MDU RESOURCES GROUP INC
Form 10-Q
November 06, 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 September 30, 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	41-0423660
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1200 West Century Avenue
P.O. Box 5650
Bismarck, North Dakota 58506-5650
(Address of principal executive offices)
(Zip Code)
(701) 530-1000
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes 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 definitions 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 (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No ý.
Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of October 30, 2015: 195,265,744 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
ATBs	Atmospheric tower bottoms
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
BPD	Barrels per day
Brazilian Transmission Lines	Company's former investment in companies owning three electric transmission lines
Btu	British thermal unit
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 Court of Appeals	Court of Appeals, State of Colorado
Colorado State District Court	Colorado Thirteenth Judicial District Court, Yuma County
Company	MDU Resources Group, Inc.
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
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
dk	Decatherm
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
EPA	United States Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
ESCP	Erosion and Sediment Control Plan
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 (previously referred to as the Company's exploration and production segment)

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
LTM	LTM, Incorporated, an indirect wholly owned subsidiary of Knife River
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 dk
MNPUC	Minnesota Public Utilities Commission
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
Notice of Civil Penalty	Notice of Civil Penalty Assessment and Order
NSPS	New Source Performance Standards
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
RCRA	Resource Conservation and Recovery Act
RIN	Renewable Identification Number
ROD	Record of Decision
RP	Rehabilitation plan
SDPUC	South Dakota Public Utilities Commission
SEC	United States 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
South Dakota Supreme Court	Supreme Court of the State of South Dakota

United States District Court for the District of Montana	United States District Court for the District of Montana, Great Falls Division
United States Supreme Court	Supreme Court of the United States
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

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 segment and Fidelity, the Company's exploration and production business), Knife River (construction materials and contracting segment), MDU Construction Services (construction services segment), Centennial Resources and Centennial Capital (both reflected in the Other category).

In the second quarter of 2015, the Company announced its plan to market Fidelity and exit that line of business. Therefore, the results of Fidelity are reflected in discontinued operations, other than certain general and administrative costs and interest expense which are reflected in the Other category. For more information on the Company's business segments and discontinued operations, see Notes 10 and 15.

Index

Part I -- Financial Information
Item 1. Financial Statements
MDU Resources Group, Inc.
Consolidated Statements of Income
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands, except per share amounts)			
Operating revenues:				
Electric, natural gas distribution and regulated pipeline and energy services	$185,224	$184,793	$806,986	$863,569
Nonregulated pipeline and energy services, construction materials and contracting, construction services and other	1,095,276	1,028,410	2,322,078	2,202,960
Total operating revenues	1,280,500	1,213,203	3,129,064	3,066,529
Operating expenses:				
Fuel and purchased power	20,616	19,236	63,761	66,826
Purchased natural gas sold	37,574	46,251	305,313	368,579
Cost of crude oil	69,122	—	116,174	—
Operation and maintenance:				
Electric, natural gas distribution and regulated pipeline and energy services	68,386	69,100	207,396	200,298
Nonregulated pipeline and energy services, construction materials and contracting, construction services and other	884,328	875,343	1,962,318	1,923,509
Depreciation, depletion and amortization	57,817	50,698	164,969	151,342
Taxes, other than income	32,914	33,682	110,392	111,120
Total operating expenses	1,170,757	1,094,310	2,930,323	2,821,674
Operating income	109,743	118,893	198,741	244,855
Other income	3,498	2,524	6,261	7,162
Interest expense	22,946	22,402	69,864	64,832
Income before income taxes	90,295	99,015	135,138	187,185
Income taxes	36,895	35,376	52,520	63,072
Income from continuing operations	53,400	63,639	82,618	124,113
Income (loss) from discontinued operations, net of tax (Note 10)	(202,626)	38,482	(778,647)	87,475
Net income (loss)	(149,226)	102,121	(696,029)	211,588
Net loss attributable to noncontrolling interest	(9,778)	(1,088)	(21,060)	(2,390)
Dividends declared on preferred stocks	171	171	514	514
Earnings (loss) on common stock	$(139,619)	$103,038	$(675,483)	$213,464
Earnings (loss) per common share - basic:				
Earnings before discontinued operations	$.32	$.33	$.53	$.66
Discontinued operations, net of tax	(1.04)	.20	(4.00)	.45
Earnings (loss) per common share - basic	$(.72)	$.53	$(3.47)	$1.11
Earnings (loss) per common share - diluted:				
Earnings before discontinued operations	$.32	$.33	$.53	$.66
Discontinued operations, net of tax	(1.04)	.20	(4.00)	.45
Earnings (loss) per common share - diluted	$(.72)	$.53	$(3.47)	$1.11
Dividends declared per common share	$.1825	$.1775	$.5475	$.5325
Weighted average common shares outstanding - basic	195,151	193,949	194,814	191,958
Weighted average common shares outstanding - diluted	195,169	194,300	194,833	192,307

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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Net income (loss)	$(149,226)	$102,121	$(696,029)	$211,588
Other comprehensive income:				
Net unrealized gain on derivative instruments qualifying as hedges:				
Reclassification adjustment for loss on derivative instruments included in net income (loss), net of tax of $60 and $60 for the three months ended and $181 and $181 for the nine months ended in 2015 and 2014, respectively	100	100	299	299
Reclassification adjustment for (gain) loss on derivative instruments included in income (loss) from discontinued operations, net of tax of $0 and $(10) for the three months ended and $0 and $83 for the nine months ended in 2015 and 2014, respectively	—	(18)	—	140
Net unrealized gain on derivative instruments qualifying as hedges	100	82	299	439
Amortization of postretirement liability losses included in net periodic benefit cost (credit), net of tax of $233 and $159 for the three months ended and $881 and $477 for the nine months ended in 2015 and 2014, respectively	382	261	1,341	781
Foreign currency translation adjustment:				
Foreign currency translation adjustment recognized during the period, net of tax of $(44) and $(89) for the three months ended and $(107) and $(36) for the nine months ended in 2015 and 2014, respectively	(73)	(146)	(176)	(58)
Reclassification adjustment for loss on foreign currency translation adjustment included in net income (loss), net of tax of $0 and $0 for the three months ended and $491 and $0 for the nine months ended in 2015 and 2014, respectively	—	—	802	—
Foreign currency translation adjustment	(73)	(146)	626	(58)
Net unrealized gain (loss) on available-for-sale investments:				
Net unrealized loss on available-for-sale investments arising during the period, net of tax of $(19) and $(33) for the three months ended and $(57) and $(48) for the nine months ended in 2015 and 2014, respectively	(35)	(62)	(105)	(89)
Reclassification adjustment for loss on available-for-sale investments included in net income (loss), net of tax of $15 and $16 for the three months ended and $53 and $54 for the nine months ended in 2015 and 2014, respectively	28	31	98	100
Net unrealized gain (loss) on available-for-sale investments	(7)	(31)	(7)	11
Other comprehensive income	402	166	2,259	1,173
Comprehensive income (loss)	(148,824)	102,287	(693,770)	212,761
Comprehensive loss attributable to noncontrolling interest	(9,778)	(1,088)	(21,060)	(2,390)

Comprehensive income (loss) attributable to common stockholders	$(139,046)	$103,375	$(672,710)	$215,151

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

MDU Resources Group, Inc.
Consolidated Balance Sheets
(Unaudited)

	September 30, 2015	September 30, 2014	December 31, 2014
(In thousands, except shares and per share amounts)			
Assets			
Current assets:			
Cash and cash equivalents	$88,630	$261,751	$81,855
Receivables, net	677,928	666,930	599,186
Inventories	258,341	289,201	289,410
Deferred income taxes	32,009	17,046	32,012
Prepayments and other current assets	56,604	70,786	83,763
Current assets held for sale	83,132	144,038	131,177
Total current assets	1,196,644	1,449,752	1,217,403
Investments	118,063	115,619	117,883
Property, plant and equipment	6,627,269	6,090,880	6,294,778
Less accumulated depreciation, depletion and amortization	2,455,402	2,353,673	2,386,113
Net property, plant and equipment	4,171,867	3,737,207	3,908,665
Deferred charges and other assets:			
Goodwill	635,204	636,039	635,204
Other intangible assets, net	7,908	10,596	9,840
Other	355,720	244,904	322,943
Noncurrent assets held for sale	499,913	1,612,057	1,620,470
Total deferred charges and other assets	1,498,745	2,503,596	2,588,457
Total assets	$6,985,319	$7,806,174	$7,832,408
Liabilities and Equity			
Current liabilities:			
Short-term borrowings	$29,500	$—	$—
Long-term debt due within one year	262,664	148,573	268,552
Accounts payable	292,612	296,580	279,115
Taxes payable	44,267	65,334	39,955
Dividends payable	35,807	34,607	35,607
Accrued compensation	60,277	59,497	57,402
Other accrued liabilities	157,650	145,905	155,765
Current liabilities held for sale	58,901	220,111	154,728
Total current liabilities	941,678	970,607	991,124
Long-term debt	2,012,441	2,060,946	1,825,278
Deferred credits and other liabilities:			
Deferred income taxes	729,980	675,167	714,022
Other liabilities	755,107	669,639	756,759
Noncurrent liabilities held for sale	31,242	271,312	295,441
Total deferred credits and other liabilities	1,516,329	1,616,118	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	195,805	194,548	194,755

Shares issued - 195,804,665 at September 30, 2015, 194,548,389 at September 30, 2014 and 194,754,812 at December 31, 2014			
Other paid-in capital	1,228,875	1,200,591	1,207,188
Retained earnings	980,421	1,713,774	1,762,827
Accumulated other comprehensive loss	(39,844)	(37,032)	(42,103)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)	(3,626)
Total common stockholders' equity	2,361,631	3,068,255	3,119,041
Total stockholders' equity	2,376,631	3,083,255	3,134,041
Noncontrolling interest	138,240	75,248	115,743
Total equity	2,514,871	3,158,503	3,249,784
Total liabilities and equity	$6,985,319	$7,806,174	$7,832,408

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

MDU Resources Group, Inc.
Consolidated Statements of Cash Flows
(Unaudited)

	Nine Months Ended September 30,	
	2015	2014
	(In thousands)	
Operating activities:		
Net income (loss)	$(696,029)	$211,588
Income (loss) from discontinued operations, net of tax	(778,647)	87,475
Income from continuing operations	82,618	124,113
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	164,969	151,342
Deferred income taxes	12,636	17,658
Excess tax benefit on stock-based compensation	—	(4,729)
Changes in current assets and liabilities:		
Receivables	(88,420)	(64,369)
Inventories	(13,919)	(22,108)
Other current assets	28,780	(26,007)
Accounts payable	61,968	(11,504)
Other current liabilities	6,820	(75)
Other noncurrent changes	4,463	(24,234)
Net cash provided by continuing operations	259,915	140,087
Net cash provided by discontinued operations	122,279	279,187
Net cash provided by operating activities	382,194	419,274
Investing activities:		
Capital expenditures	(484,483)	(367,182)
Net proceeds from sale or disposition of property and other	37,679	12,281
Investments	1,309	(916)
Net cash used in continuing operations	(445,495)	(355,817)
Net cash used in discontinued operations	(98,521)	(287,681)
Net cash used in investing activities	(544,016)	(643,498)
Financing activities:		
Issuance of short-term borrowings	29,500	—
Repayment of short-term borrowings	—	(11,500)
Issuance of long-term debt	327,470	672,351
Repayment of long-term debt	(146,333)	(318,579)
Proceeds from issuance of common stock	21,894	144,868
Dividends paid	(107,028)	(102,105)
Excess tax benefit on stock-based compensation	—	4,729
Tax withholding on stock-based compensation	—	(5,564)
Contribution from noncontrolling interest	52,000	44,900
Distribution to noncontrolling interest	(8,443)	—
Net cash provided by continuing operations	169,060	429,100
Net cash used in discontinued operations	(271)	(412)
Net cash provided by financing activities	168,789	428,688
Effect of exchange rate changes on cash and cash equivalents	(192)	(53)
Increase in cash and cash equivalents	6,775	204,411
Cash and cash equivalents -- beginning of year	81,855	57,340

Cash and cash equivalents -- end of period	$88,630	$261,751

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

10

MDU Resources Group, Inc.
Notes to Consolidated
Financial Statements
September 30, 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 September 30, 2015, up to the date of issuance of these consolidated interim financial statements.

In the second quarter of 2015, the Company announced its plan to market Fidelity, previously referred to as the Company's exploration and production segment, and exit that line of business. The Company's consolidated financial statements and accompanying notes for current and prior periods have been restated to present the results of operations of Fidelity as discontinued operations, other than certain general and administrative costs and interest expense which were previously allocated to the former exploration and production segment and do not meet the criteria for income (loss) from discontinued operations. In addition, the assets and liabilities have been treated and classified as held for sale. Unless otherwise indicated, the amounts presented in the accompanying notes to the consolidated financial statements relate to the Company's continuing operations. For more information on discontinued operations, see Note 10.

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, $26.4 million and $29.4 million at September 30, 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 September 30, 2015 and 2014, and December 31, 2014, was $9.0 million, $8.9 million and $9.5 million, respectively.

Note 4 - Inventories and natural gas in storage

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. Crude oil and refined products at Dakota Prairie Refinery are carried at lower of cost or market value using the last-in, first-out method. All other inventories are stated at the lower of average cost or market value. The portion of the cost of natural gas in storage expected to be used within one year is included in inventories. Inventories consisted of:

	September 30, 2015	September 30, 2014	December 31, 2014
	(In thousands)		
Aggregates held for resale	$115,736	$106,623	$108,161

Asphalt oil	33,581	33,551	42,135
Natural gas in storage (current)	28,222	29,979	19,302
Materials and supplies	19,404	58,011	54,282
Merchandise for resale	15,563	24,566	24,420
Crude oil	6,465	—	5,045
Refined products	5,889	—	—
Other	33,481	36,471	36,065
Total	$258,341	$289,201	$289,410

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 September 30, 2015 and 2014, and December 31, 2014, respectively.

Note 5 - Impairment of long-lived assets

During the second quarter of 2015, the Company recognized an impairment of coalbed natural gas gathering assets at the pipeline and energy services segment of $3.0 million, which is recorded in operation and maintenance expense on the Consolidated Statements of Income. The impairment is related to coalbed natural gas gathering assets located in Wyoming where there has been continued decline in natural gas development and production activity largely due to low natural gas prices. The coalbed natural gas gathering assets were written down to their estimated fair value that was determined using the income approach.

The Company is negotiating a purchase and sale agreement for the sale of certain non-strategic natural gas gathering assets at the pipeline and energy services segment and, as a result, recognized an impairment during the third quarter of 2015 of $14.1 million, largely related to these assets, which is recorded in operation and maintenance expense on the Consolidated Statements of Income. The natural gas gathering assets were written down to their estimated fair value that was determined using the market approach.

For more information on these nonrecurring fair value measurements, see Note 13.

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 (loss) per common share were computed by dividing earnings (loss) 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. 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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Weighted average common shares outstanding - basic	195,151	193,949	194,814	191,958
Effect of dilutive performance share awards	18	351	19	349
Weighted average common shares outstanding - diluted	195,169	194,300	194,833	192,307
Shares excluded from the calculation of diluted earnings per share	—	—	—	—

Note 7 - Cash flow information

Cash expenditures for interest and income taxes were as follows:

	Nine Months Ended September 30,	
	2015	2014
	(In thousands)	
Interest, net of amounts capitalized and AFUDC - borrowed of $7.5 million and $8.6 million in 2015 and 2014, respectively	$70,203	$61,610
Income taxes paid, net	$20,652	$58,345

Noncash investing transactions were as follows:

	September 30,	
	2015	2014
	(In thousands)	

Property, plant and equipment additions in accounts payable	$15,499	$49,260

Note 8 - New accounting standards

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity In April 2014, the FASB issued guidance related to the definition and reporting of discontinued operations. The guidance changed the definition of discontinued operations to include only disposals of a component or group of components that represent a strategic shift and that have a major effect on an entity's operations or financial results. The guidance also expands the disclosure requirements for transactions that meet the definition of a discontinued operation, and also requires entities to disclose information about individually significant components that are disposed of or held for sale that do not meet the definition of a discontinued operation. This guidance was effective for the Company on January 1, 2015, and is to be applied prospectively for all disposals or components initially classified as held for sale after the effective date, with early adoption permitted. The adoption required additional disclosures for the Company's discontinued operations, however it did not impact the Company's results of operations, financial position or cash flows.

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 was to be effective for the Company on January 1, 2017. In July 2015, the FASB approved a decision to defer the effective date one year and allow entities to early adopt. With this decision, the guidance will 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, however the Company has not elected to do so. 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.

Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent) In May 2015, the FASB issued guidance on fair value measurement and disclosure requirements removing the requirement to include investments in the fair value hierarchy for which fair value is measured using the net asset value per share practical expedient. The new guidance also removes the requirement to make certain disclosures for all investments that are eligible to be measured at net asset value using the practical expedient, and rather limits those disclosures to investments for which the practical expedient has been elected. This guidance will be effective for the Company on January 1, 2016, with early adoption permitted. The Company is evaluating the effects the adoption of the new guidance will have on its disclosures, however it will not impact the Company's results of operations, financial position or cash flows.

Simplifying the Measurement of Inventory In July 2015, the FASB issued guidance regarding inventory that is measured using the first-in, first-out or average cost method. The guidance does not apply to inventory measured using the last-in, first-out or the retail inventory method. The guidance requires inventory within its scope to be measured at the lower of cost or net realizable value, which is the estimated selling price in the normal course of business less reasonably predictable costs of completion, disposal and transportation. These amendments more closely align GAAP with International Financial Reporting Standards. This guidance will be effective for the Company on January 1, 2017, and should be applied prospectively with early adoption permitted as of the beginning of an interim or annual reporting period. The Company is evaluating the effects the adoption of the new guidance will have on its results of operations, financial position and cash flows.

Note 9 - Comprehensive income (loss)

The following tables include reclassification adjustments for gains (losses) on derivative instruments qualifying as hedges included in income (loss) from discontinued operations. The after-tax changes in the components of accumulated other comprehensive loss were as follows:

Three Months Ended September 30, 2015	Net Unrealized Gain (Loss) on	Postretirement Liability Adjustment	Foreign Currency Translation	Net Unrealized Gain (Loss) on Available-for-sale	Total Accumulated Other

	Derivative Instruments Qualifying as Hedges (In thousands)		Adjustment	Investments	Comprehensive Loss
Balance at beginning of period	$(2,872)	$(37,259)	$(130)	$ 15	$(40,246)
Other comprehensive loss before reclassifications	—	—	(73)	(35)	(108)
Amounts reclassified from accumulated other comprehensive loss	100	382	—	28	510
Net current-period other comprehensive income (loss)	100	382	(73)	(7)	402
Balance at end of period	$(2,772)	$(36,877)	$(203)	$ 8	$(39,844)

Three Months Ended September 30, 2014	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges (In thousands)	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
Balance at beginning of period	$(3,408)	$(33,287)	$(579)	$ 76	$(37,198)
Other comprehensive loss before reclassifications	—	—	(146)	(62)	(208)
Amounts reclassified from accumulated other comprehensive loss	82	261	—	31	374
Net current-period other comprehensive income (loss)	82	261	(146)	(31)	166
Balance at end of period	$(3,326)	$(33,026)	$(725)	$ 45	$(37,032)

Nine Months Ended September 30, 2015	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges (In thousands)	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
Balance at beginning of period	$(3,071)	$(38,218)	$(829)	$ 15	$(42,103)
Other comprehensive loss before reclassifications	—	—	(176)	(105)	(281)
Amounts reclassified from accumulated other comprehensive loss	299	1,341	802	98	2,540
Net current-period other comprehensive income (loss)	299	1,341	626	(7)	2,259
Balance at end of period	$(2,772)	$(36,877)	$(203)	$ 8	$(39,844)

Nine Months Ended September 30, 2014	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges (In thousands)	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
Balance at beginning of period	$(3,765)	$(33,807)	$(667)	$ 34	$(38,205)
Other comprehensive loss before reclassifications	—	—	(58)	(89)	(147)
Amounts reclassified from accumulated other comprehensive loss	439	781	—	100	1,320
Net current-period other comprehensive income (loss)	439	781	(58)	11	1,173
Balance at end of period	$(3,326)	$(33,026)	$(725)	$ 45	$(37,032)

Reclassifications out of accumulated other comprehensive loss were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,		Location on Consolidated Statements of Income
	2015	2014	2015	2014	
	(In thousands)				
Reclassification adjustment for loss on derivative instruments included in net income (loss):					
Interest rate derivative instruments	$(160)	$(160)	$(480)	$(480)	Interest expense
	60	60	181	181	Income taxes
	(100)	(100)	(299)	(299)	
Commodity derivative instruments, net of tax	—	18	—	(140)	Income (loss) from discontinued operations, net of tax
	(100)	(82)	(299)	(439)	
Amortization of postretirement liability losses included in net periodic benefit cost (credit)	(615)	(420)	(2,222)	(1,258)	(a)
	233	159	881	477	Income taxes
	(382)	(261)	(1,341)	(781)	
Reclassification adjustment for loss on foreign currency translation adjustment included in net income (loss)	—	—	(1,293)	—	Other income
	—	—	491	—	Income taxes
	—	—	(802)	—	
Reclassification adjustment for loss on available-for-sale investments included in net income (loss)	(43)	(47)	(151)	(154)	Other income
	15	16	53	54	Income taxes
	(28)	(31)	(98)	(100)	
Total reclassifications	$(510)	$(374)	$(2,540)	$(1,320)	

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

Note 10 - Discontinued operations

In the second quarter of 2015, the Company began the marketing and sale process of Fidelity with an anticipated sale to occur within one year. In the third and fourth quarters of 2015, the Company entered into purchase and sale agreements to sell the vast majority of Fidelity's assets, comprising greater than 90 percent of production for the nine months ended September 30, 2015. The completion of these sales is expected to occur in the fourth quarter of 2015 and the Company continues to market the remaining assets of Fidelity. The sale of Fidelity is part of the Company's strategic plan to grow its capital investments in the remaining business segments and to focus on creating a greater long-term value. The assets and liabilities for these operations have been classified as held for sale and the results of operations are shown in income (loss) from discontinued operations, other than certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. The Company's consolidated financial statements and accompanying notes for current and prior periods have been restated. At the time the assets were classified as held for sale, depreciation, depletion and amortization expense was no longer recorded.

15

The carrying amounts of the major classes of assets and liabilities that are classified as held for sale on the Company's Consolidated Balance Sheets were as follows:

	September 30, 2015	September 30, 2014	December 31, 2014
	(In thousands)		
Assets			
Current assets:			
Receivables, net	$24,703	$117,098	$94,132
Inventories	7,034	13,504	11,401
Commodity derivative instruments	8,633	11,322	18,335
Prepayments and other current assets	42,762	2,114	7,309
Total current assets held for sale	83,132	144,038	131,177
Noncurrent assets:			
Investments	37	37	37
Net property, plant and equipment	1,114,285	1,609,385	1,618,099
Deferred income taxes	141,556	—	—
Other	162	2,635	2,334
Less allowance for impairment of assets held for sale	756,127	—	—
Total noncurrent assets held for sale	499,913	1,612,057	1,620,470
Total assets held for sale	$583,045	$1,756,095	$1,751,647
Liabilities			
Current liabilities:			
Long-term debt due within one year	$—	$528	$897
Accounts payable	32,375	141,877	103,556
Taxes payable	3,769	39,693	19,900
Deferred income taxes	4,955	4,005	8,206
Accrued compensation	5,982	6,622	5,373
Commodity derivative instruments	—	44	—
Other accrued liabilities	11,820	27,342	16,796
Total current liabilities held for sale	58,901	220,111	154,728
Noncurrent liabilities:			
Long-term debt	—	510	—
Deferred income taxes	—	212,640	238,391
Other liabilities	31,242	58,162	57,050
Total noncurrent liabilities held for sale	31,242	271,312	295,441
Total liabilities held for sale	$90,143	$491,423	$450,169

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the second quarter of 2015, the estimated fair value was determined using the income and the market approaches. The income approach was determined by using the present value of future estimated cash flows. The income approach considered management’s views on current operating measures as well as assumptions pertaining to market forces in the oil and gas industry including estimated reserves, estimated prices, market differentials, estimates of well operating and future development costs and timing of operations. The estimated cash flows were discounted using a rate believed to be consistent with those used by principal market participants. The market approach was provided by a third party and based on market transactions involving similar interests in oil and natural gas properties. The fair value assessment indicated an impairment based on the carrying value exceeding the estimated fair value, which resulted in the Company writing down Fidelity’s assets at June 30, 2015, and recording an impairment of $400.0 million ($252.0 million after tax) during the second quarter of 2015. In the third quarter of 2015, the estimated fair value of Fidelity was determined by agreed upon pricing in the purchase and sale agreements for the assets subject to the agreements, which are expected to close in the fourth quarter of 2015 including customary purchase price adjustments. The values received in the bid proposals were lower than originally anticipated due to lower commodity prices than those projected in the second quarter of 2015. For those assets for which a purchase and sale agreement has not been entered into, which the Company is continuing to market, the fair value has been determined based on the market approach utilizing multiples based on similar interests in oil and natural gas properties. This fair value assessment indicated an impairment based on the current carrying value exceeding the estimated fair value, which resulted in the Company writing down Fidelity’s assets at September 30, 2015, and recording an impairment of $356.1 million ($224.4 million after tax) during the third quarter of 2015. The impairments were included in operating expenses from discontinued operations. Included in the fair value assessment at September 30, 2015, are liabilities of approximately $3 million for estimated transaction costs which will result in future cash expenditures. The estimated fair value of Fidelity's assets have been categorized as Level 3 in the fair value hierarchy.

In addition to the estimated transaction costs in the preceding paragraph, and due in part to the change in plans to now sell the assets of Fidelity rather than sell Fidelity as a company, Fidelity expects to incur approximately $11 million of exit and disposal costs associated with severance and other related matters, excluding the office lease expenses discussed in the following paragraph. The majority of these exit and disposal activities are expected to be completed by the end of the second quarter of 2016.

Fidelity plans to vacate its office space in Denver, Colorado, and is currently attempting to sublease the space. The expected future payments required under the lease agreement are approximately $12 million. This future obligation will decrease if Fidelity successfully executes sublease agreements.

Unforeseen events and changes in circumstances and market conditions and material differences in the value of the assets held for sale due to changes in estimates of future cash flows could negatively affect the estimated fair value of Fidelity and result in additional impairment charges. Various factors, including oil and natural gas prices, market differentials and changes in estimates of reserve quantities could result in future impairments of the Company's assets held for sale.

Historically, the Company used 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.

Prior to the oil and natural gas properties being classified as held for sale, capitalized costs were 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, were used to calculate the ceiling test. Accordingly, the Company was required to write down its oil and natural gas producing properties. The Company recorded a $500.4 million ($315.3 million after tax) noncash write-down in operating expenses from discontinued operations in the first quarter of 2015.

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 and had a benefit related to the resolution of this matter in the second quarter of 2014, which are reflected in discontinued operations in the consolidated financial statements and accompanying notes.

The reconciliation of the major classes of income and expense constituting pretax income (loss) from discontinued operations to the after-tax net income (loss) from discontinued operations on the Company's Consolidated Statements of Income were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Operating revenues	$58,077	$155,807	$156,100	$432,922
Operating expenses	378,361	97,982	1,394,039	299,290
Operating income (loss)	(320,284)	57,825	(1,237,939)	133,632
Other income	100	138	2,170	1,163
Interest expense	174	23	229	80
Income (loss) from discontinued operations before income taxes	(320,358)	57,940	(1,235,998)	134,715

Income taxes	(117,732)	19,458	(457,351)	47,240
Income (loss) from discontinued operations	$(202,626)	$38,482	$(778,647)	$87,475

Note 11 - Goodwill and other intangible assets

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

Nine Months Ended September 30, 2015	Balance as of January 1, 2015 *	Goodwill Acquired During the Year	Balance as of September 30, 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.

Nine Months Ended September 30, 2014	Balance as of January 1, 2014 *	Goodwill Acquired During the Year	Balance as of September 30, 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:

	September 30, 2015	September 30, 2014	December 31, 2014
	(In thousands)		
Customer relationships	$20,975	$21,310	$21,310
Accumulated amortization	(16,455)	(15,116)	(15,556)
	4,520	6,194	5,754
Noncompete agreements	4,409	5,080	5,080

Accumulated amortization	(3,632)	(4,021)	(4,098)
	777	1,059	982
Other	8,300	10,921	10,921
Accumulated amortization	(5,689)	(7,578)	(7,817)
	2,611	3,343	3,104
Total	$7,908	$10,596	$9,840

18

Amortization expense for amortizable intangible assets for the three and nine months ended September 30, 2015, was $600,000 and $2.0 million, respectively. Amortization expense for amortizable intangible assets for the three and nine months ended September 30, 2014, was $700,000 and $2.5 million, 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 September 30, 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 September 30, 2015 and 2014, and December 31, 2014, Fidelity held oil swap agreements with total forward notional volumes of 552,000, 1.4 million and 270,000 Bbl, respectively, and natural gas swap agreements with total forward notional volumes of 920,000, 7.3 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. The gains and losses on the commodity derivative instruments held by Fidelity are included in income (loss) from discontinued operations and the associated assets and liabilities are classified as held for sale.

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 income (loss) from discontinued operations 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 remained in accumulated other comprehensive income (loss) as of the de-designation date and were reclassified into earnings in future periods as the underlying hedged transactions affected 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 income (loss) from discontinued operations 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 September 30, 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 September 30, 2014, were $44,000. The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on September 30, 2014, was $44,000.

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 September 30, 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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Commodity derivatives designated as cash flow hedges:				
Amount of (gain) loss reclassified from accumulated other comprehensive loss into discontinued operations (effective portion), net of tax	$—	$(18)	$—	$140
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	100	100	299	299
Commodity derivatives not designated as hedging instruments:				
Amount of gain (loss) recognized in discontinued operations, before tax	9,607	28,755	(9,702)	16,847

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 September 30, 2015	Fair Value at September 30, 2014	Fair Value at December 31, 2014
		(In thousands)		
Not designated as hedges:				
Commodity derivatives	Current assets held for sale	$8,633	$11,322	$18,335
	Noncurrent assets held for sale	—	259	—
Total asset derivatives		$8,633	$11,581	$18,335

Liability Derivatives	Location on Consolidated Balance Sheets	Fair Value at September 30, 2015	Fair Value at September 30, 2014	Fair Value at December 31, 2014
		(In thousands)		
Not designated as hedges:				
Commodity derivatives	Current liabilities held for sale	$—	$44	$—
Total liability derivatives		$—	$44	$—

All of the Company's commodity derivative instruments at September 30, 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:

September 30, 2015	Gross Amounts Recognized on the Consolidated Balance Sheets	Gross Amounts Not Offset on the Consolidated Balance Sheets	Net
	(In thousands)		

Assets:			
Commodity derivatives	$8,633	$—	$8,633
Total assets	$8,633	$—	$8,633

20

September 30, 2014	Gross Amounts Recognized on the Consolidated Balance Sheets	Gross Amounts Not Offset on the Consolidated Balance Sheets	Net
	(In thousands)		
Assets:			
Commodity derivatives	$11,581	$(44)	$11,537
Total assets	$11,581	$(44)	$11,537
Liabilities:			
Commodity derivatives	$44	$(44)	$—
Total liabilities	$44	$(44)	$—

December 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	$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 $66.5 million, $63.6 million and $65.8 million, at September 30, 2015 and 2014, and December 31, 2014, respectively, are classified as Investments on the Consolidated Balance Sheets. The net unrealized loss on these investments was $1.7 million for the three months ended September 30, 2015, and the net unrealized gain on these investments was $700,000 for the nine months ended September 30, 2015. The net unrealized loss on these investments was $800,000 for the three months ended September 30, 2014, and the net unrealized gain on these investments was $1.2 million for the nine months ended September 30, 2014. 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:

September 30, 2015	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Mortgage-backed securities	$7,843	$29	$(18)	$7,854
U.S. Treasury securities	2,324	4	(4)	2,324
Total	$10,167	$33	$(22)	$10,178

September 30, 2014	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Mortgage-backed securities	$7,838	$71	$(8)	$7,901

U.S. Treasury securities	2,368	8	(2	)2,374
Total	$10,206	$79	$(10	)$10,275

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

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 are valued at the net asset value of shares held at the end of the quarter, based on published market quotations on active markets, or using other known sources including pricing from outside sources. Units of these funds can be redeemed on a daily basis at their net asset value and have no redemption restrictions. The assets are invested in high-quality, short-term money market instruments that consist of municipal obligations. There are no unfunded commitments related to these funds.

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 RIN obligations are based on the market approach using quoted prices from an independent pricing service. RINs are assigned to biofuels produced or imported into the United States as required by the EPA, which sets annual quotas for the percentage of biofuels that must be blended into transportation fuels consumed in the United States. As a producer of diesel fuel, Dakota Prairie Refinery is required to blend biofuels into the fuel it produces at a rate that will meet the EPA's quota. RINs are purchased in the open market to satisfy the requirement as Dakota Prairie Refinery is currently unable to blend biofuels into the diesel fuel it produces.

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 nine months ended September 30, 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 September 30, 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 September 30, 2015
	(In thousands)			
Assets:				
Money market funds	$—	$1,219	$—	$1,219
Insurance contract*	—	66,464	—	66,464
Available-for-sale securities:				
Mortgage-backed securities	—	7,854	—	7,854
U.S. Treasury securities	—	2,324	—	2,324

Total assets measured at fair value	$—	$77,861	$—	$77,861
Liabilities:				
RIN obligations	$—	$1,170	$—	$1,170
Total liabilities measured at fair value	$—	$1,170	$—	$1,170

* The insurance contract invests approximately 9 percent in common stock of mid-cap companies, 6 percent in common stock of small-cap companies, 18 percent in common stock of large-cap companies, 65 percent in fixed-income investments, 1 percent in target date investments and 1 percent in cash equivalents.

	Fair Value Measurements at September 30, 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 September 30, 2014
	(In thousands)			
Assets:				
Money market funds	$—	$684	$—	$684
Insurance contract*	—	63,578	—	63,578
Available-for-sale securities:				
Mortgage-backed securities	—	7,901	—	7,901
U.S. Treasury securities	—	2,374	—	2,374
Total assets measured at fair value	$—	$74,537	$—	$74,537

* The insurance contract invests approximately 21 percent in common stock of mid-cap companies, 17 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.

	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	$—	$890	$—	$890
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
Total assets measured at fair value	$—	$76,912	$—	$76,912

* 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 applies the provisions of the fair value measurement standard to its nonrecurring, non-financial measurements, including long-lived asset impairments. These assets are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances. The Company reviews the carrying value of its long-lived assets, excluding goodwill, whenever events or changes in circumstances indicate that such carrying amounts may not be recoverable.

During the second quarter of 2015, natural gas gathering assets at the pipeline and energy services segment were reviewed for impairment and found to be impaired and were written down to their estimated fair value using the income approach. Under this approach, fair value is determined by using the present value of future estimated cash flows. The factors used to determine the estimated future cash flows include, but are not limited to, internal estimates of gathering revenue, future commodity prices and operating costs and equipment salvage values. The estimated cash flows are discounted using a rate that approximates the weighted average cost of capital of a market participant. These fair value inputs are not typically observable. At June 30, 2015, natural gas gathering assets were written down to the nonrecurring fair value measurement of $1.1 million.

The Company is negotiating the sale of certain non-strategic natural gas gathering assets at the pipeline and energy services segment and as a result these assets were found to be impaired in the third quarter of 2015 and were written down to their estimated fair value using the market approach. The estimated fair value of natural gas gathering assets that were impaired at September 30, 2015, was largely determined by agreed upon pricing in a purchase and sale agreement that the Company is negotiating. At September 30, 2015, natural gas gathering assets were written down to the nonrecurring fair value measurement of $10.8 million.

The fair value of these natural gas gathering assets have been categorized as Level 3 in the fair value hierarchy.

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. For more information on this Level 3 nonrecurring fair value measurement, see Note 10.

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 September 30, 2015	$2,275,105	$2,350,475
Long-term debt at September 30, 2014	$2,209,519	$2,331,848
Long-term debt at December 31, 2014	$2,093,830	$2,238,548

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:

Nine Months Ended September 30, 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	(674,969)	(21,060)	(696,029)
Other comprehensive income	2,259	—	2,259
Dividends declared on preferred stocks	(514)	—	(514)
Dividends declared on common stock	(106,714)	—	(106,714)
Stock-based compensation	2,266	—	2,266
Net tax deficit on stock-based compensation	(1,632)	—	(1,632)
Issuance of common stock	21,894	—	21,894
Contribution from noncontrolling interest	—	52,000	52,000
Distribution to noncontrolling interest	—	(8,443)	(8,443)
Balance at September 30, 2015	$2,376,631	$138,240	$2,514,871

Nine Months Ended September 30, 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)	213,978	(2,390)	211,588
Other comprehensive income	1,173	—	1,173
Dividends declared on preferred stocks	(514)	—	(514)
Dividends declared on common stock	(102,461)	—	(102,461)
Stock-based compensation	4,257	—	4,257
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	144,493	—	144,493
Contribution from noncontrolling interest	—	44,900	44,900
Balance at September 30, 2014	$3,083,255	$75,248	$3,158,503

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 operates Dakota Prairie Refinery in conjunction with Calumet to refine crude oil. The facility produces and sells diesel fuel, naphtha and ATBs. This segment also provides cathodic protection and other energy-related services.

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 includes certain general and administrative costs (reflected in operation and maintenance expense) and interest expense which were previously allocated to Fidelity and do not meet the criteria for income (loss) from discontinued operations. The Other category also includes Centennial Resources' former investment in the Brazilian Transmission Lines.

Discontinued operations includes the results of Fidelity other than certain general and administrative costs and interest expense as described above. Fidelity 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. In the third and fourth quarters of 2015, the Company entered into purchase and sale agreements to sell the vast majority of Fidelity's assets, comprising greater than 90 percent of production for the nine months ended September 30, 2015. The completion of these sales is expected to occur in the fourth quarter of 2015 and the Company continues to market the remaining assets of Fidelity. Discontinued operations also includes legal expenses and a benefit related to the vacation of an arbitration award in 2014 related to Centennial Resources. For more information on discontinued operations, see Note 10.

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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
External operating revenues:				
Regulated operations:				
Electric	$74,604	$68,936	$210,646	$207,732
Natural gas distribution	89,520	96,185	553,058	616,496
Pipeline and energy services	21,100	19,672	43,282	39,341
	185,224	184,793	806,986	863,569
Nonregulated operations:				
Pipeline and energy services	96,896	17,168	174,732	47,028
Construction materials and contracting	774,288	740,496	1,475,585	1,339,371
Construction services	223,676	270,313	670,594	815,313
Other	416	433	1,167	1,248
	1,095,276	1,028,410	2,322,078	2,202,960
Total external operating revenues	$1,280,500	$1,213,203	$3,129,064	$3,066,529

25

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Intersegment operating revenues:				
Regulated operations:				
Electric	$—	$—	$—	$—
Natural gas distribution	—	—	—	—
Pipeline and energy services	3,740	3,728	31,365	27,938
	3,740	3,728	31,365	27,938
Nonregulated operations:				
Pipeline and energy services	145	174	460	544
Construction materials and contracting	244	6,322	2,450	18,445
Construction services	2,112	16,420	17,298	27,431
Other	2,379	2,601	5,943	6,069
	4,880	25,517	26,151	52,489
Intersegment eliminations	(8,620)	(29,245)	(57,516)	(80,427)
Total intersegment operating revenues	$—	$—	$—	$—
Earnings (loss) on common stock:				
Regulated operations:				
Electric	$12,605	$9,162	$26,842	$28,018
Natural gas distribution	(12,298)	(12,252)	3,777	10,516
Pipeline and energy services	5,392	3,887	15,077	10,499
	5,699	797	45,696	49,033
Nonregulated operations:				
Pipeline and energy services	(14,903)	1,173	(22,175)	4,699
Construction materials and contracting	68,823	55,218	74,324	42,199
Construction services	4,742	9,876	16,505	40,751
Other	(1,380)	(864)	(9,537)	(7,623)
	57,282	65,403	59,117	80,026
Intersegment eliminations	26	(1,644)	(1,649)	(3,070)
Earnings on common stock before income (loss) from discontinued operations	63,007	64,556	103,164	125,989
Income (loss) from discontinued operations, net of tax	(202,626)	38,482	(778,647)	87,475
Total earnings (loss) on common stock	$(139,619)	$103,038	$(675,483)	$213,464

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 (credit) for the Company's pension and other postretirement benefit plans were as follows:

	Pension Benefits		Other Postretirement Benefits	
Three Months Ended September 30,	2015	2014	2015	2014
	(In thousands)			
Components of net periodic benefit cost (credit):				
Service cost	$—	$32	$454	$379
Interest cost	4,285	4,420	902	919
Expected return on assets	(5,563)	(5,304)	(1,199)	(1,154)
Amortization of prior service cost (credit)	—	18	(343)	(348)
Amortization of net actuarial loss	1,734	1,217	511	162
Net periodic benefit cost (credit), including amount capitalized	456	383	325	(42)
Less amount capitalized	90	27	36	(65)
Net periodic benefit cost (credit)	$366	$356	$289	$23

	Pension Benefits		Other Postretirement Benefits	
Nine Months Ended September 30,	2015	2014	2015	2014
	(In thousands)			
Components of net periodic benefit cost (credit):				
Service cost	$86	$96	$1,362	$1,138
Interest cost	12,855	13,265	2,705	2,701
Expected return on assets	(16,689)	(15,913)	(3,597)	(3,463)
Amortization of prior service cost (credit)	36	54	(1,028)	(1,044)
Amortization of net actuarial loss	5,282	3,651	1,525	486
Curtailment loss	258	—	—	—
Net periodic benefit cost (credit), including amount capitalized	1,828	1,153	967	(182)
Less amount capitalized	219	195	98	(55)
Net periodic benefit cost (credit)	$1,609	$958	$869	$(127)

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 these plans for the three and nine months ended September 30, 2015, was $1.7 million and $5.3 million, respectively. The Company's net periodic benefit cost for these plans for the three and nine months ended September 30, 2014, was $1.7 million and $5.0 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. The cumulative withdrawal liability is currently estimated at $16.4 million which has been accrued on the Consolidated Balance Sheets. 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 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. On August 26, 2015, Montana-Dakota and the Advocacy Staff of the NDPSC filed a settlement agreement that resolved all issues of the application and reflected a natural gas rate increase of $2.6 million annually or approximately 2.0 percent above rates in effect for service rendered prior to April 7, 2015. A technical hearing was held on August 31 and September 1, 2015. On November 4, 2015, the NDPSC approved the settlement agreement.

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 November 2, 2015, Cascade, staff of the OPUC, the Citizens' Utility Board of Oregon and the Northwest Industrial Gas Users filed a settlement agreement that resolved all issues of the application and reflected a natural gas rate increase of approximately $600,000 annually or approximately 0.8 percent, to be effective February 1, 2016. This matter is pending before the OPUC.

On April 10, 2015, Montana-Dakota submitted a required annual request to the NDPSC to update the electric rate 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, consistent with revenues previously included in the rider. The NDPSC approved the requested rider to be effective with service rendered on and after July 1, 2015.

On June 24, 2015, Cascade filed an expedited application with the WUTC for a natural gas rate increase. Cascade requested a total increase of approximately $3.9 million annually or approximately 1.6 percent above current rates. The requested increase includes costs associated with increased infrastructure investment and the associated operating expenses. A public meeting was held on August 27, 2015, where Cascade withdrew the filing after the WUTC indicated its intention to suspend the filing. Cascade plans to file a full application for a natural gas rate increase in the fourth quarter of 2015.

On June 25, 2015, Montana-Dakota filed an application for an electric rate increase with the MTPSC. Montana-Dakota requested a total increase of approximately $11.8 million annually or approximately 21.1 percent above current rates. The increase is necessary to recover Montana-Dakota’s investments in modifications to generation facilities to comply with new EPA requirements, the addition and/or replacement of capacity and energy requirements and transmission facilities along with the additional depreciation, operation and maintenance expenses and taxes associated with the increases in investment. Montana-Dakota requested an interim increase of approximately $11.0 million annually, subject to refund, which is pending before the MTPSC. A technical hearing has been scheduled for February 9, 2016.

On June 30, 2015, Montana-Dakota filed an application with the SDPUC for an electric rate increase. Montana-Dakota requested a total increase of approximately $2.7 million annually or approximately 19.2 percent above current rates. The increase is necessary to recover Montana-Dakota’s investments in modifications to generation facilities to comply with new EPA requirements, the addition and/or replacement of capacity and energy requirements and transmission facilities along with the additional depreciation, operation and maintenance expenses and taxes associated with the increases in investment. This matter is pending before the SDPUC.

On June 30, 2015, Montana-Dakota filed an application for a natural gas rate increase with the SDPUC. Montana-Dakota requested a total increase of approximately $1.5 million annually or approximately 3.1 percent above current rates. The increase is necessary to recover increased operating expenses along with increased investment in facilities, including the related depreciation expense and taxes, partially offset by an increase in customers and throughput. This matter is pending before the SDPUC.

On September 1, 2015, and as amended on October 5, 2015, Montana-Dakota submitted an update to its transmission formula rate under the MISO tariff including a revenue requirement for the Company’s multivalue project of $3.8 million to be effective January 1, 2016.

On September 30, 2015, Great Plains filed an application for a natural gas rate increase with the MNPUC. Great Plains requested a total increase of approximately $1.6 million annually or approximately 6.4 percent above current rates. The increase is necessary to recover increased operating expenses along with increased investment in facilities, including the related depreciation expense and taxes. Great Plains requested an interim increase of $1.5 million or approximately 6.4 percent, subject to refund, to be effective January 1, 2016. This matter is pending before the MNPUC.

On October 21, 2015, Montana-Dakota filed an application with the NDPSC for an update of an electric generation resource recovery rider and requested a renewable resource cost adjustment rider. Montana-Dakota requested a combined total of approximately $25.3 million with approximately $20.0 million incremental to current rates, to be effective January 1, 2016. The electric generation resource recovery rider includes recovery of Montana-Dakota's investment in the 88-MW simple-cycle natural gas turbine and associated facilities near Mandan, North Dakota, as well as 19 MW of new generation from natural gas-fired internal combustion engines and associated facilities, near Sidney, Montana, anticipated to be in service in the fourth quarter of 2015. The renewable resource cost adjustment rider is for the recovery of the Thunder Spirit Wind project, also anticipated to be in service in the fourth quarter of 2015.

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 $21.4 million, $31.9 million and $27.6 million, which include liabilities held for sale, for contingencies, including litigation, production taxes, royalty claims and environmental matters at September 30, 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. WBI Energy Midstream expects to resolve this matter through settlement.

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.

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.

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 presented cost of repair estimates totaling approximately $21 million for alleged plumbing and mechanical system defects associated in whole or in part with work performed by Bombard Mechanical. 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.

Coos County The Oregon DEQ issued a Notice of Civil Penalty to LTM dated October 12, 2015, asserting violations of Oregon water quality statutes and rules resulting from the stockpiling and grading of earthen material during 2014 at a site in Coos County and assessing civil penalties totaling approximately $160,000. The Notice of Civil Penalty alleges violations by causing pollution to an intermittent creek, by conducting activity described in a general National Pollutant Discharge Elimination System permit without applying for coverage under the general permit, by placing the earthen materials in a location where they were likely to escape or be carried into waters of the state, and by failing to submit a revised ESCP where there was a change in the size of the project or the location of the disturbed area. The Notice of Civil Penalty also requires LTM to submit a revised ESCP containing measures to prevent further erosion from entering the intermittent creek and to file a work plan outlining how the earthen material will be permanently stabilized or removed. LTM intends to request a contested case hearing on the Notice of Civil Penalty.

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. The 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 $12.2 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 2009, multiple sales agreements were signed to sell the Company's ownership interests in the Brazilian Transmission Lines. In connection with the sale, 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. 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 September 30, 2015, expire in 2015. There were no amounts outstanding by Fidelity at September 30, 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 September 30, 2015, the fixed maximum amounts guaranteed under these agreements aggregated $125.9 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $2.8 million in 2015; $26.4 million in 2016; $22.9 million in 2017; $500,000 in 2018; $56.8 million in 2019; $12.5 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 September 30, 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 September 30, 2015, the fixed maximum amounts guaranteed under these letters of credit aggregated $51.9 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these letters of credit aggregate $12.9 million in 2015; $34.8 million in 2016; and $4.2 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above letters of credit was $1.5 million and was reflected on the Consolidated Balance Sheet at September 30, 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 September 30, 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 September 30, 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 September 30, 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 September 30, 2015, approximately $538.1 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. WBI Energy's and Calumet's cumulative capital contributions, net of distributions, as of September 30, 2015, are $230.4 million and $163.6 million, respectively. 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. The net loss attributable to noncontrolling interest on the Consolidated Statements of Income is pretax as Dakota Prairie Refining is a limited liability company.

On September 30, 2015, Dakota Prairie Refining entered into an amendment to its revolving credit agreement which increased the borrowing limit from $50 million under the original December 1, 2014, agreement to $75 million and extended the termination date from December 1, 2015 to June 30, 2016. Pursuant to the revolving credit agreement, Centennial has issued a letter of credit supporting 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 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:

	September 30, 2015	September 30, 2014	December 31, 2014
	(In thousands)		
Assets			
Current assets:			
Cash and cash equivalents	$625	$16,723	$21,376
Accounts receivable	14,648	150	2,759
Inventories	12,354	—	5,311
Other current assets	7,125	4,187	4,019
Total current assets	34,752	21,060	33,465
Net property, plant and equipment	428,383	314,551	398,984
Deferred charges and other assets:			
Other	5,052	—	3,400
Total deferred charges and other assets	5,052	—	3,400
Total assets	$468,187	$335,611	$435,849
Liabilities			
Current liabilities:			
Short-term borrowings	$29,500	$—	$—
Long-term debt due within one year	4,125	3,000	3,000
Accounts payable	21,686	36,541	55,089
Taxes payable	1,630	323	648
Accrued compensation	1,059	617	727
Other accrued liabilities	1,217	633	899
Total current liabilities	59,217	41,114	60,363
Long-term debt	64,875	69,000	69,000
Total liabilities	$124,092	$110,114	$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 September 30, 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 September 30, 2015, was $33.9 million.

Note 19 - Subsequent events

On October 1, 2015, MDU Energy Capital entered into a note purchase agreement and issued $50.0 million of Senior Notes with a due date of October 1, 2030, at an interest rate of 4.31 percent.

On October 29, 2015, the Company entered into a $150.0 million note purchase agreement and issued $98.0 million of Senior Notes with due dates ranging from October 30, 2025 to October 30, 2045, at a weighted average interest rate of 3.90 percent. The remaining $52.0 million of Senior Notes will be issued on December 10, 2015, with a due date of

December 10, 2030, at an interest rate of 4.03 percent.

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 its discontinued operations, and certain related business challenges are summarized below. For a summary of the Company's businesses, 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 and transmission 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 and refined product price volatility; tight basis differentials; environmental and regulatory requirements; recruitment and retention of a skilled workforce; and competition from other pipeline and energy services companies.

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, are ongoing challenges. 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.

Discontinued Operations

Strategy The Company is marketing and plans to sell its Fidelity assets and exit that line of business. Until such sale is accomplished, Fidelity will apply technology and utilize existing expertise to maintain production from existing leaseholds.

Challenges Risks and uncertainties associated with the marketing and sale of Fidelity including no assurance that a sale of all marketed assets will be successful; current oil and natural gas low-price environment; and retention of a skilled workforce.

Additional Information

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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(Dollars in millions, where applicable)			
Electric	$12.6	$9.2	$26.8	$28.0
Natural gas distribution	(12.3)	(12.3)	3.8	10.5
Pipeline and energy services	(9.5)	5.1	(7.1)	15.2
Construction materials and contracting	68.8	55.2	74.3	42.2
Construction services	4.7	9.9	16.5	40.8
Other	(1.3)	(1.0)	(9.6)	(7.6)
Intersegment eliminations	—	(1.6)	(1.6)	(3.1)
Earnings before discontinued operations	63.0	64.5	103.1	126.0
Income (loss) from discontinued operations, net of tax	(202.6)	38.5	(778.6)	87.5
Earnings (loss) on common stock	$(139.6)	$103.0	$(675.5)	$213.5
Earnings (loss) per common share – basic:				
Earnings before discontinued operations	$.32	$.33	$.53	$.66
Discontinued operations, net of tax	(1.04)	.20	(4.00)	.45
Earnings (loss) per common share – basic	$(.72)	$.53	$(3.47)	$1.11
Earnings (loss) per common share – diluted:				
Earnings before discontinued operations	$.32	$.33	$.53	$.66
Discontinued operations, net of tax	(1.04)	.20	(4.00)	.45
Earnings (loss) per common share – diluted	$(.72)	$.53	$(3.47)	$1.11

Three Months Ended September 30, 2015 and 2014 The Company recognized a consolidated loss of $139.6 million for the quarter ended September 30, 2015, compared to consolidated earnings of $103.0 million from the comparable prior period largely due to:

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Discontinued operations which had a fair value impairment of the Company's assets held for sale of $224.4 million (after tax); lower average realized oil prices, excluding gain/loss on commodity derivatives; and lower unrealized gain on commodity derivatives; partially offset by lower depreciation, depletion and amortization expense

- Impairments of natural gas gathering assets of $8.7 million (after tax) and a higher loss at Dakota Prairie Refinery at the pipeline and energy services business
- Lower equipment sales and rental margins and lower workloads and margins in the Western region at the construction services business

Partially offsetting these decreases were higher earnings on all product lines at the construction materials and contracting business and higher retail sales margins at the electric business.

Nine Months Ended September 30, 2015 and 2014 The Company recognized a consolidated loss of $675.5 million for the nine months ended September 30, 2015, compared to consolidated earnings of $213.5 million from the comparable prior period largely due to:

- Discontinued operations which had a fair value impairment of the Company's assets held for sale of $476.4 million (after tax); a $315.3 million after-tax noncash write-down of oil and natural gas properties; lower average realized oil prices, excluding gain/loss on commodity derivatives; and decreased oil production; partially offset by lower depreciation, depletion and amortization expense
- Lower workloads and margins in the Western region and lower margins in the Central region at the construction services business
- Impairments of natural gas gathering assets of $10.6 million (after tax) and a higher loss at Dakota Prairie Refinery at the pipeline and energy services business
- Lower retail sales volumes offset in part by natural gas retail rate increases at the natural gas distribution business

Partially offsetting these decreases were higher earnings on all product lines 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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(Dollars in millions, where applicable)			
Operating revenues	$74.6	$69.0	$210.7	$207.8
Operating expenses:				
Fuel and purchased power	20.6	19.2	63.8	66.8
Operation and maintenance	21.5	21.4	65.1	60.4
Depreciation, depletion and amortization	9.5	8.8	28.1	25.9
Taxes, other than income	3.0	2.8	9.1	8.4
	54.6	52.2	166.1	161.5
Operating income	20.0	16.8	44.6	46.3
Earnings	$12.6	$9.2	$26.8	$28.0
Retail sales (million kWh)	823.1	769.5	2,475.8	2,420.0
Average cost of fuel and purchased power per kWh	$.024	$.023	$.024	$.026

Three Months Ended September 30, 2015 and 2014 Electric earnings increased $3.4 million (38 percent) due to:

- Higher retail sales margins, primarily increased sales volumes of 7 percent to all customer classes, as well as rate recovery of new generation
- Higher other income, which includes $1.4 million (after tax) primarily related to allowance for funds used during construction

Partially offsetting these increases were higher depreciation, depletion and amortization expense of $400,000 (after tax) due to increased property, plant and equipment balances.

Nine Months Ended September 30, 2015 and 2014 Electric earnings decreased $1.2 million (4 percent) due to:

- Higher operation and maintenance expense, which includes $3.0 million (after tax) primarily due to higher contract services, primarily related to a planned outage at an electric generation station, and higher payroll and benefit-related costs
- Higher depreciation, depletion and amortization expense of $1.4 million (after tax) due to increased property, plant and equipment balances
- Higher net interest expense, which includes $1.3 million (after tax) largely related to higher long-term debt

Partially offsetting these decreases were:

- Increased retail sales margins, primarily due to rate recovery of new generation, as well as increased sales volumes of 2 percent, primarily to commercial and industrial customers
- Higher other income, which includes $1.2 million (after tax) primarily related to allowance for funds used during construction

Natural Gas Distribution

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(Dollars in millions, where applicable)			
Operating revenues	$89.5	$96.2	$553.1	$616.5
Operating expenses:				
Purchased natural gas sold	41.3	50.0	336.5	396.3
Operation and maintenance	37.7	38.0	113.6	111.8
Depreciation, depletion and amortization	15.0	13.7	44.3	40.6
Taxes, other than income	7.4	7.7	34.0	35.4
	101.4	109.4	528.4	584.1
Operating income (loss)	(11.9)	(13.2)	24.7	32.4
Earnings (loss)	$(12.3)	$(12.3)	$3.8	$10.5
Volumes (MMdk):				
Sales	7.8	8.8	60.4	68.8
Transportation	39.0	36.9	109.1	106.1
Total throughput	46.8	45.7	169.5	174.9
Degree days (% of normal)*				
Montana-Dakota/Great Plains	98%	88%	88%	106%
Cascade	116%	64%	80%	91%
Intermountain	86%	84%	85%	96%
Average cost of natural gas, including transportation, per dk	$5.33	$5.68	$5.57	$5.76

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

Three Months Ended September 30, 2015 and 2014 The natural gas distribution business experienced a seasonal loss comparable to the seasonal loss a year ago due to:

- Lower operation and maintenance expense, which includes $1.2 million (after tax) largely related to lower payroll costs and contract services
- Natural gas retail rate increases effective in 2015

Largely offsetting these increases were lower retail sales volumes of 12 percent and higher depreciation, depletion and amortization expense of $800,000 (after tax), primarily resulting from higher property, plant and equipment balances.

The previous table also reflects higher revenue and higher operation and maintenance expense related to nonutility project activity, as well as the pass-through of lower natural gas prices which are reflected in the decrease in both sales revenue and purchased natural gas sold.

Nine Months Ended September 30, 2015 and 2014 Natural gas distribution earnings decreased $6.7 million (64 percent) due to:

- Lower retail sales volumes of 12 percent, primarily resulting from warmer weather than last year, partially offset by weather normalization adjustments in certain jurisdictions. Natural gas retail rate increases also partially offset the retail sales margin decrease.
- Higher depreciation, depletion and amortization expense of $2.3 million (after tax), primarily resulting from higher property, plant and equipment balances

The previous table also reflects higher revenue and higher operation and maintenance expense related to nonutility project activity, as well as the pass-through of lower natural gas prices which are reflected in the decrease in both sales revenue and purchased natural gas sold.

Pipeline and Energy Services

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(Dollars in millions)			
Operating revenues	$121.9	$40.7	$249.8	$114.8
Operating expenses:				
Cost of crude oil	69.1	—	116.2	—
Operation and maintenance*	57.6	20.6	114.4	54.3
Depreciation, depletion and amortization	13.3	7.4	32.3	21.7
Taxes, other than income	3.8	3.4	11.0	9.9
	143.8	31.4	273.9	85.9
Operating income (loss)	(21.9)	9.3	(24.1)	28.9
Earnings (loss)*	$(9.5)	$5.1	$(7.1)	$15.2
Transportation volumes (MMdk)	71.8	60.5	210.8	166.3
Natural gas gathering volumes (MMdk)	8.4	9.6	26.7	28.7
Customer natural gas storage balance (MMdk):				
Beginning of period	11.8	11.4	14.9	26.7
Net injection (withdrawal)	7.5	7.0	4.4	(8.3)
End of period	19.3	18.4	19.3	18.4
Refined product sales (MBbls)				
Diesel fuel	535	—	798	—
Naphtha	524	—	709	—
ATBs and other	409	—	597	—
Total refined product sales	1,468	—	2,104	—

* Reflects impairments of natural gas gathering assets of $14.1 million ($8.7 million after tax) in third quarter 2015 and $3.0 million ($1.9 million after tax) in second quarter 2015. For more information, see Note 5.

Three Months Ended September 30, 2015 and 2014 Pipeline and energy services recognized a loss of $9.5 million compared to earnings of $5.1 million for the comparable prior period due to:

- Higher operation and maintenance expense excluding Dakota Prairie Refinery, which includes $8.8 million (after tax) largely related to an impairment of natural gas gathering assets of $8.7 million (after tax), as discussed in Note 5.
- The Company's after-tax portion of Dakota Prairie Refinery's results was a loss of $5.8 million in 2015 compared to an after-tax loss of $700,000 in 2014. The refinery commenced operations in May 2015. The higher loss was the result of higher operation and maintenance expense, primarily higher rail-related costs; higher depreciation, depletion and amortization expense; partially offset by refined product sales gross margin. Margins have been negatively impacted by market conditions.
- Lower gathering and processing earnings of $1.6 million (after tax), primarily related to lower rates and volumes

Partially offsetting the earnings decrease was higher earnings of $1.1 million (after tax) due to higher transportation volumes.

Nine Months Ended September 30, 2015 and 2014 Pipeline and energy services recognized a loss of $7.1 million compared to earnings of $15.2 million for the comparable prior period due to:

- Higher operation and maintenance expense excluding Dakota Prairie Refinery, which includes $12.8 million (after tax) primarily related to impairments of natural gas gathering assets of $10.6 million (after tax), as discussed in Note 5, higher payroll-related costs and the absence of an insurance settlement in 2014
- The Company's after-tax portion of Dakota Prairie Refinery's results was a loss of $12.6 million in 2015 compared to an after-tax loss of $1.5 million in 2014. The refinery commenced operations in May 2015. The higher loss was the result of higher operation and maintenance expense, primarily higher rail-related costs and higher start-up costs; higher depreciation, depletion and amortization expense; partially offset by refined product sales gross margin.

Margins have been negatively impacted by market conditions.

- Lower gathering and processing earnings of $2.0 million (after tax), primarily related to lower rates
- Lower storage services earnings of $900,000 (after tax), largely due to lower withdrawal volumes and lower average balances

Partially offsetting the earnings decrease was higher earnings of $5.6 million (after tax) due to higher transportation volumes and higher transportation rates, primarily resulting from a rate case settlement under which higher rates went into effect May 1, 2014.

Construction Materials and Contracting

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(Dollars in millions)			
Operating revenues	$774.5	$746.8	$1,478.0	$1,357.8
Operating expenses:				
Operation and maintenance	631.6	627.9	1,266.4	* 1,197.0
Depreciation, depletion and amortization	16.4	17.0	49.1	52.0
Taxes, other than income	12.0	11.8	32.1	30.7
	660.0	656.7	1,347.6	1,279.7
Operating income	114.5	90.1	130.4	78.1
Earnings	$68.8	$55.2	$74.3	* $42.2
Sales (000's):				
Aggregates (tons)	10,240	10,166	20,746	19,966
Asphalt (tons)	3,508	3,208	5,467	4,866
Ready-mixed concrete (cubic yards)	1,159	1,233	2,723	2,637

* 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 September 30, 2015 and 2014 Construction materials and contracting earnings increased $13.6 million (25 percent) due to:

- Higher earnings of $4.6 million (after tax) resulting from higher asphalt margins and volumes, which includes lower asphalt oil costs
- Higher earnings of $3.1 million (after tax), largely due to increased construction revenues and margins
- Higher earnings of $2.5 million (after tax) resulting from higher ready-mixed concrete margins
- Higher earnings of $1.4 million (after tax) resulting from higher aggregate margins and volumes
- Higher earnings from other product line margins and volumes

Partially offsetting these increases were income tax changes, which includes $2.4 million largely the result of higher effective tax rates and higher selling, general and administrative expense of $2.2 million (after tax), primarily related to higher payroll-related costs.

Lower diesel fuel costs contributed to higher earnings from all product lines.

Nine Months Ended September 30, 2015 and 2014 Construction materials and contracting earnings increased $32.1 million (76 percent) due to:

- Higher earnings of $7.9 million (after tax) resulting from higher construction revenues and margins including the effects of favorable weather
- Higher earnings of $7.0 million (after tax) resulting from higher asphalt margins and volumes, as previously discussed
- Higher earnings of $6.9 million (after tax) resulting from higher ready-mixed concrete margins and volumes
- Higher earnings of $6.1 million (after tax) resulting from higher aggregate margins and volumes
- Higher earnings from other product line margins and volumes

Partially offsetting these increases were higher selling, general and administrative expense of $4.4 million (after tax), primarily related to higher payroll-related costs; income tax changes, which includes $2.1 million largely the result of higher effective tax rates; and a MEPP withdrawal liability of $1.5 million (after tax), as discussed in Note 16.

Lower diesel fuel costs contributed to higher earnings from all product lines.

Construction Services

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In millions)			
Operating revenues	$225.8	$286.7	$687.9	$842.8
Operating expenses:				
Operation and maintenance	207.2	258.6	624.0	739.2
Depreciation, depletion and amortization	3.3	3.2	10.0	9.6
Taxes, other than income	6.7	8.0	24.0	26.6
	217.2	269.8	658.0	775.4
Operating income	8.6	16.9	29.9	67.4
Earnings	$4.7	$9.9	$16.5	$40.8

Three Months Ended September 30, 2015 and 2014 Construction services earnings decreased $5.2 million (52 percent) due to:

- Lower equipment sales and rental margins
- Lower workloads and margins in the Western region resulting from substantial completion of significant projects in 2014, lower margins in the Central region and lower workloads and margins in the Mountain region

Partially offsetting these decreases were lower selling, general and administrative expense of $1.1 million (after tax), largely related to lower payroll-related costs.

Nine Months Ended September 30, 2015 and 2014 Construction services earnings decreased $24.3 million (59 percent) due to:

- Lower workloads and margins in the Western region, as previously discussed, lower margins in the Central region and lower workloads and margins in the Mountain region
- Lower equipment sales and rental margins
- Lower electrical supply sales and margins offset in part by lower expense due to the sale of underperforming non-strategic assets in the first quarter

Partially offsetting these decreases were lower selling, general and administrative expense of $2.0 million (after tax), largely related to lower payroll-related costs.

Other

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In millions)			
Operating revenues	$2.8	$3.1	$7.1	$7.3
Operating expenses:				
Operation and maintenance	1.8	.8	9.5	8.8
Depreciation, depletion and amortization	.6	.6	1.5	1.6
Taxes, other than income	—	—	.2	.1
	2.4	1.4	11.2	10.5
Operating income (loss)	.4	1.7	(4.1)	(3.2)
Loss	$(1.3)	$(1.0)	$(9.6)	$(7.6)

Included in Other are general and administrative costs and interest expense previously allocated to Fidelity that do not meet the criteria for income (loss) from discontinued operations.

Three Months Ended September 30, 2015 and 2014 Other loss increased $300,000, primarily the result of higher insurance costs offset in part by lower income taxes.

Nine Months Ended September 30, 2015 and 2014 Other loss increased $2.0 million, 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 and higher insurance costs.

Discontinued Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In millions)			
Income (loss) from discontinued operations before intercompany eliminations, net of tax	$(202.6)	$38.4	$(778.8)	$87.1
Intercompany eliminations	—	.1	.2	.4
Income (loss) from discontinued operations, net of tax	$(202.6)	$38.5	$(778.6)	$87.5

Three Months Ended September 30, 2015 and 2014 Discontinued operations recognized a loss of $202.6 million compared to income of $38.5 million for the comparable prior period due to:

- Fair value impairment of the Company's assets held for sale of $224.4 million (after tax), as discussed in Note 10
- Lower average realized oil prices of 54 percent, excluding gain/loss on commodity derivatives
- Lower unrealized gain on commodity derivatives of $12.1 million (after tax)
- Decreased oil production of 33 percent, largely related to the divestment of certain properties in the last half of 2014, normal production declines and deferral of oil drilling activity due to the current low-price environment

Partially offsetting these decreases were:

- Lower depreciation, depletion and amortization expense of $33.4 million (after tax) due to depreciation, depletion and amortization no longer being recorded on assets held for sale
- Lower lease operating expenses of $7.1 million (after tax), largely the result of lower cost structures, as well as decreased production

Nine Months Ended September 30, 2015 and 2014 Discontinued operations recognized a loss of $778.6 million compared to income of $87.5 million for the comparable prior period due to:

- Fair value impairments of the Company's assets held for sale of $476.4 million (after tax), as discussed in Note 10
- A noncash write-down of oil and gas properties of $315.3 million (after tax), as discussed in Note 10
- Lower average realized oil prices of 53 percent, excluding gain/loss on commodity derivatives
- Decreased oil production of 31 percent, largely related to the divestment of certain properties in the last half of 2014, normal production declines and deferral of oil drilling activity due to the current low-price environment
- Lower average realized gas prices of 58 percent, excluding gain/loss on commodity derivatives

Partially offsetting these decreases were:

- Lower depreciation, depletion and amortization expense of $60.8 million (after tax) due to lower depletion rates and volumes and depreciation, depletion and amortization no longer being recorded on assets held for sale
- Favorable adjustment of $25.2 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 lease operating expenses of $18.2 million (after tax), largely the result of lower cost structures, as well as decreased production

The following table represents key statistics of Fidelity's operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Production:				
Oil (MBbls)	833	1,251	2,672	3,897
NGL (MBbls)	105	170	329	501
Natural gas (MMcf)	4,650	5,336	14,697	16,369
Total production (MBOE)	1,713	2,309	5,451	7,126
Average realized prices (excluding realized and unrealized gain/loss on commodity derivatives):				
Oil (per Bbl)	$39.29	$85.10	$42.30	$89.10
NGL (per Bbl)	$13.30	$35.81	$16.70	$38.54
Natural gas (per Mcf)	$1.68	$3.06	$1.77	$4.18
Average realized prices (including realized gain/loss on commodity derivatives):				
Oil (per Bbl)	$45.48	$83.54	$48.02	$85.50
NGL (per Bbl)	$13.30	$35.81	$16.70	$38.54
Natural gas (per Mcf)	$1.98	$3.09	$2.18	$3.88
Production costs, including taxes, per BOE:				
Lease operating costs	$6.26	$9.54	$7.54	$9.82
Gathering and transportation	1.74	1.31	1.51	1.19
Production and property taxes	2.36	5.06	2.61	5.45
	$10.36	$15.91	$11.66	$16.46

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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In millions)			
Intersegment transactions:				
Operating revenues	$8.6	$29.3	$57.5	$80.5
Purchased natural gas sold	3.7	3.7	31.2	27.8
Operation and maintenance	4.7	22.9	23.3	47.7
Depreciation, depletion and amortization	.2	—	.3	—
Income from continuing operations	—	1.6	1.6	3.1

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 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

- Organic growth opportunities are expected to result in substantial rate base growth.

- Growth Projects/Opportunities

Investments of approximately $56 million are being made in 2015 to serve growth in the electric and natural gas customer base associated with the Bakken oil development.

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 $205 million including development costs and substation upgrade costs. The project has been approved as 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 was appealed to the South Dakota Supreme Court, which on November 4, 2015, affirmed the decision of the district court. More than 90 percent of the necessary easements have been secured. The Company expects the project to be completed in 2019.

The Company is reviewing potential future generation options and is considering a large scale resource. The integrated resource plan filed in July 2015 includes a 200 MW resource addition in the 2020 timeframe.

The Company is analyzing potential projects for accommodating load growth in its industrial and agricultural sectors, with 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.

The Company also is focused on growth through potential mergers and acquisitions.

The Company is evaluating the final Clean Power Plan rule published by the EPA in October 2015, which requires existing fossil fuel-fired electric generation facilities to reduce carbon dioxide emissions. It is unknown at this time what each state will require for emissions limits or reductions from each of the Company's owned and jointly owned fossil fuel-fired electric generating units. Compliance costs will become clearer as final state plans are completed and submitted to the EPA by September 6, 2018.

- Regulatory actions

Completed Cases:

On August 11, 2014, the Company filed an application with the MTPSC for a natural gas rate increase of approximately $3.0 million annually, or 3.6 percent. The requested increase includes costs associated with the increased investment in facilities and associated depreciation, taxes and operation and maintenance expenses. An interim increase of $2.0 million annually was approved and implemented for service effective February 6, 2015, subject to refund. The MTPSC approved a $2.5 million annual increase effective with service on or after May 20, 2015.

On October 3, 2014, the Company filed an application with the WYPSC for a natural gas rate increase of approximately $788,000 annually, or 4.1 percent above current rates. The requested increase includes the costs associated with the increased investment in facilities and associated depreciation, taxes and operation and maintenance expenses. The WYPSC approved an increase of $501,000 annually, which was implemented June 1, 2015.

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 previously approved by the NDPSC. The rider was established to recover costs associated with new generation such as the Heskett III 88-MW natural gas combustion turbine. The NDPSC approved a rate adjustment of $5.3 million annually, which was implemented January 9, 2015.

On December 22, 2014, the Company filed for advanced determination of prudence with the NDPSC on the Thunder Spirit Wind project. The NDPSC approved the advanced determination of prudence and on June 30, 2015, issued a certificate of public convenience and necessity. The Company has an agreement to purchase the project, which includes 43 wind turbines totaling 107.5 MW of electric generation, at a total cost of approximately $220 million including purchase price, internal costs and AFUDC. ALLETE Clean Energy is developing the project, with an expected completion in December 2015.

On April 10, 2015, the Company filed a required annual update with the NDPSC to the electric rate environmental cost recovery rider, as discussed in Note 17.

Pending Cases:

On February 6, 2015, March 31, 2015 and September 30, 2015, the Company filed applications with the NDPSC, OPUC and MNPUC, respectively, for natural gas rate increases, as discussed in Note 17.

On June 25, 2015, the Company filed an application with the MTPSC for an electric rate increase, as discussed in Note 17. The MTPSC has nine months in which to render a decision on the application.

On June 30, 2015, the Company filed applications with the SDPUC for electric and natural gas rate increases, as discussed in Note 17. The SDPUC has six months in which to render a decision on the applications.

On September 1, 2015, and as amended on October 5, 2015, the Company submitted an update to a tracker-type mechanism with MISO, as discussed in Note 17.

On October 21, 2015, the Company filed an application with the NDPSC for an update to the generation resource recovery rider and requested a renewable resource cost adjustment rider, as discussed in Note 17.

Expected Filings:

- On June 24, 2015, the Company filed an expedited application with the WUTC for a natural gas rate increase, as discussed in Note 17.
- The Company expects to file an electric rate case in Wyoming in early 2016.

Pipeline and energy services

- The Company is focused on improving existing operations and accelerating growth to become the leading pipeline company and midstream provider in its operational areas, including expanding existing facilities and services. The Company is also evaluating expansion into other basins.
- The Company signed agreements this year to complete two expansion projects, the North Badlands expansion and the Northwest North Dakota expansion. The North Badlands project includes a 4-mile loop of the Garden Creek II pipeline and measurement and associated facilities, expected to be in service in fall of 2016. The Northwest North Dakota project includes modification of existing compression, a new unit and re-cylindering, expected to be in service the summer of 2016.
- The Company has 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 project has been delayed by the plant owner.
- The planned Wind Ridge Pipeline project, a 95-mile natural gas pipeline designed to deliver approximately 90 MMcf per day to a fertilizer plant near Spiritwood, North Dakota, has been canceled with the fertilizer plant developer's decision to not build the plant. The Company has been reimbursed for all costs incurred related to project development.
- The Company, in conjunction with Calumet, owns Dakota Prairie Refinery. The refinery processes Bakken crude oil into diesel, which is marketed within the Bakken region. Other by-products, naphtha and ATBs, are transported to other areas. The production slate includes approximately 7,000 BPD of diesel, 6,500 BPD of naphtha and 6,000 BPD of ATBs. Company crude oil purchases for the intake have been at a discount to West Texas Intermediate. However, this discount has been much narrower than anticipated because of market conditions in the Bakken. Clearbrook and Guernsey are two crude pricing points that are considered when determining purchase prices as well as other local market indicators. Diesel is sold locally at the refinery rack and Dakota Prairie Refinery posts a price based on market conditions. Dakota Prairie Refinery posted diesel prices were in the $60 to $80 per barrel range during the third quarter. Naphtha is being railed into Canada to be used as a diluent for tar sands production and is tied to C5 pricing differentials to West Texas Intermediate.

Construction materials and contracting

- Approximate work backlog as of September 30, 2015, was $533 million, compared to $476 million a year ago. Private work represents 14 percent of construction backlog and public work represents 86 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 are in the range of $1.8 billion to $2.0 billion in 2015.
- 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, three have been ratified. The one remaining contract is still in negotiations.

Construction services

- Approximate work backlog as of September 30, 2015, was $458 million, compared to $348 million a year ago. The backlog includes a variety of projects, such as substation and line construction, solar projects and other commercial, institutional and industrial projects, including petrochemical work.
- Projected revenues are in the range of $850 million to $950 million in 2015.

- The Company anticipates margins in 2015 to be 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 assets held for sale, 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 policies involving impairment testing of oil and natural gas properties and the impairment testing of assets held for sale. 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 are 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, and timing of operations. These estimates are refined as new information becomes available.

As these estimates change, calculated proved reserves may change. Prior to the oil and natural gas properties being classified as held for sale, changes in proved reserve quantities impacted the Company's depreciation, depletion and amortization expense since the Company used the units-of-production method to amortize its oil and natural gas properties. Historically, the proved reserves were the underlying basis of the "ceiling test" for the Company's oil and natural gas properties while those properties were classified as held for use.

The Company uses the full-cost method of accounting for its exploration and production activities. Prior to the oil and natural gas properties being classified as held for sale, capitalized costs were subject to a "ceiling test" that limited 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 were determined based on SEC Defined Prices and excluded cash outflows associated with asset retirement obligations that had been accrued on the balance sheet. Judgments and assumptions were made when estimating and valuing proved reserves.

In the second quarter of 2015, the Company announced its plan to market Fidelity and exit that line of business. The assets and liabilities were classified as held for sale and evaluated for impairment based on estimated fair value less cost to sell, as discussed below under impairment testing of assets held for sale.

Impairment testing of assets held for sale

The Company evaluates disposal groups classified as held for sale based on the lower of carrying value or fair value less cost to sell. The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the second quarter of 2015, the estimated fair value was determined using the income and the market approaches. The income approach was determined by using the present value of future estimated cash flows. The income approach considered management’s views on current operating measures as well as assumptions pertaining to market forces in the oil and gas industry including estimated reserves, estimated prices, market differentials, estimates of well operating and future development costs and timing of operations. The estimated cash flows were discounted using a rate believed to be consistent with those used by principal market participants. The market approach was provided by a third party and based on market transactions involving similar interests in oil and natural gas properties. In the third quarter of 2015, the estimated fair value of Fidelity was determined by agreed upon pricing in the purchase and sale agreements for the assets subject to the agreements. For those assets for which a purchase and sale agreement has not been entered into, the fair value has been determined based on the market approach utilizing multiples based on similar interests in oil and natural gas properties, as the Company believes this is the most relevant measure of fair value for these assets.

Unforeseen events and changes in circumstances and market conditions and material differences in the value of the assets held for sale due to changes in estimates of future cash flows could negatively affect the estimated fair value of Fidelity and result in additional impairment charges. Various factors, including oil and natural gas prices, market differentials and changes in estimates of reserve quantities could result in future impairments of the Company's assets held for sale.

There is risk involved when determining the fair value of assets, as there may be unforeseen events and changes in circumstances and market conditions that have a material impact on the estimated amount and timing of future cash flows. In addition, the fair value of the assets could be different using different estimates and assumptions in the valuation techniques used.

The Company believes its estimates used in calculating the fair value of its assets held for sale are reasonable based on the information that is known when the estimates are made.

Liquidity and Capital Commitments

At September 30, 2015, the Company had cash and cash equivalents of $88.6 million and available capacity of $393.5 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 in Capital resources; 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 nine months of 2015 decreased $37.1 million from the comparable period in 2014. The decrease in cash flows provided by operating activities was primarily due to lower earnings largely from lower commodity prices at the exploration and production business and lower earnings at the construction services and pipeline and energy services businesses. Partially offsetting this decrease was lower working capital requirements at the electric, natural gas distribution and construction services businesses and higher earnings at the construction materials and contracting business.

Investing activities Cash flows used in investing activities in the first nine months of 2015 decreased $99.5 million from the comparable period in 2014. The decrease in cash flows used in investing activities was primarily due to lower acquisition-related and ongoing capital expenditures at the exploration and production business, lower ongoing capital expenditures at the pipeline and energy services business and higher proceeds from the sale of property at the construction services business. Partially offsetting this decrease was higher ongoing capital expenditures at the electric business.

Financing activities Cash flows provided by financing activities in the first nine months of 2015 decreased $259.9 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 $344.9 million, as well as lower issuance of common stock. Partially offsetting this decrease was the issuance of short-term borrowings in 2015, the absence in 2015 of the 2014 repayment of short-term borrowings and lower repayment of long-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 nine months of 2015 from continuing operations were $425.6 million ($386.1 million, net of proceeds from sale or disposition of property) and are estimated to be approximately $583 million for 2015 ($527 million, net of proceeds from sale or disposition of property). Capital expenditures for the first nine months of 2015 from discontinued operations were $78.9 million ($81.9 million, net of proceeds/costs from sale or disposition of property) and are estimated to be approximately $87 million for 2015 ($90 million, net of proceeds/costs from sale or disposition of property). The estimated capital expenditures from discontinued operations excludes estimated gross proceeds of $328 million from the sale of the exploration and production assets, which does not include purchase price adjustments and income tax benefits. Estimated capital expenditures include:

- System upgrades
- Routine replacements
- Service extensions
- 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 business
- 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

- 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 September 30, 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 September 30, 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		$114.5	(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)	$39.5		$—		7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(f)	$650.0		$383.3	(b)	$39.4		5/8/19
Dakota Prairie Refining, LLC	Revolving credit agreement		$75.0		$29.5		$13.1	(d)	6/30/16

(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.

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.

The Company's coverage of fixed charges including preferred stock dividends was 2.5 times, 3.4 times and 3.1 times for the 12 months ended September 30, 2015 and 2014, and December 31, 2014, respectively.

Total equity as a percent of total capitalization was 52 percent, 59 percent and 61 percent at September 30, 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 September 30, 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 September 30, 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.
On July 21, 2015, the Company entered into a $75.0 million term loan agreement with a variable interest rate which matures on July 20, 2016. The agreement contains customary covenants and provisions, including a covenant of the Company not to permit, at any time, the ratio of funded debt to capitalization (on either a consolidated or unconsolidated basis) to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets and the making of certain investments.
On October 29, 2015, the Company entered into a $150.0 million note purchase agreement and issued $98.0 million of Senior Notes with due dates ranging from October 30, 2025 to October 30, 2045, at a weighted average interest rate of 3.90 percent. The remaining $52.0 million of Senior Notes will be issued on December 10, 2015, with a due date of December 10, 2030, at an interest rate of 4.03 percent. The agreement contains customary covenants and provisions, including a covenant of the Company not to permit, at any time, (A) the ratio of total debt (on an unconsolidated basis) to capitalization to be greater than 65 percent or (B) the ratio of funded debt (on a consolidated basis) to capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets and the making of certain investments.
MDU Energy Capital, LLC On October 1, 2015, MDU Energy Capital entered into a note purchase agreement and issued $50.0 million of Senior Notes with a due date of October 1, 2030, at an interest rate of 4.31 percent. The agreement contains customary covenants and provisions, including covenants of MDU Energy Capital not to permit, at any time, (A) the ratio of total debt (on a consolidated basis) to capitalization to be greater than 70 percent, or (B) the ratio of Cascade's total debt to Cascade's capitalization to be greater than 65 percent, or (C) the ratio of Intermountain's total debt to Intermountain's capitalization to be greater than 65 percent, and restrictions on the sale of certain assets.
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 September 30, 2015, which reduced capacity under this uncommitted private shelf agreement.

Dakota Prairie Refining, LLC On September 30, 2015, Dakota Prairie Refining entered into an amendment to its revolving credit agreement which increased the borrowing limit from $50.0 million under the original December 1, 2014, agreement to $75.0 million and extended the termination date from December 1, 2015 to June 30, 2016. The credit agreement is used to meet the operational needs of the facility.

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 from continuing operations relating to long-term debt, estimated interest payments, operating leases, purchase commitments, 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 derivative instruments held by Fidelity are classified as held for sale.

The following table summarizes derivative agreements entered into by Fidelity as of September 30, 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 (Bbl/MMBtu)	Fair Value
Oil swap agreements maturing in 2015	$58.61	552	$7,083
Natural gas swap agreement maturing in 2015	$4.28	920	$1,550

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 September 30, 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 September 30, 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; the risk related to obligations under MEPPs; and the risk related to the marketing of the Company's exploration and production business. 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 impairments of the Company's exploration and production business.

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 and timing of operations. 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 GAAP. Actual future prices and costs may be significantly different. Various factors, including lower oil and natural gas 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 impairments of the Company's exploration and production business.

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 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 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 distribution channels; changes in markets and market prices for crude oil and refined products; operating cost increases; and the inability of Dakota Prairie Refinery to fund its operations from its operating cash flows, by obtaining third-party financing or through capital contributions from Calumet or WBI Energy; 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, retire and replace certain facilities, 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 2010, the EPA issued draft regulations that outlined several possible approaches for coal combustion residuals management under the RCRA. On April 17, 2015, the EPA published a final rule for coal combustion residuals that regulates coal ash as a solid waste and not a hazardous waste. The rule requires ground water and location restriction evaluations be conducted at ash impoundments and landfills not located at coal mines by October 2017. Depending on the evaluation results, the Company’s ash impoundments may need to be upgraded or closed, and the Company may need to install replacement ash management systems in the future. The cost of replacement ash impoundments or landfills may be material. If these costs are not fully recoverable from customers, they 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 requiring 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 the Lewis & Clark Station near Sidney, Montana, will require additional particulate matter control for non-mercury metal emissions. Montana-Dakota further evaluated pollution control options and is making scrubber modifications, including installing a mist eliminator and sieve tray at the Lewis & Clark Station, to comply with the rule. On June 29, 2015, the United States Supreme Court reversed a prior decision of the D.C. Circuit Court upholding the validity of the MATS rule. The United States Supreme Court remanded the case to the D.C. Circuit Court for further proceedings; however, the D.C. Circuit Court has not yet acted regarding further proceedings. The MATS rule was not vacated or stayed; therefore, pollution controls at the Lewis & Clark Station must still be installed and in operation by April 16, 2016, for Montana-Dakota to comply with the rule.

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 that will be submitted to the Montana DEQ by July 31, 2019, to be used in determining 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.

The EPA pre-published the final Steam Electric Effluent Guidelines rule on September 30, 2015. The rule set additional limitations on existing coal-fired facility wastewater discharges. The Company's coal-fired electric generating facilities are either already in compliance with the applicable limits in the final rule or they are not applicable to the rule requirements. Therefore, no significant impact from the final rule is projected for the Company’s electric generating facility operations.

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. Impacts on Fidelity, WBI Energy Transmission and WBI Energy Midstream from this rule 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 United States 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 generating units. The EPA released a proposed rule for new units in 2012 and then re-proposed the rule on January 8, 2014. In addition, the EPA also proposed emission standards for reconstructed and modified fossil-fired electric generating units on June 18, 2014. On October 23, 2015, the EPA published the final rule establishing carbon dioxide emission limits for new, reconstructed and modified coal-fired steam electric generating units. In this same rule, the EPA established carbon dioxide emission limits for new and reconstructed base load and non-base load stationary combustion turbines. At this time, the EPA has determined not to establish emission limits for modified stationary combustion turbines and has withdrawn the proposed rule emission standards for modified stationary combustion turbines. New coal-fired generating units must comply with an emission standard of 1,400 pounds of carbon dioxide per MW hour gross, equivalent to a super critical pulverized coal unit capturing about 20 percent of its carbon dioxide emissions. Unless carbon capture and storage technology becomes available and cost effective, no new coal-fired electric generating facilities are projected to be constructed. Limits for reconstructed and modified coal-fired generating units may preclude reconstruction or modification depending on the facility. New and reconstructed base load stationary natural gas-fired combustion turbines must comply with an emission standard of 1,000 pounds of carbon dioxide per MW hour gross which should be achievable, but could limit operation to higher load levels depending on the unit. For newly constructed and reconstructed non-base load (peaking) natural gas-fired stationary combustion turbines, the EPA has established a heat input based emission standard of 120 pounds of carbon dioxide per MMBtu. This standard could limit the location a peaking unit is installed depending on natural gas quality.

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 a proposed rule limiting carbon dioxide emissions from existing fossil fuel-fired electric generating units. On October 23, 2015, the EPA published the final Clean Power Plan rule which requires existing fossil fuel-fired electric generations to reduce carbon dioxide emissions. States and utility companies, including Montana-Dakota, have submitted stay motions and petitions for review challenging the legality of the rule at the D.C. Circuit Court. With the litigation outcome pending, the rule requirements remain. By September 6, 2016, states must either make an initial submittal to the EPA requesting an extension to submit a final state plan by September 6, 2018, or submit a final plan. The state plan must demonstrate how emissions reductions will be achieved and include emission limits in the form of an annual emission cap or an emission rate that will be applied to each individual fossil fuel-fired electric generating facility starting in 2022. Emissions limits become more stringent from 2022 to 2030, with the 2030 emission limits applying thereafter. It is unknown at this time what each state will require for emissions limits or reductions from each of Montana-Dakota's owned and jointly owned fossil fuel-fired electric generating units. Compliance costs will become clearer as final state plans are completed and submitted to the EPA by September 6, 2018.

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. On September 18, 2015, the EPA published 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 includes emission reductions from 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.

While the Company entered into purchase and sale agreements to sell the vast majority of Fidelity's assets comprising greater than 90 percent of production for the nine months ended September 30, 2015, and is currently marketing the remaining assets of Fidelity, there is no assurance that a sale of all marketed assets will be successful.

As part of the Company’s corporate strategy, it is currently marketing its Fidelity assets and will exit that line of business. Such a disposition and exit is subject to various risks, including: the current purchase and sale agreements may be terminated prior to closing as a result of the due diligence process or due to inability of the purchasers to obtain financing; suitable purchasers may not be available or willing to purchase the remaining assets on terms and conditions acceptable to the Company; the agreements pursuant to which the Company divests the assets may contain continuing indemnification obligations; the inability to obtain waivers from applicable covenants under debt agreements; the Company may incur substantial costs in connection with the marketing and sale of the assets; the marketing and sale of the assets could distract management, divert resources, disrupt the Company’s ongoing business and make it difficult for the Company to maintain its current business standards, controls and procedures; uncertainties associated with the sale may cause a loss of key management personnel at Fidelity which could make it more difficult to sell the assets or operate the business in the event that the Company is unable to sell it; there could be various tax consequences dependent on the nature of the sale; the Company may be required to record additional impairment charges that could have an adverse effect on the Company’s financial condition; and the Company may not be able to redeploy the proceeds from any sale of the assets in a manner that produces similar revenues and growth rates or enhances shareholder value.

Item 4. Mine Safety Disclosures

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

Item 6. Exhibits

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

Signatures

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

		MDU RESOURCES GROUP, INC.
DATE: November 6, 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.	
12	Computation of Ratio of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividends
31(a)	Certification of Chief Executive Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31(b)	Certification of Chief Financial Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32	Certification of Chief Executive Officer and Chief Financial Officer furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
95	Mine Safety Disclosures
101	The following materials from MDU Resources Group, Inc.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 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

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.