divestment of certain natural gas properties and the deferral of certain gas development activity are expected to result in gathering volumes being lower in 2012 compared to last year. The decline is expected to be partially offset by higher transportation volumes related to growth projects placed in service in the Bakken area.

- In August 2012, the Company placed in service approximately 13 miles of high-pressure transmission pipeline from the Stateline processing facilities in northwestern North Dakota to deliver gas into the Northern Border Pipeline.

- The Company continues to pursue expansion of facilities and services offered to customers. Energy development within its geographic region, which includes portions of Colorado, Wyoming, Montana and North Dakota, is expanding, most notably the Bakken of North Dakota and eastern Montana. The Company owns an extensive natural gas pipeline system in the Bakken area. Ongoing energy development is expected to have many direct and indirect benefits to this business.

Exploration and production

-

The Company has increased its expected capital expenditures to approximately $525 million in 2012. The Company has improved efficiencies across its portfolio to reduce individual well costs. However, an increase in the number of total planned wells for the year as well as the drilling of higher WI wells has resulted in higher total projected capital expenditures for the year. The Company continues its focus on returns by allocating the majority of its capital investment into the production of oil given the current commodity price environment.

- For 2012, the Company expects a 25 to 30 percent increase in oil production and a 25 to 30 percent decrease in natural gas production. The projected decline in natural gas production is primarily the result of a decision to curtail certain natural gas properties as well as divestments and the deferral of certain natural gas development activity because of sustained low natural gas prices.

- The Company has a total of seven drilling rigs deployed on its acreage in the Bakken, Texas and Paradox areas.

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- Bakken Area

The Company owns a total of approximately 127,000 net acres of leaseholds in Mountrail, Stark and Richland counties.

Capital expenditures are now expected to total approximately $265 million this year; an expansion of $165 million compared to 2011. The increase in the Bakken projected capital expenditures from earlier this year relates to more operated wells being drilled in 2012 along with the drilling of higher WI wells.

Mountrail County, North Dakota

The Company has had strong recent well results in the area. The Amundson 23-14H (15 percent WI) came on production October 16, 2012, with a 24-hour IP rate of 1,353 Bbls of oil and 582 Mcf of natural gas and the Luke 19-20-29H (58 percent WI) began producing October 18, 2012, at a 24-hour IP rate of 968 Bbls and 678 Mcf.

Approximately 40 remaining middle Bakken locations have been identified. This does not include any additional Three Forks potential, which is currently being evaluated. Estimated gross ultimate recovery rates per well are 250,000 to 600,000 Bbls.

Stark County, North Dakota

The Company has had strong recent well results in the Pavlish 19-20H (71 percent WI) and Kudrna 5-8H (81 percent WI) with 24-hour IP rates of 1,097 Bbls of oil and 657 Mcf of natural gas, and 1,151 Bbls of oil and 571 Mcf, respectively. The Pavlish came on production on September 19, 2012, and the Kudrna September 20, 2012.

Based on current information and assuming 1,280-acre spacing, the Company has identified approximately 40 future drill sites. Estimated gross ultimate recovery rates per well are 200,000 to 400,000 Bbls.

Richland County, Montana

On September 30, 2012, the Company brought the Klose (66 percent WI) well on line with a 24-hour IP rate of 371 Bbls of oil and 82 Mcf of natural gas.

Approximately 100 potential gross well sites have been identified. Estimated gross ultimate recovery rates per well are 250,000 to 500,000 Bbls.

Paradox Basin - Cane Creek Federal Unit, Utah

The Company holds approximately 75,000 net exploratory leasehold acres.

The drilling of six operated wells is planned for this year with approximately $45 million of capital expenditures.

The Company has experienced strong well results with the Cane Creek 12-1 (100 percent WI) consistently producing approximately 1,500 BOPD excluding natural gas over the past three weeks with consistently high flowing pressures.

Approximately 50 to 75 future net locations have been identified. Estimated gross ultimate recovery rates per well range from 250,000 to 1 million Bbls.

Texas

The Company is targeting areas that have the potential for higher liquids content with approximately $65 million of capital planned for this year.

Approximately 50 potential gross well sites have been identified. Estimated gross ultimate recovery rates per well are 250,000 to 400,000 Bbls.

Heath Shale

The Company holds approximately 90,000 net exploratory leasehold acres in the Heath Shale oil prospect in Montana and expects to spend approximately $40 million this year.

Two recently completed wells have had IP rates in excess of 200 Bbls per day. Production optimization efforts continue in the Heath with ongoing cleanouts of the horizontal laterals and paraffin treatment to assure sustainable production from the field.

Sioux County, Nebraska

The Company has entered into an exploration agreement where it will drill two vertical wells and one horizontal well. The vertical wells in the project have been drilled and are undergoing selective well testing. The horizontal well is planned for the first half of next year. After evaluating these initial wells, the Company may exercise an option to purchase a 65 percent WI in approximately 79,000 gross acres.

Other Opportunities

The Company has spent approximately $25 million in the Niobrara area where the economic viability and other horizons are currently being evaluated.

The remaining forecasted 2012 capital has been allocated to other operated and non-operated opportunities, including $25 million for acquisitions of leaseholds acquired earlier this year primarily in the Bakken, Richland County area.

- Earnings guidance reflects estimated average NYMEX index prices for November and December in the ranges of $90.00 to $95.00 per Bbl of crude oil and $3.00 to $3.50 per Mcf of natural gas. Estimated prices do not reflect potential basis differentials.

- For the last three months of 2012, the Company has hedged 8,000 BOPD utilizing swaps and costless collars at a weighted average price of $101.34 and $81.25/$95.88 (floor/ceiling) respectively, and 49,500 MMBtu of natural gas per day utilizing swaps at a weighted average price of $4.38.

- For 2013, the Company has hedged 7,000 BOPD utilizing swaps and costless collars with a weighted average price of $99.83 and $92.50/$107.03 (floor/ceiling) respectively, and 30,000 MMBtu of natural gas per day utilizing swaps at a weighted average price of $3.89.

- The hedges that are in place as of October 31, 2012, are summarized in the following chart:

Commodity	Type	Index	Period Outstanding	Forward Notional Volume (Bbl/MMBtu)	Price (Per Bbl/MMBtu)
Crude Oil	Collar	NYMEX	10/12 - 12/12	92,000	$80.00-$87.80
Crude Oil	Collar	NYMEX	10/12 - 12/12	92,000	$80.00-$94.50
Crude Oil	Collar	NYMEX	10/12 - 12/12	92,000	$80.00-$98.36
Crude Oil	Collar	NYMEX	10/12 - 12/12	46,000	$85.00-$102.75
Crude Oil	Collar	NYMEX	10/12 - 12/12	46,000	$85.00-$103.00
Crude Oil	Swap	NYMEX	10/12 - 12/12	46,000	$100.10
Crude Oil	Swap	NYMEX	10/12 - 12/12	46,000	$100.00
Crude Oil	Swap	NYMEX	10/12 - 12/12	92,000	$110.30
Crude Oil	Swap	NYMEX	10/12 - 12/12	92,000	$96.00
Crude Oil	Swap	NYMEX	10/12 - 12/12	92,000	$99.00
Natural Gas	Swap	NYMEX	10/12 - 12/12	874,000	$6.27
Natural Gas	Swap	NYMEX	10/12 - 12/12	460,000	$5.005
Natural Gas	Swap	NYMEX	10/12 - 12/12	230,000	$5.005
Natural Gas	Swap	NYMEX	10/12 - 12/12	230,000	$5.0125
Natural Gas	Swap	NYMEX	10/12 - 12/12	920,000	$3.05
Natural Gas	Swap	NYMEX	10/12 - 12/12	920,000	$2.805
Natural Gas	Swap	Ventura	10/12 - 12/12	920,000	$4.87
Crude Oil	Collar	NYMEX	1/13 - 12/13	182,500	$95.00-$117.00
Crude Oil	Collar	NYMEX	1/13 - 12/13	182,500	$95.00-$117.00
Crude Oil	Collar	NYMEX	1/13 - 12/13	365,000	$90.00-$97.05
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$95.00
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$95.30
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$100.00
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$100.02
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$102.00
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$102.00
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$104.00
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$104.00
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$98.00
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$98.00
Natural Gas	Swap	NYMEX	1/13 - 12/13	3,650,000	$3.76
Natural Gas	Swap	NYMEX	1/13 - 12/13	3,650,000	$3.90
Natural Gas	Swap	NYMEX	1/13 - 12/13	3,650,000	$4.00
Natural Gas	Basis Swap	CIG	10/12 - 12/12	690,000	$0.405
Natural Gas	Basis Swap	CIG	10/12 - 12/12	184,000	$0.41

Notes:

- 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.
- For all basis swaps, index prices are below NYMEX prices and are reported as a positive amount in the price column.

Construction materials and contracting

- Work backlog as of September 30, 2012, was approximately $464 million, compared to approximately $448 million a year ago. Private work represents 17 percent of the backlog, up from 8 percent in the second quarter. Public work represents 83 percent of the backlog. The backlog includes a variety of projects such as highway paving projects, airports, bridge work, reclamation and harbor expansions.

- The Company's backlog in the Bakken area of North Dakota is approximately $49 million.

- Projected revenues included in the Company's 2012 earnings guidance are approximately $1.5 billion.
- The Company anticipates margins in 2012 to be slightly lower compared to 2011.
- The Company continues to pursue opportunities for expansion in energy projects such as refineries, transmission, wind towers and geothermal. Initiatives are aimed at capturing additional market share and expansion into new markets.
- As the country's fifth largest sand and gravel producer, the Company will continue to strategically manage its 1.1 billion tons of aggregate reserves in all its markets, as well as take further advantage of being vertically integrated.
- Of the ten labor contracts that Knife River was negotiating, as reported in Items 1 and 2 - Business and Properties - General in the 2011 Annual Report, five have been ratified. The five remaining contracts are still in negotiations.

Construction services

- Work backlog as of September 30, 2012, was approximately $370 million, compared to approximately $331 million a year ago. The backlog includes a variety of projects such as substation and line construction, solar and other commercial, institutional and industrial projects including refinery work.
- The Company's backlog in the Bakken area of North Dakota is approximately $1 million.
- Projected revenues included in the Company's 2012 earnings guidance are approximately $900 million.
- The Company anticipates margins in 2012 to be higher compared to 2011.
- The Company continues to pursue opportunities for expansion in energy projects such as refineries, transmission, substations, utility services, as well as solar. Initiatives are aimed at capturing additional market share and expansion into new markets.

NEW ACCOUNTING STANDARDS

For information regarding new accounting standards, see Note 8, which is incorporated by reference.

CRITICAL ACCOUNTING POLICIES INVOLVING SIGNIFICANT ESTIMATES

The Company's critical accounting policies involving significant estimates include impairment testing of oil and natural gas production properties, impairment testing of long-lived assets and intangibles, revenue recognition, pension and other postretirement benefits, and income taxes. There were no material changes in the Company's critical accounting policies involving significant estimates from those reported in the 2011 Annual Report. For more information on critical accounting policies involving significant estimates, see Part II, Item 7 in the 2011 Annual Report.

LIQUIDITY AND CAPITAL COMMITMENTS

At September 30, 2012, the Company had cash and cash equivalents of $74.2 million and available capacity of $281.4 million under the outstanding credit facilities of the Company and its subsidiaries. The Company expects to meet its obligations for debt maturing within one year from various sources, including internally generated funds; the Company's credit facilities, as described below; and through the issuance of long-term debt.

Cash flows

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 2012 decreased $82.3 million from the comparable period in 2011. The decrease was largely due to higher working capital requirements of $107.4 million, primarily at the exploration and production business. Excluding the effect of the write-down of oil and natural gas properties, the decrease was partially offset by increased cash flows due to higher deferred income taxes of $19.6 million, largely due to increased capital expenditures at the exploration and production business.

Investing activities Cash flows used in investing activities in the first nine months of 2012 increased $326.6 million from the comparable period in 2011. The increase was primarily due to higher ongoing capital expenditures of $290.3 million, largely at the exploration and production and electric and natural gas distribution businesses, as well as increased acquisition-related capital expenditures at the pipeline and energy services business. Lower investments partially offset the increase in cash flows used in investing activities.

Financing activities Cash flows provided by financing activities in the first nine months of 2012 increased $423.6 million from the comparable period in 2011, primarily due to higher issuance of long-term debt of $400.1 million and lower repayment of short-term borrowings of $20.0 million.

Defined benefit pension plans
There were no material changes to the Company's qualified noncontributory defined benefit pension plans from those reported in the 2011 Annual Report. For more information, see Note 17 and Part II, Item 7 in the 2011 Annual Report.

Capital expenditures
Net capital expenditures for the first nine months of 2012 were $702.2 million and are estimated to be approximately $940 million for 2012. Estimated capital expenditures include:

- System upgrades
- Routine replacements
- Service extensions
- Routine equipment maintenance and replacements
- Buildings, land and building improvements
- Pipeline and gathering projects, including an acquisition as discussed in Note 16
- Further development of existing properties, acquisition of additional leasehold acreage and exploratory drilling at the exploration and production segment
- Power generation opportunities, including certain costs for additional electric generating capacity
- Environmental upgrades
- Other growth opportunities

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 2012 capital expenditures referred to previously. The Company expects the 2012 estimated capital expenditures to be funded by various sources, including internally generated funds; the Company's credit facilities, as described below; and through the issuance of long-term debt.

Capital resources
Certain debt instruments of the Company and its subsidiaries, including those discussed later, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions, all of which the Company and its subsidiaries, as applicable, were in compliance with at September 30, 2012. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued. For additional information on the covenants, certain other conditions and cross-default provisions, see Part II, Item 8 - Note 9, in the 2011 Annual Report.

The following table summarizes the outstanding credit facilities of the Company and its subsidiaries at September 30, 2012:

Company	Facility		Facility Limit		Amount Outstanding		Letters of Credit		Expiration Date	
			(In millions)							
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement	(a)	$100.0		$50.0	(b)	$—		5/26/15	
Cascade Natural Gas Corporation	Revolving credit agreement		$50.0	(c)	$—		$1.9	(d)	12/27/13	(e)
Intermountain Gas Company	Revolving credit agreement		$65.0	(f)	$11.0		$—		8/11/13	
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(g)	$500.0		$350.5	(b)	$20.2	(d)	6/8/17	

(a) The $125 million commercial paper program is supported by a revolving credit agreement with various banks totaling $100 million (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $150 million). There were no amounts outstanding under the credit agreement. On October 4, 2012, the credit agreement was increased to $125 million and the expiration date was extended to October 4, 2017.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $75 million.
(d) The outstanding letters of credit, as discussed in Note 19, reduce amounts available under the credit agreement.
(e) Effective June 27, 2012, Cascade extended the credit agreement.
(f) Certain provisions allow for increased borrowings, up to a maximum of $80 million.
(g) The $500 million commercial paper program is supported by a revolving credit agreement with various banks totaling $500 million (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $650 million). There were no amounts outstanding under the credit agreement.

The Company's and Centennial's respective commercial paper programs are supported by revolving credit agreements. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements. The commercial paper borrowings may vary during the period, largely the result of fluctuations in working capital requirements due to the seasonality of the construction businesses.

The following includes information related to the preceding table.

MDU Resources Group, Inc. On October 4, 2012, the Company amended the revolving credit agreement to increase the borrowing limit to $125.0 million and extend the termination date to October 4, 2017. The Company's revolving credit agreement supports its commercial paper program. Any commercial paper borrowings under this agreement would be classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. The Company's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Downgrades in the Company's credit ratings have not limited, nor are currently expected to limit, the Company's ability to access the capital markets. If the Company were to experience a downgrade of its credit ratings, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings.

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

The Company's coverage of fixed charges including preferred stock dividends was 2.8 times and 4.0 times for the 12 months ended September 30, 2012 and December 31, 2011, respectively.

Common stockholders' equity as a percent of total capitalization was 61 percent, 66 percent and 66 percent at September 30, 2012 and 2011 and December 31, 2011, respectively. This ratio is calculated as the Company's common stockholders' equity, divided by the Company's total capital. Total capital is the Company's total debt, including short-term borrowings and long-term debt due within one year, plus stockholders' equity. This ratio indicates how a company is financing its operations, as well as its financial strength.

The Company currently has a shelf registration statement on file with the SEC, under which the Company may issue and sell any combination of common stock and debt securities. The Company may sell all or a portion of such securities if warranted by market conditions and the Company's capital requirements. Any public offer and sale of such securities will be made only by means of a prospectus meeting the requirements of the Securities Act and the rules and regulations thereunder. The Company's board of directors currently has authorized the issuance and sale of up to an aggregate of $1.0 billion worth of such securities. The Company's board of directors reviews this authorization on a periodic basis and the aggregate amount of securities authorized may be increased in the future.

Centennial Energy Holdings, Inc. On June 8, 2012, Centennial entered into an amended and restated revolving credit agreement which replaced the previous $400 million revolving credit agreement and extended the termination date to June 8, 2017. The credit agreement contains customary covenants and provisions, including a covenant of Centennial not to permit, as of the end of any fiscal quarter, the ratio of total consolidated debt to total consolidated capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on subsidiary indebtedness and the making of certain loans and investments.

Centennial's revolving credit agreement contains 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 agreement will be in default.

Centennial's revolving credit agreement supports its commercial paper program. On June 28, 2012, Centennial entered into a new private placement memorandum related to their commercial paper program to increase the borrowing limit to $500.0 million. Any commercial paper borrowings under this agreement would be classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. Centennial's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Downgrades in Centennial's credit ratings have not limited, nor are currently expected to limit, Centennial's ability to access the capital markets. If Centennial were to experience a downgrade of its credit ratings, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings.

Off balance sheet arrangements

In connection with the sale of the Brazilian Transmission Lines, Centennial has agreed to guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries who are the sellers in three purchase and sale agreements for periods ranging up to 10 years from the date of sale. The guarantees were required by the buyers as a condition to the sale of the Brazilian Transmission Lines.

Centennial continues to guarantee CEM's obligations under a construction contract for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. For more information, see Note 19.

Contractual obligations and commercial commitments

There are no material changes in the Company's contractual obligations relating to estimated interest payments, operating leases, commodity derivatives, interest rate derivatives and minimum funding requirements for its defined benefit plans for 2012 from those reported in the 2011 Annual Report.

The Company's contractual obligations relating to long-term debt at September 30, 2012, increased $318.3 million or 22% from December 31, 2011. At September 30, 2012, the Company's contractual obligations related to long-term debt totaled $1.7 billion. The scheduled maturities (for the twelve months ended September 30, of each year listed) totaled $240.6 million in 2013; $41.0 million in 2014; $166.7 million in 2015; $388.5 million in 2016; $443.9 million in 2017; and $462.3 million thereafter. The Company intends to refinance long-term debt due within one year.

The Company's contractual obligations relating to purchase commitments at September 30, 2012, increased $498.9 million or 41% from December 31, 2011, largely related to natural gas supply and transportation contracts. At September 30, 2012, the Company's contractual obligations related to purchase commitments totaled $1.7 billion. The scheduled commitment amounts (for the twelve months ended September 30, of each year listed) totaled $467.5 million in 2013; $275.5 million in 2014; $169.3 million in 2015; $90.8 million in 2016; $25.2 million in 2017; and $695.1 million thereafter.

For more information on the Company's uncertain tax positions, see Note 14.

For more information on contractual obligations and commercial commitments, see Part II, Item 7 in the 2011 Annual Report.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to the impact of market fluctuations associated with commodity prices, interest rates and foreign currency. 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 oil and natural gas and basis differentials on forecasted sales of oil and natural gas production. Cascade utilizes derivative instruments to manage a portion of its regulated natural gas supply portfolio in order to manage fluctuations in the price of natural gas. For more information on derivative instruments and commodity price risk, see Part II, Item 7A in the 2011 Annual Report, the Consolidated Statements of Comprehensive Income and Note 12.

The following table summarizes derivative agreements entered into by Fidelity and Cascade as of September 30, 2012. These agreements call for Fidelity to receive fixed prices and pay variable prices and for Cascade to receive variable prices and pay fixed prices.

(Forward notional volume and fair value in thousands)

	Weighted Average Fixed Price (Per Bbl/MMBtu)	Forward Notional Volume (Bbl/MMBtu)	Fair Value
Fidelity			
Oil swap agreements maturing in 2012	$101.34	368	$3,164
Oil swap agreements maturing in 2013	$99.83	1,825	$11,157
Natural gas swap agreements maturing in 2012	$4.38	4,554	$4,806
Natural gas swap agreement maturing in 2013	$3.76	3,650	$(307)
Natural gas basis swap agreements maturing in 2012	$.41	874	$(174)
Cascade			
Natural gas swap agreement maturing in 2012	$4.47	31	$(53)

	Weighted Average Floor/Ceiling Price (Per Bbl)	Forward Notional Volume (Bbl)	Fair Value
Fidelity			
Oil collar agreements maturing in 2012	$81.25/$95.88	368	$(843)
Oil collar agreements maturing in 2013	$92.50/$107.03	730	$2,814

Interest rate risk
There were no material changes to interest rate risk faced by the Company from those reported in the 2011 Annual Report. For more information, see Part II, Item 7A in the 2011 Annual Report.

Centennial entered into interest rate swap agreements to manage a portion of its interest rate exposure on the forecasted issuance of long-term debt. The agreements call for Centennial to receive payments from or make payments to counterparties based on the difference between fixed and variable rates as specified by the interest rate swap agreements. For more information on derivative instruments, see the Consolidated Statements of Comprehensive Income and Note 12.

The following table summarizes derivative instruments entered into by Centennial as of September 30, 2012. The agreements call for Centennial to receive variable rates and pay fixed rates.

(Notional amount and fair value in thousands)

	Weighted Average Fixed Interest Rate	Notional Amount	Fair Value
Centennial			
Interest rate swap agreement with mandatory termination date in 2012	3.15%	$10,000	$(1,343)
Interest rate swap agreements with mandatory termination dates in 2013	3.22%	$50,000	$(6,436)

Foreign currency risk
The Company's equity method investment in ECTE is exposed to market risks from changes in foreign currency exchange rates between the U.S. dollar and the Brazilian Real. For more information, see Part II, Item 8 - Note 4 in the 2011 Annual Report.

At September 30, 2012 and 2011, and December 31, 2011, the Company had no outstanding foreign currency hedges.

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) under the Exchange Act. The Company's disclosure controls and other procedures are designed to provide reasonable assurance that information required to be disclosed in the reports that the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The Company's disclosure controls and procedures include controls and procedures designed to provide reasonable assurance that information required to be disclosed is accumulated and communicated to management, including the Company's chief executive officer and chief financial officer, to allow timely decisions regarding required disclosure. The Company's management, with the participation of the Company's chief executive officer and chief financial officer, has evaluated the effectiveness of the Company's disclosure controls and procedures. Based upon that evaluation, the chief executive officer and the chief financial officer have concluded that, as of the end of the period covered by this report, such controls and procedures were effective at a reasonable assurance level.

Changes in internal controls
No change in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the quarter ended September 30, 2012, that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II -- OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see Note 19, which is incorporated herein 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 in the 2011 Annual Report other than the risk related to the Company's exploration and production and pipeline and energy services businesses being dependent on factors which are subject to various external influences that cannot be controlled; the risk that actual quantities of recoverable oil and natural gas reserves and discounted future net cash flows from those reserves may vary significantly from estimated amounts; the risk related to environmental laws and regulations; the risk associated with electric generation operation that could be adversely impacted by global climate change initiatives to reduce GHG emissions; and the risk related to increased costs related to obligations under multiemployer pension plans. 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.

Economic Risks

The Company's exploration and production and pipeline and energy services businesses are dependent on factors, including commodity prices and commodity price basis differentials, which are subject to various external influences that cannot be controlled.

These factors include: fluctuations in oil and natural gas production and prices; fluctuations in commodity price basis differentials; availability of economic supplies of natural gas; drilling successes in oil and natural gas operations; the timely receipt of necessary permits and approvals; the ability to contract for or to secure necessary drilling rig and service contracts and to retain employees to identify, drill for and develop reserves; the ability to acquire oil and natural gas properties; and other risks incidental to the development and operations of oil and natural gas wells, processing plants and pipeline systems. Volatility in oil and natural gas prices could negatively affect the results of operations, cash flows and asset values of the Company's exploration and production and pipeline and energy services businesses.

Actual quantities of recoverable oil and natural gas reserves and discounted future net cash flows from those reserves may vary significantly from estimated amounts. There is a risk that changes in estimates of proved reserve quantities or other factors including downward movements in prices, could result in additional future noncash write-downs of the Company's oil and natural gas properties.

The process of estimating oil and natural gas reserves is complex. Reserve estimates are based on assumptions relating to oil and natural gas pricing, drilling and operating expenses, capital expenditures, taxes, timing of operations, and the percentage of interest owned by the Company in the properties. The reserve estimates are prepared for each of the Company's properties by internal engineers assigned to an asset team by geographic area. The internal engineers analyze available geological, geophysical, engineering and economic data for each geographic area. The internal engineers make various assumptions regarding this data. The extent, quality and reliability of this data can vary. Although the Company has prepared its reserve estimates in accordance with guidelines established by the industry and the SEC, significant changes to the reserve estimates may occur based on actual results of production, drilling, costs and pricing.

The Company bases the estimated discounted future net cash flows from proved reserves on prices and current costs in accordance with SEC requirements. Actual future prices and costs may be significantly different. Given the current pricing environment, there is risk that lower SEC Defined Prices, changes in estimates of reserve quantities, unsuccessful results of exploration and development efforts or changes in operating and development costs could result in additional future noncash write-downs of the Company's oil and natural gas properties.

Environmental and Regulatory Risks
The Company's operations are subject to environmental laws and regulations that may increase costs of operations, impact or limit business plans, or expose the Company to environmental liabilities.

The Company is subject to environmental laws and regulations affecting many aspects of its present and future operations, including air quality, water quality, waste management and other environmental considerations. These laws and regulations can result in increased capital, operating and other costs, delays as a result of litigation and administrative proceedings, and compliance, remediation, containment, monitoring and reporting obligations, particularly with regard to laws relating to electric generation operations and oil and natural gas development. These laws and regulations generally require the Company to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Although the Company strives to comply with all applicable environmental laws and regulations, public officials and entities, as well as private individuals and organizations, may seek injunctive relief or other remedies to enforce applicable environmental laws and regulations with which they have differing interpretations of the Company's legal or regulatory compliance. The Company cannot predict the outcome (financial or operational) of any related litigation or administrative proceedings that may arise.

Existing environmental laws and regulations may be revised and new laws and regulations seeking to protect the environment may be adopted or become applicable to the Company. These laws and regulations could require the Company to limit the use or output of certain facilities, restrict the use of certain fuels, install pollution control equipment or initiate pollution control technologies, remediate environmental contamination, remove or reduce environmental hazards, or prevent or limit the development of resources. Revised or additional laws and regulations, that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material adverse effect on the Company's results of operations and cash flows.

The EPA has issued draft regulations that outline several possible approaches for coal combustion residuals management under the RCRA. One approach, designating coal ash as a hazardous waste, would significantly change the manner and increase the costs of managing coal ash at five plants that supply electricity to customers of Montana-Dakota. This designation also could significantly increase costs for Knife River, which beneficially uses fly ash as a cement replacement in ready-mixed concrete and road base applications.

In December 2011, the EPA finalized the Mercury and Air Toxics rule that will require reductions in mercury and other toxic air emissions from coal- and oil-fired electric utility steam generating units. Montana-Dakota is evaluating the pollution control technologies needed at its electric generation resources to comply with this final rule. Controls must be installed by April 16, 2015. One additional year may be granted by the permitting authority to install pollution controls if needed to ensure electric system reliability.

Hydraulic fracturing is an important common practice used by the Company that involves injecting water; sand; guar, a water thickening agent; and trace amounts of chemicals under pressure into rock formations to stimulate oil and natural gas production. The EPA is developing a study to review the potential effects of hydraulic fracturing on underground sources of drinking water; the results of that study could impact future legislation or regulation. The BLM has released draft well stimulation regulations for hydraulic fracturing operations. The comment period for these regulations closed September 10, 2012. Fidelity worked with industry trade associations, other oil and gas operators and service companies in reviewing and commenting on the proposed regulations. If implemented, the BLM regulations would only affect Fidelity's operations on BLM-administered lands. If adopted as proposed, the BLM regulations, along with other legislative initiatives and regulatory studies, proceedings or initiatives at federal or state agencies that focus on the hydraulic fracturing process could result in additional compliance, reporting and disclosure requirements. Future legislation or regulation could increase compliance and operating costs, as well as delay or inhibit the Company's ability to develop its oil and natural gas reserves.

The EPA published a final NSPS rule for the oil and natural gas industry on August 16, 2012. The NSPS rule phases in over the next two years. The first phase was effective October 15, 2012, and primarily covers natural gas wells that are hydraulically fractured. Under the new rule, gas vapors or emissions from the natural gas wells must be captured or combusted utilizing a high efficiency device. Additional reporting requirements and control devices covering oil and natural gas production equipment, will be phased in on certain new oil and gas facilities with a final effective date of January 1, 2015. Impacts on Fidelity from this new rule are likely to include implementation of recordkeeping, reporting and testing requirements and the acquisition and installation of required equipment.

Initiatives to reduce GHG emissions could adversely impact the Company's electric generation operations.

Concern that GHG emissions are contributing to global climate change has led to international, federal and state legislative and regulatory proposals to reduce or mitigate the effects of GHG emissions. In late March 2012, the EPA proposed a GHG NSPS for new fossil fuel-fired electric generating units, including coal-fired units and natural gas-fired combined-cycle units. The EPA's new carbon dioxide emissions standard is equivalent to emissions from a natural gas-fired, high-efficiency combined-cycle unit. This stringent standard does not allow for any new coal-fired electric generation to be constructed unless the generating unit's carbon dioxide emissions are captured and sequestered. The EPA has not applied this new standard to existing fossil fuel-fired units or existing units that make modifications, therefore no impacts to Montana-Dakota's existing electric generation facilities are expected. However, it is not clear that the EPA will always exempt required future pollution control project modifications from GHG NSPS. If the EPA does not clearly exempt these projects, the Company's electric generation operations could be adversely impacted.

The primary GHG emitted from the Company's operations is carbon dioxide from combustion of fossil fuels at Montana-Dakota's electric generating facilities, particularly its coal-fired facilities. Approximately 70 percent of Montana-Dakota's owned generating capacity and more than 90 percent of the electricity it generates is from coal-fired facilities. Montana-Dakota also owns approximately 100 MW of natural gas- and oil-fired peaking plants.

The future of GHG regulation remains uncertain. Montana-Dakota's existing electric generating facilities may be subject to GHG laws or regulations within the next few years, including the EPA's proposed GHG NSPS for new fossil fuel-fired units, as well as when the EPA develops any separate GHG NSPS specifically for existing and modified units. Implementation of treaties, legislation or regulations to reduce GHG emissions could affect Montana-Dakota's electric utility operations by requiring expanded energy conservation efforts or increased development of renewable energy sources, as well as other mandates that could significantly increase capital expenditures and operating costs. If Montana-Dakota does not receive timely and full recovery of GHG emission compliance costs from its customers, then such costs could have an adverse impact on the results of its operations.

Due to the uncertain availability of technologies to control GHG emissions and the unknown obligations that potential GHG emission legislation or regulations may create, the Company cannot determine the potential financial impact on its operations.

Other Risks
An increase in costs related to obligations under multiemployer pension plans could have a material negative effect on the Company's results of operations and cash flows.

Various operating subsidiaries of the Company participate in approximately 75 multiemployer pension plans for employees represented by certain unions. The Company is required to make contributions to these plans in amounts established under numerous collective bargaining agreements between the operating subsidiaries and those unions.

The Company may be obligated to increase its contributions to underfunded plans that are classified as being in endangered, seriously endangered, or critical status as defined by the Pension Protection Act of 2006. Plans classified as being in one of these statuses are required to adopt RPs or FIPs to improve their funded status through increased contributions, reduced benefits or a combination of the two. Based on available information, the Company believes that approximately 40 percent of the multiemployer plans to which it contributes are currently in endangered, seriously endangered or critical status.

The Company may also be required to increase its contributions to multiemployer plans where the other participating employers in such plans withdraw from the plan and are not able to contribute an amount sufficient to fund the unfunded liabilities associated with their participants in the plans. The amount and timing of any increase in the Company's required contributions to multiemployer pension plans may also depend upon one or more of the following factors including the outcome of collective bargaining, actions taken by trustees who manage the plans, the industry for which contributions are made, future determinations that additional plans reach endangered, seriously endangered or critical status, government regulations and the actual return on assets held in the plans, among others. The Company may experience increased operating expenses as a result of the required contributions to multiemployer pension plans, which may have a material adverse effect on the Company's results of operations, financial position or cash flows.

In addition, pursuant to ERISA, as amended by MPPAA, the Company could incur a partial or complete withdrawal liability upon withdrawing from a plan, exiting a market in which it does business with a union workforce or upon termination of a plan to the extent these plans are underfunded.

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

None.

ITEM 4. MINE SAFETY DISCLOSURES

For information regarding mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Act and Item 104 of Regulation S-K, see Exhibit 95 to this Form 10-Q, which is incorporated herein by reference.

ITEM 6. EXHIBITS

See the index to exhibits immediately preceding the exhibits filed with this report.

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 7, 2012	BY:	/s/ Doran N. Schwartz Doran N. Schwartz Vice President and Chief Financial Officer
		BY:	/s/ Nicole A. Kivisto Nicole A. Kivisto Vice President, Controller and Chief Accounting Officer

EXHIBIT INDEX

Exhibit No.	
3	Company Bylaws, as amended and restated, on August 16, 2012
4	First Amendment to Credit Agreement, dated October 4, 2012, among MDU Resources Group, Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent
+10(a)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 29, 2012
+10(b)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 29, 2012
+10(c)	Form of Agreement for Termination of Change of Control Employment Agreement, effective November 1, 2012, by and between MDU Resources Group, Inc. and William E. Schneider, John G. Harp, Steven L. Bietz, David L. Goodin, William R. Connors, Mark A. Del Vecchio, Nicole A. Kivisto, Cynthia J. Norland, Paul K. Sandness, Doran N. Schwartz and John P. Stumpf
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
95	Mine Safety Disclosures
101	The following materials from MDU Resources Group, Inc.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2012, formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Balance Sheets, (iv) the Consolidated Statements of Cash Flows and (v) the Notes to Consolidated Financial Statements, tagged in summary and detail

+ Management contract, compensatory plan or arrangement.

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.