RANGE RESOURCES CORP
Form 10-Q
October 24, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

(Mark one)

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2017

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from   to

Commission File Number: 001-12209

RANGE RESOURCES CORPORATION

(Exact Name of Registrant as Specified in Its Charter)

Delaware	34-1312571
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
	76102
100 Throckmorton Street, Suite 1200	

Fort Worth, Texas
(Address of Principal Executive Offices) (Zip Code)
Registrant's telephone number, including area code

(817) 870-2601

Former Name, Former Address and Former Fiscal Year, if changed since last report: Not applicable

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 No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, 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 shorter period that the registrant was required to submit and post such files).

Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer		Accelerated Filer
Non-Accelerated Filer	(Do not check if smaller reporting company)	Smaller Reporting Company Emerging Growth Company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes No

248,139,327 Common Shares were outstanding on October 23, 2017

RANGE RESOURCES CORPORATION

FORM 10-Q

Quarter Ended September 30, 2017

Unless the context otherwise indicates, all references in this report to “Range Resources,” “Range,” “we,” “us,” or “our” are to Range Resources Corporation and its directly and indirectly owned subsidiaries.

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PART I – FINANCIAL INFORMATION

ITEM 1. Financial Statements

RANGE RESOURCES CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands, except per share data)

	September 30, 2017 (Unaudited)	December 31, 2016
Assets		
Current assets:		
Cash and cash equivalents	$529	$314
Accounts receivable, less allowance for doubtful accounts of $6,609 and $5,559	285,166	241,718
Derivative assets	30,176	13,278
Inventory and other	21,379	26,573
Total current assets	337,250	281,883
Derivative assets	512	205
Goodwill	1,641,197	1,654,292
Natural gas and oil properties, successful efforts method	13,061,390	12,386,153
Accumulated depletion and depreciation	(3,492,614)	(3,129,816)
	9,568,776	9,256,337
Other property and equipment	114,073	112,796
Accumulated depreciation and amortization	(98,469)	(95,923)
	15,604	16,873
Other assets	74,400	72,655
Total assets	$11,637,739	$11,282,245
Liabilities		
Current liabilities:		
Accounts payable	$317,112	$229,190
Asset retirement obligations	7,271	7,271
Accrued liabilities	277,355	265,843
Accrued interest	37,095	35,340
Derivative liabilities	32,533	165,009
Total current liabilities	671,366	702,653
Bank debt	1,082,708	876,428
Senior notes	2,850,692	2,848,591
Senior subordinated notes	48,562	48,498
Deferred tax liabilities	1,042,889	943,343
Derivative liabilities	16,292	24,491
Deferred compensation liabilities	91,014	119,231
Asset retirement obligations and other liabilities	296,736	310,642

Total liabilities	6,100,259	5,873,877
Commitments and contingencies		
Stockholders' Equity		
Preferred stock, $1 par, 10,000,000 shares authorized, none issued and outstanding	—	—
Common stock, $0.01 par, 475,000,000 shares authorized, 248,138,258 issued at September 30, 2017 and 247,174,903 issued at December 31, 2016	2,481	2,471
Common stock held in treasury, 14,967 shares at September 30, 2017 and 30,547 shares at December 31, 2016	(599)	(1,209)
Additional paid-in capital	5,555,830	5,524,423
Retained earnings (deficit)	(20,232)	(117,317)
Total stockholders' equity	5,537,480	5,408,368
Total liabilities and stockholders' equity	$11,637,739	$11,282,245

See accompanying notes.

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RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited, in thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Revenues and other income:				
Natural gas, NGLs and oil sales	$507,541	$304,477	$1,573,128	$738,570
Derivative fair value (loss) income	(88,426)	64,556	188,326	(11,334)
Brokered natural gas, marketing and other	63,117	44,174	170,544	119,181
Total revenues and other income	482,232	413,207	1,931,998	846,417
Costs and expenses:				
Direct operating	36,888	22,387	96,331	67,112
Transportation, gathering, processing and compression	191,645	138,764	560,883	400,871
Production and ad valorem taxes	11,993	6,717	31,125	18,653
Brokered natural gas and marketing	59,773	44,622	169,180	122,105
Exploration	22,767	6,943	45,769	18,641
Abandonment and impairment of unproved properties	42,568	6,082	52,181	23,769
General and administrative	53,035	41,024	152,853	127,745
MRD Merger expenses	—	33,791	—	36,412
Termination costs	(47)	136	4,049	303
Deferred compensation plan	(9,203)	(11,636)	(36,838)	30,166
Interest	49,179	45,967	144,206	121,464
Depletion, depreciation and amortization	159,749	131,489	462,074	374,440
Impairment of proved properties and other assets	63,679	—	63,679	43,040
(Gain) loss on the sale of assets	(102)	2,597	(23,509)	7,544
Total costs and expenses	681,924	468,883	1,721,983	1,392,265
(Loss) income before income taxes	(199,692)	(55,676)	210,015	(545,848)
Income tax (benefit) expense:				
Current	—	—	—	—
Deferred	(71,992)	(13,705)	98,054	(185,169)
	(71,992)	(13,705)	98,054	(185,169)
Net (loss) income	$(127,700)	$(41,971)	$111,961	$(360,679)
Net (loss) income per common share:				
Basic	$(0.52)	$(0.23)	$0.45	$(2.10)
Diluted	$(0.52)	$(0.23)	$0.45	$(2.10)
Dividends paid per common share	$0.02	$0.02	$0.06	$0.06
Weighted average common shares outstanding:				
Basic	245,244	180,683	245,027	171,571
Diluted	245,244	180,683	245,280	171,571

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited, in thousands)

	Nine Months Ended September 30, 2017	2016
Operating activities:		
Net income (loss)	$111,961	$(360,679)
Adjustments to reconcile net income (loss) to net cash provided from operating activities:		
Deferred income tax expense (benefit)	98,054	(185,169)
Depletion, depreciation and amortization and impairment	525,753	417,480
Exploration dry hole costs	9,166	2
Abandonment and impairment of unproved properties	52,181	23,769
Derivative fair value (income) loss	(188,326)	11,334
Cash settlements on derivative financial instruments	16,062	260,657
Allowance for bad debt	1,050	800
Amortization of deferred financing costs and other	4,184	5,383
Deferred and stock-based compensation	3,937	72,689
(Gain) loss on the sale of assets	(23,509)	7,544
Changes in working capital:		
Accounts receivable	(39,694)	31,985
Inventory and other	(1,504)	(776)
Accounts payable	44,715	(41,268)
Accrued liabilities and other	(13,498)	(37,914)
Net cash provided from operating activities	600,532	205,837
Investing activities:		
Additions to natural gas and oil properties	(771,067)	(339,446)
Additions to field service assets	(4,687)	(1,542)
Acreage purchases	(46,967)	(29,203)
MRD Merger, net of cash acquired	—	7,180
Proceeds from disposal of assets	27,583	191,834
Purchases of marketable securities held by the deferred compensation plan	(25,410)	(33,460)
Proceeds from the sales of marketable securities held by the deferred compensation plan	28,755	37,900
Net cash used in investing activities	(791,793)	(166,737)
Financing activities:		
Borrowings on credit facilities	1,486,000	1,887,000
Repayments on credit facilities	(1,282,000)	(1,045,000)
Repayment of Memorial credit facility	—	(597,000)
Repayment of senior notes	(500)	(273,011)
Debt issuance costs	(247)	(6,381)
Dividends paid	(14,876)	(11,654)
Taxes paid for shares withheld	(6,971)	(3,800)
Change in cash overdrafts	5,588	432
Proceeds from the sales of common stock held by the deferred compensation plan	4,482	10,385
Net cash provided from (used in) financing activities	191,476	(39,029)

Increase in cash and cash equivalents	215	71
Cash and cash equivalents at beginning of period	314	471
Cash and cash equivalents at end of period	$529	$542

See accompanying notes.

RANGE RESOURCES CORPORATION

SELECTED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

(1) SUMMARY OF ORGANIZATION AND NATURE OF BUSINESS

Range Resources Corporation is a Fort Worth, Texas-based independent natural gas, natural gas liquids ("NGLs") and oil company primarily engaged in the exploration, development and acquisition of natural gas and oil properties in the Appalachian and the North Louisiana regions of the United States. Our objective is to build stockholder value through consistent returns focused on the growth, on a per share debt-adjusted basis, of both reserves and production. Range is a Delaware corporation with our common stock listed and traded on the New York Stock Exchange under the symbol "RRC".

(2) BASIS OF PRESENTATION

These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Range Resources Corporation 2016 Annual Report on Form 10-K filed with the Securities and Exchange Commission (the "SEC") on February 22, 2017. The results of operations for the third quarter and the nine months ended September 30, 2017 are not necessarily indicative of the results to be expected for the full year. These consolidated financial statements are unaudited but, in the opinion of management, reflect all adjustments necessary for fair presentation of the results for the periods presented. All adjustments are of a normal recurring nature unless otherwise disclosed. These consolidated financial statements, including selected notes, have been prepared in accordance with the applicable rules of the SEC and do not include all of the information and disclosures required by accounting principles generally accepted in the United States of America ("U.S. GAAP") for complete financial statements.

On September 16, 2016, we issued approximately 77.0 million shares of common stock in exchange for all outstanding shares of common stock of Memorial Resources Development Corp. ("Memorial" or "MRD Merger") using an exchange ratio of 0.375 of a share of Range common stock for each share of Memorial common stock. For additional information, see Note 4.

Inventory. As of September 30, 2017, we had \$11.7 million of material and supplies inventory compared to \$9.4 million at December 31, 2016. Material and supplies inventory consists of primarily tubular goods and equipment used in our operations and is stated at lower of specific cost of each inventory item or market. At September 30, 2017, we also had commodity inventory of \$2.2 million compared to \$8.3 million at December 31, 2016. Commodity inventory as of September 30, 2017 consists of natural gas and NGLs held in storage or as line fill in pipelines.

(3) NEW ACCOUNTING STANDARDS

Not Yet Adopted

In May 2014, an accounting standards update was issued that supersedes the existing revenue recognition requirements. This standard includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which we expect to be entitled in exchange for those goods or services. Among other things, the standard also eliminates industry-specific revenue guidance, requires enhanced disclosures about revenue, provides guidance for transactions that were not previously addressed comprehensively and improves guidance for multiple-element arrangements. This standard is effective for us in first quarter 2018 and we expect to adopt the new standard using the modified retrospective method of adoption. We are utilizing a bottom-up approach to analyze the impact of the new standard on our contracts by reviewing our current accounting policies and practices to identify potential differences that would result from applying the requirements of the new standard to our revenue contracts and the impact of adopting this standards update on our total revenues, operating income (loss) and our consolidated balance sheet. We are currently completing our detailed analysis of our portfolio of contracts at the individual contract level as we continue to evaluate the impact of this accounting standards update on our consolidated results of operations, financial position, cash flows and financial disclosures, in addition to developing any process or control changes necessary. We have identified and implemented a number of control changes necessary for adoption.

In February 2016, an accounting standards update was issued that requires an entity to recognize a right-of-use asset and lease liability for all leases with terms of more than twelve months. Classification of leases as either a finance or operating lease will determine the recognition, measurement and presentation of expenses. This accounting standards update also requires certain quantitative and qualitative disclosures about leasing arrangements. This standard is effective for us in first quarter 2019 and should be applied using a modified retrospective approach for leases that exist or are entered into after the beginning of the earliest comparative period in the financial statements and early adoption is permitted. We are evaluating the provisions of this accounting standards update and assessing the impact it will have on our consolidated results of operations, financial position or cash flows but based on our preliminary review of the update, we expect that we will have operating leases with durations greater than twelve months on our balance sheet. As we continue to evaluate and implement the standard, we will provide additional information about the expected financial impact at a future date.

In August 2016, an accounting standards update was issued that clarifies how entities classify certain cash receipts and cash payments on the statement of cash flows. The guidance is effective for us in first quarter 2018 and will be applied retrospectively with early adoption permitted. We are evaluating the provisions of this accounting standards update and assessing the impact, if any, it may have on our consolidated cash flow statement presentation.

Recently Adopted

In March 2016, an accounting standards update was issued that simplifies several aspects of the accounting for share-based payment award transactions. Among other things, this new guidance requires all income tax effects of share-based awards to be recognized in the statement of operations when the awards vest or are settled, allows an employer to repurchase more of an employee's shares for tax withholding purposes without triggering liability accounting and allows a policy election to account for forfeitures as they occur. This new standard is effective for annual periods beginning after December 15, 2016. Early adoption is permitted. We elected to early adopt this accounting standards update in fourth quarter 2016 and reflected any adjustments as of January 1, 2016, the beginning of the annual period that includes the interim period of adoption. The following summarizes the impact of the adoption of this update on our consolidated financial statements:

Income taxes - Upon adoption of this standard, all excess tax benefits and tax deficiencies (including tax benefits of dividends on share-based payment awards) are recognized as income tax expense or benefit in our consolidated statements of operations. The tax effects of exercised or vested awards are treated as discrete items in the reporting period in which they occur. Adoption of this new standard resulted in the recognition of an excess tax deficiency in our provision for income taxes rather than paid-in capital of $2.1 million for the year ended December 31, 2016 and affected our previously reported first quarter 2016 results as follows (in thousands, except per share data):

	Three Months Ended March 31, 2016	
	As Reported (unaudited)	As Adjusted
Statements of Operations		
Income tax benefit	$(44,038)	$(41,976)
Net loss	(91,710)	(93,772)
Basic earnings per share	(0.55)	(0.56)
Diluted earnings per share	(0.55)	(0.56)

In addition, we recorded a cumulative-effect adjustment to retained earnings (deficit) and reduced our deferred tax liability by $101.1 million for previously unrecognized tax benefits due to our NOL position as of December 31, 2016.

Forfeitures - Prior to adoption, share-based compensation expense was recognized on a straight line basis, net of estimated forfeitures, such that expense was recognized only for share-based awards that are expected to vest. We have elected to continue to estimate forfeitures.

Statements of cash flows - The presentation requirements for cash flows related to employee taxes paid for withheld shares were adjusted retrospectively. These cash flows have historically been presented as an operating activity. Upon adoption of this new standard, these cash outflows were classified as a financing activity. Prior periods have been adjusted as follows (in thousands):

	As Reported Net cash provided from	As Adjusted Net cash provided from operating

	operating activities	activities
Three months ended March 31, 2016	$87,424	$90,785
Six months ended June 30, 2016	169,604	173,201
Nine months ended September 30, 2016	202,037	205,837

	As Reported Net cash used in financing activities	As Adjusted Net cash used in financing activities
Three months ended March 31, 2016	$(72,473)	$(75,834)
Six months ended June 30, 2016	(95,411)	(99,008)
Nine months ended September 30, 2016	(35,229)	(39,029)

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In January 2017, an accounting standards update was issued that eliminates the requirements to calculate the implied fair value of goodwill to measure goodwill impairment charge. Instead, entities will record an impairment charge based on the excess of a reporting unit's carrying amount over its fair value. This standard is effective for annual periods beginning after December 15, 2019 and should be applied on a prospective basis. Early adoption is permitted for any goodwill impairment tests performed in first quarter 2017 or later. We elected to adopt this accounting standards update in first quarter 2017. The adoption did not have a significant impact on our consolidated results of operations, financial position, cash flows or financial disclosures; however, this standard did change our policy for our annual goodwill impairment assessment by eliminating the requirement to calculate the implied fair value of goodwill.

(4) ACQUISITIONS AND DISPOSITIONS

Memorial Merger

On September 16, 2016, we completed our merger with Memorial which was accomplished through the merger of Medina Merger Sub, Inc., a Delaware corporation and a direct, wholly-owned subsidiary of Range, with and into Memorial, with Memorial surviving as a wholly-owned subsidiary of Range. The results of Memorial's operations since the effective time of the MRD Merger are included in our consolidated statements of operations. The MRD Merger was effected through the issuance of approximately 77.0 million shares of Range common stock in exchange for all outstanding shares of Memorial using an exchange ratio of 0.375 of a share of Range common stock for each share of Memorial common stock. At the effective time of the MRD Merger, Memorial's liabilities, which are reflected in Range's consolidated financial statements, included approximately $1.2 billion fair value of outstanding debt. In the last nine months of 2016, we incurred MRD Merger-related expenses of approximately $37.2 million which includes consulting, investment banking, advisory, legal and other merger-related fees.

Allocation of Purchase Price. The MRD Merger has been accounted for as a business combination, using the acquisition method. The following table represents the final allocation of the total purchase price of the MRD Merger to the assets acquired and the liabilities assumed based on the fair value at the effective time of the MRD Merger, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill (in thousands, except shares and stock price):

Purchase price:	
Shares of Range common stock issued to Memorial stockholders	77,042,749
Range common stock price per share at September 15, 2016 (close)	$39.37
Total purchase price	$3,033,173
Plus fair value of liabilities assumed by Range:	
Accounts payable	$55,624
Other current liabilities	108,367
Long-term debt	1,204,449
Deferred taxes	547,706
Other long-term liabilities	77,223
Total purchase price plus liabilities assumed	$5,026,542
Fair value of Memorial assets:	
Cash and equivalents	$7,180
Other current assets	99,969
Derivative instruments	152,994
Natural gas and oil properties:	
Proved property	1,122,311

Unproved property	1,999,187
Other property and equipment	3,579
Goodwill [a]	1,641,197
Other	125
Total asset value	$5,026,542

[a] Goodwill will not be deductible for income tax purposes.

The fair value measurements of derivative instruments assumed were determined based on published forward commodity price curves as of the date of the MRD Merger and represent Level 2 inputs. Derivative instruments in an asset position include a measure of counterparty nonperformance risk and the fair values of commodity derivative instruments in a liability position include a measure of our own nonperformance risk, based on the current published credit default swap rates and other market based indicators. The fair value measurements of long-term debt were estimated based on published market prices and represent Level 1 inputs.

The fair value measurements of natural gas and oil properties and asset retirement obligations are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of natural gas and oil properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of natural gas and oil properties include estimates of: (i) recoverable reserves, (ii) production rates, (iii) future operating and development costs, (iv) future commodity prices and (v) a market-based weighted average costs of capital rate. These inputs require significant judgments and estimates by management at the time of the valuation and may be subject to change. Management utilized the assistance of a third party valuation expert to estimate the value of natural gas and oil properties acquired. In some cases, certain amounts allocated to unproved properties are based on a market approach using third party published data which provides lease pricing information based on certain geographic areas and represent Level 2 inputs.

Goodwill is attributed to net deferred tax liabilities arising from the differences between the purchase price allocated to Memorial's assets and liabilities based on fair value and the tax basis of these assets and liabilities. In addition, the total consideration for the MRD Merger included a control premium, which resulted in a higher value compared to the fair value of net assets acquired. There are also other qualitative assumptions of long-term factors that the MRD Merger creates including additional potential for exploration and development opportunities, additional scale and efficiencies in other basins in which we operate and substantial operating and administrative synergies.

The results of operations attributable to Memorial are included in our consolidated statements of operations beginning on September 16, 2016. We recognized $369.9 million of natural gas, oil and NGLs revenues and $220.0 million of field net operating income from these assets from January 1, 2017 to September 30, 2017.

Pro forma Financial Information. The following pro forma condensed combined financial information was derived from the historical financial statements of Range and Memorial and gives effect to the MRD Merger as if it had occurred on January 1, 2016. The information below reflects pro forma adjustments for the issuance of Range common stock in exchange for Memorial's outstanding shares of common stock, as well as pro forma adjustments based on available information and certain assumptions that we believe are reasonable, including (i) the depletion of Memorial's fair-valued proved oil and gas properties and (ii) the estimated tax impacts of the pro forma adjustments. Additionally, pro forma results for the nine months ended September 30, 2016 were adjusted to exclude $36.4 million of merger-related costs incurred by Range and $7.1 million incurred by Memorial. The pro forma results of operations do not include any cost savings or other synergies that may result from the MRD Merger or any estimated costs that have been or will be incurred by us to integrate the Memorial assets. The pro forma condensed combined financial information is not necessarily indicative of the results that might have actually occurred had the MRD Merger taken place on January 1, 2016. In addition, the pro forma financial information below is not intended to be a projection of future results (in thousands, except per share amounts).

	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2016
Revenues	$521,669	$1,080,768
Net loss	$(18,257)	$(431,225)
Loss per share:		

Basic	$(0.08)	$(1.77)
Diluted	$(0.08)	$(1.77)

2017 Dispositions

We recognized a pretax net gain on the sale of assets of $102,000 in third quarter 2017 compared to a pretax net loss of $2.6 million in the same period of the prior year and a pretax net gain on the sale of assets of $23.5 million in first nine months 2017 compared to a pretax net loss of $7.5 million in the same period of the prior year.

Western Oklahoma. In first nine months 2017, we sold certain properties in Western Oklahoma for proceeds of $26.0 million and we recorded a gain of $22.1 million related to this sale, after closing adjustments and transaction fees.

Other. In third quarter 2017, we sold miscellaneous inventory and other assets for proceeds of $295,000 resulting in a pretax gain of $102,000. In first six months 2017, we sold miscellaneous unproved properties, inventory, other assets and surface acreage for proceeds of $1.3 million resulting in a pretax gain of $1.3 million.

2016 Dispositions

Western Oklahoma. In third quarter 2016, we sold properties in Western Oklahoma for proceeds of $900,000 and we recorded a loss of $2.6 million. In first six months 2016, we sold certain properties in Western Oklahoma for proceeds of $77.7 million and we recorded a $2.7 million loss related to this sale, after closing adjustments and transaction fees.

Pennsylvania. In first nine months 2016, we sold our non-operated interest in certain wells and gathering facilities in northeast Pennsylvania for proceeds of $111.5 million. After closing adjustments, we recorded a loss of $2.1 million related to this sale.

Other. In third quarter 2016, we sold miscellaneous inventory and surface property for proceeds of $131,000 resulting in a gain of $30,000. In first six months 2016, we sold miscellaneous proved and unproved properties, inventory, other assets and surface acreage for proceeds of $1.7 million resulting in a pretax loss of $198,000. Included in the $1.7 million of proceeds is $1.2 million received from the sale of proved properties in Mississippi and South Texas.

(5) GOODWILL

During 2016, we recorded goodwill associated with the MRD Merger, which represents the cost of the acquired entity over the net amounts assigned to assets acquired and liabilities assumed. Goodwill is assessed for impairment whenever events or circumstances indicate that impairment of the carrying value of goodwill is likely, but no less often than annually. Our impairment test is typically performed during the fourth quarter; however, we performed an impairment test as of third quarter 2017 due to a significant decline of our market capitalization. Management utilized the assistance of a third-party valuation expert to determine the fair value of our business (our reporting unit). The fair value was determined based on both a market and an income approach. The fair value measurement using an income approach was based on internally developed estimates of future production levels, prices, drilling and operating costs and discount rates, which are Level 3 inputs. As a result of this measurement, the fair value of our business exceeded the carrying value of net assets and we did not record an impairment charge during third quarter 2017.

(6) INCOME TAXES

Income tax (benefit) expense was as follows (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Income tax (benefit) expense	$(71,992)	$(13,705)	$98,054	$(185,169)
Effective tax rate	36.1 %	24.6 %	46.7 %	33.9 %

We compute our quarterly taxes under the effective tax rate method based on applying an anticipated annual effective rate to our year-to-date income, except for discrete items. Income taxes for discrete items are computed and recorded in the period that the specific transaction occurs. For third quarter and nine months ended September 30, 2017 and 2016, our overall effective tax rate was different than the federal statutory rate of 35% due primarily to state income taxes and other tax items which are detailed below (dollars in thousands).

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Total (loss) income before income taxes	$(199,692)	$(55,676)	$210,015	$(545,848)

U.S. federal statutory rate	35 %	35 %	35 %	35 %
Total tax (benefit) expense at statutory rate	(69,892)	(19,487)	73,505	(191,047)
State and local income taxes, net of federal benefit	(6,537)	(2,007)	6,591	(17,963)
Non-deductible executive compensation	296	446	436	1,128
Non-deductible transaction costs	—	4,838	—	4,838
Tax less than book equity compensation	56	44	4,808	5,374
Change in valuation allowances:				
Federal net operating loss carryforwards & other	69	—	3,487	—
State net operating loss carryforwards & other	4,286	2,815	10,498	10,514
Rabbi trust and other	(508)	(620)	(1,561)	1,656
Permanent differences and other	238	266	290	331
Total (benefit) expense for income taxes	$(71,992)	$(13,705)	$98,054	$(185,169)
Effective tax rate	36.1 %	24.6 %	46.7 %	33.9 %

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(7) (LOSS) INCOME PER COMMON SHARE

Basic income or loss per share attributable to common shareholders is computed as (1) income or loss attributable to common shareholders (2) less income allocable to participating securities (3) divided by weighted average basic shares outstanding. Diluted income or loss per share attributable to common shareholders is computed as (1) basic income or loss attributable to common shareholders (2) plus diluted adjustments to income allocable to participating securities (3) divided by weighted average diluted shares outstanding. The following tables set forth a reconciliation of income or loss attributable to common shareholders to basic income or loss attributable to common shareholders to diluted income or loss attributable to common shareholders (in thousands except per share amounts):

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2017	2016	2017	2016
Net (loss) income, as reported	$(127,700)	$(41,971)	$111,961	$(360,679)
Participating earnings [(a)]	(58)	(56)	(1,251)	(167)
Basic net (loss) income attributed to common shareholders	(127,758)	(42,027)	110,710	(360,846)
Reallocation of participating earnings [(a)]	—	—	1	—
Diluted net (loss) income attributed to common shareholders	$(127,758)	$(42,027)	$110,711	$(360,846)
Net (loss) income per common share:				
Basic	$(0.52)	$(0.23)	$0.45	$(2.10)
Diluted	$(0.52)	$(0.23)	$0.45	$(2.10)

(a) Restricted Stock Awards represent participating securities because they participate in nonforfeitable dividends or distributions with common equity owners. Income allocable to participating securities represents the distributed and undistributed earnings attributable to the participating securities. Participating securities, however, do not participate in undistributed net losses.

The following table provides a reconciliation of basic weighted average common shares outstanding to diluted weighted average common shares outstanding (in thousands):

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2017	2016	2017	2016
Weighted average common shares outstanding – basic [(1)]	245,244	180,683	245,027	171,571
Effect of dilutive securities:				
Director and employee PSUs and RSUs	—	—	253	—
Weighted average common shares outstanding – diluted	245,244	180,683	245,280	171,571

(1) 2017 includes common stock issued in connection with the exchange of 77.0 million shares for all outstanding Memorial common stock on September 16, 2016.

Weighted average common shares outstanding–basic for third quarter 2017 excludes 2.9 million shares of restricted stock held in our deferred compensation plan compared to 2.8 million shares in third quarter 2016 (although all awards are issued and outstanding upon grant). Weighted average common shares outstanding-basic for both the first nine months 2017 and the first nine months 2016 exclude 2.8 million shares of restricted stock. Due to our net loss from operations for the three months ended September 30, 2017, we excluded all outstanding stock appreciation rights ("SARs"), restricted stock and performance shares from the computation of diluted net loss per share because the effect would have been anti-dilutive. For first nine months 2017, SARs of 659,000 were outstanding but not included in the computation of diluted net income per share because the grant prices of the SARs were greater than the average market price of the common shares and would be anti-dilutive to the computations. In addition, there were 405,000 shares of equity awards for first nine months 2017 excluded from the computation of diluted net income per share because their effect would have been antidilutive. Due to our net loss from operations for the three months and the nine months ended September 30, 2016, we excluded all outstanding SARs, restricted stock and performance shares from the computation of diluted net loss per share because the effect would have been anti-dilutive.

(8) SUSPENDED EXPLORATORY WELL COSTS

We capitalize exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. Capitalized exploratory well costs are included in natural gas and oil properties in the accompanying consolidated balance sheets. If an exploratory well is determined to be impaired, the well costs are charged to exploration expense in the accompanying consolidated statements of operations. We do not have any suspended exploratory well costs as of September 30, 2017. The following table reflects the change in capitalized exploratory well costs for the nine months ended September 30, 2017 and the year ended December 31, 2016 (in thousands):

	September 30, 2017	December 31, 2016
Balance at beginning of period	$7,412	$4,161
Additions to capitalized exploratory well costs pending the determination of proved reserves	1,388	9,128
Reclassifications to wells, facilities and equipment based on determination of proved reserves	—	(5,877)
Capitalized exploratory well costs charged to expense	(8,800)	—
Balance at end of period	—	7,412
Less exploratory well costs that have been capitalized for a period of one year or less	—	(7,412)
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$—	$—
Number of projects that have exploratory well costs that have been capitalized greater than one year	—	—

(9) INDEBTEDNESS

We had the following debt outstanding as of the dates shown below (bank debt interest rate at September 30, 2017 is shown parenthetically). No interest was capitalized during the three months or the nine months ended September 30, 2017 or the year ended December 31, 2016 (in thousands).

	September 30, 2017	December 31, 2016
Bank debt (2.8%)	$1,086,000	$882,000
Senior notes:		
4.875% senior notes due 2025	750,000	750,000
5.00% senior notes due 2023	741,531	741,531
5.00% senior notes due 2022	580,032	580,032
5.75% senior notes due 2021	475,952	475,952
5.875% senior notes due 2022	329,244	329,244
Other senior notes due 2022	590	1,090
Total senior notes	2,877,349	2,877,849
Senior subordinated notes:		
5.00% senior subordinated notes due 2023	7,712	7,712
5.00% senior subordinated notes due 2022	19,054	19,054

5.75% senior subordinated notes due 2021	22,214	22,214
Total senior subordinated notes	48,980	48,980
Total debt	4,012,329	3,808,829
Unamortized premium	6,336	7,241
Unamortized debt issuance costs	(36,703)	(42,553)
Total debt net of debt issuance costs	$3,981,962	$3,773,517

Bank Debt

In October 2014, we entered into an amended and restated revolving bank facility, which we refer to as our bank debt or our bank credit facility, which is secured by substantially all of our assets and has a maturity date of October 16, 2019. The bank credit facility provides for a maximum facility amount of $4.0 billion. The bank credit facility provides for a borrowing base subject to redeterminations annually by May and for event-driven unscheduled redeterminations. As part of our annual redetermination completed on March 21, 2017, our borrowing base was reaffirmed at $3.0 billion and our bank commitment was also reaffirmed at $2.0 billion. As of September 30, 2017, our bank group was composed of twenty-nine financial institutions with no one bank holding more than 5.8% of the total facility. The borrowing base may be increased or decreased based on our request and sufficient proved reserves, as determined by the bank group. The commitment amount may be increased to the borrowing base, subject to payment of a mutually acceptable commitment fee to those banks agreeing to participate in the facility increase. As of September 30, 2017, the outstanding balance under our bank credit facility was $1.1 billion, before deducting debt issuance costs. Additionally, we had $285.8 million of undrawn letters of credit leaving $628.2 million of committed borrowing capacity available under the facility. During a non-investment grade period, borrowings under the bank credit facility can either be at the alternate base rate (“ABR,” as defined in the bank credit facility agreement) plus a spread ranging from 0.25% to 1.25% or LIBOR borrowings at the LIBOR Rate (as defined in the bank credit facility agreement) plus a spread ranging from 1.25% to 2.25%. The applicable spread is dependent upon borrowings relative to the borrowing base. We may elect, from time to time, to convert all or any part of our LIBOR loans to base rate loans or to convert all or any of the base rate loans to LIBOR loans. The weighted average interest rate was 2.8% in third quarter 2017 compared to 2.3% in third quarter 2016. The weighted average interest rate was 2.6% for first nine months 2017 compared to 2.3% for first nine months 2016. A commitment fee is paid on the undrawn balance based on an annual rate of 0.30% to 0.375%. At September 30, 2017, the commitment fee was 0.3% and the interest rate margin was 1.5% on our LIBOR loans and 0.5% on our base rate loans.

At any time during which we have an investment grade debt rating from Moody’s Investors Service, Inc. or Standard & Poor’s Ratings Services and we have elected, at our discretion, to effect the investment grade rating period, certain collateral security requirements, including the borrowing base requirement and restrictive covenants, will cease to apply and an additional financial covenant (as defined in the bank credit facility) will be imposed. During the investment grade period, borrowings under the credit facility can either be at the ABR plus a spread ranging from 0.125% to 0.75% or at the LIBOR Rate plus a spread ranging from 1.125% to 1.75% depending on our debt rating. The commitment fee paid on the undrawn balance would range from 0.15% to 0.30%. We currently do not have an investment grade debt rating.

Senior Notes

In May 2015, we issued $750.0 million aggregate principal amount of 4.875% senior notes due 2025 (the “Outstanding Notes”) for net proceeds of $737.4 million after underwriting discounts and commissions of $12.6 million. The notes were issued at par and were offered to qualified institutional buyers and non-U.S. persons outside of the United States in compliance with Rule 144A and Regulation S under the Securities Act of 1933, as amended (the “Securities Act”). On April 8, 2016, all of the Outstanding Notes were exchanged for an equal principal amount of registered 4.875% senior notes due 2025 pursuant to an effective registration statement on Form S-4 filed with the SEC on February 29, 2016 under the Securities Act (the “Exchange Notes”). The Exchange Notes are identical to the Outstanding Notes except the Exchange Notes are registered under the Securities Act and do not have restrictions on transfer, registration rights or provisions for additional interest. Under certain circumstances, if we experience a change of control, noteholders may require us to repurchase all of our senior notes at 101% of the aggregate principal amount plus accrued and unpaid interest, if any.

In September 2016, in conjunction with the MRD Merger, we issued $329.2 million senior unsecured 5.875% notes due 2022 (the "5.875% Notes"). In addition, we also completed a debt exchange offer to exchange senior subordinated notes for the following senior notes (in thousands):

	Principal Amount
5.00% senior notes due 2023	$741,531
5.00% senior notes due 2022	$580,032
5.75% senior notes due 2021	$475,952

All of the notes were offered to qualified institutional buyers and to non-U.S. persons outside the United States in compliance with Rule 144A and Regulation S under the Securities Act. On October 5, 2017, the 5.875% Notes, the 5.00% senior notes due 2023, the 5.00% senior notes due 2022 and the 5.75% senior notes due 2021 (collectively, the "Old Notes") were exchanged for an equal principal amount of registered notes pursuant to an effective registration statement on Form S-4 filed with the SEC on August 9, 2017 under the Securities Act (the "New Notes"). The New Notes are identical to the Old Notes except the New Notes are registered under the Securities Act and do not have restrictions on transfer, registration rights or provisions for additional interest. Under certain circumstances, if we experience a change of control, noteholders may require us to repurchase all of our senior notes at 101% of the aggregate principal amount plus accrued and unpaid interest, if any.

Senior Subordinated Notes

If we experience a change of control, noteholders may require us to repurchase all or a portion of our senior subordinated notes at 101% of the aggregate principal amount plus accrued and unpaid interest, if any. All of the senior subordinated notes and the guarantees by our subsidiary guarantors are general, unsecured obligations and are subordinated to our bank debt and are subordinated to existing and future senior debt that we or our subsidiary guarantors are permitted to incur.

Guarantees

Range is a holding company which owns no operating assets and has no significant operations independent of its subsidiaries. The guarantees by our subsidiaries, which are directly or indirectly owned by Range, of our senior notes, senior subordinated notes and our bank credit facility are full and unconditional and joint and several, subject to certain customary release provisions. A subsidiary guarantor may be released from its obligations under the guarantee:

- in the event of a sale or other disposition of all or substantially all of the assets of the subsidiary guarantor or a sale or other disposition of all the capital stock of the subsidiary guarantor, to any corporation or other person (including an unrestricted subsidiary of Range) by way of merger, consolidation, or otherwise; or
- if Range designates any restricted subsidiary that is a guarantor to be an unrestricted subsidiary in accordance with the terms of the indenture.

Debt Covenants

Our bank credit facility contains negative covenants that limit our ability, among other things, to pay cash dividends, incur additional indebtedness, sell assets, enter into certain hedging contracts, change the nature of our business or operations, merge, consolidate, or make certain investments. In addition, we are required to maintain a ratio of EBITDAX (as defined in the bank credit facility agreement) to cash interest expense of equal to or greater than 2.5 and a current ratio (as defined in the bank credit facility agreement) of no less than 1.0. In addition, the ratio of the present value of proved reserves (as defined in the credit agreement) to total debt must be equal to or greater than 1.5 until Range has two investment grade ratings. We were in compliance with applicable covenants under the bank credit facility at September 30, 2017.

(10) ASSET RETIREMENT OBLIGATIONS

Our asset retirement obligations primarily represent the estimated present value of the amounts we will incur to plug, abandon and remediate our producing properties at the end of their productive lives. Significant inputs used in determining such obligations include estimates of plugging and abandonment costs, estimated future inflation rates and well lives. The inputs are calculated based on historical data as well as current estimated costs. A reconciliation of our liability for plugging and abandonment costs for the nine months ended September 30, 2017 is as follows (in thousands):

	Nine Months Ended September 30, 2017
Beginning of period	$ 257,943
Liabilities incurred	5,597
Liabilities settled	(6,125)

Disposition of wells	(2,427)
Accretion expense	11,022
Change in estimate	862
End of period	266,872
Less current portion	(7,271)
Long-term asset retirement obligations	$ 259,601

Accretion expense is recognized as a component of depreciation, depletion and amortization expense in the accompanying consolidated statements of operations.

(11) CAPITAL STOCK

We have authorized capital stock of 485.0 million shares which includes 475.0 million shares of common stock and 10.0 million shares of preferred stock. We currently have no preferred stock issued or outstanding. The following is a schedule of changes in the number of common shares outstanding since the beginning of 2016:

	Nine Months Ended September 30, 2017	Year Ended December 31, 2016
Beginning balance	247,144,356	169,316,460
MRD Merger	—	77,042,749
Restricted stock grants	536,536	490,609
Restricted stock units vested	341,358	266,541
PSU-TSR units settled	85,461	—
Shares retired	—	(739)
Treasury shares issued	15,580	28,736
Ending balance	248,123,291	247,144,356

(12) DERIVATIVE ACTIVITIES

We use commodity-based derivative contracts to manage exposure to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. We typically do not utilize complex derivatives, as we utilize commodity swaps, collars, options or combinations thereof to (1) reduce the effect of price volatility of the commodities we produce and sell and (2) support our annual capital budget and expenditure plans. In third quarter 2017, we entered into combined natural gas derivative instruments containing a fixed price swap and a sold option to extend or double the volume (referred to as a swaption in the table below). The swap price is a fixed price determined at the time of the swaption contract. If the option is exercised, the contract will become a swap treated consistently with our fixed-price swaps. The fair value of our derivative contracts, represented by the estimated amount that would be realized upon termination, based on a comparison of the contract price and a reference price, generally the New York Mercantile Exchange ("NYMEX") for natural gas and crude oil or Mont Belvieu for NGLs, approximated a net loss of $14.6 million at September 30, 2017. These contracts expire monthly through December 2019. The following table sets forth our commodity-based derivative volumes by year as of September 30, 2017, excluding our basis and freight swaps which are discussed separately below:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price
Natural Gas			
2017	Swaps (1)	878,370 Mmbtu/day	$ 3.21
2018	Swaps	477,534 Mmbtu/day	$ 3.22
January-March 2019	Swaps	50,000 Mmbtu/day	$ 3.01
2017	Collars (1)	122,609 Mmbtu/day	$ 3.45–$ 4.11
2018	Collars	60,000 Mmbtu/day	$ 3.40–$ 3.76
2017	Purchased Puts (1)	185,870 Mmbtu/day	$ 3.50 (2)
2017	Sold Calls	17,935 Mmbtu/day	$ 3.75 (3)
April-December 2018	Swaptions	320,000 Mmbtu/day (4)	$ 3.04 (4)
2019	Swaptions	60,000 Mmbtu/day (4)	$ 3.00 (4)
Crude Oil			
2017	Swaps (1)	9,511 bbls/day	$ 56.03
2018	Swaps	6,000 bbls/day	$ 52.96
2019	Swaps	1,000 bbls/day	$ 51.50
NGLs (C2-Ethane)			
2017	Swaps	3,000 bbls/day	$ 0.27/gallon
2018	Swaps	250 bbls/day	$ 0.29/gallon
NGLs (C3-Propane)			
2017	Swaps	17,576 bbls/day	$ 0.61/gallon
2018	Swaps	8,935 bbls/day	$0.66/gallon
NGLs (NC4-Normal Butane)			
2017	Swaps	9,000 bbls/day	$ 0.76/gallon
2018	Swaps	4,558 bbls/day	$ 0.81/gallon
NGLs (C5-Natural Gasoline)			
2017	Swaps	6,416 bbls/day	$ 1.08/gallon

2018	Swaps	4,027 bbls/day	$ 1.17/gallon

(1) Includes derivative instruments assumed in connection with the MRD Merger.

(2) Weighted average deferred premium is ($0.32).

(3) Weighted average deferred premium is $0.31.

(4) Contains a combined derivative instrument consisting of a fixed price swap and a sold option to extend or double the volume. For April through December of 2018, we have swaps in place for 160,000 Mmbtu per day on which the counterparty can elect to double the volume at a weighted average price of $3.02. We also have swaps in place for 160,000 Mmbtu per day on which the counterparty can elect to extend the contract through December 2019 at a weighted average price of $3.07. In 2019, if the counterparty elects to double the volume, we would have additional swaps covering 60,000 Mmbtu per day at a weighted average price of $3.00.

Every derivative instrument is required to be recorded on the balance sheet as either an asset or a liability measured at its fair value. We recognize all changes in fair value of these derivatives as earnings in derivative fair value income or loss in the periods in which they occur.

Basis Swap Contracts

In addition to the swaps described above, at September 30, 2017, we had natural gas basis swap contracts which lock in the differential between NYMEX Henry Hub and certain of our physical pricing indices primarily in Appalachia. These contracts settle monthly through March 2019 and include a total volume of 130,120,000 Mmbtu. The fair value of these contracts was a loss of $4.7 million on September 30, 2017.

At September 30, 2017, we also had propane basis swap contracts which lock in the differential between Mont Belvieu and international propane indices. The contracts settle monthly through December 2018 and include a total volume of 659,000 barrels in 2017 and 750,000 barrels in 2018. The fair value of these contracts was a gain of $1.1 million on September 30, 2017.

Freight Swap Contracts

In connection with our international propane basis swaps, at September 30, 2017, we had freight swap contracts which lock in the freight rate for a specific trade route on the Baltic Exchange. These contracts settle monthly in fourth quarter 2017 through December 2018 and cover 5,000 metric tons per month with a fair value gain of $45,000 on September 30, 2017.

Derivative Assets and Liabilities

The combined fair value of derivatives included in the accompanying consolidated balance sheets as of September 30, 2017 and December 31, 2016 is summarized below. The assets and liabilities are netted where derivatives with both gain and loss positions are held by a single counterparty and we have master netting arrangements. The tables below provide additional information relating to our master netting arrangements with our derivative counterparties (in thousands):

		September 30, 2017		
		Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
Derivative assets:				
Natural gas	–swaps	$37,288	$(12,385)	$24,903
	–swaptions	9,092	(8,711)	381
	–basis swaps	3,782	(2,774)	1,008
	–collars	6,214	(2,101)	4,113
	–puts	8,547	(4,238)	4,309
Crude oil	–swaps	7,133	(2,918)	4,215
NGLs	–C2 ethane swaps	82	(82)	—
	–C3 propane swaps	—	(2,956)	(2,956)
	–C3 propane basis swaps	18,169	(18,169)	—
	–NC4 butane swaps	34	(4,340)	(4,306)
	–C5 natural gasoline swaps	115	(1,094)	(979)

Freight	–swaps	47	(47)	—
		$90,503	$(59,815)	$ 30,688

		September 30, 2017		
		Gross Amounts of Recognized (Liabilities)	Gross Amounts Offset in the Balance Sheet	Net Amounts of (Liabilities) Presented in the Balance Sheet
Derivative liabilities:				
Natural gas	–swaps	$(10,805)	$12,385	$1,580
	–swaptions	(16,694)	8,711	(7,983)
	–basis swaps	(8,458)	2,774	(5,684)
	–collars	—	2,101	2,101
	–puts	—	4,238	4,238
	–calls	(29)	—	(29)
Crude oil	–swaps	(1,031)	2,918	1,887
NGLs	–C2 ethane swaps	(125)	82	(43)
	–C3 propane swaps	(36,046)	2,956	(33,090)
	–C3 propane basis swaps	(17,072)	18,169	1,097
	–NC4 butane swaps	(13,700)	4,340	(9,360)
	–C5 natural gasoline swaps	(4,678)	1,094	(3,584)
Freight	–swaps	(2)	47	45
		$(108,640)	$59,815	$(48,825)

		December 31, 2016		
		Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
Derivative assets:				
Natural gas	–swaps	$13,213	$(11,425)	$1,788
	–basis swaps	12,535	(9,437)	3,098
	–collars	6,298	(6,298)	—
	–puts	18,159	(15,429)	2,730
Crude oil	–swaps	9,356	(3,489)	5,867
NGLs	–C2 ethane swaps	53	(53)	—
	–C3 propane basis swaps	17,396	(17,396)	—

	–NC4 butane swaps	4	(4)	—
Freight	–swaps	65	(65)	—
		$77,079	$(63,596)	$ 13,483

		December 31, 2016		
		Gross Amounts of Recognized (Liabilities)	Gross Amounts Offset in the Balance Sheet	Net Amounts of (Liabilities) Presented in the Balance Sheet
Derivative liabilities:				
Natural gas	–swaps	$(158,359)	$11,425	$(146,934)
	–basis swaps	(687)	9,437	8,750
	–collars	(2,625)	6,298	3,673
	–puts	—	15,429	15,429
	–calls	(1,041)	—	(1,041)
Crude oil	–swaps	(13,206)	3,489	(9,717)
NGLs	–C2 ethane swaps	(1,008)	53	(955)
	–C3 propane swaps	(32,437)	—	(32,437)
	–C3 propane basis swaps	(18,138)	17,396	(742)
	–NC4 butane swaps	(13,419)	4	(13,415)
	–C5 natural gasoline swaps	(12,176)	—	(12,176)
Freight	–swaps	—	65	65
		$(253,096)	$63,596	$(189,500)

The effects of our derivatives on our consolidated statements of operations are summarized below (in thousands):

	Derivative Fair Value (Loss) Income			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Commodity swaps	$(87,861)	$38,662	$172,457	$(40,270)
Swaptions	(7,602)	—	(7,602)	—
Collars	956	1,320	15,221	1,320
Puts	(73)	2,842	9,646	2,842
Calls	104	—	1,144	—
Basis swaps	6,113	21,853	(2,554)	24,929
Freight swaps	(63)	(121)	14	(155)
Total	$(88,426)	$64,556	$188,326	$(11,334)

(13) FAIR VALUE MEASUREMENTS

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. There are three approaches for measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value amount using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset. This is often referred to as current replacement cost. The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

The fair value accounting standards do not prescribe which valuation technique should be used when measuring fair value and do not prioritize among the techniques. These standards establish a fair value hierarchy that prioritizes the inputs used in applying the various valuation techniques. Inputs broadly refer to the assumptions that market participants use to make pricing decisions, including assumptions about risk. Level 1 inputs are given the highest priority in the fair value hierarchy while Level 3 inputs are given the lowest priority. The three levels of the fair value hierarchy are as follows:

- Level 1 – Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.
- Level 3 – Unobservable inputs for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management's best estimates of the assumptions market participants would use in determining fair value. Our level 3 measurements consist of instruments using standard pricing models and other valuation methods that utilize unobservable pricing inputs that are significant to the overall fair value.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy.

Significant uses of fair value measurements include:

- impairment assessments of long-lived assets;
- impairment assessments of goodwill; and
- recorded value of derivative instruments and trading securities.

The need to test long-lived assets and goodwill can be based on several indicators, including a significant reduction in prices of natural gas, oil and condensate, NGLs, sustained declines in our common stock, unfavorable adjustments to reserves, significant changes in the expected timing of production, other changes to contracts or changes in the regulatory environment in which a property is located.

Fair Values – Recurring

We use a market approach for our recurring fair value measurements and endeavor to use the best information available. The following tables present the fair value hierarchy table for assets and liabilities measured at fair value, on a recurring basis (in thousands):

		Fair Value Measurements at September 30, 2017 using:			
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of September 30, 2017
Trading securities held in the deferred compensation plans		$64,784	$ —	$ —	$ 64,784
Derivatives	–swaps	—	(21,733)	—	(21,733)
	–collars	—	6,214	—	6,214
	–puts	—	8,547	—	8,547
	–calls	—	(29)	—	(29)
	–basis swaps	—	(3,601)	22	(3,579)
	–freight swaps	—	45	—	45
	–swaptions	—	—	(7,602)	(7,602)

		Fair Value Measurements at December 31, 2016 using:			
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of December 31, 2016
Trading securities held in the deferred compensation plans		$61,717	$ —	$ —	$ 61,717
Derivatives	–swaps	—	(207,979)	—	(207,979)
	–collars	—	3,673	—	3,673
	–puts	—	18,159	—	18,159
	–calls	—	(1,041)	—	(1,041)
	–basis swaps	—	11,106	—	11,106
	–freight swaps	—	65	—	65

Our trading securities in Level 1 are exchange-traded and measured at fair value with a market approach using end of period market values. Derivatives in Level 2 are measured at fair value with a market approach using third-party pricing services, which have been corroborated with data from active markets or broker quotes. As of September 30, 2017, a portion of our natural gas derivative instruments contain swaptions where the counterparty has the right, but not the obligation, to enter into a fixed price swap on a pre-determined date. Derivatives in Level 3 are measured at fair value with a market approach using third-party pricing services, which have been corroborated with data from active markets or broker quotes. Subjectivity in the volatility factors utilized can cause a significant change in the fair value measurement of our swaptions. The following is a reconciliation of the beginning and ending balances for derivative instruments classified as Level 3 in the fair value hierarchy (in thousands):

	As of September 30, 2017
Beginning balance	$ —
Changes in fair value of derivative instruments	(7,602)
Settlements received	—
Ending balance	$ (7,602)

Our trading securities held in the deferred compensation plan are accounted for using the mark-to-market accounting method and are included in other assets in the accompanying consolidated balance sheets. We elected to adopt the fair value option to simplify our accounting for the investments in our deferred compensation plan. Interest, dividends, and mark-to-market gains or losses are included in deferred compensation plan expense in the accompanying consolidated statements of operations. For third quarter 2017, interest and dividends were $1.5 million and the mark-to-market adjustment was a gain of $1.1 million compared to interest and dividends of $192,000 and a mark-to-market gain of $2.3 million in third quarter 2016. For first nine months 2017, interest and dividends were $2.4 million and the mark-to-market gain was $4.1 million compared to interest and dividends of $509,000 and mark-to-market adjustment of a gain of $3.7 million in the same period of the prior year.

Fair Values—Non-recurring

Our proved natural gas and oil properties are reviewed for impairment periodically as events or changes in circumstances indicate the carrying amount may not be recoverable. In third quarter 2017, there were indicators that the carrying value of certain of our oil and gas properties in Oklahoma and in the Texas Panhandle may be impaired and undiscounted future cash flows attributed to these assets indicated their carrying amounts were not expected to be recovered. Their remaining fair value was measured using an income approach based upon internal estimates of future production levels, prices, drilling and operating costs and discount rates, which are Level 3 measurements. We also considered the potential sale of certain of these properties. We recorded non-cash charges in the third quarter and nine months ended 2017 of $63.7 million related to these properties. In addition, we recorded non-cash charges in first nine months 2016 of $43.0 million related to our natural gas and oil properties in Western Oklahoma. Our estimates of future cash flows attributable to our natural gas and oil properties could decline further with lower commodity prices which may result in additional impairment charges. The following table presents the value of these assets measured at fair value on a non-recurring basis at the time impairment was recorded (in thousands):

	Nine Months Ended September 30, 2017		Nine Months Ended September 30, 2016	
	Fair Value	Impairment	Fair Value	Impairment
Natural gas and oil properties	$85,597	$63,679	$90,150	$43,040

Fair Values—Reported

The following table presents the carrying amounts and the fair values of our financial instruments as of September 30, 2017 and December 31, 2016 (in thousands):

	September 30, 2017		December 31, 2016	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:				
Commodity swaps, options and basis swaps	$30,688	$30,688	$13,483	$13,483
Marketable securities [(a)]	64,784	64,784	61,717	61,717
(Liabilities):				
Commodity swaps, options and basis swaps	(48,825)	(48,825)	(189,500)	(189,500)
Bank credit facility [(b)]	(1,086,000)	(1,086,000)	(882,000)	(882,000)
5.75% senior notes due 2021 [(b)]	(475,952)	(493,567)	(475,952)	(496,180)
5.00% senior notes due 2022 [(b)]	(580,032)	(579,342)	(580,032)	(577,132)
5.875% senior notes due 2022 [(b)]	(329,244)	(339,464)	(329,244)	(343,648)
Other senior notes due 2022 [(b)]	(590)	(584)	(1,090)	(1,104)
5.00% senior notes due 2023 [(b)]	(741,531)	(738,164)	(741,531)	(735,043)
4.875% senior notes due 2025 [(b)]	(750,000)	(736,028)	(750,000)	(724,688)
5.75% senior subordinated notes due 2021 [(b)]	(22,214)	(22,596)	(22,214)	(22,325)
5.00% senior subordinated notes due 2022 [(b)]	(19,054)	(18,692)	(19,054)	(18,387)
5.00% senior subordinated notes due 2023 [(b)]	(7,712)	(7,671)	(7,712)	(7,645)
Deferred compensation plan [(c)]	(106,008)	(106,008)	(139,580)	(139,580)

(a) Marketable securities, which are held in our deferred compensation plans, are actively traded on major exchanges.

(b) The book value of our bank debt approximates fair value because of its floating rate structure. The fair value of our senior notes and our senior subordinated notes is based on end of period market quotes which are Level 2 inputs.

(c) The fair value of our deferred compensation plan is updated at the closing price on the balance sheet date which is a Level 1 input.

Our current assets and liabilities contain financial instruments, the most significant of which are trade accounts receivable and payable. We believe the carrying values of our current assets and liabilities approximate fair value. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments and (2) our historical and expected incurrence of bad debt expense. Non-financial liabilities initially measured at fair value include asset retirement obligations. For additional information, see Note 10.

Concentrations of Credit Risk

As of September 30, 2017, our primary concentrations of credit risk are the risks of not collecting accounts receivable and the risk of a counterparty's failure to perform under derivative obligations. Most of our receivables are from a diverse group of companies, including major energy companies, pipeline companies, local distribution companies, financial institutions and end-users in various industries. Letters of credit or other appropriate securities are obtained as deemed necessary to limit our risk of loss. Our allowance for uncollectable receivables was $6.6 million at September 30, 2017 compared to $5.6 million at December 31, 2016. Our derivative exposure to credit risk is diversified primarily among major investment grade financial institutions, where we have master netting agreements which provide for offsetting payables against receivables from separate derivative contracts. To manage counterparty risk associated with our derivatives, we select and monitor our counterparties based on our assessment of their financial strength and/or credit ratings. We may also limit the level of exposure with any single counterparty. At September 30, 2017, our derivative counterparties include twenty-two financial institutions, of which all but five are secured lenders in our bank credit facility. At September 30, 2017, our net derivative asset includes a net payable of $20.8 million to these five counterparties that are not participants in our bank credit facility.

(14) STOCK-BASED COMPENSATION PLANS

Stock-Based Awards

We have one active equity-based stock plan, our Amended and Restated 2005 Equity-Based Incentive Compensation Plan, which we refer to as the 2005 Plan. Under this plan, various awards may be issued to non-employee directors and employees pursuant to decisions of the Compensation Committee, which is composed of only non-employee, independent directors. In 2005, we granted SARs which represent the right to receive a payment equal to the excess of the fair market value of shares of our common stock on the date the right is exercised over the value of the stock on the date of grant. All SARs granted under the 2005 Plan will be settled in shares of stock, vest over a three-year period and have a maximum term of five years from the date they are granted. In 2011, the Compensation Committee of the Board of Directors began granting restricted stock units under this plan. These restricted stock units, which we refer to as restricted stock Equity Awards, vest over a three-year period. All awards granted have been issued at prevailing market prices at the time of grant and the vesting of these awards is based upon an employee’s continued employment with us, with the exception of employment termination due to death, disability or retirement.

In 2014, the Compensation Committee also began granting market-based performance share unit (“TSR”) awards under our 2005 Plan. The number of shares to be issued is determined by our total shareholder return compared to the total shareholder return of a predetermined group of peer companies over the performance period. The grant date fair value of the TSR awards is determined using a Monte Carlo simulation and is recognized as stock-based compensation expense over the three-year performance period. The actual payout of shares granted depends on our total shareholder return compared to our peer companies and will be between zero and 150%, unless our return is negative in which case the payout is capped at 100%. In first quarter 2017, the Compensation Committee also began granting performance-based unit awards based on production growth per share (“PGPS”) and reserve growth per share (“RGPS”). The number of shares to be issued depends on our level of success in achieving specifically identified performance targets. The grant date fair value is determined by the market value of our stock on the grant date and is recognized as stock-based compensation expense over the three-year performance period. The actual payout of shares granted will be between zero and 150%.

The Compensation Committee also grants restricted stock to certain employees and non-employee directors of the Board of Directors as part of their compensation. Upon grant of these restricted shares, which we refer to as restricted stock Liability Awards, the shares generally are placed in our deferred compensation plan and, upon vesting, employees are allowed to take withdrawals either in cash or in stock based on their distribution elections. Compensation expense is recognized over the vesting period, which is typically three years for employee grants and immediate vesting for non-employee directors. All restricted stock awards are issued at prevailing market prices at the time of the grant and vesting is based upon an employee’s continued employment with us, with the exception of employment termination due to death, disability or retirement. Prior to vesting, all restricted stock awards have the right to vote such shares and receive dividends thereon. These Liability Awards are classified as a liability and are remeasured at fair value each reporting period. This mark-to-market adjustment is reported as deferred compensation plan expense in the accompanying consolidated statements of operations.

Total Stock-Based Compensation Expense

Stock-based compensation represents amortization of restricted stock and performance share expense. Unlike the other forms of stock-based compensation, the mark-to-market adjustment of the liability related to the vested restricted stock held in our deferred compensation plan is directly tied to the change in our stock price and not directly related to the functional expenses and therefore, is not allocated to the functional categories. The following table details the allocation of stock-based compensation to functional expense categories (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Direct operating expense	$517	$497	$1,563	$1,781
Brokered natural gas and marketing expense	389	455	1,040	1,349
Exploration expense	561	608	1,596	1,669
General and administrative expense	9,959	11,126	35,156	37,682
Termination costs	(31)	—	1,665	—
Total stock-based compensation	$11,395	$12,686	$41,020	$42,481

Market-Based TSR Awards

The following is a summary of our non-vested TSR awards outstanding at September 30, 2017:

	Number of Units	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2016	395,908	$ 44.39
Units granted [(a)]	358,519	26.26
Units vested	(221,274)	43.01
Units forfeited	(3,679)	44.21
Outstanding at September 30, 2017	529,474	$ 32.69

[(a)] Amounts granted reflect the number of performance units granted; however, the actual payout of shares will be between zero and 150% of the performance units granted depending on the total shareholder return ranking compared to the peer companies at the end of the three-year performance period.

The following assumptions were used to estimate the fair value of TSRs granted during first nine months 2017 and 2016:

	Nine Months Ended September 30,	
	2017	2016
Risk-free interest rate	1.49 %	0.94 %
Expected annual volatility	44 %	49 %
Weighted average grant date fair value per unit	$26.26	$36.64

We recorded TSR compensation expense of $9.7 million in first nine months 2017 compared to $9.1 million in the same period of 2016. During first nine months 2017, 89,000 TSR awards (or approximately 40% of the 2014-2016 performance period grants) were forfeited due to our final total shareholder return being less than the original performance target (included in "Units vested" in the table above).

Performance-Based PGPS/RGPS Awards

The following is a summary of our non-vested PGPS/RGPS awards outstanding at September 30, 2017:

	Number of Units	Weighted Average Grant Date Fair Value of Range Stock
Outstanding at December 31, 2016	—	—
Units granted [(a)]	122,921	$25.53
Units vested	(20,231)	25.64
Outstanding at September 30, 2017	102,690	$25.51

[(a)] Amounts granted reflect the number of performance units granted; however, the actual payout of shares will be between zero and 150% depending on achievement of specifically identified performance targets.

We recorded PGPS/RGPS compensation expense of $124,000 in first nine months 2017.

Restricted Stock Awards

Equity Awards

In first nine months 2017, we granted 883,000 restricted stock Equity Awards to employees at an average grant price of $32.81 compared to 940,000 restricted stock Equity Awards granted to employees at an average grant price of $28.18 in first nine months 2016. These awards generally vest over a three-year period. We recorded compensation expense for these Equity Awards of $18.1 million in first nine months 2017 compared to $17.2 million in the same period of 2016. Equity Awards are not issued to employees until they are vested. Employees do not have the option to receive cash.

Liability Awards

In first nine months 2017, we granted 451,000 shares of restricted stock Liability Awards as compensation to employees at an average price of $25.95 with vesting over a three-year period and 90,000 shares were granted to non-employee directors at an average price of $25.01 with immediate vesting. In first nine months 2016, we granted 457,000 shares of Liability Awards as compensation to employees at an average price of $35.70 with vesting generally over a three-year period and 56,000 shares were granted to non-employee directors at an average price of $38.62 with immediate vesting. We recorded compensation expense for Liability Awards of $12.0 million in first nine months 2017 compared to $14.6 million in the same period of 2016. Substantially all of these awards are held in our deferred compensation plan, are classified as a liability and are remeasured at fair value at the end of each reporting period. This mark-to-market adjustment is reported as deferred compensation expense in our consolidated statements of operations (see additional discussion below). The following is a summary of the status of our non-vested restricted stock outstanding at September 30, 2017:

	Equity Awards		Liability Awards	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2016	765,971	$ 33.62	425,018	$ 43.48
Granted	882,826	32.81	540,878	25.96
Vested	(546,565)	35.10	(325,629)	37.45
Forfeited	(90,850)	32.85	(4,342)	31.10
Outstanding at September 30, 2017	1,011,382	$ 32.18	635,925	$ 31.75

Stock Appreciation Right Awards

There were 383,000 SARs outstanding at September 30, 2017. Information with respect to SARs activity is summarized below:

	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2016	1,003,600	$ 69.08
Exercised	—	—
Expired/forfeited	(620,821)	62.29
Outstanding at September 30, 2017	382,779	$ 76.54

Deferred Compensation Plan

Our deferred compensation plan gives non-employee directors and officers the ability to defer all or a portion of their salaries, bonuses or director fees and invest in Range common stock or make other investments at the individual's discretion. Range provides a partial matching contribution to officers which vests over three years. The assets of the plan are held in a grantor trust, which we refer to as the Rabbi Trust, and are therefore available to satisfy the claims of our general creditors in the event of bankruptcy or insolvency. Our stock held in the Rabbi Trust is treated as a liability award as employees are allowed to take withdrawals from the Rabbi Trust either in cash or in Range stock. The liability for the vested portion of the stock held in the Rabbi Trust is reflected as deferred compensation liability in the accompanying consolidated balance sheets and is adjusted to fair value each reporting period by a charge or credit to deferred compensation plan expense on our consolidated statements of operations. The assets of the Rabbi Trust, other than our common stock, are invested in marketable securities and reported at their market value as other assets in the accompanying consolidated balance sheets. The deferred compensation liability reflects the vested market value of the marketable securities and Range stock held in the Rabbi Trust. Changes in the market value of the marketable securities and changes in the fair value of the deferred compensation plan liability are charged or credited to deferred compensation plan expense each quarter. We recorded mark-to-market gain of $9.2 million in third quarter 2017 compared to mark-to-market gain of $11.6 million in third quarter 2016. We recorded a mark-to-market gain of $36.8 million in first nine months 2017 compared to a mark-to-market loss of $30.2 million in first nine months 2016. The Rabbi Trust held 2.9 million shares (2.2 million of which were vested) of Range stock at September 30, 2017 compared to 2.7 million shares (2.3 million of which were vested) at December 31, 2016.

(15) SUPPLEMENTAL CASH FLOW INFORMATION

	Nine Months Ended September 30,	
	2017	2016
	(in thousands)	
Net cash provided from operating activities included:		
Income taxes paid to (refunded from) taxing authorities	$98	$(101)
Interest paid	136,863	134,583
Non-cash investing and financing activities included:		
Increase in asset retirement costs capitalized	6,460	4,655
Increase in accrued capital expenditures	52,289	12,523

(16) COMMITMENTS AND CONTINGENCIES

Litigation

We are the subject of, or party to, a number of pending or threatened legal actions, administrative proceedings and claims arising in the ordinary course of our business. While many of these matters involve inherent uncertainty, we believe that the amount of the liability, if any, ultimately incurred with respect to these actions, proceedings or claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future annual results of operations. We estimate and provide for potential losses that may arise out of litigation and regulatory proceedings to the extent that such losses are probable and can be reasonably estimated. We will continue to evaluate our litigation and regulatory proceedings quarterly and will establish and adjust any estimated liability as appropriate to reflect our assessment of the then current status of litigation and regulatory proceedings. Significant judgment is required in making these estimates and our final liabilities may ultimately be materially different.

We have been named as a defendant in a lawsuit styled Seagraves v Range Resources Corporation; Cause No. 2:17-CV-01009-MRH, filed in the United States District Court for the Western District of Pennsylvania. The lawsuit asserts claims under the federal Fair Labor Standards Act as well as the comparable Pennsylvania state law statute seeking certification of a class of individuals or assertion of a collective action on behalf of individuals who were paid a day rate directly or indirectly by one of our subsidiaries and who the Plaintiff alleges were misclassified as independent contractors. We cannot predict with certainty the outcome of the litigation, but we intend to defend the litigation and the claims asserted against us.

Transportation and Gathering Contracts

In first nine months 2017, our transportation and gathering commitments increased by approximately $402.0 million over the next twenty-two years (through 2038) primarily due to extension of terms and pricing changes for current contracts.

(17) OFFICE CLOSING AND TERMINATION COSTS

In first quarter 2017, we recorded accruals for severance, other personnel costs and accelerated vesting of stock-based compensation as part of a continuing effort to reduce our general and administrative expenses due, in part, to the lower commodity price environment. The following summarizes our termination costs for the three months and nine months ended September 30, 2017 and 2016 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Severance costs	$—	$—	$2,422	$—
Building lease	(16)	136	(37)	303
Stock-based compensation	(31)	—	1,664	—
Total termination costs	$(47)	$136	$4,049	$303

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The following details our accrued liability as of September 30, 2017 (in thousands):

	September 30, 2017
Beginning balance at December 31, 2016	$2,460
Accrued severance costs	2,422
Accrued building rent	(37)
Payments	(2,290)
Ending balance at September 30, 2017	$2,555

(18) Capitalized Costs and Accumulated Depreciation, Depletion and Amortization [(a)]

	September 30, 2017	December 31, 2016
	(in thousands)	
Natural gas and oil properties:		
Properties subject to depletion	$10,172,411	$9,462,350
Unproved properties	2,888,979	2,923,803
Total	13,061,390	12,386,153
Accumulated depreciation, depletion and amortization	(3,492,614)	(3,129,816)
Net capitalized costs	$9,568,776	$9,256,337

(a) Includes capitalized asset retirement costs and the associated accumulated amortization.

(19) Costs Incurred for Property Acquisition, Exploration and Development [(a)]

	Nine Months Ended September 30, 2017	Year Ended December 31, 2016
	(in thousands)	
Acquisitions:		
Acreage purchases	$41,817	$ 33,142
Oil and gas properties	7,875	3,098,772
Asset retirement obligations	—	21,908
Development	809,961	497,795
Exploration:		
Drilling	1,008	37,680
Expense	44,173	30,027
Stock-based compensation expense	1,596	2,298
Gas gathering facilities:		
Development	6,292	3,595
Subtotal	912,722	3,725,217
Asset retirement obligations	6,460	(24,064)
Total costs incurred	$919,182	$ 3,701,153

[a] Includes costs incurred whether capitalized or expensed.

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

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. Certain sections of Management's Discussion and Analysis of Financial Condition and Results of Operations include forward-looking statements concerning trends or events potentially affecting our business. These statements contain words such as "anticipates," "believes," "expects," "targets," "plans," "projects," "could," " "should," "would" or similar words indicating that future outcomes are uncertain. In accordance with "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in the forward-looking statements. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future revenues and operating results are based on our current forecasts for our existing operations and do not include the potential impact of any future events. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise. For additional risk factors affecting our business, see Item 1A. Risk Factors as set forth in our Annual Report on Form 10-K for the year ended December 31, 2016, as filed with the SEC on February 22, 2017.

Overview of Our Business

We are a Fort Worth, Texas-based independent natural gas, natural gas liquids ("NGLs") and oil company engaged in the exploration, development and acquisition of natural gas and crude oil properties primarily in the Appalachian and North Louisiana regions of the United States. We operate in one segment and have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on a geographical or an area-by-area basis.

Our overarching business objective is to build stockholder value through consistent returns focused on growth, on a per share debt-adjusted basis, of both reserves and production. Our strategy to achieve our business objective is to increase reserves and production through internally generated drilling projects occasionally coupled with complementary acquisitions and divestitures of non-core assets. Our revenues, profitability and future growth depend substantially on prevailing prices for natural gas, NGLs, crude oil and condensate and on our ability to economically find, develop, acquire, produce and market natural gas, NGLs and crude oil reserves. The price risk on a portion of our production is mitigated using commodity derivative contracts. However, these derivative contracts are limited in duration. Natural gas, NGLs and crude oil prices continue to be depressed. Prices for natural gas, NGLs and oil fluctuate widely and affect:

- revenues, profitability and cash flow;
- the quantity of natural gas, NGLs and oil we can economically produce;
- the amount of cash flows available for capital expenditures; and
- our ability to borrow and raise additional capital.

We prepare our financial statements in conformity with U.S. GAAP which requires us to make estimates and assumptions that affect our reported results of operations and the amount of our reported assets, liabilities and proved natural gas, NGLs and oil reserves. We use the successful efforts method of accounting for our natural gas, NGLs and oil activities.

Market Conditions

Prices for our products significantly impact our revenue, net income and cash flow. Natural gas, NGLs and oil are commodities and prices for these commodities are inherently volatile. The following table lists average New York

Mercantile Exchange ("NYMEX") prices for natural gas and oil and the Mont Belvieu NGL composite price for the three months and nine months ended September 30, 2017 and 2016:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2017	2016	Change	%	2017	2016	Change	%
Average NYMEX prices [(a)]								
Natural gas (per mcf)	$3.00	$2.82	$ 0.18	6 %	$3.15	$2.31	$ 0.84	36%
Oil (per bbl)	48.14	44.96	3.18	7 %	49.35	41.24	8.11	20%
Mont Belvieu NGLs composite (per gallon) [(b)]	0.56	0.40	0.16	40%	0.53	0.38	0.15	39%

[(a)] Based on weighted average of bid week prompt month prices.

[(b)] Based on our estimated NGLs product composition per barrel.

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Consolidated Results of Operations

Overview of Third Quarter 2017 Results

During third quarter 2017, we reported the following financial and operating results:

- 32% production growth over the same period of 2016;
- revenue from the sale of natural gas, NGLs and oil increased 67% from the same period of 2016 with a 27% increase in average realized prices (before cash settlements on our derivatives) and an increase in production volumes;
- revenue realized from the sale of natural gas, NGLs and oil including cash settlements on our derivatives increased 47% from the same period of 2016;
- increased direct operating expenses per mcfe by 25% from the same period of 2016;
- reduced general and administrative expense per mcfe 3% from the same period of 2016;
- reduced interest expense per mcfe 18% from the same period of 2016;
- reduced our depletion, depreciation and amortization ("DD&A") rate per mcfe by 8% from the same period of 2016;
- entered into additional derivative contracts for 2017, 2018 and 2019; and
- realized $189.2 million of cash flow from operating activities, an increase of $156.6 million from the same period of 2016.

Our financial results are significantly impacted by commodity prices. For the third quarter 2017, we experienced an increase in revenue from the sale of natural gas, NGLs and oil due to a 15% increase in net realized prices (average prices including all derivative settlements and third party transportation costs paid by us) and 32% higher production volumes when compared to the same quarter of 2016. During third quarter 2017, we recognized net loss of $127.7 million, or $0.52 per diluted common share compared to net loss of $42.0 million, or $0.23 per diluted common share, during third quarter 2016. The significant increase in net loss for third quarter 2017 from third quarter 2016 is primarily due to a $63.7 million impairment charge related to oil and gas properties in Oklahoma and Texas Panhandle and an unfavorable derivative fair value adjustment. One of our primary focuses over the past few years has been to increase efficiencies and reduce costs throughout our organization through a number of internal initiatives. As a result, over the past several years, we have achieved reductions in many of our expenses per mcfe when compared to the prior year. The addition of our North Louisiana properties resulted in an increase in direct operating expenses per mcfe in third quarter 2017. We do, however, receive higher net sales prices from these same North Louisiana properties when compared to our other properties which results in higher margins. We generated $189.2 million of cash flows from operating activities in third quarter 2017, an increase of $156.6 million from third quarter 2016 which reflects improvements in realized prices, higher production volumes and lower comparative working capital outflows ($4.4 million inflow during third quarter 2017 compared to $43.7 million outflow in third quarter 2016).

Overview of First Nine Months 2017 Results

During first nine months 2017, we reported the following financial and operating results:

- 35% production growth over the same period of 2016;
- revenue from the sale of natural gas, NGLs and oil increased 113% from the same period of 2016 with a 57% increase in average realized prices (before cash settlements on our derivatives) and an increase in production volumes;
- revenue realized from the sale of natural gas, NGLs and oil including cash settlements on our derivatives increased 59% from the same period of 2016;
- increased direct operating expenses per mcfe by 6% from the same period of 2016;
- reduced general and administrative expense per mcfe 9% from the same period of 2016;
- reduced interest expense per mcfe 13% from the same period of 2016;
- reduced our DD&A rate per mcfe by 8% from the same period of 2016;

- entered into additional derivative contracts for 2017, 2018 and 2019; and
- realized $600.5 million of cash flow from operating activities, an increase of $394.7 million from the same period of 2016.

During first nine months 2017, we recognized net income of $112.0 million, or $0.45 per diluted common share compared to net loss of $360.7 million, or $2.10 per diluted common share, during first nine months 2016. The significant swing from a net loss in the nine months ended September 30, 2016 to net income in the nine months ended September 30, 2017 was primarily due to improvements in realized prices, higher production volumes and a favorable derivative fair value adjustment. We experienced an increase in revenue from the sale of natural gas, NGLs and oil due to a 27% increase in realized prices (average prices including all derivative settlements and third party transportation costs paid by us) and 35% higher production volumes when compared to first nine months 2016. We continue to evaluate opportunities to reduce our general and administrative expenses and, in early 2017, implemented additional work force reductions. We generated $600.5 million of cash flows from operating activities in first nine months 2017, an increase of $394.7 million from first nine months 2016.

Memorial Merger

On September 16, 2016, we completed the MRD Merger. The MRD Merger adds a premier onshore U.S. natural gas resource play as an existing core operating area. The North Louisiana location provides geographic and marketing diversity to our high quality Appalachia basin assets. We have seen significant improvements in drilling and completion costs by applying best practices from our Marcellus division and capitalizing on synergies. On September 16, 2016, we issued approximately 77.0 million shares of common stock and assumed approximately $1.2 billion in debt in exchange for all outstanding shares of Memorial using an exchange ratio of 0.375 of a share of Range common stock for each share of Memorial common stock. See also Note 4 to our unaudited consolidated financial statements for more information.

Natural Gas, NGLs and Oil Sales, Production and Realized Price Calculations

Our revenues vary primarily as a result of changes in realized commodity prices and production volumes. We generally sell natural gas, NGLs and oil under two types of agreements, which are common in our industry. Both types of agreements include transportation charges. One type of agreement is a netback agreement, under which we sell natural gas or oil at the wellhead and collect a price, net of transportation costs incurred by the purchaser. In this case, we record revenue at the price we receive from the purchaser. For our NGLs production, we may receive a net price from the purchaser (which is net of processing costs) which is also recorded as revenue at the net price we receive from the purchaser. Under the other type of agreement, we sell natural gas, NGLs or oil at a specific delivery point, pay transportation and other costs to a third party and receive proceeds from the purchaser with no transportation cost deduction. In that case, we record transportation costs and other costs that we pay to third parties as transportation, gathering, processing and compression expense.

In third quarter 2017, natural gas, NGLs and oil sales increased 67% compared to third quarter 2016 with a 27% increase in average realized prices (before cash settlements on our derivatives) and a 32% increase in average daily production. In the nine months ended September 30, 2017, natural gas, NGLs and oil sales increased 113% compared to the same period of 2016 with a 57% increase in average realized prices (before cash settlements on our derivatives) and a 35% increase in production. The following table illustrates the primary components of natural gas, NGLs, oil and condensate sales for the three months and nine months ended September 30, 2017 and 2016 (in thousands):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2017	2016	Change	%	2017	2016	Change	%
Natural gas, NGLs and oil sales								
Gas	$301,114	$197,476	$103,638	52 %	$1,009,000	$464,098	$544,902	117%
NGLs	150,593	75,259	75,334	100%	412,440	198,877	213,563	107%
Oil	55,834	31,742	24,092	76 %	151,688	75,595	76,093	101%
Total natural gas, NGLs and oil sales	$507,541	$304,477	$203,064	67 %	$1,573,128	$738,570	$834,558	113%

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Our production continues to grow through drilling success, additional NGLs extraction and newly acquired production which is partially offset by the natural production decline of our wells and non-core asset sales. Third quarter 2017 production volumes from our newly acquired North Louisiana properties were approximately 360.0 Mmcfe per day. Production volumes from the Marcellus Shale in third quarter 2017 were 1.6 Bcfe per day. When compared to the same period of 2016, our Marcellus production volumes increased 15% for third quarter 2017. In first nine months 2017, production volumes from our newly acquired North Louisiana properties were 390.6 Mmcfe per day. Production volumes from the Marcellus Shale in first nine months 2017 were 1.5 Bcfe per day. When compared to the same period of 2016, our Marcellus production volumes increased 12% for first nine months 2017. Our production for the three months and nine months ended September 30, 2017 and 2016 is set forth in the following table:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2017	2016	Change	%	2017	2016	Change	%
Production [(a)]								
Natural gas (mcf)	121,644,949	93,466,385	28,178,564	30%	357,389,113	261,331,126	96,057,987	37%
NGLs (bbls)	8,892,778	6,739,161	2,153,617	32%	25,953,773	19,579,843	6,373,930	33%
Crude oil (bbls)	1,288,303	810,878	477,425	59%	3,406,373	2,504,757	901,616	36%
Total (mcfe) [(b)]	182,731,435	138,766,619	43,964,816	32%	533,549,989	393,838,726	139,711,263	35%
Average daily production [(a)]								
Natural gas (mcf)	1,322,228	1,015,939	306,289	30%	1,309,118	953,763	355,355	37%
NGLs (bbls)	96,661	73,252	23,409	32%	95,069	71,459	23,610	33%
Crude oil (bbls)	14,003	8,814	5,189	59%	12,478	9,141	3,337	37%
Total (mcfe) [(b)]	1,986,211	1,508,333	477,878	32%	1,954,396	1,437,368	517,028	36%

[(a)] Represents volumes sold regardless of when produced.

[(b)] Oil and NGLs are converted to mcfe at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil to natural gas, which is not indicative of the relationship between oil and natural gas prices.

Our average realized price received (including all derivative settlements and third-party transportation costs) during third quarter 2017 was $1.82 per mcfe compared to $1.58 per mcfe in third quarter 2016. Our average realized price received (including all derivative settlements and third-party transportation costs) was $1.93 per mcfe in first nine months 2017 compared to $1.52 per mcfe in the same period of the prior year. Although we record transportation costs on two separate bases, as required by U.S. GAAP, we believe computed final realized prices should include the total impact of transportation, gathering, processing and compression expense. Our average realized price (including all derivative settlements and third-party transportation costs) calculation also includes all cash settlements for derivatives. Average realized prices (excluding derivative settlements) do not include derivative settlements or third party transportation costs which are reported in transportation, gathering, processing and compression expense on the accompanying consolidated statements of operations. Average realized prices (excluding derivative settlements) do include transportation costs where we receive net revenue proceeds from purchasers.

Realized prices include the impact of basis differentials. The prices we receive for our natural gas can be more or less than the NYMEX price because of adjustments for delivery location, relative quality and other factors. Average natural gas differentials were $0.52 per mcf below NYMEX in third quarter 2017 compared to $0.71 per mcf below NYMEX in third quarter 2016. We also realized gains on our basis hedging in third quarter 2017 of $0.01 per mcf compared to a realized gain of $0.03 per mcf in third quarter 2016. Average natural gas differentials were $0.33 per mcf below NYMEX in first nine months 2017 compared to $0.53 per mcf below NYMEX in the same period of the prior year. We also realized gains on basis hedging of $0.03 per mcf in first nine months 2017 compared to a gain of $0.04 in the same period of 2016. Average realized price calculations for the three months and the nine months ended September 30, 2017 and 2016 are shown below:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2017	2016	Change	%	2017	2016	Change	%
Average Prices								
Average realized prices (excluding derivative settlements):								
Natural gas (per mcf)	$2.48	$2.11	$0.37	18%	$2.82	$1.78	$1.04	58%
NGLs (per bbl)	16.93	11.17	5.76	52%	15.89	10.16	5.73	56%
Crude oil and condensate (per bbl)	43.34	39.15	4.19	11%	44.53	30.18	14.35	48%
Total (per mcfe) [a]	2.78	2.19	0.59	27%	2.95	1.88	1.07	57%
Average realized prices (including all derivative settlements):								
Natural gas (per mcf)	$2.69	$2.50	$0.19	8 %	$2.92	$2.56	$0.36	14%
NGLs (per bbl)	15.14	12.43	2.71	22%	14.60	11.45	3.15	28%
Crude oil and condensate (per bbl)	48.46	49.97	(1.51)	(3 %)	48.90	41.87	7.03	17%
Total (per mcfe) [a]	2.87	2.58	0.29	11%	2.98	2.54	0.44	17%
Average realized prices (including all derivative settlements and third party transportation costs paid by Range):								
Natural gas (per mcf)	$1.60	$1.43	$0.17	12%	$1.84	$1.46	$0.38	26%
NGLs (per bbl)	8.54	6.60	1.94	29%	7.82	5.71	2.11	37%
Crude oil and condensate (per bbl)	48.46	49.97	(1.51)	(3 %)	48.90	41.87	7.03	17%
Total (per mcfe) [a]	1.82	1.58	0.24	15%	1.93	1.52	0.41	27%

[a] Oil and NGLs are converted to mcfe at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil to natural gas, which is not indicative of the relationship between oil and natural gas prices.

Transportation, gathering, processing and compression expense was $191.6 million in third quarter 2017 compared to $138.8 million in third quarter 2016. Transportation, gathering, processing and compression expense was $560.9 million in first nine months 2017 compared to $400.9 million in the same period of 2016. These third party costs are higher in 2017 when compared to 2016 due to our production growth in the Marcellus Shale where we have third party transportation, gathering, processing and compression agreements. For 2017, these costs also include additional third party costs for our newly acquired North Louisiana production. We have included these costs in the calculation of average realized prices (including all derivative settlements and third party transportation expenses paid by Range). The following table summarizes transportation, gathering, processing and compression expense for the three months and the nine months ended September 30, 2017 and 2016 (in thousands) and on a per mcf and per barrel basis:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2017	2016	Change	%	2017	2016	Change	%
Natural gas	$133,019	$99,465	$33,554	34%	$384,769	$288,355	$96,414	33%
NGLs	58,626	39,299	19,327	49%	176,114	112,516	63,598	57%
Total	$191,645	$138,764	$52,881	38%	$560,883	$400,871	$160,012	40%

Natural gas (per mcf)	$1.09	$1.06	$0.03	3 %	$1.08	$1.10	$(0.02)	(2 %)
NGLs (per bbl)	$6.59	$5.83	$0.76	13%	$6.79	$5.75	$1.04	18%

Derivative fair value (loss) income was a loss of $88.4 million in third quarter 2017 compared to a gain of $64.6 million in third quarter 2016. Derivative fair value (loss) income was a gain of $188.3 million in first nine months 2017 compared to a loss of $11.3 million in the same period of 2016. All of our derivatives are accounted for using the mark-to-market accounting method. Mark-to-market accounting treatment can result in more volatility of our revenues as the change in the fair value of our commodity derivative positions is included in total revenue. As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our derivatives. Gains on our derivatives generally indicate lower wellhead revenues in the future

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while losses indicate higher future wellhead revenues. The following table summarizes the impact of our commodity derivatives for the three months and the nine months ended September 30, 2017 and 2016 (in thousands):

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Derivative fair value (loss) income per consolidated statements of operations	$(88,426)	$64,556	$188,326	$(11,334)
Non-cash fair value (loss) gain: [1]				
Natural gas derivatives	$(16,409)	$25,441	$155,827	$(195,038)
Oil derivatives	(18,991)	(5,221)	9,951	(35,556)
NGLs derivatives	(69,820)	(8,656)	6,505	(41,242)
Freight derivatives	(63)	(121)	(19)	(155)
Total non-cash fair value (loss) gain [1]	$(105,283)	$11,443	$172,264	$(271,991)
Net cash receipt on derivative settlements:				
Natural gas derivatives	$26,250	$35,822	$34,647	$205,985
Oil derivatives	6,602	8,777	14,874	29,277
NGL derivatives	(15,995)	8,514	(33,459)	25,395
Total net cash receipt (payment)	$16,857	$53,113	$16,062	$260,657

(1) Non-cash fair value adjustments on commodity derivatives is a non-U.S. GAAP measure. Non-cash fair value adjustments on commodity derivatives only represent the net change between periods of the fair market values of commodity derivative positions and exclude the impact of settlements on commodity derivatives during the period. We believe that non-cash fair value adjustments on commodity derivatives is a useful supplemental disclosure to differentiate non-cash fair market value adjustments from settlements on commodity derivatives during the period. Non-cash fair value adjustments on commodity derivatives is not a measure of financial or operating performance under U.S. GAAP, nor should it be considered a substitute for derivative fair value income or loss as reported in our consolidated statements of operations.

Brokered natural gas, marketing and other revenue in third quarter 2017 was $63.1 million compared to $44.2 million in third quarter 2016 with significantly higher sales volumes for our brokered natural gas volumes. Brokered natural gas, marketing and other revenues in first nine months 2017 was $170.5 million compared to $119.2 million in the same period of the prior year due to significantly higher sales prices and higher brokered natural gas volumes. In first nine months 2016, we also received $8.9 million from the sale of brokered NGLs volumes compared to $728,000 in the same period of 2017.

Operating Costs Per mcfe

We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per mcfe, basis. The following presents information about certain of our expenses on a per mcfe basis for the three months and the nine months ended September 30, 2017 and 2016:

	Three Months Ended September 30, 2017	2016	Change	%	Nine Months Ended September 30, 2017	2016	Change	%
Direct operating expense	$0.20	$0.16	$0.04	25 %	$0.18	$0.17	$0.01	6 %
Production and ad valorem tax expense	0.07	0.05	0.02	40 %	0.06	0.05	0.01	20 %
General and administrative expense	0.29	0.30	(0.01)	(3 %)	0.29	0.32	(0.03)	(9 %)
Interest expense	0.27	0.33	(0.06)	(18%)	0.27	0.31	(0.04)	(13%)

DD&A	0.87	0.95	(0.08)	(8 %)	0.87	0.95	(0.08)	(8 %)

Direct operating expense was $36.9 million in third quarter 2017 compared to $22.4 million in third quarter 2016. Direct operating expenses include normally recurring expenses to operate and produce our wells, non-recurring well workovers and repair-related expenses. Our direct operating costs increased primarily due to our newly acquired North Louisiana properties partially offset by our continuing cost reduction efforts. We experienced cost increases in many categories of direct operating expenses including personnel costs, well service costs, water handling and disposal costs and workovers. We incurred $3.5 million ($0.02 per mcfe) of workover costs in third quarter 2017 compared to $55,000 in third quarter 2016. On a per mcfe basis, direct operating expense in third quarter 2017 increased 25% from the same period of 2016 with the increase consisting of higher workover and well service costs.

Direct operating expense was $96.3 million in first nine months 2017 compared to $67.1 million in the same period of 2016. Our direct operating costs increased primarily due to our newly acquired North Louisiana properties partially offset by our continuing cost reduction efforts. We experienced cost increases in many categories of direct operating expenses including personnel costs, equipment leasing, water hauling and disposal costs and workovers. We incurred $6.9 million of workover costs in first nine months 2017 compared to $3.0 million in the same period of 2016. On a per mcfe basis, direct operating expense in first nine months 2017 increased 6% to $0.18 from $0.17 in the same period of 2016 with the increase consisting of higher well service costs. The following table summarizes direct operating expenses per mcfe for the three months and the nine months ended September 30, 2017 and 2016:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2017	2016	Change	%	2017	2016	Change	%
Lease operating expense	$0.18	$0.15	$ 0.03	20 %	$0.17	$0.16	$ 0.01	6 %
Workovers	0.02	0.01	0.01	100%	0.01	0.01	—	—%
Stock-based compensation (non-cash)	—	—	—	— %	—	—	—	—%
Total direct operating expense	$0.20	$0.16	$ 0.04	25 %	$0.18	$0.17	$ 0.01	6 %

Production and ad valorem taxes are paid based on market prices, not hedged prices. This expense category also includes the Pennsylvania impact fee. Production and ad valorem taxes (excluding the impact fee) were $4.1 million in third quarter 2017 compared to $946,000 in third quarter 2016 with an increase in volumes subject to production and ad valorem taxes due to our newly acquired North Louisiana properties. On a per mcfe basis, production and ad valorem taxes (excluding the impact fee) were $0.03 in third quarter 2017 compared to $0.01 in third quarter 2016. In February 2012, the Commonwealth of Pennsylvania enacted an “impact fee” which functions as a tax on unconventional natural gas and oil production from the Marcellus Shale in Pennsylvania. Included in third quarter 2017 is a $7.9 million impact fee ($0.04 per mcfe) compared to $5.8 million ($0.04 per mcfe) in third quarter 2016. Production and ad valorem taxes (excluding the impact fee) were $8.4 million ($0.02 per mcfe) in first nine months 2017 compared to $1.9 million ($0.01 per mcfe) in the same period of 2016 due to an increase in volumes subject to production and ad valorem taxes. Included in first nine months 2017 is a $22.7 million ($0.04 per mcfe) impact fee compared to $16.8 million ($0.04 per mcfe) in the same period of 2016.

General and administrative (“G&A”) expense was $53.0 million in third quarter 2017 compared to $41.0 million for third quarter 2016. The third quarter 2017 increase of $12.0 million when compared to the same period of 2016 is primarily due to higher salaries and benefits, higher legal costs (including legal settlements), higher Louisiana franchise taxes and higher office expenses, including technology. At September 30, 2017, the number of G&A employees was approximately the same when compared to September 30, 2016. G&A expense for first nine months 2017 increased $25.1 million when compared to the same period of the prior year due to higher salaries and benefits, higher legal costs (including legal settlements), higher Louisiana franchise taxes and higher office expenses. On a per mcfe basis, third quarter 2017 G&A expense decreased 3% from third quarter 2016 and 9% from first nine months 2016 primarily due to lower salaries and benefits on a per mcfe basis partially offset by higher legal costs. The following table summarizes G&A expenses per mcfe for the first three months and first nine months ended September 30, 2017 and 2016:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2017	2016	Change	%	2017	2016	Change	%
General and administrative	$0.24	$0.22	$ 0.02	9 %	$0.22	$0.22	$ —	— %
Stock-based compensation (non-cash)	0.05	0.08	(0.03)	(38%)	0.07	0.10	(0.03)	(30%)
Total general and administrative expense	$0.29	$0.30	$ (0.01)	(3 %)	$0.29	$0.32	$ (0.03)	(9 %)

Interest expense was $49.2 million for third quarter 2017 compared to $46.0 million for third quarter 2016 and was $144.2 million in first nine months 2017 compared to $121.5 million in the same period of 2016. The following table presents information about interest expense per mcfe for the three months and nine months ended September 30, 2017 and 2016:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2017	2016	Change	%	2017	2016	Change	%
Bank credit facility	$0.05	$0.03	$0.02	67 %	$0.05	$0.02	$0.03	150 %
Senior notes	0.20	0.10	0.10	100 %	0.21	0.08	0.13	163 %
Subordinated notes	—	0.14	(0.14)	(100%)	—	0.17	(0.17)	(100%)
Amortization of deferred financing costs and other	0.02	0.06	(0.04)	(67 %)	0.01	0.04	(0.03)	(75 %)
Total interest expense	$0.27	$0.33	$(0.06)	(18 %)	$0.27	$0.31	$(0.04)	(13 %)
Average debt outstanding (in thousands)	$4,003,045	$2,875,991	$1,127,054	39 %	$3,915,044	$2,768,873	$1,146,171	41 %
Average interest rate [(a)]	4.7 %	5.2 %	(0.5 %)	(10 %)	4.7 %	5.3 %	(0.6 %)	(11 %)

[(a)] Includes commitment fees but excludes debt issue costs and amortization of discounts.

On an absolute basis, the increase in interest expense for third quarter 2017 from the same period of 2016 was primarily due to higher average outstanding debt balances partially offset by lower average interest rates. The third quarter 2016 also includes an additional $6.6 million of transaction costs associated with our senior subordinated note exchange. See Note 9 to our unaudited consolidated financial statements for additional information. Average debt outstanding on the bank credit facility for third quarter 2017 was $1.1 billion compared to $226.1 million in third quarter 2016 and the weighted average interest rate on the bank credit facility was 2.8% in third quarter 2017 compared to 2.3% in third quarter 2016.

On an absolute basis, the increase in interest expense for first nine months 2017 from the same period of 2016 was primarily due to higher average outstanding debt balances partially offset by lower average interest rates. Average debt outstanding on the bank credit facility was $989.0 million for first nine months 2017 compared to $151.8 million for the same period 2016 and the weighted average interest rate on the bank credit facility was 2.6% in first nine months 2017 compared to 2.3% in first nine months 2016.

Depletion, depreciation and amortization expense was $159.7 million in third quarter 2017 compared to $131.5 million in third quarter 2016. This increase is due to a 32% increase in production volumes somewhat offset by an 8% decrease in depletion rates. Depletion expense, the largest component of DD&A expense, was $0.84 per mcfe in third quarter 2017 compared to $0.91 per mcfe in third quarter 2016. We have historically adjusted our depletion rates in the fourth quarter of each year based on the year-end reserve report and at other times during the year when circumstances indicate there has been a significant change in reserves or costs. Our depletion rate per mcfe continues to decline due to the mix of production from our properties with lower depletion rates and asset sales.

DD&A expense was $462.1 million in first nine months 2017 compared to $374.4 million in the same period of 2016. This increase is due to a 35% increase in production volumes somewhat offset by a 7% decrease in depletion rates. Depletion expense was $0.84 per mcfe in first nine months 2017 compared to $0.90 per mcfe in the same period of 2016. The following table summarizes DD&A expense per mcfe for the three months and nine months ended September 30, 2017 and 2016:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2017	2016	Change	%	2017	2016	Change	%
Depletion and amortization	$0.84	$0.91	$(0.07)	(8%)	$0.84	$0.90	$(0.06)	(7%)
Depreciation	0.01	0.01	—	—%	0.01	0.02	(0.01)	(50%)
Accretion and other	0.02	0.03	(0.01)	(33%)	0.02	0.03	(0.01)	(33%)
Total DD&A expense	$0.87	$0.95	$(0.08)	(8%)	$0.87	$0.95	$(0.08)	(8%)

Other Operating Expenses

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include stock-based compensation, brokered natural gas and marketing expense, exploration expense, abandonment and impairment of unproved properties, MRD Merger expenses, termination costs, deferred compensation plan expenses and impairment of proved properties. Stock-based compensation includes the amortization of restricted stock grants, PSUs and SARs grants. The following table details the allocation of stock-based compensation to functional expense categories for the three months and nine months ended September 30, 2017 and 2016 (in thousands):

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2017	2016	2017	2016
Direct operating expense	$517	$497	$1,563	$1,781
Brokered natural gas and marketing expense	389	455	1,040	1,349
Exploration expense	561	608	1,596	1,669
General and administrative expense	9,959	11,126	35,156	37,682
Termination costs	(31)	—	1,665	—
Total stock-based compensation	$11,395	$12,686	$41,020	$42,481

Brokered natural gas and marketing expense was $59.8 million in third quarter 2017 compared to $44.6 million in third quarter 2016. The increase reflects significantly higher broker purchase volumes. Brokered natural gas and marketing expense was $169.2 million for first nine months 2017 compared to $122.1 million in the same period of 2016. This increase reflects higher brokered purchase prices and significantly higher purchase volumes. The first nine months 2016 also includes $8.5 million of purchased NGLs volumes compared to $601,000 in the same period of 2017.

Exploration expense was $22.8 million in third quarter 2017 compared to $6.9 million in third quarter 2016 due to higher dry hole costs, higher seismic and delay rental costs. Exploration expense was $45.8 million in first nine months 2017 compared to $18.6 million in the same period of 2016 due to higher seismic expenses, higher dry hole costs and delay rental costs. The following table details our exploration expenses for the three months and nine months ended September 30, 2017 and 2016 (in thousands):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2017	2016	Change	%	2017	2016	Change	%
Seismic	$5,143	$236	$4,907	2,079%	$14,096	$1,417	$12,679	895%
Delay rentals and other	5,333	2,804	2,528	90%	11,910	7,432	4,477	60%
Personnel expense	2,725	3,293	(568)	(17%)	9,001	8,121	880	11%
Stock-based compensation expense	561	608	(47)	(8%)	1,596	1,669	(73)	(4%)
Dryhole expense	9,005	2	9,003	—%	9,166	2	9,164	—%
Total exploration expense	$22,767	$6,943	$15,823	228%	$45,769	$18,641	$27,127	146%

Abandonment and impairment of unproved properties was $42.6 million in third quarter 2017 compared to $6.1 million in third quarter 2016. Abandonment and impairment of unproved properties was $52.2 million in first nine months 2017 compared to $23.8 million in the same period of 2016. We assess individually significant unproved properties for impairment on a quarterly basis and recognize a loss where circumstances indicate impairment in value. In determining whether a significant unproved property is impaired we consider numerous factors including, but not limited to, current exploration plans, favorable or unfavorable activity on the property being evaluated and/or adjacent properties, our geologists' evaluation of the property and the remaining months in the lease term for the property. Impairment of individually insignificant unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. The increase in abandonment expense reflects additional expected lease expirations in both North Louisiana and Pennsylvania, due in part to budgeting constraints. As we continue to review our acreage positions and high grade our drilling inventory based on the current price environment, additional leasehold impairments and abandonments may be recorded.

MRD Merger expenses of $33.8 million in third quarter 2016 and $36.4 million in the first nine months 2016 represents amounts paid through September 30, 2016 in connection with the MRD Merger, which includes consulting, investment banking, advisory, legal and other merger-related fees. There were no MRD Merger expenses in first nine months 2017.

Termination costs were a reduction of $47,000 for third quarter 2017 compared to an increase of $136,000 in the same period of 2016. In first quarter 2017, we implemented additional work force reductions which increased these costs to $2.4 million for estimated severance costs and $1.7 million of accelerated vesting of equity grants. Termination costs were $4.0 million in first nine months 2017 compared to $303,000 in the same period of the prior year. In 2016, these costs represent additional building lease costs related to the closing of our Oklahoma City office.

Deferred compensation plan expense was a gain of $9.2 million in third quarter 2017 compared to a gain of $11.6 million in third quarter 2016. This non-cash item relates to the increase or decrease in value of the liability associated with our common stock that is vested and held in our deferred compensation plan. The deferred compensation liability is adjusted to fair value by a charge or a credit to deferred compensation plan expense. Our stock price decreased from $23.17 at June 30, 2017 to $19.57 at September 30, 2017. In the same quarter of the prior year, our stock price decreased from $43.14 at June 30, 2016 to $38.75 at September 30, 2016. During first nine months 2017, deferred compensation was a gain of $36.8 million compared to a loss of $30.2 million in the same period of 2016. Our stock price decreased from $34.36 at December 31, 2016 to $19.57 at September 30, 2017. In the same period of 2016, our stock price increased from $24.61 at December 31, 2015 to $38.75 at September 30, 2016.

Impairment of proved properties and other assets was $63.7 million in both third quarter and first nine months 2017 compared to $43.0 million in first nine months 2016. We assess our proved natural gas and oil properties whenever events or circumstances indicate the carrying value of these assets may not be recoverable. The cash flows we use to assess proved property impairment includes numerous assumptions including (1) future reserve adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves (2) results of future drilling activities (3) future commodity prices and (4) increases or decreases in production and capital costs. All inputs are evaluated at each measurement date. In third quarter 2017, impairment expense was recorded related to certain oil and gas properties in Oklahoma and the Texas Panhandle. In first nine months 2016, impairment expense was recorded related to certain of our oil and gas properties in Western Oklahoma. Our analysis of these properties, which included the possibility of a sale of these properties, determined that undiscounted future cash flows were less than their carrying values.

(Gain) loss on the sale of assets was a gain of $102,000 in third quarter 2017 compared to a loss of $2.6 million in third quarter 2016. (Gain) loss on sale of assets was a gain of $23.5 million in first nine months 2017 compared to a loss of $7.5 million in the same period of 2016. In first quarter 2017, we sold properties in Western Oklahoma for $26.0 million of proceeds and, after closing adjustments, we recognized a gain of $22.1 million related to this sale. In first quarter 2016, we sold our non-operated interest in certain wells and gathering facilities in Northeast Pennsylvania for proceeds of $111.5 million and, after closing adjustments, we recognized a loss of $2.1 million related to this sale. In third quarter 2016, we sold certain properties in Western Oklahoma for proceeds of $77.7 million, after closing adjustments, and recorded a $2.7 million loss related to this sale.

Income tax (benefit) expense was a benefit of $72.0 million in third quarter 2017 compared to a benefit of $13.7 million in third quarter 2016. For the third quarter 2017, the effective tax rate was 36.1% compared to 24.6% in 2016. Income tax expense was $98.1 million in first nine months 2017 compared to a benefit of $185.2 million in the same period of 2016. For first nine months 2017, the effective tax rate was 46.7% compared to 33.9% in first nine months 2016. The 2017 and 2016 effective tax rates were different than the statutory tax rate due to state income taxes and other discrete tax items which are detailed below. We expect our effective tax rate to be approximately 38% for the remainder of 2017, before any discreet tax items (dollars in thousands).

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2017	2016	2017	2016
Total (loss) income before income taxes	$(199,692)	$(55,676)	$210,015	$(545,848)
U.S. federal statutory rate	35 %	35 %	35 %	35 %
Total tax (benefit) expense at statutory rate	(69,892)	(19,487)	73,505	(191,047)
State and local income taxes, net of federal benefit	(6,537)	(2,007)	6,591	(17,963)
Non-deductible executive compensation	296	446	436	1,128
Non-deductible transaction costs	—	4,838	—	4,838
Tax less than book equity compensation	56	44	4,808	5,374
Change in valuation allowances:				
Federal net operating loss carryforwards & other	69	—	3,487	—
State net operating loss carryforwards & other	4,286	2,815	10,498	10,514
Rabbi trust and other	(508)	(620)	(1,561)	1,656
Permanent differences and other	238	266	290	331
Total (benefit) expense for income taxes	$(71,992)	$(13,705)	$98,054	$(185,169)
Effective tax rate	36.1 %	24.6 %	46.7 %	33.9 %

Management’s Discussion and Analysis of Financial Condition, Capital Resources and Liquidity

Cash Flow

Cash flows from operations are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivatives. Our cash flows from operations are also impacted by changes in working capital. We generally maintain low cash and cash equivalent balances because we use available funds to reduce our bank debt. Short-term liquidity needs are satisfied by borrowings under our bank credit facility. Because of this, and because our principal source of operating cash flows (proved reserves to be produced in the following year) cannot be reported as working capital, we often have low or negative working capital. From time to time, we enter into various derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future natural gas, NGLs and oil production. The production we hedge has varied and will continue to vary from year-to-year depending on, among other things, our expectation of future commodity prices. Any payments due to counterparties under our derivative contracts should ultimately be funded by prices received from the sale of our production. Production receipts, however, often lag payments to the counterparties. As of September 30, 2017, we have entered into hedging agreements covering 136.0 Bcfe for the remainder of 2017, 319.5 Bcfe for 2018 and 24.1 Bcfe in 2019, not including our basis swaps.

The following table presents sources and uses of cash and cash equivalents for the nine months ended September 30, 2017 and 2016 (in thousands):

	Nine Months Ended September 30,	
	2017	2016
Sources of cash and cash equivalents		
Operating activities	$600,532	$205,837
Disposal of assets	27,583	191,834
Borrowing on credit facility	1,486,000	1,887,000
Other	38,825	55,897
Total sources of cash and cash equivalents	$2,152,940	$2,340,568
Uses of cash and cash equivalents		
Additions to natural gas and oil properties	$(771,067)	$(339,446)
Repayment on credit facility	(1,282,000)	(1,045,000)
Repayment of Memorial credit facility	—	(597,000)
Repayment of senior notes	(500)	(273,011)
Acreage purchases	(46,967)	(29,203)
Other property	(4,687)	(1,542)
Dividends paid	(14,876)	(11,654)
Other	(32,628)	(43,641)
Total uses of cash and cash equivalents	$(2,152,725)	$(2,340,497)

Net cash provided from operating activities in first nine months 2017 was $600.5 million compared to $205.8 million in first nine months 2016. Cash provided from continuing operations is largely dependent upon commodity prices and production volumes, net of the effects of settlement of our derivative contracts. The increase in cash provided from operating activities from 2016 to 2017 reflects a 35% increase in production and higher net realized prices (an increase of 27%) somewhat offset by higher operating costs. As of September 30, 2017, we have hedged more than 70% of our projected total production for the remainder of 2017, with more than 75% of our projected natural gas production hedged. Net cash provided from continuing operations is affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital (as reflected in our consolidated statements of cash flows) for first nine months 2017 were negative $10.0 million compared to negative $48.0 million for first nine months 2016.

Disposal of assets in first nine months 2017 includes $26.0 million of proceeds received from the sale of certain Western Oklahoma properties which closed in February 2017. First nine months 2016 includes $111.5 million of proceeds received from the sale of certain of our properties in Northeast Pennsylvania which closed in March 2016 and $77.7 million of proceeds received from the sale of certain properties in Western Oklahoma which closed in June 2016.

Liquidity and Capital Resources

Our main sources of liquidity and capital resources are internally generated cash flow from operations, a bank credit facility with uncommitted and committed availability, access to the debt and equity capital markets and asset sales. We must find new reserves and develop existing reserves to maintain and grow our production and cash flows. We accomplish this primarily through successful drilling programs which require substantial capital expenditures. We continue to take steps to ensure we have adequate capital resources and liquidity to fund our capital expenditure program. In first nine months 2017, we continued to reduce our operating costs per unit of production and we entered into additional commodity derivative contracts for 2017, 2018 and 2019 to protect future cash flows. In March 2017, our borrowing base and credit facility commitment were reaffirmed through May 1, 2018.

During first nine months 2017, our net cash provided from operating activities of $600.5 million, proceeds we received from asset sales and borrowings under our bank credit facility were used to fund approximately $822.7 million of capital expenditures (including acreage acquisitions). At September 30, 2017, we had $529,000 in cash and total assets of $11.6 billion.

Long-term debt at September 30, 2017 totaled $4.0 billion, including $1.1 billion outstanding on our bank credit facility, $2.9 billion of senior notes and $49.0 million of senior subordinated notes. Our available committed borrowing capacity at September 30, 2017 was $628.2 million. Cash is required to fund capital expenditures necessary to offset inherent declines in production and reserves that are typical in the oil and natural gas industry. Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding or acquiring additional reserves. We currently believe that net cash generated from operating activities, unused committed borrowing capacity under the bank credit facility and proceeds from asset sales combined with our natural gas, NGLs and oil derivatives contracts currently in place will be adequate to satisfy near-term financial obligations and liquidity needs. To the extent our capital requirements exceed our internally generated cash flow and proceeds from asset sales, debt or equity securities may be issued to fund these requirements. Long-term cash flows are subject to a number of variables including the level of production and prices as well as various economic conditions that have historically affected the oil and natural gas business. A further material decline in natural gas, NGLs and oil prices or a reduction in production and reserves would reduce our ability to fund capital expenditures, meet financial obligations and operate profitably. We establish a capital budget at the beginning of each calendar year and review it during the course of the year, taking into account various factors including the commodity price environment. Our 2017 capital budget is $1.15 billion.

We operate in an environment with numerous financial and operating risks, including, but not limited to, the inherent risks of the search for, development and production of natural gas, NGLs and oil, the ability to buy properties and sell production at prices which provide an attractive return and the highly competitive nature of the industry. Our ability to expand our reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, bank borrowings, asset sales or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to offset inherent declines in production and proven reserves. Commodity prices continue to be depressed and, as such, we have adjusted and must continue to adjust our business through efficiencies and cost reductions to compete in the current price environment which also requires reductions in overall debt levels over time. We would expect to monitor the market and look for opportunities to refinance or reduce debt based on market conditions.

Credit Arrangements

As of September 30, 2017, we maintained a revolving credit facility with a borrowing base of $3.0 billion and aggregate lender commitments of $2.0 billion, which we refer to as our bank credit facility. The bank credit facility, during a non-investment grade period, is secured by substantially all of our assets and has a maturity date of October 16, 2019. Availability under the bank credit facility is subject to a borrowing base set by the lenders annually with an option to set more often in certain circumstances. Availability under the bank credit facility, during an investment grade period, is limited to aggregate lender commitments. As of September 30, 2017, the outstanding balance under our credit facility was $1.1 billion. Additionally, we had $285.8 million of undrawn letters of credit leaving $628.2 million of committed borrowing capacity available under the facility at the end of third quarter 2017.

Our bank credit facility imposes limitations on the payment of dividends and other restricted payments (as defined under our bank credit facility). These agreements also contain customary covenants relating to debt incurrence, liens, investments and financial ratios. We were in compliance with all covenants at September 30, 2017. See Note 9 to our unaudited consolidated financial statements for additional information regarding our bank debt.

Cash Dividend Payments

In February 2016, the Board of Directors approved a reduction of our quarterly dividend from $0.04 per share to $0.02 per share. On September 1, 2017, our Board of Directors declared a dividend of two cents per share ($5.0 million) on our outstanding common stock, which was paid on September 30, 2017 to stockholders of record at the close of business on September 15, 2017. The amount of future dividends is subject to discretionary declaration by the Board of Directors and primarily depends on earnings, capital expenditures, debt covenants and various other factors.

Cash Contractual Obligations

Our contractual obligations include long-term debt, operating leases, derivative obligations, asset retirement obligations and transportation, processing and gathering commitments. As of September 30, 2017, we do not have any capital leases. As of September 30, 2017, we do not have any significant off-balance sheet debt or other such unrecorded obligations and we have not guaranteed any debt of any unrelated party. As of September 30, 2017, we had a total of $285.8 million of undrawn letters of credit under our bank credit facility.

Since December 31, 2016, there have been no material changes to our contractual obligations other than a $204.0 million increase in our outstanding bank credit facility balance and an extension of terms related to existing processing and gathering contracts. Our contractual obligations for firm transportation and gathering contracts increased by approximately $402.0 million over the next twenty-two years related to this extension.

Hedging – Oil and Gas Prices

We use commodity-based derivative contracts to manage our exposure to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. We utilize commodity swap and option contracts to (1) reduce the effect of price volatility on the commodities we produce and sell and (2) support our annual capital budget and expenditure plans. While there is a risk that the financial benefit of rising natural gas, NGLs and oil prices may not be captured, we believe the benefits of stable and predictable cash flow are more important. Among these benefits are a more efficient utilization of existing personnel and planning for future staff additions, the flexibility to enter into long-term projects requiring substantial committed capital, smoother and more efficient execution of our ongoing development drilling and production enhancement programs, more consistent returns on invested capital, and better access to bank and other credit markets. The fair value of these contracts which is represented by the estimated amount that would be realized or payable on termination is based on a comparison of the contract price and a reference price, generally NYMEX for natural gas and oil or Mont Belvieu for NGLs, approximated a pretax loss of $14.6 million at September 30, 2017. The contracts expire monthly through December 2019. At September 30, 2017, the following commodity-based derivative contracts were outstanding, excluding our basis swaps which are discussed separately below:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price
Natural Gas			
2017	Swaps (1)	878,370 Mmbtu/day	$ 3.21
2018	Swaps	477,534 Mmbtu/day	$ 3.22
January – March 2019	Swaps	50,000 Mmbtu/day	$ 3.01
2017	Collars (1)	122,609 Mmbtu/day	$ 3.45–$ 4.11
2018	Collars	60,000 Mmbtu/day	$ 3.40–$ 3.76
2017	Purchased Puts (1)	185,870 Mmbtu/day	$ 3.50 (2)
2017	Sold Calls	17,935 Mmbtu/day	$ 3.75 (3)
April-December 2018	Swaptions	320,000 Mmbtu/day (4)	$ 3.04 (4)
2019	Swaptions	60,000 Mmbtu/day (4)	$ 3.00 (4)
Crude Oil			
2017	Swaps (1)	9,511 bbls/day	$ 56.03
2018	Swaps	6,000 bbls/day	$ 52.96
2019	Swaps	1,000 bbls/day	$ 51.50
NGLs (C2-Ethane)			
2017	Swaps	3,000 bbls/day	$ 0.27/gallon
2018	Swaps	250 bbls/day	$ 0.29/gallon
NGLs (C3-Propane)			
2017	Swaps	17,576 bbls/day	$ 0.61/gallon
2018	Swaps	8,935 bbls/day	$ 0.66/gallon
NGLs (NC4-Normal Butane)			
2017	Swaps	9,000 bbls/day	$ 0.76/gallon
2018	Swaps	4,558 bbls/day	$ 0.81/gallon

NGLs (C5-Natural Gasoline)			
2017	Swaps	6,416 bbls/day	$ 1.08/gallon
2018	Swaps	4,027 bbls/day	$ 1.17/gallon

(1) Includes derivative instruments assumed in connection with the MRD Merger.

(2) Weighted average deferred premium is ($0.32).

(3) Weighted average deferred premium is $0.31.

(4) Contains a combined derivative instrument consisting of a fixed price swap and a sold option to extend or double the volume. For April through December of 2018, we have swaps in place for 160,000 Mmbtu per day on which the counterparty can elect to double the volume at a weighted average price of $3.02. We also have swaps in place for 160,000 Mmbtu per day on which the counterparty can elect to extend the contract through December 2019 at a weighted average price of $3.07. In 2019, if the counterparty elects to double the volume, we would have additional swaps covering 60,000 Mmbtu per day at a weighted average price of $3.00.

In addition to the swaps discussed above, we have entered into natural gas basis swap agreements. The price we received for our natural gas production can be more or less than the NYMEX Henry Hub price because of adjustments for delivery location ("basis"), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix the basis adjustments. The fair value of the basis swaps was a loss of $4.7 million at September 30, 2017. The volumes are for 130,120,000 Mmbtu and they expire monthly through October 2018.

At September 30, 2017, we also had propane basis swap contracts which lock in the differential between Mont Belvieu and international propane indices. These contracts settle monthly through December 2018 and include total volume of 659,000 barrels in 2017 and 750,000 barrels in 2018. The fair value of these contracts was a gain of $1.1 million on September 30, 2017.

Interest Rates

At September 30, 2017, we had approximately $4.0 billion of debt outstanding. Of this amount, $2.9 billion bore interest at fixed rates averaging 5.2%. Bank debt totaling $1.1 billion bears interest at floating rates, which was 2.8% at September 30, 2017. The 30-day LIBOR Rate on September 30, 2017 was approximately 1.2%. A 1% increase in short-term interest rates on the floating-rate debt outstanding on September 30, 2017 would cost us approximately $10.9 million in additional annual interest expense.

Off-Balance Sheet Arrangements

We do not currently utilize any significant off-balance sheet arrangements with unconsolidated entities to enhance our liquidity or capital resource position, or for any other purpose. However, as is customary in the oil and gas industry, we have various contractual work commitments, some of which are described above under cash contractual obligations.

Inflation and Changes in Prices

Our revenues, the value of our assets and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in natural gas, NGLs and oil prices and the costs to produce our reserves. Natural gas, NGLs and oil prices are subject to significant fluctuations that are beyond our ability to control or predict. Although certain of our costs and expenses are affected by general inflation, inflation does not normally have a significant effect on our business. We expect costs for the remainder of 2017 to continue to be a function of supply.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas, NGLs and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market-risk exposure. All of our market-risk sensitive instruments were entered into for purposes other than trading. All accounts are U.S. dollar denominated.

Market Risk

We are exposed to market risks related to the volatility of natural gas, NGLs and oil prices. We employ various strategies, including the use of commodity derivative instruments, to manage the risks related to these price fluctuations. These derivative instruments apply to a varying portion of our production and provide only partial price protection. These arrangements limit the benefit to us of increases in prices but offer protection in the event of price declines. Further, if our counterparties defaulted, this protection might be limited as we might not receive the benefits of the derivatives. Realized prices are primarily driven by worldwide prices for oil and spot market prices for North American natural gas production. Natural gas and oil prices have been volatile and unpredictable for many years. Changes in natural gas prices affect us more than changes in oil prices because approximately 65% of our December 31, 2016 proved reserves are natural gas. We are also exposed to market risks related to changes in interest rates. These risks did not change materially from December 31, 2016 to September 30, 2017.

Commodity Price Risk

We use commodity-based derivative contracts to manage exposures to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. At times, certain of our derivatives are swaps where we receive a fixed price for our production and pay market prices to the counterparty. Our derivatives program can also include collars, which establish a minimum floor price and a predetermined ceiling price. At September 30, 2017, our derivative program includes swaps, collars and options. In third quarter 2017, we entered into natural gas derivative instruments containing a fixed price swap and a sold option (referred to as a swaption in the table below). The fair value of these contracts, represented by the estimated amount that would be realized upon immediate liquidation as of September 30, 2017, approximated a net unrealized pretax loss of $14.6 million. These contracts expire monthly through December 2019. At September 30, 2017, the following commodity derivative contracts were outstanding, excluding our basis swaps which are discussed below:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price	Fair Market Value (in thousands)
Natural Gas				
2017	Swaps (1)	878,370 Mmbtu/day	$ 3.21	$ 12,756
2018	Swaps	477,534 Mmbtu/day	$ 3.22	$ 20,917
January – March 2019	Swaps	50,000 Mmbtu/day	$ 3.01	$ 1,608
2017	Collars (1)	122,609 Mmbtu/day	$ 3.45–$ 4.11	$ 5,046
2018	Collars	60,000 Mmbtu/day	$ 3.40–$ 3.76	$ 1,167
2017	Purchased Puts (1)	185,870 Mmbtu/day	$ 3.50 (2)	$ 8,547
2017	Sold Calls	17,935 Mmbtu/day	$ 3.75 (3)	$ (29)
April-December 2018	Swaptions	320,000 Mmbtu/day (4)	$ 3.04 (3)	$ (3,794)
2019	Swaptions	60,000 Mmbtu/day (4)	$3.00 (4)	$ (12,606)
Crude Oil				
2017	Swaps (1)	9,511 bbls/day	$ 56.03	$ 3,536
2018	Swaps	6,000 bbls/day	$ 52.96	$ 2,372
2019	Swaps	1,000 bbls/day	$ 51.50	$ 194
NGLs (C2-Ethane)				
2017	Swaps	3,000 bbls/day	$ 0.27/gallon	$ (55)
2018	Swaps	250 bbls/day	$ 0.29/gallon	$ 12
NGLs (C3-Propane)				
2017	Swaps	17,576 bbls/day	$ 0.61/gallon	$ (20,399)
2018	Swaps	8,935 bbls/day	$ 0.66/gallon	$ (15,647)
NGLs (NC4-Normal Butane)				
2017	Swaps	9,000 bbls/day	$ 0.76/gallon	$ (9,776)
2018	Swaps	4,558 bbls/day	$ 0.81/gallon	$ (3,890)
NGLs (C5-Natural Gasoline)				