MDU RESOURCES GROUP INC
Form 10-Q
May 08, 2015

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 March 31, 2015

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 May 1, 2015: 194,770,955 shares.

DEFINITIONS

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

Abbreviation or Acronym	
2014 Annual Report	Company's Annual Report on Form 10-K for the year ended December 31, 2014
AFUDC	Allowance for funds used during construction
ASC	FASB Accounting Standards Codification
Bbl	Barrel
Bicent	Bicent Power LLC
Big Stone Station	475-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
Bombard Mechanical	Bombard Mechanical, LLC, an indirect wholly owned subsidiary of MDU Construction Services
BOPD	Barrels of oil per day
Brazilian Transmission Lines	Company's former investment in companies owning three electric transmission lines
Btu	British thermal unit
California Superior Court	Superior Court of the State of California, County of Los Angeles (South District - Long Beach)
Calumet	Calumet Specialty Products Partners, L.P.
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
Clean Water Act	Federal Clean Water Act
Colorado State District Court	Colorado Thirteenth Judicial District Court, Yuma County
Company	MDU Resources Group, Inc.
Connolly-Pacific	Connolly-Pacific Co., an indirect wholly owned subsidiary of Knife River
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
Coyote Station	427-MW coal-fired electric generating facility near Beulah, North Dakota (25 percent ownership)
Dakota Prairie Refinery	20,000-barrel-per-day diesel topping plant built by Dakota Prairie Refining in southwestern North Dakota
Dakota Prairie Refining	Dakota Prairie Refining, LLC, a limited liability company jointly owned by WBI Energy and Calumet
dk	Decatherm
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
EBITDA	Earnings before interest, taxes, depreciation, depletion and amortization
EPA	U.S. Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
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
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
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

LWG	Lower Willamette Group
MATS	Mercury and Air Toxics Standards
MBbls	Thousands of barrels
MBOE	Thousands of BOE
Mcf	Thousand cubic feet
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
MEPP	Multiemployer pension plan
MISO	Midcontinent Independent System Operator, Inc.
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
Nevada State District Court	District Court Clark County, Nevada
NGL	Natural gas liquids
NSPS	New Source Performance Standards
NYMEX	New York Mercantile Exchange
Oil	Includes crude oil and condensate
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
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
VIE	Variable interest entity
WBI Energy	WBI Energy, Inc., an indirect wholly owned subsidiary of WBI Holdings
WBI Energy Midstream	WBI Energy Midstream, LLC, an indirect wholly owned subsidiary of WBI Holdings
WBI Energy Transmission	WBI Energy Transmission, Inc., an indirect wholly owned subsidiary of WBI Holdings
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
WUTC	Washington Utilities and Transportation Commission

WYPSC	Wyoming Public Service Commission

3

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.

INDEX

PART I -- FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	Three Months Ended March 31,	
	2015	2014
	(In thousands, except per share amounts)	
Operating revenues:		
Electric, natural gas distribution and pipeline and energy services	$427,444	$491,541
Exploration and production, construction materials and contracting, construction services and other	491,066	551,312
Total operating revenues	918,510	1,042,853
Operating expenses:		
Fuel and purchased power	23,819	26,544
Purchased natural gas sold	202,960	244,892
Cost of crude oil	2,270	—
Operation and maintenance:		
Electric, natural gas distribution and pipeline and energy services	79,425	67,284
Exploration and production, construction materials and contracting, construction services and other	440,993	445,951
Depreciation, depletion and amortization	95,507	99,557
Taxes, other than income	47,483	55,721
Write-down of oil and natural gas properties (Note 5)	500,400	—
Total operating expenses	1,392,857	939,949
Operating income (loss)	(474,347)	102,904
Other income	2,324	2,183
Interest expense	23,149	20,971
Income (loss) before income taxes	(495,172)	84,116
Income taxes	(185,727)	27,932
Income (loss) from continuing operations	(309,445)	56,184
Loss from discontinued operations, net of tax (Note 10)	—	(45)
Net income (loss)	(309,445)	56,139
Net loss attributable to noncontrolling interest	(3,528)	(523)
Dividends declared on preferred stocks	171	171
Earnings (loss) on common stock	$(306,088)	$56,491
Earnings (loss) per common share - basic:		
Earnings (loss) before discontinued operations	$(1.57)	$.30
Discontinued operations, net of tax	—	—
Earnings (loss) per common share - basic	$(1.57)	$.30
Earnings (loss) per common share - diluted:		
Earnings (loss) before discontinued operations	$(1.57)	$.30
Discontinued operations, net of tax	—	—
Earnings (loss) per common share - diluted	$(1.57)	$.30

Dividends declared per common share	$.1825	$.1775
Weighted average common shares outstanding - basic	194,479	189,820
Weighted average common shares outstanding - diluted	194,479	190,432

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

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

	Three Months Ended March 31,	
	2015	2014
	(In thousands)	
Net income (loss)	$(309,445)	$56,139
Other comprehensive income:		
Reclassification adjustment for loss on derivative instruments included in net income (loss), net of tax of $60 and $204 for the three months ended in 2015 and 2014, respectively	99	344
Amortization of postretirement liability losses included in net periodic benefit cost, net of tax of $230 and $168 for the three months ended in 2015 and 2014, respectively	375	275
Foreign currency translation adjustment:		
Foreign currency translation adjustment recognized during the period, net of tax of $(68) and $28 for the three months ended in 2015 and 2014, respectively	(112)	46
Reclassification adjustment for loss on foreign currency translation adjustment included in net income (loss), net of tax of $490 and $0 for the three months ended in 2015 and 2014, respectively	802	—
Foreign currency translation adjustment	690	46
Net unrealized gain on available-for-sale investments:		
Net unrealized loss on available-for-sale investments arising during the period, net of tax of $(11) and $(19) for the three months ended in 2015 and 2014, respectively	(21)	(36)
Reclassification adjustment for loss on available-for-sale investments included in net income (loss), net of tax of $19 and $20 for the three months ended in 2015 and 2014, respectively	36	38
Net unrealized gain on available-for-sale investments	15	2
Other comprehensive income	1,179	667
Comprehensive income (loss)	(308,266)	56,806
Comprehensive loss attributable to noncontrolling interest	(3,528)	(523)
Comprehensive income (loss) attributable to common stockholders	$(304,738)	$57,329

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

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

	March 31, 2015	March 31, 2014	December 31, 2014
(In thousands, except shares and per share amounts)			
ASSETS			
Current assets:			
Cash and cash equivalents	$122,241	$83,700	$81,855
Receivables, net	564,090	690,761	693,318
Inventories	336,598	301,332	300,811
Deferred income taxes	32,987	29,427	23,806
Commodity derivative instruments	7,127	81	18,335
Prepayments and other current assets	98,503	99,229	76,848
Total current assets	1,161,546	1,204,530	1,194,973
Investments	118,407	113,763	117,920
Property, plant and equipment	9,299,713	9,150,269	9,693,171
Less accumulated depreciation, depletion and amortization	4,233,193	3,954,442	4,166,407
Net property, plant and equipment	5,066,520	5,195,827	5,526,764
Deferred charges and other assets:			
Goodwill	635,204	636,039	635,204
Other intangible assets, net	9,166	12,296	9,840
Other	326,542	246,394	325,277
Total deferred charges and other assets	970,912	894,729	970,321
Total assets	$7,317,385	$7,408,849	$7,809,978
LIABILITIES AND EQUITY			
Current liabilities:			
Short-term borrowings	$16,100	$—	$—
Long-term debt due within one year	409,292	12,227	269,449
Accounts payable	259,881	399,935	382,671
Taxes payable	48,436	61,847	45,631
Dividends payable	35,687	33,980	35,607
Accrued compensation	37,797	40,016	62,775
Commodity derivative instruments	—	12,186	—
Other accrued liabilities	179,672	185,287	172,561
Total current liabilities	986,865	745,478	968,694
Long-term debt	1,780,694	2,093,605	1,825,278
Deferred credits and other liabilities:			
Deferred income taxes	804,757	899,420	952,413
Other liabilities	810,626	720,542	813,809
Total deferred credits and other liabilities	1,615,383	1,619,962	1,766,222
Commitments and contingencies			
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 - 195,191,129 at March 31, 2015,	195,191	191,839	194,755

191,838,720 at March 31, 2014 and 194,754,812 at December 31, 2014			
Other paid-in capital	1,214,867	1,110,221	1,207,188
Retained earnings	1,421,220	1,625,692	1,762,827
Accumulated other comprehensive loss	(40,924)	(37,538)	(42,103)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)	(3,626)
Total common stockholders' equity	2,786,728	2,886,588	3,119,041
Total stockholders' equity	2,801,728	2,901,588	3,134,041
Noncontrolling interest	132,715	48,216	115,743
Total equity	2,934,443	2,949,804	3,249,784
Total liabilities and equity	$7,317,385	$7,408,849	$7,809,978

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

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

	Three Months Ended March 31, 2015	2014
	(In thousands)	
Operating activities:		
Net income (loss)	$(309,445)	$56,139
Loss from discontinued operations, net of tax	—	(45)
Income (loss) from continuing operations	(309,445)	56,184
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	95,507	99,557
Deferred income taxes	(160,633)	35,965
Unrealized loss on commodity derivatives	11,208	6,712
Write-down of oil and natural gas properties	500,400	—
Changes in current assets and liabilities, net of acquisitions:		
Receivables	101,371	25,611
Inventories	(44,408)	(19,809)
Other current assets	(20,349)	(22,324)
Accounts payable	(53,334)	(11,525)
Other current liabilities	(16,119)	(28,355)
Other noncurrent changes	(9,537)	(4,987)
Net cash provided by continuing operations	94,661	137,029
Net cash provided by discontinued operations	—	8
Net cash provided by operating activities	94,661	137,037
Investing activities:		
Capital expenditures	(189,463)	(179,646)
Acquisitions, net of cash acquired	—	(206,304)
Net proceeds from sale or disposition of property and other	26,801	5,179
Investments	2,449	458
Net cash used in continuing operations	(160,213)	(380,313)
Net cash provided by discontinued operations	—	—
Net cash used in investing activities	(160,213)	(380,313)
Financing activities:		
Issuance of short-term borrowings	16,100	—
Repayment of short-term borrowings	—	(11,500)
Issuance of long-term debt	149,332	309,501
Repayment of long-term debt	(54,162)	(58,232)
Proceeds from issuance of common stock	9,864	54,843
Dividends paid	(35,607)	(33,737)
Excess tax benefit on stock-based compensation	—	4,833
Contribution from noncontrolling interest	20,500	16,000
Net cash provided by continuing operations	106,027	281,708
Net cash provided by discontinued operations	—	—
Net cash provided by financing activities	106,027	281,708

Effect of exchange rate changes on cash and cash equivalents	(89)	43
Increase in cash and cash equivalents	40,386	38,475
Cash and cash equivalents -- beginning of year	81,855	45,225
Cash and cash equivalents -- end of period	$122,241	$83,700

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

MDU RESOURCES GROUP, INC.
NOTES TO CONSOLIDATED
FINANCIAL STATEMENTS

March 31, 2015 and 2014
(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 2014 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 2014 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 March 31, 2015, 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 consist 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 $29.3 million, $22.6 million and $30.9 million at March 31, 2015 and 2014, and December 31, 2014, respectively.

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 at March 31, 2015 and 2014, and December 31, 2014, was $9.4 million, $10.9 million and $9.5 million, respectively.

Note 4 - Inventories and natural gas in storage
Inventories, other than natural gas in storage for the Company's regulated operations, are 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 is included in inventories. Inventories consisted of:

	March 31, 2015	March 31, 2014	December 31, 2014
	(In thousands)		
Aggregates held for resale	$112,029	$104,106	$108,161
Asphalt oil	89,578	66,292	42,135
Materials and supplies	65,599	68,809	65,683
Merchandise for resale	15,688	22,463	24,420
Natural gas in storage (current)	9,303	6,129	19,302

Other	44,401	33,533	41,110
Total	$336,598	$301,332	$300,811

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, is included in other assets and was $49.3 million, $47.4 million and $49.3 million at March 31, 2015 and 2014, and December 31, 2014, 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, plus the effects of cash flow hedges, less applicable income taxes. Proved reserves and associated future cash flows are determined based on SEC Defined Prices and exclude cash outflows associated with asset retirement obligations that have been accrued on the balance sheet. 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 cost under the full-cost method of accounting exceeded the full-cost ceiling at March 31, 2015. SEC Defined Prices, adjusted for market differentials, are used to calculate the ceiling test. Accordingly, the Company was required to write down its oil and natural gas producing properties. The noncash write-down amounted to $500.4 million ($315.3 million after tax) for the three months ended March 31, 2015.

At March 31, 2014 and December 31, 2014, the Company's full-cost ceiling exceeded the Company's capitalized cost. Various factors, including lower SEC Defined Prices, market differentials, changes in estimates of proved reserve quantities, unsuccessful results of exploration and development efforts or changes in operating and development costs could result in future noncash write-downs of the Company's oil and natural gas properties.

SEC Defined Prices for each quarter for the last 12 months were as follows:

SEC Defined Prices for the 12 months ended	NYMEX Oil Price (per Bbl)	Henry Hub Gas Price (per MMBtu)	Ventura Gas Price (per MMBtu)
March 31, 2015	$82.72	$3.87	$3.96
December 31, 2014	94.99	4.34	7.71
September 30, 2014	99.08	4.24	7.60
June 30, 2014	100.27	4.10	7.47

For purposes of comparison, first-of-the-month prices were as follows:

	NYMEX Oil Price (per Bbl)	Henry Hub Gas Price (per MMBtu)	Ventura Gas Price (per MMBtu)
April 2015	$50.09	$2.63	$2.45
May 2015	59.15	2.57	2.51

Given the current oil and natural gas pricing environment, the Company believes it is likely it will have noncash write-downs of its oil and natural gas properties in future quarters until such time as commodity prices begin to recover.

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 period ended March 31, 2015, was computed by dividing the loss on common stock by the weighted average number of shares of common stock outstanding during the period. Due to the loss on common stock for the period ended March 31, 2015, the effect of outstanding performance share awards was excluded from the computation of diluted loss per common share as their effect was antidilutive. In 2014, there were no shares excluded from the calculation of diluted earnings per share. 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 calculations was as follows:

	Three Months Ended March 31, 2015	2014
	(In thousands)	
Weighted average common shares outstanding - basic	194,479	189,820
Effect of dilutive performance share awards	—	612
Weighted average common shares outstanding - diluted	194,479	190,432
Shares excluded from the calculation of diluted earnings per share	87	—

Note 7 - Cash flow information

Cash expenditures for interest and income taxes were as follows:

	Three Months Ended March 31, 2015	2014
	(In thousands)	
Interest, net of amounts capitalized and AFUDC - borrowed of $2.6 million and $2.4 million in 2015 and 2014, respectively	$23,874	$20,850
Income taxes paid (refunded), net	$(1,339)	$9,435

Noncash investing transactions were as follows:

	March 31, 2015	2014
	(In thousands)	
Property, plant and equipment additions in accounts payable	$54,134	$65,736

Note 8 - New Accounting Standards

Revenue from Contracts with Customers In May 2014, the FASB issued guidance on accounting for revenue from contracts with customers. The guidance provides for a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry specific guidance. This guidance will be effective for the Company on January 1, 2017. In April 2015, the FASB tentatively decided to defer the effective date one year and allow entities to early adopt. If these proposals are adopted, the guidance would be effective for the Company on January 1, 2018. Entities will have the option of using either a full retrospective or modified retrospective approach to adopting the guidance. Under the modified approach, an entity would recognize the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings in the period of adoption. In addition, the modified approach will require additional disclosures. The Company is evaluating the effects the adoption of the new revenue guidance will have on its results of operations, financial position, cash flows and disclosures, as well as its method of adoption.

Simplifying the Presentation of Debt Issuance Costs In April 2015, the FASB issued guidance on simplifying the presentation of debt issuance costs in the financial statements. This guidance requires entities to present debt issuance costs as a direct deduction to the related debt liability. The amortization of these costs will be reported as interest expense. The guidance will be effective for the Company on January 1, 2016, and is to be applied retrospectively. Early adoption of this guidance is permitted. The guidance will require a reclassification of the debt issuance costs on the Consolidated Balance Sheets, but will not impact the Company's results of operations or cash flows.

Note 9 - Comprehensive income (loss)

The after-tax changes in the components of accumulated other comprehensive loss were as follows:

Three Months Ended March 31, 2015	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
	(In thousands)				
Balance at beginning of period	$(3,071)	$(38,218)	$(829)	$15	$(42,103)
Other comprehensive loss before reclassifications	—	—	(112)	(21)	(133)
Amounts reclassified from accumulated other comprehensive loss	99	375	802	36	1,312
Net current-period other comprehensive income	99	375	690	15	1,179
Balance at end of period	$(2,972)	$(37,843)	$(139)	$30	$(40,924)

Three Months Ended March 31, 2014	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
	(In thousands)				
Balance at beginning of period	$(3,765)	$(33,807)	$(667)	$34	$(38,205)
Other comprehensive income (loss) before reclassifications	—	—	46	(36)	10
Amounts reclassified from accumulated other comprehensive loss	344	275	—	38	657
Net current-period other comprehensive income	344	275	46	2	667
Balance at end of period	$(3,421)	$(33,532)	$(621)	$36	$(37,538)

Reclassifications out of accumulated other comprehensive loss were as follows:

	Three Months Ended		Location on Consolidated Statements of Income
	March 31, 2015	March 31, 2014	
	(In thousands)		
Reclassification adjustment for loss on derivative instruments included in net income (loss):			
Commodity derivative instruments	$—	$(388)	Operating revenues
Interest rate derivative instruments	(159)	(160)	Interest expense
	(159)	(548)	
	60	204	Income taxes
	(99)	(344)	
Amortization of postretirement liability losses included in net periodic benefit cost	(605)	(443)	(a)
	230	168	Income taxes
	(375)	(275)	
Reclassification adjustment for loss on foreign currency translation adjustment included in net income (loss)	(1,292)	—	Other income
	490	—	Income taxes
	(802)	—	
Reclassification adjustment for loss on available-for-sale investments included in net income (loss)	(55)	(58)	Other income
	19	20	Income taxes
	(36)	(38)	
Total reclassifications	$(1,312)	$(657)	

(a) Included in net periodic benefit cost (credit). For more information, see Note 16.

Note 10 - Discontinued operations

In 2007, Centennial Resources sold CEM to Bicent. In connection with the sale, Centennial Resources 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 incurred legal expenses in the first quarter of 2014, which are reflected in discontinued operations in the consolidated financial statements and accompanying notes at March 31, 2014. Discontinued operations are included in the Other category.

Note 11 - Goodwill and other intangible assets

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

Three Months Ended March 31, 2015	Balance as of January 1, 2015*	Goodwill Acquired During the Year	Balance as of March 31, 2015*
	(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	103,441	—	103,441

Total	$635,204	$—	$635,204

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

Three Months Ended March 31, 2014	Balance as of January 1, 2014*	Goodwill Acquired During the Year	Balance as of March 31, 2014*
	(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	104,276	—	104,276
Total	$636,039	$—	$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.

Year Ended December 31, 2014	Balance as of January 1, 2014*	Goodwill Acquired During the Year/Other	Balance as of December 31, 2014*
	(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	104,276	(835)	103,441
Total	$636,039	$(835)	$635,204

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

Other amortizable intangible assets were as follows:

	March 31, 2015	March 31, 2014	December 31, 2014
	(In thousands)		
Customer relationships	$20,975	$21,310	$21,310
Accumulated amortization	(15,649)	(14,230)	(15,556)
	5,326	7,080	5,754
Noncompete agreements	4,409	5,580	5,080
Accumulated amortization	(3,504)	(4,335)	(4,098)
	905	1,245	982
Other	8,300	10,920	10,921
Accumulated amortization	(5,365)	(6,949)	(7,817)
	2,935	3,971	3,104
Total	$9,166	$12,296	$9,840

Amortization expense for amortizable intangible assets for the three months ended March 31, 2015 and 2014, was $700,000 and $800,000, respectively. Estimated amortization expense for amortizable intangible assets is $2.5 million in 2015, $2.2 million in 2016, $1.9 million in 2017, $1.0 million in 2018, $900,000 in 2019 and $1.4 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 March 31, 2015, the Company had no outstanding foreign currency or interest rate hedges.

The fair value of 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 a liability.

Fidelity

At March 31, 2015 and 2014, and December 31, 2014, Fidelity held oil swap and collar agreements with total forward notional volumes of 958,000, 2.7 million and 270,000 Bbl, respectively, and natural gas swap agreements with total forward notional volumes of 2.8 million, 14.7 million and 5.0 million MMBtu, respectively. Fidelity utilizes these derivative instruments to manage a portion of the market risk associated with fluctuations in the price of oil and natural gas on its forecasted sales of oil and natural gas production.

Effective April 1, 2013, Fidelity elected to de-designate all commodity derivative contracts previously designated as cash flow hedges and elected to discontinue hedge accounting prospectively for all of its commodity derivative instruments. When the criteria for hedge accounting is not met or when hedge accounting is not elected, realized gains and losses and unrealized gains and losses are both recorded in operating revenues on the Consolidated Statements of Income. As a result of discontinuing hedge accounting on commodity derivative instruments, gains and losses on the oil and natural gas derivative instruments remain in accumulated other comprehensive income (loss) as of the de-designation date and are reclassified into earnings in future periods as the underlying hedged transactions affect earnings. At April 1, 2013, accumulated other comprehensive income (loss) included $1.8 million of unrealized gains, representing the mark-to-market value of the Company's commodity derivative instruments that qualified as cash flow hedges as of the balance sheet date, which the Company has subsequently reclassified into earnings.

Prior to April 1, 2013, changes in the fair value attributable to the effective portion of the hedging instruments, net of tax, were recorded in stockholders' equity as a component of accumulated other comprehensive income (loss). To the extent that the hedges were not effective or did not qualify for hedge accounting, the ineffective portion of the changes in fair market value was recorded directly in earnings. Gains and losses on the oil and natural gas derivative instruments were 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 were settled.

Certain of Fidelity's derivative instruments contain cross-default provisions that state if Fidelity or any of its affiliates fails to make payment with respect to certain indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of the derivative instruments in liability positions. Fidelity had no derivative instruments that were in a liability position with credit-risk-related contingent features at March 31, 2015 and December 31, 2014. The aggregate fair value of Fidelity's derivative instruments with credit-risk related contingent features that were in a liability position at March 31, 2014, were $12.2 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 March 31, 2014, were $12.2 million.

Centennial

Centennial has historically entered into interest rate derivative instruments to manage a portion of its interest rate exposure on the forecasted issuance of long-term debt. As of March 31, 2015 and 2014, and December 31, 2014, Centennial had no outstanding interest rate swap agreements.

Fidelity and Centennial

The gains and losses on derivative instruments were as follows:

	Three Months Ended March 31,	
	2015	2014
	(In thousands)	
Commodity derivatives designated as cash flow hedges:		
Amount of loss reclassified from accumulated other comprehensive loss into operating revenues (effective portion), net of tax	$—	$ 244

Interest rate derivatives designated as cash flow hedges:		
Amount of loss reclassified from accumulated other comprehensive loss into interest expense (effective portion), net of tax	99	100
Commodity derivatives not designated as hedging instruments:		
Amount of loss recognized in operating revenues, before tax	(11,208)	(6,712)

Over the next 12 months net losses of approximately $400,000 (after tax) are estimated to be reclassified from accumulated other comprehensive income (loss) into earnings, as the hedged transactions affect earnings.

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

Asset Derivatives	Location on Consolidated Balance Sheets	Fair Value at March 31, 2015	Fair Value at March 31, 2014	Fair Value at December 31, 2014
		(In thousands)		
Not designated as hedges:				
Commodity derivatives	Commodity derivative instruments	$7,127	$81	$18,335
	Other assets - noncurrent	—	249	—
Total asset derivatives		$7,127	$330	$18,335

Liability Derivatives	Location on Consolidated Balance Sheets	Fair Value at March 31, 2015	Fair Value at March 31, 2014	Fair Value at December 31, 2014
		(In thousands)		
Not designated as hedges:				
Commodity derivatives	Commodity derivative instruments	$—	$12,186	$—
Total liability derivatives		$—	$12,186	$—

All of the Company's commodity derivative instruments at March 31, 2015 and 2014, and December 31, 2014, were subject to legally enforceable master netting agreements. However, the Company's policy is to not offset fair value amounts for derivative instruments and, as a result, the Company's derivative assets and liabilities are presented gross on the Consolidated Balance Sheets. The gross derivative assets and liabilities (excluding settlement receivables and payables that may be subject to the same master netting agreements) presented on the Consolidated Balance Sheets and the amount eligible for offset under the master netting agreements is presented in the following table:

March 31, 2015	Gross Amounts Recognized on the Consolidated Balance Sheets	Gross Amounts Not Offset on the Consolidated Balance Sheets	Net
	(In thousands)		
Assets:			
Commodity derivatives	$7,127	$—	$7,127
Total assets	$7,127	$—	$7,127

March 31, 2014	Gross Amounts Recognized on the Consolidated Balance Sheets	Gross Amounts Not Offset on the Consolidated Balance Sheets	Net
	(In thousands)		
Assets:			
Commodity derivatives	$330	$(330)	$—
Total assets	$330	$(330)	$—
Liabilities:			
Commodity derivatives	$12,186	$(330)	$11,856
Total liabilities	$12,186	$(330)	$11,856

December 31, 2014	Gross Amounts Recognized on the Consolidated Balance	Gross Amounts Not Offset on the Consolidated Balance	Net

	Sheets (In thousands)	Sheets	
Assets:			
Commodity derivatives	$ 18,335	$ —	$ 18,335
Total assets	$ 18,335	$ —	$ 18,335

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, which consist of an insurance contract, 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 $67.8 million, $63.3 million and $65.8 million, at March 31, 2015 and 2014, and December 31, 2014, respectively, are classified as Investments on the Consolidated Balance Sheets. The net unrealized gains on these investments were $2.0 million and $900,000 for the three months ended March 31, 2015 and 2014, 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 available-for-sale securities, which include 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. Unrealized gains or losses are recorded in accumulated other comprehensive income (loss). Details of available-for-sale securities were as follows:

March 31, 2015	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Mortgage-backed securities	$7,792	$58	$(18)	$7,832
U.S. Treasury securities	2,337	9	(4)	2,342
Total	$10,129	$67	$(22)	$10,174

March 31, 2014	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Mortgage-backed securities	$7,943	$63	$(17)	$7,989
U.S. Treasury securities	2,069	9	—	2,078
Total	$10,012	$72	$(17)	$10,067

December 31, 2014	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Mortgage-backed securities	$6,594	$60	$(18)	$6,636
U.S. Treasury securities	3,574	—	(19)	3,555
Total	$10,168	$60	$(37)	$10,191

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 estimated fair values of the Company's assets and liabilities measured on a recurring basis are determined using the market approach.

The Company's 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 mortgage-backed securities and U.S. Treasury securities are based on comparable market transactions, other observable inputs or other sources, including pricing from outside sources.

The estimated fair value of the Company's Level 2 insurance contract is based on contractual cash surrender values that are determined primarily by investments in managed separate accounts of the insurer. These amounts approximate fair value. The managed separate accounts are valued based on other observable inputs or corroborated market data.

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 also 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 months ended March 31, 2015 and 2014, there were no transfers between Levels 1 and 2.

The Company's assets and liabilities measured at fair value on a recurring basis were as follows:

	Fair Value Measurements at March 31, 2015, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at March 31, 2015
	(In thousands)			
Assets:				
Money market funds	$—	$16,945	$—	$16,945
Insurance contract*	—	67,797	—	67,797
Available-for-sale securities:				
Mortgage-backed securities	—	7,832	—	7,832
U.S. Treasury securities	—	2,342	—	2,342
Commodity derivative instruments	—	7,127	—	7,127
Total assets measured at fair value	$—	$102,043	$—	$102,043

* The insurance contract invests approximately 20 percent in common stock of mid-cap companies, 18 percent in common stock of small-cap companies, 28 percent in common stock of large-cap companies, 32 percent in fixed-income investments, 1 percent in target date investments and 1 percent in cash equivalents.

	Fair Value Measurements at March 31, 2014, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at March 31, 2014
	(In thousands)			
Assets:				
Money market funds	$—	$20,267	$—	$20,267
Insurance contract*	—	63,269	—	63,269
Available-for-sale securities:				
Mortgage-backed securities	—	7,989	—	7,989
U.S. Treasury securities	—	2,078	—	2,078
Commodity derivative instruments	—	330	—	330
Total assets measured at fair value	$—	$93,933	$—	$93,933
Liabilities:				
Commodity derivative instruments	$—	$12,186	$—	$12,186
Total liabilities measured at fair value	$—	$12,186	$—	$12,186

* The insurance contract invests approximately 29 percent in common stock of mid-cap companies, 27 percent in common stock of small-cap companies, 28 percent in common stock of large-cap companies and 16 percent in fixed-income investments.

	Fair Value Measurements at December 31, 2014, 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, 2014
	(In thousands)			
Assets:				
Money market funds	$—	$18,473	$—	$18,473
Insurance contract*	—	65,831	—	65,831
Available-for-sale securities:				
Mortgage-backed securities	—	6,636	—	6,636
U.S. Treasury securities	—	3,555	—	3,555
Commodity derivative instruments	—	18,335	—	18,335
Total assets measured at fair value	$—	$112,830	$—	$112,830

* The insurance contract invests approximately 20 percent in common stock of mid-cap companies, 18 percent in common stock of small-cap companies, 29 percent in common stock of large-cap companies, 32 percent in fixed-income investments and 1 percent in cash equivalents.

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 only. 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 March 31, 2015	$2,189,986	$2,340,681
Long-term debt at March 31, 2014	$2,105,832	$2,186,839
Long-term debt at December 31, 2014	$2,094,727	$2,239,445

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

Note 14 - Equity

A summary of the changes in equity was as follows:

Three Months Ended March 31, 2015	Total Stockholders' Equity	Noncontrolling Interest	Total Equity
	(In thousands)		
Balance at December 31, 2014	$3,134,041	$115,743	$3,249,784
Net loss	(305,917)	(3,528)	(309,445)
Other comprehensive income	1,179	—	1,179
Dividends declared on preferred stocks	(171)	—	(171)
Dividends declared on common stock	(35,515)	—	(35,515)
Stock-based compensation	(121)	—	(121)
Net tax deficit on stock-based compensation	(1,632)	—	(1,632)
Issuance of common stock	9,864	—	9,864
Contribution from noncontrolling interest	—	20,500	20,500
Balance at March 31, 2015	$2,801,728	$132,715	$2,934,443

Three Months Ended March 31, 2014	Total Stockholders' Equity	Noncontrolling Interest	Total Equity
	(In thousands)		
Balance at December 31, 2013	$2,823,164	$32,738	$2,855,902
Net income (loss)	56,662	(523)	56,139
Other comprehensive income	667	—	667
Dividends declared on preferred stocks	(171)	—	(171)
Dividends declared on common stock	(33,809)	—	(33,809)
Stock-based compensation	1,336	—	1,336
Issuance of common stock upon vesting of performance shares, net of shares used for tax withholdings	(5,564)	—	(5,564)
Excess tax benefit on stock-based compensation	4,729	—	4,729
Issuance of common stock	54,574	—	54,574
Contribution from noncontrolling interest	—	16,001	16,001
Balance at March 31, 2014	$2,901,588	$48,216	$2,949,804

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 internal reporting of these operating segments is defined based on the reporting and review process used by the Company's chief executive officer. The vast majority of the Company's operations are located within the United States.

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 and processing facilities primarily in the Rocky Mountain and northern Great Plains regions of the United States. This segment recently commenced operations of Dakota Prairie Refinery in conjunction with Calumet to refine crude oil. The facility has begun producing diesel fuel and is expected to begin sales of diesel during May 2015. This segment also provides cathodic protection and other energy-related services.

The exploration and production segment is engaged in oil and natural gas development and production activities in the Rocky Mountain and Mid-Continent/Gulf States regions of the United States. The Company intends to market its exploration and production business in the future. The plan to market this business has been delayed due to low oil prices.

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 provides utility construction services specializing in constructing and maintaining electric and communications lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization. This segment also provides utility excavation and inside electrical and mechanical services, and manufactures and distributes transmission line construction equipment and supplies.

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, automobile liability and pollution liability coverages. Centennial Capital also owns certain real and personal property. The Other category also included Centennial Resources' investment in the Brazilian Transmission Lines.

The information below follows the same accounting policies as described in Note 1 of the Company's Notes to Consolidated Financial Statements in the 2014 Annual Report. Information on the Company's businesses was as follows:

Three Months Ended March 31, 2015	External Operating Revenues	Inter-segment Operating Revenues	Earnings (Loss) on Common Stock
	(In thousands)		
Electric	$71,776	$—	$8,328
Natural gas distribution	330,573	—	21,450
Pipeline and energy services	25,095	21,341	4,018
	427,444	21,341	33,796
Exploration and production	49,710	5,226	(328,904)
Construction materials and contracting	205,658	948	(14,635)
Construction services	235,403	11,695	4,760
Other	295	1,772	(255)
	491,066	19,641	(339,034)
Intersegment eliminations	—	(40,982)	(850)
Total	$918,510	$—	$(306,088)

Three Months Ended March 31, 2014	External Operating Revenues	Inter-segment Operating Revenues	Earnings (Loss) on Common Stock
	(In thousands)		
Electric	$73,647	$—	$11,033
Natural gas distribution	374,233	—	27,263
Pipeline and energy services	43,661	18,276	4,349
	491,541	18,276	42,645
Exploration and production	116,669	20,867	20,939
Construction materials and contracting	164,423	4,017	(23,574)
Construction services	269,892	3,738	16,568
Other	328	1,724	264
	551,312	30,346	14,197
Intersegment eliminations	—	(48,622)	(351)
Total	$1,042,853	$—	$56,491

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 - Employee benefit plans

Pension and other postretirement 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 March 31,	2015	2014	2015	2014
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	$40	$33	$483	$379
Interest cost	4,364	4,440	914	858
Expected return on assets	(5,373)	(5,125)	(1,175)	(1,067)
Amortization of prior service cost (credit)	18	18	(342)	(348)
Amortization of net actuarial loss	1,735	1,313	461	318
Net periodic benefit cost, including amount capitalized	784	679	341	140
Less amount capitalized	76	95	29	29
Net periodic benefit cost	$708	$584	$312	$111

Nonqualified benefit plans

In addition to the qualified plan defined pension benefits reflected in the table, the Company has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide 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 months ended March 31, 2015 and 2014, was $1.7 million and $1.7 million, respectively.

Multiemployer plans

On September 24, 2014, Knife River provided notice to the Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming that it was withdrawing from the plan effective October 26, 2014. The plan administrator will determine Knife River's withdrawal liability. For the three months ended March 31, 2015, the Company accrued an additional withdrawal liability of approximately $2.4 million (approximately $1.5 million after tax). The total withdrawal liability is currently estimated at $16.4 million (approximately $9.8 million after tax). The assessed withdrawal liability for this plan may be significantly different from the current estimate.

Note 17 - Regulatory matters and revenues subject to refund

On August 11, 2014, Montana-Dakota filed an application with the MTPSC for a natural gas rate increase. Montana-Dakota requested a total increase of approximately $3.0 million annually or approximately 3.6 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, depreciation and taxes associated with the increased investment as well as an increase in Montana-Dakota's operation and maintenance expenses. On February 3, 2015, the MTPSC approved an interim increase of $2.0 million or approximately 2.3 percent, subject to refund, to be effective with service rendered on and after February 6, 2015. On March 18, 2015, Montana-Dakota and the Montana Consumer Counsel filed a settlement agreement that resolved all issues of the application and reflected a natural gas rate increase of $2.5 million annually or approximately 3.0 percent. An amended stipulation reflecting minor changes in rate design was submitted on March 24, 2015. On April 28, 2015, the MTPSC approved the settlement rates, which are expected to be effective with service rendered on and after May 11, 2015.

On October 3, 2014, Montana-Dakota filed an application with the WYPSC for a natural gas rate increase. Montana-Dakota requested a total increase of approximately $788,000 annually or approximately 4.1 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 and the associated operation and maintenance expenses, depreciation and taxes associated with the increase in investment. On April 16, 2015, Montana-Dakota and the Wyoming Office of Consumer Advocate filed a stipulation and agreement that resolved all issues between the parties and reflected a natural gas rate increase of $501,000 annually or approximately 2.6 percent. The WYPSC has scheduled a hearing for this matter on May 19, 2015.

On November 14, 2014, Montana-Dakota filed an application with the NDPSC for approval to implement the rate adjustment associated with the electric generation resource recovery rider approved by the NDPSC on August 20, 2014. On January 7, 2015, the NDPSC approved the rate adjustments of $5.3 million annually to be effective with service rendered on and after January 9, 2015.

On December 22, 2014, Montana-Dakota filed an application for advance determination of prudence and a certificate of public convenience and necessity with the NDPSC for the Thunder Spirit Wind project. This project will provide energy, capacity and renewable energy credits to Montana-Dakota's electric customers in North Dakota, Montana and South Dakota. The NDPSC has scheduled a hearing for this matter on May 14, 2015.

On February 6, 2015, Montana-Dakota filed an application with the NDPSC for a natural gas rate increase. Montana-Dakota requested a total increase of approximately $4.3 million annually or approximately 3.4 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, depreciation and taxes associated with the increased investment as well as an increase in Montana-Dakota's operation and maintenance expenses. Montana-Dakota requested an interim increase of $4.3 million or 3.4 percent, subject to refund, which was approved by the NDPSC on March 11, 2015, effective with service rendered on or after April 7, 2015. A technical hearing has been scheduled for July 20-21, 2015. This matter is pending before the NDPSC.

On March 31, 2015, Cascade filed an application with the OPUC for a natural gas rate increase. Cascade requested a total increase of approximately $3.6 million annually or approximately 5.1 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 and the associated operation and maintenance expenses, depreciation and taxes associated with the increase in investment, as well as environmental remediation expenses.

On April 10, 2015, Montana-Dakota submitted a request to the NDPSC to update the environmental cost recovery rider to reflect actual costs incurred through February 2015 and projected costs through June 2016 related to the recovery of Montana-Dakota's share of the costs resulting from the environmental retrofit required to be installed at the Big Stone Station. The request also includes costs associated with the environmental upgrade required at the Lewis & Clark Station to comply with the EPA's MATS rule. The filing also requests a revision to the environmental cost recovery rider that will allow future recovery of ongoing reagent costs required to meet environmental standards as a monthly adjustment. A total of $8.1 million is requested to be recovered under the adjustment. If approved, the rates would be effective July 1, 2015, through June 30, 2016.

Note 18 - 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, in some circumstances, an estimate of the possible loss. The Company had accrued liabilities of $25.8 million, $31.4 million and $27.6 million for contingencies, including litigation, production taxes, royalty claims and environmental matters at March 31, 2015 and 2014, and December 31, 2014, respectively, which include amounts that may have been accrued for matters discussed in Litigation and Environmental matters within this note.

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. In October 2010, the arbitration panel issued an award in favor of SourceGas for approximately $26.6 million. 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. On remand of the matter to the Colorado State District Court, SourceGas may 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. The parties subsequently settled the breach of contract claim and, subject to final determination on liability, stipulated to the damages on the common carrier claim, for amounts that are not material. A trial on the common carrier claim was held during July 2013. On December 9, 2014, the United States District Court for the District of Montana issued an order determining WBI Energy Midstream breached its obligations as a common carrier and ordered judgment in favor of Omimex for the amount of the stipulated damages. WBI Energy Midstream filed an appeal from the United States District Court for the District of Montana's order and judgment.

Exploration and Production During the ordinary course of its business, Fidelity is subject to audit for various production related taxes by certain state and federal tax authorities for varying periods as well as claims for royalty obligations under lease agreements for oil and gas production. Disputes may exist regarding facts and questions of law relating to the tax and royalty obligations.

On May 15, 2013, Austin Holdings, LLC filed an action against Fidelity in Wyoming State District Court alleging Fidelity violated the Wyoming Royalty Payment Act and implied lease covenants by deducting production costs from and by failing to properly report and pay royalties for coalbed methane gas production in Wyoming. The plaintiff, in addition to declaratory and injunctive relief, seeks class certification for similarly situated persons and an unspecified amount of monetary damages on behalf of the class for unpaid royalties, interest, reporting violations and attorney fees. The Company reached a settlement of the matter, subject to final court approval, for an amount that is not material.

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.

Former Employee Litigation On August 6, 2012, a former employee and his spouse filed actions against Connolly-Pacific and others in California Superior Court alleging the former employee contracted acute myelogenous leukemia from exposure to substances while employed as a seaman by the defendants. The plaintiffs request compensatory damages of approximately $23.8 million plus punitive damages, costs and interest. Connolly-Pacific is contesting the claims and believes it has meritorious defenses to them. Connolly-Pacific will seek insurance coverage for defense costs and any liability incurred in the litigation.

Construction Services Bombard Mechanical is a third-party defendant in litigation pending in Nevada State District Court in which the plaintiff claims damages attributable to defects in the construction of a 48 story residential tower built in 2008 for which Bombard Mechanical performed plumbing and mechanical work as a subcontractor. On

March 12, 2015, the plaintiff submitted cost of repair estimates totaling approximately $26 million for alleged defects related to plumbing and mechanical system defects. Bombard Mechanical is being defended in the action under a policy of insurance subject to a reservation of rights.

The Company also is subject to other litigation, and actual and potential claims in the ordinary course of its business which may include, but are not limited to, matters involving property damage, personal injury, and environmental, contractual, statutory and regulatory obligations. Accruals are based on the best information available but actual losses in future periods are affected by various factors making them uncertain. After taking into account liabilities accrued for the foregoing matters, management believes that the outcomes with respect to the above issues and other probable and reasonably possible losses in excess of the amounts accrued, while uncertain, 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 released a ROD in January 2015 that selected a remediation alternative for the site as recommended in an earlier staff report. 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 $1.7 million for remediation of this site. In January 2013, the OPUC approved Cascade's application to defer environmental remediation costs at the Eugene site for a period of 12 months starting November 30, 2012. Cascade received orders reauthorizing the deferred accounting for the 12-month periods starting November 30, 2013 and December 1, 2014.

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 of Superfund sites. Cascade has entered into an administrative settlement agreement and consent order with the EPA regarding the scope and schedule for a remedial investigation and feasibility study for the site. Cascade has accrued $12.4 million for the remedial investigation, feasibility study and 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 and entered into agreement with 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. The accruals related to these matters are reflected in regulatory assets.

Guarantees

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.

WBI Holdings has guaranteed certain of Fidelity's oil and natural gas swap agreement obligations. There is no fixed maximum amount guaranteed in relation to the oil and natural gas swap agreements as the amount of the obligation is dependent upon oil and natural gas commodity prices. The amount of derivative activity entered into by the subsidiary is limited by corporate policy. The guarantees of the oil and natural gas swap agreements at March 31, 2015, expire in 2015; however, Fidelity may continue to enter into additional derivative instruments and, as a result, WBI Holdings from time to time may issue additional guarantees on these derivative instruments. There were no amounts outstanding by Fidelity at March 31, 2015. 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 March 31, 2015, the fixed maximum amounts guaranteed under these agreements aggregated $76.8 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $42.6 million in 2015; $14.5 million in 2016; $1.2 million in 2017; $500,000 in 2018; $500,000 in 2019; $13.5 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 $200,000 and was reflected on the Consolidated Balance Sheet at March 31, 2015. 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 and other agreements, some of which are guaranteed by other subsidiaries of the Company. At March 31, 2015, the fixed maximum amounts guaranteed under these letters of credit, aggregated $42.5 million. In 2015 and 2016, $14.3 million and $28.2 million, respectively, of letters of credit are scheduled to expire. The amount outstanding by subsidiaries of the Company under the above letters of credit was $300,000 and was reflected on the Consolidated Balance Sheet at

March 31, 2015. In the event of default under these letter of credit obligations, the subsidiary issuing the letter of credit for that particular obligation would be required to make payments under its letter of credit.

Centennial and WBI Holdings have guaranteed certain debt obligations of Dakota Prairie Refining. For more information, see Variable interest entities in this note.

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 March 31, 2015, the fixed maximum amount guaranteed under this agreement was $4.0 million and is scheduled to expire in 2016. 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 March 31, 2015, 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 March 31, 2015.

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. At March 31, 2015, approximately $536.7 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Variable interest entities
The Company evaluates its arrangements and contracts with other entities to determine if they are VIEs and if so, if the Company is the primary beneficiary.

Dakota Prairie Refining, LLC On February 7, 2013, WBI Energy and Calumet formed a limited liability company, Dakota Prairie Refining, and entered into an operating agreement to develop, build and operate Dakota Prairie Refinery in southwestern North Dakota. WBI Energy and Calumet each have a 50 percent ownership interest in Dakota Prairie Refining. WBI Energy's and Calumet's capital commitments, based on a total project cost of $300 million, under the agreement are $150 million and $75 million, respectively. Capital commitments in excess of $300 million are being shared equally between WBI Energy and Calumet. The total project cost is currently estimated at approximately $425 million to $435 million. Dakota Prairie Refining entered into a term loan for project debt financing of $75 million on April 22, 2013. The operating agreement provides for allocation of profits and losses consistent with ownership interests; however, deductions attributable to project financing debt will be allocated to Calumet. Calumet's future cash distributions from Dakota Prairie Refining will be decreased by the principal and interest to be paid on the project debt, while the cash distributions to WBI Energy will not be decreased. Pursuant to the operating agreement, Centennial agreed to guarantee Dakota Prairie Refining's obligation under the term loan.

On December 1, 2014, Dakota Prairie Refining entered into a $50 million revolving credit agreement with an expiration date of December 1, 2015. Pursuant to the revolving credit agreement, WBI Holdings has guaranteed 50 percent of the credit agreement and Calumet has issued a letter of credit supporting 50 percent of the credit agreement. The credit agreement is used to meet the operational needs of the facility.

Dakota Prairie Refining has been determined to be a VIE, and the Company has determined that it is the primary beneficiary as it has an obligation to absorb losses that could be potentially significant to the VIE through WBI Energy's equity investment and Centennial's guarantee of the third-party term loan. Accordingly, the Company consolidates Dakota Prairie Refining in its financial statements and records a noncontrolling interest for Calumet's ownership interest.

Dakota Prairie Refinery has commenced operations. The facility has begun producing diesel fuel and is expected to begin sales of diesel during May 2015. The assets of Dakota Prairie Refining shall be used solely for the benefit of Dakota Prairie Refining. The total assets and liabilities of Dakota Prairie Refining reflected on the Company's Consolidated Balance Sheets were as follows:

28

	March 31, 2015	March 31, 2014	December 31, 2014
	(In thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$10,784	$22,996	$21,376
Accounts receivable	2,335	—	2,759
Inventories	7,902	—	5,311
Other current assets	2,926	1,135	4,019
Total current assets	23,947	24,131	33,465
Net property, plant and equipment	425,944	207,260	398,984
Deferred charges and other assets:			
Other	4,562	—	3,400
Total deferred charges and other assets	4,562	—	3,400
Total assets	$454,453	$231,391	$435,849
LIABILITIES			
Current liabilities:			
Short-term borrowings	$16,100	$—	$—
Long-term debt due within one year	3,000	3,000	3,000
Accounts payable	23,654	16,103	55,089
Taxes payable	569	113	648
Accrued compensation	683	164	727
Other accrued liabilities	1,016	580	899
Total current liabilities	45,022	19,960	60,363
Long-term debt	69,000	72,000	69,000
Total liabilities	$114,022	$91,960	$129,363

Fuel Contract On October 10, 2012, the Coyote Station entered into a new coal supply agreement with Coyote Creek that will replace a coal supply agreement expiring in May 2016. 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.

The new coal supply agreement creates a variable interest in Coyote Creek due to the transfer of all operating and economic risk to the Coyote Station owners, as the agreement is structured so the price of the coal will cover all costs of operations as well as future reclamation costs. The Coyote Station owners are also providing a guarantee of the value of the assets of Coyote Creek as they would be required to buy the assets at book value should they terminate the contract prior to the end of the contract term and are providing a guarantee of the value of the equity of Coyote Creek in that they are required to buy the entity at the end of the contract term at equity value. Although the Company has determined that Coyote Creek is a VIE, the Company has concluded that it is not the primary beneficiary of Coyote Creek because the authority to direct the activities of the entity is shared by the four unrelated owners of the Coyote Station, with no primary beneficiary existing. As a result, Coyote Creek is not required to be consolidated in the Company's financial statements.

At March 31, 2015, Coyote Creek was not yet operational. The assets and liabilities of Coyote Creek and exposure to loss as a result of the Company's involvement with the VIE, based on the Company's ownership percentage, at March 31, 2015, was $20.8 million.

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
- Divestiture of certain assets to fund capital growth projects throughout the Company

The Company has capabilities to fund its growth and operations through various sources, including internally generated funds, commercial paper facilities, revolving credit facilities, the issuance from time to time of debt and equity securities and asset sales. 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 safe and reliable competitively priced energy and related services to customers. The electric and natural gas distribution segments continually seek opportunities to retain, grow and expand their customer base through extensions of existing operations, including building and upgrading electric generation and transmission and natural gas systems, 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 timely recovery and permitted returns on investment as well as subject to certain operational, system integrity and environmental regulations. These regulations can require substantial investment to upgrade facilities. 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, investments in 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/refining activities; and expansion of related energy services.

Challenges Challenges for this segment include: energy price volatility; tight 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 The Company intends to market and sell its exploration and production business. However, the Company has delayed its plan in light of the recent volatility in oil prices. Until such sale is accomplished, this segment will apply technology and utilize existing expertise to increase production and reserves from existing leaseholds. By optimizing existing operations, this segment is focused on balancing its oil and natural gas commodity mix to maximize profitability.

Challenges Risks and uncertainties associated with the marketing and sale of the Fidelity assets; current oil and natural gas low-price environment; timely receipt of necessary permits and approvals; environmental and regulatory requirements; recruitment and retention of a skilled workforce; utilizing appropriate technologies; inflationary pressure on development and operating costs; irregularities in geological formations; 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; develop and recruit talented employees; and continue growth through organic and acquisition opportunities. 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 Recruitment and retention of key personnel and 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 superior return on investment by: building new and strengthening existing customer relationships; effectively controlling costs; retaining, developing and recruiting talented employees; continue growth through organic and acquisition opportunities; and 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 2014 Annual Report. For more information on 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 (loss) by each of the Company's businesses.

	Three Months Ended March 31,	
	2015	2014
	(Dollars in millions, where applicable)	
Electric	$8.3	$11.0
Natural gas distribution	21.5	27.3
Pipeline and energy services	4.0	4.3
Exploration and production	(328.9)	20.9

Construction materials and contracting	(14.6)	(23.6)
Construction services	4.8	16.6
Other	(.3)	.3
Intersegment eliminations	(.9)	(.3)
Earnings (loss) on common stock	$(306.1)	$56.5
Earnings (loss) per common share – basic	$(1.57)	$.30
Earnings (loss) per common share – diluted	$(1.57)	$.30

31

Three Months Ended March 31, 2015 and 2014 Consolidated earnings for the quarter ended March 31, 2015, decreased $362.6 million from the comparable prior period largely due to:

- A noncash write-down of oil and natural gas properties of $315.3 million (after tax); lower average realized commodity prices, excluding gain/loss on commodity derivatives; and decreased oil production; partially offset by a favorable adjustment related to realized gain/loss on commodity derivatives at the exploration and production business
- Lower workloads and margins in the Western region at the construction services business
- Lower earnings related to decreased retail sales volumes at the natural gas distribution business

Partially offsetting these decreases were lower seasonal losses resulting from higher construction revenues and margins, as well as higher aggregate and ready-mixed concrete margins and volumes at the construction materials and contracting business.

FINANCIAL AND OPERATING DATA

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

Electric

	Three Months Ended March 31,	
	2015	2014
	(Dollars in millions, where applicable)	
Operating revenues	$71.8	$73.7
Operating expenses:		
Fuel and purchased power	23.8	26.6
Operation and maintenance	21.1	18.4
Depreciation, depletion and amortization	9.4	8.5
Taxes, other than income	3.1	2.9
	57.4	56.4
Operating income	14.4	17.3
Earnings	$8.3	$11.0
Retail sales (million kWh)	907.7	928.9
Average cost of fuel and purchased power per kWh	$.025	$.027

Three Months Ended March 31, 2015 and 2014 Electric earnings decreased $2.7 million (25 percent) due to:

- Higher operation and maintenance expense, which includes $1.7 million (after tax) largely due to higher contract services, primarily related to a planned outage at an electric generation station
- Higher net interest expense, which includes $900,000 (after tax) largely related to higher long-term debt
- Higher depreciation, depletion and amortization expense of $500,000 (after tax) due to increased property, plant and equipment balances

Partially offsetting these decreases were increased retail sales margins, primarily due to rate recovery of generation and environmental upgrades, reduced in part by decreased sales volumes of 2 percent, primarily to residential customers.

Natural Gas Distribution

	Three Months Ended March 31,	
	2015	2014
	(Dollars in millions, where applicable)	
Operating revenues	$330.6	$374.2
Operating expenses:		
Purchased natural gas sold	222.2	257.3
Operation and maintenance	38.4	37.9
Depreciation, depletion and amortization	14.6	13.3
Taxes, other than income	16.6	17.8
	291.8	326.3
Operating income	38.8	47.9
Earnings	$21.5	$27.3
Volumes (MMdk):		
Sales	38.9	45.3
Transportation	35.1	39.3
Total throughput	74.0	84.6
Degree days (% of normal)*		
Montana-Dakota/Great Plains	87%	107%
Cascade	78%	100%
Intermountain	84%	96%
Average cost of natural gas, including transportation, per dk	$5.71	$5.68

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

Three Months Ended March 31, 2015 and 2014 Natural gas distribution earnings decreased $5.8 million (21 percent) due to:

- Lower earnings of $5.7 million (after tax) related to decreased retail sales volumes of 14 percent, largely resulting from significantly warmer weather than last year, partially offset by weather normalization adjustments in certain jurisdictions
- Higher depreciation, depletion and amortization expense of $800,000 (after tax), primarily resulting from increased property, plant and equipment balances

Partially offsetting these decreases was lower regulated operation and maintenance expense, primarily related to lower benefit-related costs.

The previous table also reflects higher revenue and higher operation and maintenance expense related to nonutility project activity.

Pipeline and Energy Services

	Three Months Ended March 31, 2015	2014
	(Dollars in millions)	
Operating revenues	$46.4	$61.9
Operating expenses:		
Purchased natural gas sold	6.5	26.2
Cost of crude oil	2.3	—
Operation and maintenance	20.2	16.8
Depreciation, depletion and amortization	8.7	7.1
Taxes, other than income	3.5	3.1
	41.2	53.2
Operating income	5.2	8.7
Earnings	$4.0	$4.3
Transportation volumes (MMdk)	68.0	52.5
Natural gas gathering volumes (MMdk)	9.4	9.5
Customer natural gas storage balance (MMdk):		
Beginning of period	14.9	26.7
Net withdrawal	(7.7)	(16.3)
End of period	7.2	10.4

Three Months Ended March 31, 2015 and 2014 Pipeline and energy services earnings decreased $300,000 (8 percent) due to:

- Higher operation and maintenance expense, which includes $1.3 million (after tax) primarily due to start-up costs related to the Company's portion of Dakota Prairie Refinery
- Lower storage services earnings, largely due to lower withdrawal volumes, average storage balances and rates
- Higher depreciation, depletion and amortization expense, which includes $600,000 (after tax) primarily related to the Company's portion of certain in-service components at Dakota Prairie Refinery

Partially offsetting the earnings decrease was higher earnings of $2.7 million (after tax) due to higher transportation rates, primarily resulting from a rate case settlement under which higher rates went into effect May 1, 2014, and higher transportation volumes, largely off-system volumes.

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

Exploration and Production

	Three Months Ended March 31, 2015	2014
	(Dollars in millions, where applicable)	
Operating revenues:		
Oil	$37.5	$113.6
NGL	2.2	6.9
Natural gas	10.0	30.5
Realized gain (loss) on commodity derivatives	16.4	(6.8)
Unrealized loss on commodity derivatives	(11.2)	(6.7)
	54.9	137.5
Operating expenses:		
Operation and maintenance:		
Lease operating costs	16.9	24.2
Gathering and transportation	2.5	2.3
Other	8.1	11.8
Depreciation, depletion and amortization	42.7	49.5
Taxes, other than income:		
Production and property taxes	5.2	13.0
Other	.2	.4
Write-down of oil and natural gas properties	500.4	—
	576.0	101.2
Operating income (loss)	(521.1)	36.3
Earnings (loss)	$(328.9)	$20.9
Production:		
Oil (MBbls)	965	1,280
NGL (MBbls)	116	164
Natural gas (MMcf)	4,954	5,278
Total production (MBOE)	1,907	2,324
Average realized prices (excluding realized and unrealized gain/loss on commodity derivatives):		
Oil (per Bbl)	$38.91	$88.74
NGL (per Bbl)	$18.65	$42.26
Natural gas (per Mcf)	$2.02	$5.77
Average realized prices (including realized gain/loss on commodity derivatives):		
Oil (per Bbl)	$52.75	$85.75
NGL (per Bbl)	$18.65	$42.26
Natural gas (per Mcf)	$2.64	$5.21
Average depreciation, depletion and amortization rate, per BOE	$21.20	$20.45
Production costs, including taxes, per BOE:		
Lease operating costs	$8.86	$10.39
Gathering and transportation	1.30	1.01
Production and property taxes	2.72	5.58
	$12.88	$16.98

Three Months Ended March 31, 2015 and 2014 Exploration and production earnings decreased $349.8 million due to:

- A noncash write-down of oil and natural gas properties of $315.3 million (after tax), as discussed in Note 5
- Lower average realized oil and NGL prices of 56 percent, excluding gain/loss on commodity derivatives
- Lower average realized natural gas prices of 65 percent, excluding gain/loss on commodity derivatives
- Decreased oil production of 25 percent, largely related to normal production declines, deferral of oil drilling activity due to the current low-price environment and divestment of certain properties in the last half of 2014
- Unrealized loss on commodity derivatives of $7.0 million (after tax) in 2015 compared to $4.3 million (after tax) in 2014

Partially offsetting these decreases were:

- Favorable adjustment of $14.6 million (after tax) related to realized gain/loss on commodity derivatives, due to lower commodity prices relative to hedge prices in 2015 compared to higher commodity prices relative to hedge prices in 2014
- Lower production taxes of $4.9 million (after tax), largely related to lower oil and natural gas prices and production
- Lower lease operating expenses of $4.6 million (after tax), largely the result of lower cost structures, as well as decreased production, as previously discussed
- Lower depreciation, depletion and amortization expense of $4.3 million (after tax) due to lower volumes, offset in part by higher depletion rates
- Lower general and administrative expense of $2.4 million (after tax), primarily related to lower payroll-related costs and professional services

Construction Materials and Contracting

	Three Months Ended March 31,	
	2015	2014
	(Dollars in millions)	
Operating revenues	$206.6	$168.5
Operating expenses:		
Operation and maintenance*	201.1	175.8
Depreciation, depletion and amortization	16.5	17.6
Taxes, other than income	8.8	8.3
	226.4	201.7
Operating loss	(19.8)	(33.2)
Loss*	$(14.6)	$(23.6)
Sales (000's):		
Aggregates (tons)	3,566	2,829
Asphalt (tons)	232	184
Ready-mixed concrete (cubic yards)	576	497

* Reflects a MEPP withdrawal liability of approximately $2.4 million ($1.5 million after tax) in 2015. For more information, see Note 16.

Three Months Ended March 31, 2015 and 2014 Construction materials and contracting experienced a seasonal first quarter loss of $14.6 million compared to a loss of $23.6 million a year ago (38 percent decreased loss). The improvement was the result of:

- Higher earnings of $3.5 million (after tax) resulting from higher construction revenues and margins due to favorable weather that allowed an early start of the construction season
- Higher earnings of $2.6 million (after tax) resulting from higher aggregate margins and volumes
- Higher earnings of $2.5 million (after tax) resulting from higher ready-mixed concrete margins and volumes
- Higher earnings from other product lines

The improvement was partially offset by a MEPP withdrawal liability of $1.5 million (after tax), as discussed in Note 16.

Construction Services

	Three Months Ended March 31,	
	2015	2014
	(In millions)	
Operating revenues	$247.1	$273.6
Operating expenses:		
Operation and maintenance	225.0	234.0
Depreciation, depletion and amortization	3.3	3.2
Taxes, other than income	10.0	10.2
	238.3	247.4
Operating income	8.8	26.2
Earnings	$4.8	$16.6

Three Months Ended March 31, 2015 and 2014 Construction services earnings decreased $11.8 million (71 percent), primarily due to lower workloads and margins in the Western region resulting from substantial completion of significant projects in 2014, as well as higher expense of $1.4 million (after tax) related to underperforming assets that were sold in the first quarter.

Other

	Three Months Ended March 31,	
	2015	2014
	(In millions)	
Operating revenues	$2.1	$2.1
Operating expenses:		
Operation and maintenance	.8	1.2
Depreciation, depletion and amortization	.5	.6
	1.3	1.8
Operating income	.8	.3
Earnings (loss)	$(.3)	$.3

Three Months Ended March 31, 2015 and 2014 Other earnings decreased $600,000, primarily due to a foreign currency translation loss including effects of the sale of the Company's remaining interest in the Brazilian Transmission Lines in January 2015.

Intersegment Transactions

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

	Three Months Ended March 31,	
	2015	2014
	(In millions)	
Intersegment transactions:		
Operating revenues	$41.0	$48.6
Purchased natural gas sold	25.7	38.6
Operation and maintenance	13.7	9.2

Depreciation, depletion and amortization	.2	.2
Earnings (loss) on common stock	.9	.3

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 Item 1A - Risk Factors, as well as Part I, Item 1A - Risk Factors in the 2014 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.

- The Company's long-term compound annual growth goals on adjusted earnings per share from operations are in the range of 7 to 10 percent.

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

- The Company focuses on creating value through vertical integration between its business units.

Electric and natural gas distribution

- Rate base growth is projected to be approximately 11 percent compounded annually over the next five years, including plans for an approximate $1.8 billion gross capital investment program with $477 million planned for 2015. Although a prolonged period of lower commodity prices may slow Bakken-area growth in the future, the Company continues to see strong current growth with increases of 4.4 percent in electric customer counts and 3.6 percent in natural gas customers in the first quarter compared to a year ago in this area.

- Regulatory actions

Completed Cases:

On July 10, 2014, the NDPSC approved recovery of $8.6 million annually effective July 15, 2014, to reflect actual costs incurred through February 2014 and projected costs through June 2015 for an environmental cost recovery rider related to costs resulting from the retrofit required to be installed at the Big Stone Station. The Company's share of the cost for the installation is approximately $90 million and is expected to be complete in 2015. The NDPSC had earlier approved advance determination of prudence for recovery of costs on the system.

On August 11, 2014, the Company filed an application with the MTPSC for a natural gas rate increase, as discussed in Note 17.

On November 14, 2014, the Company filed an application with the NDPSC for approval to implement the rate adjustment associated with the electric generation resource recovery rider, as discussed in Note 17.

Pending Cases:

On October 3, 2014, February 6, 2015 and March 31, 2015, the Company filed applications with the WYPSC, NDPSC and OPUC, respectively, for natural gas rate increases, as discussed in Note 17.

On December 22, 2014, the Company filed for advanced determination of prudence with the NDPSC on the Thunder Spirit Wind project, as discussed in Note 17. The Company recently signed an agreement to purchase the project, which includes 43 wind turbines totaling 107.5 MW of electric generation at a cost of approximately $200 million with approximately $55 million already funded in 2014. The project is being developed by ALLETE Clean Energy with an expected completion in December 2015.

On April 10, 2015, the Company filed an update with the NDPSC to the environmental cost recovery rider, as discussed in Note 17.

Expected Filings:

The Company expects to file electric rate cases in Montana, South Dakota and Wyoming and natural gas rate cases in Washington, Minnesota and South Dakota.

- Investments of approximately $60 million are being made to serve the growing electric and natural gas customer base associated with the Bakken oil development where customer growth is higher than the national average. This reflects a slightly lower capital expenditure level compared to 2014, anticipating a tempering of economic activity due to recent lower oil prices.

- The Company, along with a partner, expects to build a 345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota, about 160 miles. The Company’s share of the cost is estimated at approximately $170 million. The project is a MISO multivalue project. A route application was filed in August 2013 with the state of South Dakota and in October 2013 with the state of North Dakota. A route permit was approved July 10, 2014, in North Dakota and August 13, 2014, in South Dakota. The South Dakota route permit was appealed and a district court ruled in favor of the project. The district court decision has been appealed to the South Dakota Supreme Court. The Company continues to expect the project to be completed in 2019.

- The Company is pursuing additional generation projects to meet projected capacity requirements, including 19 MW of natural gas generation at the Lewis & Clark Station to be in service later this year.

- The Company is analyzing potential projects for accommodating load growth in its industrial and agricultural sectors, with company- and customer-owned pipelines designed to serve existing facilities utilizing fuel oil or propane, and to serve new customers.

- 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.

- Montana-Dakota's labor agreement with the International Brotherhood of Electrical Workers was in effect through April 30, 2015, and Cascade's labor agreement with the International Chemical Workers Union was in effect through April 1, 2015, as reported in Items 1 and 2 - Business Properties - General in the 2014 Annual Report. These contracts are currently in negotiations.

Pipeline and energy services

- The Company, in conjunction with Calumet, formed Dakota Prairie Refining to develop, build and operate Dakota Prairie Refinery. Construction began on the facility in late March 2013 and operations have commenced. The facility has begun producing diesel fuel and is expected to begin sales of diesel as the plant ramps up during May 2015. The refinery processes Bakken crude oil into diesel, which is marketed within the Bakken region. Other by-products, naphtha and atmospheric tower bottoms, are being transported to other areas. The total project cost is estimated to be approximately $425 million to $435 million. EBITDA for the first full year of operation is projected to be in the range of $60 million to $80 million, to be shared equally with Calumet.

- The Company is evaluating the construction of a second 20,000-barrel-per-day refinery to be located near Minot, North Dakota, in the Bakken region. The Company expects economic evaluation of this project to continue through much of 2015.

- The Company continues work on acquiring easements as well as filing its application for its planned Wind Ridge Pipeline project, a 95-mile natural gas pipeline designed to deliver approximately 90 MMcf per day to an announced fertilizer plant near Spiritwood, North Dakota. The project is estimated to cost approximately $120 million, with an in-service date in 2017. There is an opportunity to expand this pipeline's capacity to serve other customers in eastern North Dakota.

- The Company has entered into an agreement with an anchor shipper to construct a pipeline to connect the Demicks Lake gas processing plant in northwestern North Dakota to deliver natural gas into a new interconnect with the Northern Border Pipeline. Project costs are estimated to be $50 million to $60 million.

- The Company continues to pursue new growth opportunities and expansion of existing facilities and services offered to customers. The Company expects energy development to continue to grow long term within its geographic region, most notably in the Bakken area, where the Company owns an extensive natural gas pipeline system. The Company plans to invest $1.1 billion of capital related to ongoing energy and industrial development over the next five years.

Exploration and production

- The Company intends to market and sell its exploration and production company and although an actual sale date is unknown, for forecasting purposes the Company is assuming a sale transaction after 2015.
- During 2015, the Company plans to continue to focus on maximizing the value of the Company to market it for sale, including focusing on lowering its cost structure beyond the 25 percent general and administrative cost reduction already in place.

- The Company expects to spend approximately $108 million in gross capital expenditures in 2015, operating within projected cash flows. The Company currently has no rigs drilling on its operated properties and anticipates commencing drilling in the second half of this year.

- Key activities for 2015 include:

Commissioning and start-up of the gas gathering and processing facilities in the Paradox Basin.

Fracture stimulate two wells and drill new wells in the Paradox Basin.

Completion of a backlog of wells in the non-operated Powder River Basin.

Completion of 2014 activity carryover in the Bakken.

Drilling of additional horizontal wells in East Texas is currently not planned in this low natural gas price environment.

- Operational updates:

The Cane Creek Unit 28-3 well (100 percent working interest) completed in mid-December 2014 and slowly ramped up to about 600 BOPD, has continued to flow 600 BOPD on an 11/64ths inch choke at a current flowing tubing pressure of approximately 1,790 pounds per square inch.

Commissioning of the Blues Hills natural gas plant in the Paradox field began in late January 2015 with first gas sales occurring March 10, 2015. Commissioning of the plant is expected to be completed by the end of May 2015.

Per unit lease operating costs in the first quarter of 2015 were 15 percent lower than costs for the same time period in 2014 after adjusting for 2014 asset divestments. Lower operating costs have been achieved through reductions in costs of services as well as optimization of production operations.

- Annual oil production is expected to decline approximately 27 percent in 2015 primarily due to 2014 divestments in the Bakken and limited oil-related investments in 2015. Annual natural gas and NGL volumes are estimated to decrease 10 percent and 27 percent, respectively, in 2015, primarily the result of 2014 asset divestments in South Texas. The December 2015 oil production rate is estimated to decrease 20 percent compared to December 2014, while natural gas and NGL rates are estimated to decrease 5 percent and 3 percent, respectively. The Company is assuming average NYMEX index prices for May through December 2015 of $54.50 per Bbl of crude oil, $2.83 per Mcf of natural gas and $21.94 per Bbl of NGL.

- Derivatives in place as of May 3, 2015, include:

For April through June 2015, 7,000 BOPD of swaps at a weighted average price of $53.21, and a 1,500 BOPD costless collar with a floor/ceiling of $50.00/$57.50.

For July through September 2015, 6,000 BOPD at a weighted average price of $55.78.

For October through December 2015, 6,000 BOPD at a weighted average price of $58.61.

For April through December 2015, 10,000 MMBtu of natural gas per day at a weighted average price of $4.28.

Construction materials and contracting

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Approximate work backlog as of March 31, 2015, was $664 million, compared to $653 million a year ago. Private work represents 10 percent of construction backlog and public work represents 90 percent of backlog. The backlog includes a variety of projects such as highway grading, paving and underground projects, airports, bridge work and subdivisions.

- Projected revenues included in the Company's 2015 earnings guidance are in the range of $1.7 billion to $1.9 billion.

- The Company anticipates margins in 2015 to be higher compared to 2014 margins.

- The Company continues to pursue opportunities for expansion in energy projects such as petrochemical, transmission, wind towers and geothermal. Initiatives are aimed at capturing additional market share and expanding 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 four labor contracts that Knife River was negotiating, as reported in Items 1 and 2 - Business Properties - General in the 2014 Annual Report, two have been ratified. The two remaining contracts are still in negotiations.

Construction services

- Approximate work backlog as of March 31, 2015, was $321 million, compared to $397 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 petrochemical work.

- Projected revenues included in the Company's 2015 earnings guidance are in the range of $1.1 billion to $1.3 billion.

- The Company anticipates margins in 2015 to be slightly lower compared to 2014 margins.

- The Company continues to pursue opportunities for expansion in energy projects such as petrochemical, transmission, substations, utility services and solar. Initiatives are aimed at capturing additional market share and expanding 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 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 2014 Annual Report other than the critical accounting policy involving impairment testing of oil and natural gas properties which reflects updated SEC Defined Prices. For more information on critical accounting policies involving significant estimates, see Part II, Item 7 in the 2014 Annual Report.

Oil and natural gas properties

Estimates of proved reserves were prepared in accordance with guidelines established by the industry and the SEC. The estimates are arrived at using actual historical wellhead production trends and/or standard reservoir engineering methods utilizing available geological, geophysical, engineering and economic data. The extent, quality and reliability of this data can vary. Other factors used in the reserve estimates are prices, market differentials, estimates of well operating and future development costs, taxes, timing of operations, and the interests owned by the Company in the properties. These estimates are refined as new information becomes available.

As these estimates change, calculated proved reserves may change. Changes in proved reserve quantities impact the Company's depreciation, depletion and amortization expense since the Company uses the units-of-production method to amortize its oil and natural gas properties. The proved reserves are the underlying basis of the "ceiling test" for the Company's oil and natural gas properties.

The Company uses the full-cost method of accounting for its exploration and production activities. Under this method, 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, plus the effects of cash flow hedges, less applicable income taxes. Proved reserves and associated future cash flows are determined based on SEC Defined Prices and exclude cash flows associated with asset retirement obligations that have been accrued on the balance sheet. Judgments and assumptions are made when estimating and valuing proved reserves. Various factors, including lower SEC Defined Prices, market differentials, changes in estimates of proved reserve quantities, unsuccessful results of exploration and development efforts or changes in operating and development costs could result in future noncash write-downs of the Company's oil and natural gas properties.

SEC Defined Prices for each quarter for the last 12 months were as follows:

SEC Defined Prices for the 12 months ended	NYMEX Oil Price (per Bbl)	Henry Hub Gas Price (per MMBtu)	Ventura Gas Price (per MMBtu)
March 31, 2015	$82.72	$3.87	$3.96
December 31, 2014	94.99	4.34	7.71
September 30, 2014	99.08	4.24	7.60
June 30, 2014	100.27	4.10	7.47

For purposes of comparison, first-of-the-month prices were as follows:

	NYMEX Oil Price (per Bbl)	Henry Hub Gas Price (per MMBtu)	Ventura Gas Price (per MMBtu)
April 2015	$50.09	$2.63	$2.45
May 2015	59.15	2.57	2.51

Given the current oil and natural gas pricing environment, the Company believes it is likely it will have noncash write-downs of its oil and natural gas properties in future quarters until such time as commodity prices begin to recover.

LIQUIDITY AND CAPITAL COMMITMENTS

At March 31, 2015, the Company had cash and cash equivalents of $122.2 million and available capacity of $588.0 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 later; and through the issuance of long-term debt and the Company's equity securities.

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 three months of 2015 decreased $42.4 million from the comparable period in 2014. Excluding the effect of the write-down of oil and natural gas properties, the decrease in cash flows provided by operating activities was primarily due to lower earnings at the exploration and production and construction services businesses and lower deferred income taxes at the construction materials and contracting business. Partially offsetting this decrease was lower working capital requirements at the electric, natural gas distribution and construction services businesses.

Investing activities Cash flows used in investing activities in the first three months of 2015 decreased $220.1 million from the comparable period in 2014. The decrease in cash flows used in investing activities was primarily due to lower acquisition-related capital expenditures at the exploration and production business and higher proceeds from the sale of property at the construction services business.

Financing activities Cash flows provided by financing activities in the first three months of 2015 decreased $175.7 million from the comparable period in 2014. The decrease in cash flows provided by financing activities was primarily due to lower issuance of long-term debt of $160.2 million, as well as lower issuance of common stock. Partially offsetting this decrease was higher issuance and lower repayment of short-term debt.

Defined benefit pension plans

There were no material changes to the Company's qualified noncontributory defined benefit pension plans from those reported in the 2014 Annual Report. For more information, see Note 16 and Part II, Item 7 in the 2014 Annual Report.

Capital expenditures

Capital expenditures for the first three months of 2015 were $132.5 million ($104.7 million, net of proceeds from sale or disposition of property) and are estimated to be approximately $755 million for 2015 ($676 million, net of proceeds from sale or disposition of property). Estimated capital expenditures include:

- System upgrades
- Routine replacements
- Service extensions

42

- Routine equipment maintenance and replacements
- Buildings, land and building improvements
- Pipeline, gathering and other midstream projects
- Further development of existing properties at the exploration and production segment
- Power generation and transmission opportunities, including certain costs for additional electric generating capacity and purchase agreement of electric wind generation
- Environmental upgrades
- The Company's proportionate share of Dakota Prairie Refinery at the pipeline and energy services segment
- Evaluation for a potential second refinery at the pipeline and energy services segment
- 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 2015 capital expenditures referred to previously. The Company expects the 2015 estimated capital expenditures to be funded by various sources, including internally generated funds; the Company's credit facilities, as described later; through the issuance of long-term debt and the Company's equity securities; and asset sales.

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 March 31, 2015. 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 more information on the covenants, certain other conditions and cross-default provisions, see Part II, Item 8 - Note 9, in the 2014 Annual Report.

The following table summarizes the outstanding revolving credit facilities of the Company and its subsidiaries at March 31, 2015:

Company	Facility		Facility Limit		Amount Outstanding		Letters of Credit		Expiration Date
			(In millions)						
MDU Resources Group, Inc.	Commercial paper/ Revolving credit agreement	(a)	$175.0		$41.0	(b)	$—		5/8/19
Cascade Natural Gas Corporation	Revolving credit agreement		$50.0	(c)	$—		$2.2	(d)	7/9/18
Intermountain Gas Company	Revolving credit agreement		$65.0	(e)	$3.5		$—		7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/ Revolving credit agreement	(f)	$650.0		$335.5	(b)	$—		5/8/19
Dakota Prairie Refining, LLC	Revolving credit agreement		$50.0	(g)	$16.1		$3.7	(d)	12/1/15

(a) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $225.0 million). There were no amounts outstanding under the credit agreement.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $75.0 million.

(d) An outstanding letter of credit reduces the amount available under the credit agreement.
(e) Certain provisions allow for increased borrowings, up to a maximum of $90.0 million.
(f) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $800.0 million). There were no amounts outstanding under the credit agreement.
(g) Certain provisions allow for increased borrowing, up to a maximum of $75.0 million.

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. The Company's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are 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.

Due to the $315.3 million after-tax noncash write-down of oil and natural gas properties in 2015, earnings were insufficient by $172.1 million to cover fixed charges for the twelve months ended March 31, 2015. If the $315.3 million after-tax noncash write-down was excluded, the ratio of earnings to fixed charges including preferred stock dividends would have been 3.8 times for the twelve months ended March 31, 2015. The Company's coverage of fixed charges including preferred stock dividends was 4.8 times and 4.5 times for the 12 months ended March 31, 2014 and December 31, 2014, respectively.

The coverage of fixed charges including preferred stock dividends that excludes the effect of the after-tax noncash write-down of oil and natural gas properties is a non-GAAP financial measure. The Company believes that this non-GAAP financial measure is useful because the excluded write-down is not indicative of the Company's cash flows available to meet its fixed charges obligations. The presentation of this additional information is not meant to be considered a substitute for the financial measure prepared in accordance with GAAP.

Total equity as a percent of total capitalization was 57 percent, 58 percent and 61 percent at March 31, 2015 and 2014, and December 31, 2014, respectively. This ratio is calculated as the Company's total 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 total equity. This ratio indicates how a company is financing its operations, as well as its financial strength.

On May 20, 2013, the Company entered into an Equity Distribution Agreement with Wells Fargo Securities, LLC with respect to the issuance and sale of up to 7.5 million shares of the Company's common stock. The common stock may be offered for sale, from time to time until February 28, 2016, in accordance with the terms and conditions of the agreement. Proceeds from the shares of common stock under the agreement have been and are expected to be used for corporate development purposes and other general corporate purposes. Under the agreement, the Company did not issue any shares of stock between January 1, 2015 and March 31, 2015. Since inception of the Equity Distribution Agreement, the Company has issued a cumulative total of 4.4 million shares of stock receiving net proceeds of $144.7 million through March 31, 2015.

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. Centennial's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are 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.

Prior to the maturity of the Centennial credit agreement, Centennial expects that it will negotiate the extension or replacement of this agreement, which provides credit support to access the capital markets. In the event Centennial is unable to successfully negotiate this agreement, or in the event the fees on this facility become too expensive, which Centennial does not currently anticipate, it would seek alternative funding.

WBI Energy Transmission, Inc. WBI Energy Transmission has a $175.0 million amended and restated uncommitted long-term private shelf agreement with an expiration date of September 12, 2016. WBI Energy Transmission had $100.0 million of notes outstanding at March 31, 2015, which reduced capacity under this uncommitted private shelf agreement.

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.

Contractual obligations and commercial commitments
There are no material changes in the Company's contractual obligations relating to long-term debt, estimated interest payments, operating leases, purchase commitments, derivatives, asset retirement obligations, uncertain tax positions and minimum funding requirements for its defined benefit plans for 2015 from those reported in the 2014 Annual Report.

For more information on contractual obligations and commercial commitments, see Part II, Item 7 in the 2014 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 and interest rates. The Company has policies and procedures to assist in controlling these market risks and utilizes derivatives to manage a portion of its risk.

For more information on derivative instruments and commodity price risk, see Part II, Item 7A in the 2014 Annual Report, the Consolidated Statements of Comprehensive Income and Notes 9 and 12.

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 on forecasted sales of oil and natural gas production.

The following table summarizes derivative agreements entered into by Fidelity as of March 31, 2015. These agreements call for Fidelity to receive fixed prices and pay variable prices.

(Forward notional volume and fair value in thousands)

	Weighted Average Fixed Price (Per Bbl/MMBtu)	Forward Notional Volume	Fair Value

		(Bbl/MMBtu)	
Oil swap agreements maturing in 2015	$53.68	821	$2,674
Natural gas swap agreement maturing in 2015	$4.28	2,750	$4,118

	Weighted Average Floor/Ceiling Price (Per Bbl)	Forward Notional Volume (Bbl)	Fair Value
Oil collar agreement maturing in 2015	$50.00/$57.50	137	$335

Interest rate risk

There were no material changes to interest rate risk faced by the Company from those reported in the 2014 Annual Report.

At March 31, 2015, the Company had no outstanding interest rate 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 March 31, 2015, 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 18, 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 2014 Annual Report other than 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 associated with the regulatory approval, permitting, construction, startup and/or operation of power generation facilities; the risk associated with the operation of Dakota Prairie Refinery; the risk related to environmental laws and regulations; the risk that the Company's operations could be adversely impacted by initiatives to reduce GHG emissions; and the risk related to obligations under MEPPs. 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

Actual quantities of recoverable oil, NGL 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 low oil and natural gas prices, could result in future noncash write-downs of the Company's oil and natural gas properties.

The process of estimating oil, NGL and natural gas reserves is complex. Reserve estimates are based on assumptions relating to oil, NGL 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 proved 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 proved reserve estimates in accordance with guidelines established by the industry and the SEC, significant changes to the proved reserve estimates may occur based on actual results of production, drilling, costs, pricing and investment levels.

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. Various factors, including lower SEC Defined Prices, market differentials, changes in estimates of proved reserve quantities, unsuccessful results of exploration and development efforts or changes in operating and development costs could result in future noncash write-downs of the Company's oil and natural gas properties.

SEC Defined Prices for each quarter for the last 12 months were as follows:

SEC Defined Prices for the 12 months ended	NYMEX Oil Price (per Bbl)	Henry Hub Gas Price (per MMBtu)	Ventura Gas Price (per MMBtu)
March 31, 2015	$82.72	$3.87	$3.96
December 31, 2014	94.99	4.34	7.71
September 30, 2014	99.08	4.24	7.60
June 30, 2014	100.27	4.10	7.47

For purposes of comparison, first-of-the-month prices were as follows:

	NYMEX Oil Price (per Bbl)	Henry Hub Gas Price (per MMBtu)	Ventura Gas Price (per MMBtu)
April 2015	$50.09	$2.63	$2.45
May 2015	59.15	2.57	2.51

Given the current oil and natural gas pricing environment, the Company believes it is likely it will have noncash write-downs of its oil and natural gas properties in future quarters until such time as commodity prices begin to recover.

The regulatory approval, permitting, construction, startup and/or operation of power generation facilities may involve unanticipated events or delays that could negatively impact the Company's business and its results of operations and cash flows.

The construction, startup and operation of power generation facilities involve many risks, which may include: delays; breakdown or failure of equipment; inability to obtain required governmental permits and approvals; inability to complete

47

financing; inability to negotiate acceptable equipment acquisition, construction, fuel supply, off-take, transmission, transportation or other material agreements; changes in markets and market prices for power; cost increases and overruns; the risk of performance below expected levels of output or efficiency; and the inability to obtain full cost recovery in regulated rates. Such unanticipated events could negatively impact the Company's business, its results of operations and cash flows.

The operation of Dakota Prairie Refinery may involve unanticipated events or delays that could negatively impact the Company's business and its results of operations and cash flows.

The operation of Dakota Prairie Refinery involves many risks, which may include: breakdown or failure of the equipment and systems; inability to operate within environmental permit parameters; inability to produce refined products to required specifications; inability to obtain crude oil supply; inability to effectively manage new rail routes; changes in markets and market prices for crude oil and refined products; and operating cost increases; as well as the risk of performance below expected levels of output or efficiency. Such unanticipated events could negatively impact the Company's business, its results of operations and cash flows.

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 operations, including air quality, water quality, waste management and other environmental considerations. These laws and regulations can increase capital, operating and other costs, cause delays as a result of litigation and administrative proceedings, and create compliance, remediation, containment, monitoring and reporting obligations, particularly relating to electric generation operations and oil and natural gas development and processing. 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 and private entities and private individuals may interpret the Company's legal or regulatory requirements differently and seek injunctive relief or other remedies against the Company. The Company cannot predict the outcome (financial or operational) of any such litigation or administrative proceedings.

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 controls, remediate environmental contamination, remove or reduce environmental hazards, or prevent or limit the development of resources. Revised or additional laws and regulations that increase compliance costs or restrict operations, particularly if costs are not fully recoverable from customers, could have a material adverse effect on the Company's results of operations and cash flows.

In December 2011, the EPA finalized the MATS rule that will require reductions in mercury and other air emissions from coal- and oil-fired electric utility steam generating units. Montana-Dakota evaluated the pollution control technologies needed at its electric generation resources to comply with this rule and determined that the Lewis & Clark Station near Sidney, Montana, will require additional particulate matter control for non-mercury metal emissions. Montana-Dakota has further evaluated pollution control options and intends to comply with the rule by making scrubber modifications, including installing a mist eliminator and sieve tray. With a one-year extension granted on January 30, 2015, by the Montana DEQ, controls must be in place by April 16, 2016.

On August 15, 2014, the EPA published a final rule under Section 316(b) of the Clean Water Act, establishing requirements for water intake structures at existing steam electric generating facilities. The purpose of the rule is to reduce impingement and entrainment of fish and other aquatic organisms at cooling water intake structures. The majority of the Company's electric generating facilities are either not subject to the rule or have completed studies that project compliance expenditures are not material. The Lewis & Clark Station will complete a study by 2018 that will be used to determine any required controls. It is unknown at this time what controls may be required or if compliance costs will be material. The installation schedule for any required controls would be established with the permitting agency after the study is completed.

Fidelity uses hydraulic fracturing, an important common practice that involves injecting water, sand, a water-thickening agent called guar, and trace amounts of chemicals, under pressure, into rock formations to stimulate oil, NGL and natural gas production. Fidelity follows state regulations for well drilling and completion, including regulations on hydraulic fracturing and recovered-fluids disposal. Fidelity reports fracturing fluid constituents on state or national websites. The EPA is developing a study to review potential effects of hydraulic fracturing on underground sources of drinking water; the results of that study could impact future legislation or regulation. The BLM issued well-stimulation regulations for hydraulic fracturing operations, effective June 24, 2015, that impact Fidelity’s compliance, reporting and disclosures on operations only on BLM-administered lands. The BLM’s regulations could increase Fidelity’s compliance and operating costs, as well as delay or inhibit the Company’s ability to develop its oil, NGL and natural gas reserves.

On August 16, 2012, the EPA published a final NSPS rule for the oil and natural gas industry that took effect in phases. The first phase was effective October 15, 2012, and primarily covers natural gas wells that are hydraulically fractured. Under the rule, gas vapors or emissions from the natural gas wells must be captured or combusted utilizing a high-efficiency device. Effective January 2015, additional reporting requirements and control devices covering oil and natural gas production equipment were phased in for certain new oil and gas facilities. This rule's impacts on Fidelity, WBI Energy Transmission and WBI Energy Midstream are not expected to be material and have included implementing recordkeeping, reporting and testing requirements and purchasing and installing required equipment.

Initiatives to reduce GHG emissions could adversely impact the Company's 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. On June 25, 2013, President Obama released his Climate Action Plan for the U.S. in which he stated his goal to reduce GHG emissions "in the range of 17 percent" below 2005 levels by 2020. The president issued a memorandum to the EPA on the same day, instructing the EPA to re-propose the GHG NSPS rule for new electric generation units. The EPA released the re-proposed rule on January 8, 2014, in the Federal Register, which takes the place of the rule proposed in 2012 for new electric generation units that the EPA did not finalize. This rule applies to new fossil fuel-fired electric generation units, including coal-fired units, natural gas-fired combined-cycle units and natural gas-fired simple-cycle peaking units. The EPA's 1,100 pounds of carbon dioxide per MW hour emissions standard for coal-fired units does not allow any new coal-fired electric generation to be constructed unless carbon dioxide is captured and sequestered.

President Obama also directed the EPA to develop a GHG NSPS standard for existing fossil fuel-fired electric generation units by June 1, 2014, with finalization by June 1, 2015. On June 18, 2014, the EPA published in the Federal Register a proposed rule limiting carbon dioxide emissions from existing fossil fuel-fired electric generating units and a separate proposed rule limiting carbon dioxide emissions from existing units that are modified or reconstructed.

In the proposed rule for existing sources, the EPA requires carbon dioxide emission reductions from each state and instructs each state, or group of states that work together, to submit a plan to the EPA by June 30, 2016, that demonstrates how the state will achieve the targeted emission reductions by 2030. The state plans could include performance standards, emissions reductions or limits on generation for each existing fossil fuel-fired generating unit. It is unknown at this time what each state will require for emissions reductions from each Montana-Dakota owned and jointly owned fossil fuel-fired electric generating unit. In the EPA’s proposed GHG rule for modified or reconstructed fossil fuel-fired sources, the EPA proposes emissions limits that potentially could be unachievable. Montana-Dakota does not plan to modify or reconstruct any fossil fuel-fired units at this time, but it may modify or reconstruct units in the future that may require compliance with the rule limitations.

The Company’s primary GHG emission is carbon dioxide from fossil fuels combustion at Montana-Dakota's electric generating facilities, particularly its coal-fired facilities. Approximately 60 percent of Montana-Dakota's owned generating capacity and more than 90 percent of the electricity it generates is from coal-fired facilities.

On January 14, 2015, President Obama announced a goal to reduce methane emissions from the oil and natural gas industry by 40 to 45 percent below 2012 levels by 2025. The EPA will issue in mid-2015 a proposed rule on standards for methane and GHG emissions from new and modified sources within the oil and natural gas industry, with a final rule expected in 2016. The rule is expected to include emission reductions on sources such as oil well completions, pneumatic pumps, and leaks from well sites, gathering and boosting stations, and compressor stations. The president will continue to evaluate further methods of methane reduction including additional leak detection controls and emission reporting, enhanced venting and flaring requirements for sources on public lands, and upgrades to existing natural gas transmission and distribution infrastructure. It is unknown at this time how the Company will be impacted or if compliance costs will be material.

There also may be new treaties, legislation or regulations to reduce GHG emissions that could affect Montana-Dakota's electric utility operations by requiring additional energy conservation efforts or 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 adversely impact the results of its operations.

In addition to Montana-Dakota's electric generation operations, the GHG emissions from the Company's other operations are monitored, analyzed and reported as required by applicable laws and regulations. The Company monitors GHG regulations and the potential for GHG regulations to impact 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 MEPPs 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 85 MEPPs 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 MEPPs to which it contributes are currently in endangered, seriously endangered or critical status.

The Company may also be required to increase its contributions to MEPPs 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 MEPPs 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, actions taken by the plans' other participating employers, 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 MEPPs, 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.

On September 24, 2014, Knife River provided notice to the plan administrator of one of the MEPPs to which it is a participating employer that it was withdrawing from that plan effective October 26, 2014. The plan administrator will determine Knife River’s withdrawal liability, which the Company currently estimates at approximately $16.4 million (approximately $9.8 million after tax). The assessed withdrawal liability for this plan may be significantly different from the current estimate.

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: May 8, 2015	BY:	/s/ Doran N. Schwartz Doran N. Schwartz Vice President and Chief Financial Officer
	BY:	/s/ Nathan W. Ring Nathan W. Ring Vice President, Controller and Chief Accounting Officer

EXHIBIT INDEX

Exhibit No.	
3	Bylaws of MDU Resources Group, Inc., as amended and restated on April 2, 2015
+10(a)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated February 17, 2015
+10(b)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 13, 2015
+10(c)	MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart, as of March 31, 2015
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 March 31, 2015, 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.