RANGE RESOURCES CORP
Form 10-Q
July 28, 2015

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

(Mark one)

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2015

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.)
100 Throckmorton Street, Suite 1200	76102

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 þ 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 þ 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. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

Yes ¨ No þ

169,361,512 Common Shares were outstanding on July 27, 2015

RANGE RESOURCES CORPORATION

FORM 10-Q

Quarter Ended June 30, 2015

Unless the context otherwise indicates, all references in this report to "Range," "we," "us," or "our" are to Range Resources Corporation and its directly and indirectly owned subsidiaries and its ownership interests in equity method investments.

TABLE OF CONTENTS

PART I – FINANCIAL INFORMATION

ITEM 1. Financial Statements

RANGE RESOURCES CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands, except share data)

	June 30, 2015 (Unaudited)	December 31, 2014
Assets		
Current assets:		
Cash and cash equivalents	$ 521	$ 448
Accounts receivable, less allowance for doubtful accounts of $2,961 and $2,719	115,006	188,941
Derivative assets	237,167	363,049
Inventory and other	20,914	17,854
Total current assets	373,608	570,292
Derivative assets	31,654	40,314
Natural gas and oil properties, successful efforts method	10,966,160	10,567,971
Accumulated depletion and depreciation	(2,725,802)	(2,590,398)
	8,240,358	7,977,573
Other property and equipment	128,198	127,808
Accumulated depreciation and amortization	(95,584)	(90,227)
	32,614	37,581
Other assets	127,697	121,020
Total assets	$ 8,805,931	$ 8,746,780
Liabilities		
Current liabilities:		
Accounts payable	$ 206,748	$ 396,942
Asset retirement obligations	17,689	15,067
Accrued liabilities	162,724	187,973
Accrued interest	45,650	39,695
Deferred tax liabilities	73,941	115,587
Total current liabilities	506,752	755,264
Bank debt	364,000	723,000
Senior notes	750,000	—
Subordinated notes	2,350,000	2,350,000
Deferred tax liabilities	999,532	997,494
Derivative liabilities	125	—
Deferred compensation liabilities	156,460	178,599
Asset retirement obligations and other liabilities	297,648	284,994
Total liabilities	5,424,517	5,289,351

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, 169,356,015 issued at June 30, 2015 and 168,711,131 issued at December 31, 2014	1,693	1,687
Common stock held in treasury, 62,511 shares at June 30, 2015 and 82,954 shares at December 31, 2014	(2,358)	(3,088)
Additional paid-in capital	2,428,168	2,400,475
Retained earnings	953,911	1,058,355
Total stockholders' equity	3,381,414	3,457,429
Total liabilities and stockholders' equity	$8,805,931	$8,746,780

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited, in thousands, except per share data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Revenues and other income:				
Natural gas, NGLs and oil sales	$258,053	$477,517	$583,536	$1,049,534
Derivative fair value (loss) income	(34,791)	(24,109)	88,048	(170,959)
Gain on the sale of assets	2,909	282,064	2,734	281,711
Brokered natural gas, marketing and other	21,339	30,052	35,824	62,580
Total revenues and other income	247,510	765,524	710,142	1,222,866
Costs and expenses:				
Direct operating	34,780	34,935	71,917	74,730
Transportation, gathering and compression	95,198	76,809	184,624	150,970
Production and ad valorem taxes	9,242	10,844	19,170	22,522
Brokered natural gas and marketing	27,031	34,775	48,593	68,904
Exploration	5,025	13,621	12,911	28,467
Abandonment and impairment of unproved properties	12,330	9,332	23,821	19,327
General and administrative	55,964	56,888	104,293	106,100
Termination costs	417	—	6,367	—
Deferred compensation plan	(7,282)	10,519	(12,906)	8,484
Interest	43,479	45,488	82,686	90,889
Loss on early extinguishment of debt	—	24,596	—	24,596
Depletion, depreciation and amortization	151,895	133,361	299,185	262,043
Impairment of proved properties and other assets	—	24,991	—	24,991
Total costs and expenses	428,079	476,159	840,661	882,023
(Loss) income before income taxes	(180,569)	289,365	(130,519)	340,843
Income tax (benefit) expense:				
Current	—	(1)	—	5
Deferred	(61,975)	117,977	(39,609)	136,928
	(61,975)	117,976	(39,609)	136,933
Net (loss) income	$(118,594)	$171,389	$(90,910)	$203,910
Net (loss) income per common share:				
Basic	$(0.71)	$1.04	$(0.55)	$1.24
Diluted	$(0.71)	$1.04	$(0.55)	$1.24
Dividends paid per common share	$0.04	$0.04	$0.08	$0.08
Weighted average common shares outstanding:				
Basic	166,421	161,909	166,230	161,354
Diluted	166,421	162,813	166,230	162,323

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

(Unaudited, in thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net (loss) income	$(118,594)	$171,389	$(90,910)	$203,910
Other comprehensive income:				
De-designated hedges reclassified into natural gas, NGLs and oil sales, net of taxes [1]	—	(3,046)	—	(4,286)
Total comprehensive (loss) income	$(118,594)	$168,343	$(90,910)	$199,624

[1] Amounts are net of income tax benefit of $1,866 for the three months ended June 30, 2014 and $2,790 for the six months ended June 30, 2014. As of March 31, 2013, we elected to discontinue hedge accounting prospectively and as of December 31, 2014, all remaining accumulated other comprehensive income (“AOCI”) hedging gains had been transferred to earnings.

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited, in thousands)

	Six Months Ended June 30,	
	2015	2014
Operating activities:		
Net (loss) income	$(90,910)	$203,910
Adjustments to reconcile net (loss) income to net cash provided from operating activities:		
Loss from equity method investments, net of distributions	—	3,096
Deferred income tax (benefit) expense	(39,609)	136,928
Depletion, depreciation and amortization and impairment	299,185	287,034
Exploration dry hole costs	106	1
Abandonment and impairment of unproved properties	23,821	19,327
Derivative fair value (income) loss	(88,048)	170,959
Cash settlements on derivative financial instruments that do not qualify for hedge accounting	222,716	(130,762)
Allowance for bad debt	250	250
Amortization of deferred financing costs, loss on extinguishment of debt and other	3,090	29,812
Deferred and stock-based compensation	19,792	47,912
Gain on the sale of assets	(2,734)	(281,711)
Changes in working capital:		
Accounts receivable	73,695	1,275
Inventory and other	(3,749)	(6,872)
Accounts payable	3,492	20,115
Accrued liabilities and other	(50,955)	(59,751)
Net cash provided from operating activities	370,142	441,523
Investing activities:		
Additions to natural gas and oil properties	(671,166)	(546,354)
Additions to field service assets	(1,574)	(5,119)
Acreage purchases	(51,450)	(110,471)
Equity method investments and other	(75)	1,103
Proceeds from disposal of assets	14,301	146,140
Purchases of marketable securities held by the deferred compensation plan	(19,897)	(11,251)
Proceeds from the sales of marketable securities held by the deferred compensation plan	24,992	13,343
Net cash used in investing activities	(704,869)	(512,609)
Financing activities:		
Borrowing on credit facilities	1,009,000	1,175,000
Repayment on credit facilities	(1,368,000)	(1,195,000)
Issuance of senior notes	750,000	—
Repayment of subordinated notes	—	(312,000)
Debt issuance costs	(13,929)	—
Dividends paid	(13,534)	(13,114)
Issuance of common stock, net of offering expenses	—	396,662

Change in cash overdrafts	(35,921)	4,679
Proceeds from the sales of common stock held by the deferred compensation plan	7,184	14,803
Net cash provided from financing activities	334,800	71,030
Increase (decrease) in cash and cash equivalents	73	(56)
Cash and cash equivalents at beginning of period	448	348
Cash and cash equivalents at end of period	$521	$292

See accompanying notes.

RANGE RESOURCES CORPORATION

SELECTED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

(1) SUMMARY OF ORGANIZATION AND NATURE OF BUSINESS

Range Resources Corporation (“Range,” “we,” “us,” or “our”) 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 Midcontinent regions of the United States. Our objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. 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 2014 Annual Report on Form 10-K filed with the Securities and Exchange Commission (the “SEC”) on February 24, 2015. The results of operations for the second quarter and the six months ended June 30, 2015 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.

(3) NEW ACCOUNTING STANDARDS

Not Yet Adopted

In May 2014, the Financial Accounting Standards Board (“FASB”) issued an accounting standard for “Revenue from Contracts with Customers,” which supersedes the revenue recognition requirements in “Topic 605, Revenue Recognition” and requires entities to recognize revenue in a way that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In July, 2015, the FASB approved a one-year deferral of the effective date of this new standard so now the new guidance is effective for us for the reporting period beginning January 1, 2018, with early adoption permitted in the first quarter 2017. Entities have the option of using either a fully retrospective or modified approach to adopt the new standard. We are currently evaluating the new guidance and have not determined the impact this standard may have on our financial statements or decided upon the method of adoption.

In August 2014, the FASB issued an accounting standards update that requires management to assess an entity’s ability to continue as a going concern by incorporating and expanding upon certain principles that are currently in United States auditing standards. This standard is effective for us in first quarter 2017 and early adoption is permitted. We do not expect the adoption of this standard to have any impact on our consolidated results of operations, financial position or cash flows.

In April 2015, the FASB issued an accounting standards update, "Interest-Imputation of Interest: Simplifying the Presentation of Debt Issuance Cost" which requires entities to present debt issuance cost related to a recognized debt liability as a direct deduction of the carrying amount of debt in the balance sheet, consistent with the presentation of debt discounts. This standard is effective for us for the reporting period beginning January 1, 2016, with early adoption permitted. Entities will be required to apply the guidance on a retrospective basis to each period presented as a change in accounting principle. We do not expect the adoption of this standard to have any material impact on our consolidated results of operations, financial position or cash flows. We will adopt the new standard as of December 31, 2015.

Recently Adopted

In April 2014, an accounting standards update was issued that raised the threshold for a disposal to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other material disposal transactions that do not meet the revised definition of a discontinued operation. Under the updated standard, a disposal of a component or group of components of an entity is required to be reported as discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results when the component or group of components of the entity (1) has been disposed of by a sale, (2) has been disposed of other than by a sale or (3) is classified as held for sale. This accounting standards update was effective for annual periods beginning on or after December 15, 2014 and is applied prospectively. Early adoption was permitted but only for disposals (or classifications that are held for sale) that had not been reported in financial statements previously issued or available for use. We adopted this new standard in first quarter 2014 and, as a result, the Conger Exchange (see discussion below) is not reported as a discontinued operation.

(4) ACQUISITIONS AND DISPOSITIONS

2015 Dispositions

In second quarter 2015, we sold miscellaneous unproved property and inventory for proceeds of $3.6 million resulting in a pre-tax gain of $2.9 million. In first quarter 2015, we also sold miscellaneous unproved and proved property and inventory for proceeds of

$10.7 million resulting in a pre-tax loss of $175,000. Included in the $10.7 million of proceeds is $10.5 million received from the sale of certain West Texas properties which closed in February 2015.

2014 Dispositions

In addition to the Conger Exchange described below, we sold miscellaneous unproved and proved property and inventory in the three months and the six months ended June 30, 2014 for total proceeds of $1.1 million resulting in a pre-tax gain of $1.6 million.

Conger Exchange Transaction

In April 2014, we entered into an exchange agreement with EQT Corporation and certain of its affiliates (collectively, “EQT”) in which we sold our Conger assets in Glasscock and Sterling Counties, Texas in exchange for producing properties and gas gathering assets in Virginia and $145.0 million in cash, before closing adjustments (“the Conger Exchange”). We closed the exchange transaction on June 16, 2014 and recognized a pre-tax gain of $285.1 million, before selling expenses of $5.0 million, which is recognized as a gain on sale of assets in our consolidated statements of operations for the three months and six months ended June 30, 2014. For the period from January 1, 2014 through June 16, 2014, we recognized $21.9 million of field net operating income (defined as natural gas, oil and NGLs sales and net brokered margin less direct operating expenses, production and ad valorem taxes and transportation expenses) for our Conger assets.

For the period from June 16, 2014 through June 30, 2014, we recognized $2.8 million of natural gas, oil and NGLs sales from the property interests acquired in the Conger Exchange and we recognized $2.1 million of field net operating income (defined as natural gas, oil and NGLs sales less direct operating expenses, production and ad valorem taxes and transportation expenses).

(5) INCOME TAXES

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Income tax (benefit) expense	$(61,975)	$117,976	$(39,609)	$136,933
Effective tax rate	34.3 %	40.8 %	30.3 %	40.2 %

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 second quarter and the six months ended June 30, 2015 and 2014, our overall effective tax rate was different than the federal statutory rate of 35% due primarily to state income taxes, valuation allowances and other permanent differences. The three months ended June 30, 2015 includes tax expense of $6.1 million and the six months ended June 30, 2015 includes $11.3 million of income tax expense related to increases in our valuation allowances for state net operating loss and credit carryforwards. The three months ended June 30, 2015 includes an income tax expense of $1.1 million and the six months ended June 30, 2015 includes an income tax benefit of $874,000 adjusting our valuation allowance for our deferred tax asset related to future deferred compensation plan distributions of our senior executives.

(6) (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 stockholders 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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net (loss) income, as reported	$(118,594)	$171,389	$(90,910)	$203,910
Participating earnings [a]	(111)	(2,868)	(224)	(3,460)
Basic net (loss) income attributed to common shareholders	(118,705)	168,521	(91,134)	200,450
Reallocation of participating earnings [a]	¾	15	¾	19
Diluted net (loss) income attributed to common shareholders	$(118,705)	$168,536	$(91,134)	$200,469
Net (loss) income per common share:				
Basic	$(0.71)	$1.04	$(0.55)	$1.24
Diluted	$(0.71)	$1.04	$(0.55)	$1.24

[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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Weighted average common shares outstanding – basic	166,421	161,909	166,230	161,354
Effect of dilutive securities:				
Director and employee stock options and SARs	¾	904	¾	969
Weighted average common shares outstanding – diluted	166,421	162,813	166,230	162,323

Weighted average common shares-basic for both the three months ended June 30, 2015 and the three months ended June 30, 2014 excludes 2.8 million shares of restricted stock held in our deferred compensation plans (although all awards are issued and outstanding upon grant). Weighted average common shares-basic for both the six months ended June 30, 2015 and the six months ended June 30, 2014 excludes 2.8 million shares of restricted stock held in our deferred compensation plans. Due to our net loss from operations for the three months and the six months ended June 30, 2015, we excluded all outstanding stock appreciation rights ("SARs") and restricted stock from the computation of diluted net loss per share because the effect would have been anti-dilutive to the computations. All SARs outstanding for the three months ended June 30, 2014 and the six months ended June 30, 2014 were included in the computations of diluted income per share because the grant prices of the SARs were less than the average market price of the common stock.

(7) 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 presented 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 did not have any exploratory well costs that have been capitalized for a period greater than one year as of December 31, 2014 and June

30, 2015. The following table reflects the change in capitalized exploratory well costs for the six months ended June 30, 2015 and the year ended December 31, 2014 (in thousands):

	June 30, 2015	December 31, 2014
Balance at beginning of period	$2,996	$6,964
Additions to capitalized exploratory well costs pending the determination of proved reserves	35,111	18,747
Reclassifications to wells, facilities and equipment based on determination of proved reserves	¾	(15,735)
Divested wells	¾	(6,980)
Balance at end of period	38,107	2,996
Less exploratory well costs that have been capitalized for a period of one year or less	(38,107)	(2,996)
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$¾	$¾

9

(8) INDEBTEDNESS

We had the following debt outstanding as of the dates shown below (bank debt interest rate at June 30, 2015 is shown parenthetically). No interest was capitalized during the three months or six months ended June 30, 2015 or the year ended December 31, 2014 (in thousands):

	June 30, 2015	December 31, 2014
Bank debt (1.5%)	$364,000	$ 723,000
Senior notes:		
4.875% senior notes due 2025	750,000	¾
Senior subordinated notes:		
6.75% senior subordinated notes due 2020	500,000	500,000
5.75% senior subordinated notes due 2021	500,000	500,000
5.00% senior subordinated notes due 2022	600,000	600,000
5.00% senior subordinated notes due 2023	750,000	750,000
Total debt	$3,464,000	$ 3,073,000

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. On June 30, 2015, the bank commitments were $2.0 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 31, 2015, our borrowing base was reaffirmed at $3.0 billion and our bank commitment was also reaffirmed at $2.0 billion. As of June 30, 2015, our bank group was composed of twenty-nine financial institutions with no one bank holding more than 6% of the total facility. The bank credit facility amount may be increased to the committed borrowing base amount, subject to the banks agreeing to participate in the facility increase and our payment of a mutually acceptable commitment fee to those banks. As of June 30, 2015, the outstanding balance under our bank credit facility was $364.0 million. Additionally, we had $108.7 million of undrawn letters of credit leaving $1.5 billion 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 agreement) plus a spread ranging from 0.25% to 1.25% or LIBOR borrowings at the LIBOR Rate (as defined in the bank credit 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 1.7% for the three months ended June 30, 2015 compared to 2.1% for the three months ended June 30, 2014. The weighted average interest rate was 1.7% for the six months ended June 30, 2015 compared to 2.1% for the six months ended June 30, 2014. A commitment fee is paid on the undrawn balance based on an annual rate of 0.30% to 0.375%. At June 30, 2015, the commitment fee was 0.30% and the interest rate margin was 1.25% on our LIBOR loans and 0.25% 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%.

Senior Notes

In May 2015, we issued $750.0 million aggregate principal amount of 4.875% senior notes due 2025 (the “4.875% Notes”) for net proceeds of $737.8 million after underwriting discounts and commissions of $12.2 million. The notes were issued at par. The 4.875% 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 of the Securities Act of 1933, as amended (the “Securities Act”). Interest due on the 4.875% Notes is payable semi-annually in May and November and is unconditionally guaranteed on a senior unsecured basis by all of our subsidiary guarantors. On or after February 15, 2025, we may redeem the notes, in whole or in part and from time to time, at 100% of the principal amount, plus accrued and unpaid interest. Upon the occurrence of certain changes in control, we must offer to repurchase the 4.875% Notes. The 4.875% Notes are unsecured and are subordinated to all of our existing and future secured debt, rank equally with all of Range’s existing and future senior unsecured debt, and rank senior to all of our existing and future subordinated debt. On the closing of the 4.875% Notes, we used the net proceeds to repay borrowings under our bank credit facility pending our intended redemption of all of our 6.75% senior subordinated notes due 2020, which we expect to complete in August 2015 using borrowings under our bank credit facility.

Senior Subordinated Notes

If we experience a change of control, bondholders 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 will be subordinated to existing and future senior debt that we or our subsidiary guarantors are permitted to incur under the bank credit facility and the indentures governing the subordinated notes.

Early Extinguishment of Debt

On July 1, 2015, we announced a call for the redemption of $500.0 million of our outstanding 6.75% senior subordinated notes due 2020 at a price of 103.375% of par plus accrued and unpaid interest and we estimate we will recognize a loss on early extinguishment of debt of $22.5 million. The notes will be redeemed on August 3, 2015. On May 27, 2014, we announced a call for the redemption of $300.0 million of our outstanding 8.0% senior subordinated notes due 2019 at 104.0% of par plus accrued and unpaid interest, which were redeemed on June 26, 2014. In second quarter 2014, we recognized a $24.6 million loss on early extinguishment of debt, including transaction call premium cost as well as expensing of the remaining deferred financing costs on the repurchased debt.

Guarantees

Range Resources Corporation 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 credit agreement) to cash interest expense of equal to or greater than 2.5 and a current ratio (as defined in the credit 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 June 30, 2015.

The indentures governing our senior subordinated notes contain various restrictive covenants that are substantially identical to each other and may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, enter into transactions with affiliates, or change the nature of our business. At June 30, 2015, we were in compliance with these covenants.

(9) 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. In the first six months 2015, we increased our estimated abandonment costs on certain of our water impoundments and changed estimated well lives for certain wells in Pennsylvania. A reconciliation of our liability for plugging and abandonment costs for the six months ended June 30, 2015 is as follows (in thousands):

	Six Months Ended June 30, 2015
Beginning of period	$ 287,463
Liabilities incurred	2,994
Liabilities settled	(7,410)
Disposition of wells	(4,115)
Accretion expense	9,570
Change in estimate	15,690
End of period	304,192
Less current portion	17,689
Long-term asset retirement obligations	$ 286,503

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

(10) 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 2014:

	Six Months Ended June 30, 2015	Year Ended December 31, 2014
Beginning balance	168,628,177	163,342,894
Equity offering	—	4,560,000
SARs exercised	76,989	195,242
Restricted stock grants	324,294	270,062
Restricted stock units vested	243,601	244,413
Treasury shares issued	20,443	15,566
Ending balance	169,293,504	168,628,177

(11) 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 do not utilize complex derivatives, as we typically utilize commodity swaps or collars 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. 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 oil or Mont Belvieu for NGLs, approximated a net asset of $262.8 million at June 30, 2015. These contracts expire monthly through December 2017. The following table sets forth our commodity-based derivative volumes by year as of June 30, 2015, excluding our basis swaps which are discussed separately below:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price
Natural Gas			
2015	Collars	145,000 Mmbtu/day	$ 4.07–$ 4.56
2015	Swaps	737,500 Mmbtu/day	$ 3.63
2016	Swaps	630,000 Mmbtu/day	$ 3.42
2017	Swaps	20,000 Mmbtu/day	$ 3.49
Crude Oil			
2015	Swaps	11,250 bbls day	$ 85.87
2016	Swaps	3,000 bbls/day	$ 70.54
NGLs (C3-Propane)			
2015	Swaps	13,000 bbls/day	$ 0.58/gallon
2016	Swaps	5,500 bbls/day	$ 0.60/gallon
NGLs (NC4-Normal Butane)			
2015	Swaps	3,500 bbls/day	$ 0.72/gallon
2016	Swaps	2,500 bbls/day	$ 0.72/gallon
NGLs (C5-Natural Gasoline)			
2015	Swaps	4,000 bbls/day	$ 1.16/gallon
2016	Swaps	2,500 bbls/day	$ 1.23/gallon

Every derivative instrument is required to be recorded on the balance sheet as either an asset or a liability measured at its fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, changes in fair value of these non-hedge derivatives are recognized in earnings as derivative fair value income or loss.

Basis Swap Contracts

In addition to the collars and swaps above, at June 30, 2015, we had natural gas basis swap contracts that are not designated for hedge accounting, which lock in the differential between NYMEX and certain of our physical pricing indices primarily in Appalachia. These contracts settle monthly through March 2017 and include a total volume of 50,565,000 Mmbtu. The fair value of these contracts was an asset of $5.9 million on June 30, 2015.

Derivative Assets and Liabilities

The combined fair value of derivatives included in the accompanying consolidated balance sheets as of June 30, 2015 and December 31, 2014 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):

		June 30, 2015		
		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	$157,138	$(1,119)	$ 156,019
	–collars	31,149	—	31,149
	–basis swaps	7,240	(1,380)	5,860
Crude oil	–swaps	64,690	(2,731)	61,959
NGLs	–C3 swaps	13,966	—	13,966
	–NC4 swaps	2,774	(5)	2,769
	–C5 swaps	402	(3,303)	(2,901)
		$277,359	$(8,538)	$ 268,821

		June 30, 2015		
		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	$(1,244)	$ 1,119	$ (125)
	–basis swaps	(1,380)	1,380	—
Crude oil	–swaps	(2,731)	2,731	—
NGLs	–NC4 swaps	(5)	5	—
	–C5 swaps	(3,303)	3,303	—
		$(8,663)	$ 8,538	$ (125)

December 31, 2014		
Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance	Net Amounts of Assets Presented in the Balance Sheet

			Sheet	
Derivative assets:				
Natural gas	–swaps	$198,740	$ —	$ 198,740
	–collars	57,460	—	57,460
	–basis swaps	2,442	(755)	1,687
Crude oil	–swaps	128,578	—	128,578
NGLs	–C3 swaps	14,727	—	14,727
	–C5 swaps	2,171	—	2,171
		$404,118	$ (755)	$ 403,363

		December 31, 2014		
		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	–basis swaps	$(755)	$ 755	$ —
		$(755)	$ 755	$ —

For the three and six months ended June 30, 2014, the realized gains from our cash flow hedges (for those derivatives that previously qualified for hedge accounting which were reclassified from AOCI into revenue) is summarized below (in thousands):

	Three Months Ended June 30, 2014	Six Months Ended June 30, 2014
Swaps	$1,052	$1,888
Collars	3,860	5,188
Income taxes	(1,866)	(2,790)
	$3,046	$4,286

The effects of our non-hedge derivatives (those derivatives that do not qualify for hedge accounting) on our consolidated statements of operations are summarized below (in thousands):

	Three Months Ended June 30, Derivative Fair Value Income (Loss)	
	2015	2014
Swaps	$(42,100)	$(38,521)
Collars	(1,650)	1,032
Basis swaps	8,959	13,380
Total	$(34,791)	$(24,109)

	Six Months Ended June 30, Derivative Fair Value Income (Loss)	
	2015	2014
Swaps	$83,676	$(82,593)
Collars	6,765	(38,116)
Basis swaps	(2,393)	(50,250)
Total	$88,048	$(170,959)

(12) 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 does 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 that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of 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.

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 June 30, 2015 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 June 30, 2015
Trading securities held in the deferred compensation plans	$64,420	$ —	$ —	$ 64,420
Derivatives –swaps	—	231,687	—	231,687
–collars	—	31,149	—	31,149
–basis swaps	—	5,860	—	5,860

	Fair Value Measurements at December 31, 2014 using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of December 31, 2014
Trading securities held in the deferred compensation plans	$68,454	$ —	$ —	$ 68,454
Derivatives –swaps	—	344,216	—	344,216
–collars	—	57,460	—	57,460
–basis swaps	—	1,687	—	1,687

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.

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 second quarter 2015, interest and dividends were $139,000 and the mark-to-market adjustment was a loss of $576,000 compared to interest and dividends of $103,000 and mark-to-market gain of $2.1 million in second quarter 2014. For the six months ended June 30, 2015, interest and dividends were $248,000 and the mark-to-market adjustment was a gain of $832,000 compared to interest and dividends of $171,000 and the mark-to-market adjustment of a gain of $2.6 million in the same period of 2014.

Fair Values—Reported

The following table presents the carrying amounts and the fair values of our financial instruments as of June 30, 2015 and December 31, 2014 (in thousands):

	June 30, 2015		December 31, 2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:				
Commodity swaps, collars and basis swaps	$268,821	$268,821	$403,363	$403,363
Marketable securities[a]	64,420	64,420	68,454	68,454
(Liabilities):				
Commodity swaps	(125)	(125)	—	—
Bank credit facility[b]	(364,000)	(364,000)	(723,000)	(723,000)
Deferred compensation plan[c]	(182,648)	(182,648)	(203,433)	(203,433)
4.875% senior notes due 2025[b]	(750,000)	(728,438)	—	—
6.75% senior subordinated notes due 2020[b]	(500,000)	(515,625)	(500,000)	(523,125)
5.75% senior subordinated notes due 2021[b]	(500,000)	(513,125)	(500,000)	(520,000)
5.00% senior subordinated notes due 2022[b]	(600,000)	(588,750)	(600,000)	(601,500)
5.00% senior subordinated notes due 2023[b]	(750,000)	(733,125)	(750,000)	(754,688)

(a) Marketable securities, which are held in our deferred compensation plans, are actively traded on major exchanges. Refer to Note 13 for additional information.

(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. Refer to Note 8 for additional information.

(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 9.

Concentrations of Credit Risk

As of June 30, 2015, 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 security are obtained as deemed necessary to limit our risk of loss. Our allowance for uncollectible receivables was $3.0 million at June 30, 2015 and $2.7 million at December 31, 2014. As of June 30, 2015, our derivative contracts consist of swaps and collars. Our exposure to credit risk is diversified 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 June 30, 2015, our derivative counterparties include seventeen financial institutions, of which all but two are secured lenders in our bank credit facility. At June 30, 2015, our net derivative assets include a net receivable from these two counterparties that are not included in our bank credit facility of $19.9 million.

(13) STOCK-BASED COMPENSATION PLANS

Stock-Based Awards

In 2005, we began granting SARs which represent the right to receive a payment equal to the excess of the fair market value of shares of common stock on the date the right is exercised over the value of the stock on the date of grant. All SARs granted under our Amended and Restated 2005 Equity-Based Incentive Compensation Plan (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. Beginning in first quarter 2011, the Compensation Committee of the Board of Directors began granting restricted stock units under our equity-based stock compensation plans. 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 shares is based upon an employee's continued employment with us.

In first quarter 2014, the Compensation Committee also began granting performance share unit ("PSU") 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 PSU 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%.

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. Compensation expense is recognized over the balance of 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. 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, PSUs and SARs 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 plans 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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Direct operating expense	$654	$1,937	$1,540	$2,789
Brokered natural gas and marketing expense	619	1,130	1,125	1,658
Exploration expense	751	1,222	1,483	2,375
General and administrative expense	15,953	20,696	27,033	32,300
Termination costs	434	–	1,721	–
Total stock-based compensation	$18,411	$24,985	$32,902	$39,122

Stock Appreciation Right Awards

We have one active equity-based stock plan, the 2005 Plan. Under this plan, incentive and non-qualified stock options, SARs, and various other awards may be issued to non-employee directors and employees pursuant to decisions of the Compensation Committee, which is comprised of only non-employee, independent directors. There were 1.5 million SARs outstanding at June 30, 2015. Information with respect to SARs activity is summarized below:

	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2014	1,966,549	$ 59.80
Exercised	(427,238)	45.67

Expired/forfeited	(9,469)	65.04
Outstanding at June 30, 2015	1,529,842	$ 63.71

Performance Share Unit Awards

The following is a summary of our non-vested PSU awards outstanding at June 30, 2015:

	Units	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2014	134,341	$ 86.11
Units granted [(a)]	276,204	56.78
Units vested	(67,652)	70.39
Units forfeited	(4,080)	76.85
Outstanding at June 30, 2015	338,813	$ 65.46

[(a)] Amounts granted reflect the number of performance units granted; however, the actual payout of shares will be between zero percent 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 PSUs granted during first six months 2015 and 2014:

	Six Months Ended	
	June 30, 2015	June 30, 2014
Risk-free interest rate	1.0 %	0.77 %
Expected annual volatility	33 %	33 %
Weighted average grant date fair value per unit	$56.78	$86.14

We recorded PSU compensation expense of $4.1 million in first six months 2015 compared to $4.7 million in the same period of 2014.

Restricted Stock Awards

Equity Awards

In first six months 2015, we granted 583,000 restricted stock Equity Awards to employees at an average grant price of $52.45 compared to 355,000 restricted stock Equity Awards granted to employees at an average grant price of $84.96 in first six months 2014. These awards generally vest over a three-year period. We recorded compensation expense for these Equity Awards of $14.0 million in first six months 2015 compared to $14.7 million in the same period of 2014. Equity Awards are not issued to employees until they are vested. Employees do not have the option to receive cash.

Liability Awards

In first six months 2015, we granted 294,000 shares of restricted stock Liability Awards as compensation to employees at an average price of $56.20 with vesting generally over a three-year period and 39,000 shares were granted to non-employee directors at an average price of $58.35 with immediate vesting. In first six months 2014, we granted 207,000 shares of Liability Awards as compensation to employees at an average price of $87.27 with vesting generally over a three-year period and 61,000 shares were granted to non-employee directors at an average price of $88.47 with immediate vesting. We recorded compensation expense for Liability Awards of $11.7 million in first six months 2015 compared to $15.2 million in first six months 2014. 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 June 30, 2015:

	Equity Awards		Liability Awards	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2014	360,415	$ 79.60	304,504	$ 80.33
Granted	583,011	52.45	332,588	56.45
Vested	(246,295)	66.73	(188,330)	68.80

Forfeited	(11,569)		68.38	(8,294)		74.22
Outstanding at June 30, 2015	685,562	$	61.33	440,468	$	67.35

Deferred Compensation Plan

Our deferred compensation plan gives non-employee directors and officers the ability to defer all or a portion of their salaries and bonuses and invest in Range common stock or make other investments at the individual's discretion. Range provides a partial matching contribution 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 $7.3 million in second quarter 2015 compared to mark-to-market loss of $10.5 million in second quarter 2014. We recorded mark-to-market gain of $12.9 in the six months ended June 30, 2015 compared to mark-to-market loss of $8.5 million in the same period of 2014. The Rabbi Trust held 2.8 million shares (2.4 million of vested shares) of Range stock at June 30, 2015 compared to 2.8 million shares (2.5 million of vested shares) at December 31, 2014.

(14) SUPPLEMENTAL CASH FLOW INFORMATION

	Six Months Ended June 30,	
	2015	2014
	(in thousands)	
Net cash provided from operating activities included:		
Income taxes paid to taxing authorities	$—	$39
Interest paid	73,189	89,381
Non-cash investing and financing activities included:		
Increase in asset retirement costs capitalized	18,684	5,516
(Decrease) increase in accrued capital expenditures	(156,897)	15,211

(15) 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.

Transportation and Gathering Contracts

In first six months 2015, our transportation and gathering commitments increased by approximately $71.5 million over the next nine years primarily from new firm transportation contracts.

Delivery Commitments

In first six months 2015, we entered into new agreements with several pipeline companies and end users to deliver natural gas volumes from our production. The new agreements are to deliver from 1,000 Mmbtu per day to 40,000 Mmbtu per day of natural gas and the commitments are between two and five years and began as early as second quarter 2015.

(16) OFFICE CLOSING AND TERMINATION COSTS

In first quarter 2015, we announced the closing of our Oklahoma City administrative and operational office to reduce our general and administrative expenses, due in part to the impact of lower commodity prices on our operations. In the year ended December 31, 2014, we accrued an estimated $8.4 million termination costs relating to the closure of this office. In first six months 2015, those plans and personnel involved were finalized which resulted in additional accruals for severance and other costs for personnel involved of $275,000, additional accelerated vesting of stock-based compensation of $948,000 and $3.2 million of building lease costs. Also in first six months 2015, additional accruals for severance of $1.1 million and stock-based compensation of $772,000 were recorded for additional expected personnel reductions in order to reduce our lease operating expenses due to the lower commodity price environment. The following summarizes our termination costs for the six months ended June 30, 2015 and the year ended December 31, 2014 (in thousands):

	Six Months Ended June 30, 2015	Year Ended December 31, 2014
Termination costs	$1,414	$5,372
Building lease	3,232	—
Stock-based compensation	1,721	2,999
	$6,367	$8,371

The following details our accrued liability as of June 30, 2015 (in thousands):

	Six Months Ended June 30, 2015
Beginning balance	$5,372
Additional accrued termination costs	1,414
Accrued building rent	3,232
Payments	(6,089)
Ending balance	$3,929

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

	June 30, 2015	December 31, 2014
	(in thousands)	
Natural gas and oil properties:		
Properties subject to depletion	$10,019,744	$9,624,725

Unproved properties	946,416	943,246
Total	10,966,160	10,567,971
Accumulated depreciation, depletion and amortization	(2,725,802)	(2,590,398)
Net capitalized costs	$ 8,240,358	$ 7,977,573

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

21

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

	Six Months Ended June 30, 2015	Year Ended December 31, 2014	
	(in thousands)		
Acquisitions	$—	$ 404,252	(b)
Acreage purchases	36,653	226,475	
Development	484,369	1,119,896	
Exploration:			
Drilling	39,962	180,925	
Expense	11,429	58,979	
Stock-based compensation expense	1,483	4,569	
Gas gathering facilities:			
Development	4,655	13,137	
Subtotal	578,551	2,008,233	
Asset retirement obligations	18,684	56,822	
Total costs incurred	$597,235	$ 2,065,055	

[a] Includes costs incurred whether capitalized or expensed.

[b] The year ended December 31, 2014 represents the EQT assets in Virginia we received as part of the Conger Exchange transaction. The transaction was recorded at fair value and we also received $145.0 million in cash, before closing adjustments.

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 acquisitions. 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, 2014, as filed with the SEC on February 24, 2015.

Overview of Our Business

We are 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 Midcontinent 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.

Our overarching business objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. Our strategy to achieve our business objective is to increase reserves and production through internally generated drilling projects occasionally coupled with complementary acquisitions. 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 and produce natural gas, NGLs and crude oil reserves. Prices for natural gas, NGLs and oil fluctuate widely and affect:

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

We prepare our financial statements in conformity with generally accepted accounting principles, which require 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 commodities are inherently volatile and have decreased significantly in recent months. 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 six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Average NYMEX prices [a]				
Natural gas (per mcf)	$2.64	$4.67	$2.81	$4.79
Oil (per bbl)	57.88	102.97	53.14	100.74
Mont Belvieu NGL composite (per gallon) [b]	0.41	0.81	0.42	0.86

[a] Based on weighted average of bid week prompt month prices.
[b] Based on our estimated NGL product component per barrel.

Consolidated Results of Operations

Overview of Second Quarter 2015 Results

During second quarter 2015, we achieved the following financial and operating results:

- achieved 24% production growth over the same period of 2014;
- revenue from the sale of natural gas, NGLs and oil decreased 46% from the same period of 2014 with a 56% decline in average sales prices somewhat offset by our increase in production volumes;
- revenue from the sale of natural gas, NGLs and oil including cash settlements on our derivatives declined 15% from the same period of 2014;
- continued expansion of our activities in the Marcellus Shale in Pennsylvania by growing production, proving up acreage and acquiring additional unproved acreage;
- reduced direct operating expenses per mcfe by 20% from the same period of 2014;
- reduced our depletion, depreciation and amortization ("DD&A") rate per mcfe by 8% from the same period of 2014;
- issued $750.0 million of 4.875% senior notes due 2025;
- entered into additional derivative contracts for 2015, 2016 and 2017; and
- realized $159.5 million of cash flow from operating activities.

Our financial results have been significantly impacted by lower commodity prices. We experienced a decrease in revenue from the sale of natural gas, NGLs and oil due to a 38% decrease in realized prices (average prices including all derivative settlements and third party transportation costs paid by Range) partially offset by 24% higher production volumes when compared to second quarter 2014. Our second quarter 2015 production growth was due to the continued success of our drilling program, particularly in the Marcellus Shale. During second quarter 2015, we recognized a net loss of $118.6 million, or $0.71 per diluted common share, compared to net income of $171.4 million, or $1.04 per diluted common share, during second quarter 2014. When comparing second quarter 2015 to second quarter 2014, in addition to lower realized prices, we also reported an unfavorable non-cash fair value adjustment on our commodity derivatives (a non-GAAP measure) and lower gains on asset sales. These decreases were partially offset by a favorable non-cash mark-to-market adjustment related to our deferred compensation plan, lower impairment of proved properties and no loss on extinguishment of debt.

Overview of the First Six Months 2015 Results

During the six months ended June 30, 2015, we achieved the following financial and operating results:

- achieved 25% production growth from the same period of 2014;
- revenue from the sale of natural gas, NGLs and oil decreased 44% from the same period of 2014 with a 55% decline in average sale prices somewhat offset by our increase in production volumes;
- revenue from the sale of natural gas, NGLs and oil including cash settlements on our derivatives declined 12% from the same period of 2014;
- reduced direct operating expense per mcfe by 24% from the same period of 2014;
- reduced our DD&A rate by 9% from the same period of 2014;
- issued $750.0 million of 4.875% senior notes due 2025;
- entered into additional derivative contracts for 2015, 2016 and 2017; and
- realized $370.1 million of cash flow from operating activities.

For the six months ended June 30, 2015, we recognized a net loss of $90.9 million, or $0.55 per diluted common share compared to net income of $203.9 million or $1.24 per diluted common share in the same period of 2014. In the first six months 2015, we experienced a decrease in revenue from the sale of natural gas, NGLs and oil due to a 35% decrease in realized prices partially offset by 25% higher production volumes. When comparing the first six months 2015 to the same period of 2014, in addition to lower realized prices, we also reported an unfavorable non-cash fair value adjustment on our commodity derivatives (a non-GAAP measure), lower gains on asset sales, additional termination costs and unfavorable brokered gas and marketing margins which includes higher operating costs on our company-owned gathering lines. These decreases were partially offset by a favorable non-cash mark-to-market adjustment related to our deferred compensation plan, lower impairment of proved properties and no loss on extinguishment of debt.

One of our primary focuses in 2015 has been to reduce costs throughout the organization, through a number of internal initiatives. For example, we announced in early 2015 we were closing our Oklahoma City administrative and operational office to reduce our general and administrative expenses. In addition, we have also made personnel reductions in Pennsylvania to reduce lease operating expenses. In light of recent declines in commodity prices, our goal is to continue to reduce costs on a per mcfe basis where possible.

We believe natural gas, NGLs and oil prices will remain volatile and will be affected by, among other things, weather, the U.S. and worldwide economy, worldwide geopolitical events, new technology, the timing of infrastructure build out and the level of oil and gas production in North America and worldwide. Although we have entered into derivative contracts covering a portion of our production volumes for the remainder of 2015 and for 2016 and 2017, a sustained lower price environment would result in lower prices for unprotected volumes and reduce the prices that we can enter into derivative contracts for additional volumes in the future.

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. Revenues from the sale of natural gas, NGLs and oil sales include netback arrangements where we sell natural gas or oil at the wellhead and collect a price, net of transportation costs incurred by the purchaser. In this instance, we record revenue at the price we receive from the purchaser. Revenues are also realized from sales arrangements where we sell natural gas or oil at a specific delivery point and receive proceeds from the purchaser with no transportation cost deductions. Third party transportation costs we incur to move our commodity to the delivery point are reported in transportation, gathering and compression expense. Cash settlements and changes in the market value of derivative contracts are included in derivative fair value income or loss in our consolidated statements of operations. Effective March 1, 2013, we elected to de-designate all commodity contracts that were previously designated as cash flow hedges and elected to discontinue hedge accounting prospectively.

In second quarter 2015, natural gas, NGLs and oil sales decreased 46% compared to second quarter 2014 with a 56% decrease in average realized prices partially offset by a 24% increase in production. In the six months ended June 30, 2015, natural gas, NGLs and oil sales decreased 44% compared to the same period in 2014 with a 55% decrease in average realized prices partially offset by a 25% increase in production. The following table illustrates the primary components of natural gas, NGLs, oil and condensate sales for the three months and the six months ended June 30, 2015 and 2014 (in thousands):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2015	2014	Change	%	2015	2014	Change	%
Natural gas, NGLs and oil sales								
Gas	$171,664	$275,726	$(104,062)	(38 %)	$400,404	$621,952	$(221,548)	(36 %)
Gas hedges realized [a]	¾	3,626	(3,626)	(100%)	¾	4,794	(4,794)	(100%)
Total gas revenue	$171,664	$279,352	$(107,688)	(39 %)	$400,404	$626,746	$(226,342)	(36 %)
Total NGLs revenue	$40,945	$109,998	$(69,053)	(63 %)	$100,756	$245,502	$(144,746)	(59 %)
Oil	$45,444	$86,881	$(41,437)	(48 %)	$82,376	$175,002	$(92,626)	(53 %)
Oil hedges realized [a]	¾	1,286	(1,286)	(100%)	¾	2,284	(2,284)	(100%)
Total oil revenue	$45,444	$88,167	$(42,723)	(48 %)	$82,376	$177,286	$(94,910)	(54 %)
Combined	$258,053	$472,605	$(214,552)	(45 %)	583,536	1,042,456	(458,920)	(44 %)
Combined hedges [a]	¾	4,912	(4,912)	(100%)	¾	7,078	(7,078)	(100%)
Total natural gas, NGLs and oil sales	$258,053	$477,517	$(219,464)	(46 %)	$583,536	$1,049,534	$(465,998)	(44 %)

[a] Cash settlements related to derivatives that qualified or were historically designated for hedge accounting.

Our production continues to grow through drilling success as we place new wells on production partially offset by the natural production decline of our natural gas and oil wells and asset sales. When compared to the same period of 2014, our second quarter 2015 production volumes increased 32% in our Appalachian region and decreased 39% in our Midcontinent region. Our Midcontinent production volumes were negatively impacted by the Conger Exchange transaction which closed June 2014 and the sale of certain other West Texas properties which closed February 2015. For the first six months 2015, our production volumes increased 32% in our Appalachian region and decreased 36% in our Midcontinent region when compared to the same period of 2014. When compared to the same periods of 2014, our Marcellus production volumes increased 32% for both the second quarter 2015 and the six months ended June 30, 2015. Production volumes from the Marcellus Shale in second quarter 2015 were 106.6 Bcfe. Our production for the three months and six months ended June 30, 2015 and 2014 is set forth in the following table:

	Three Months Ended June 30, 2015	2014	Change	%	Six Months Ended June 30, 2015	2014	Change	%
Production [(a)]								
Natural gas (mcf)	87,737,330	67,761,616	19,975,714	29%	168,237,366	129,779,197	38,458,169	30%
NGLs (bbls)	5,105,127	4,470,854	634,273	14%	10,464,403	8,942,335	1,522,068	17%
Crude oil (bbls)	1,089,417	989,609	99,808	10%	2,228,377	2,024,754	203,623	10%
Total (mcfe) [(b)]	124,904,594	100,524,394	24,380,200	24%	244,394,046	195,581,731	48,812,315	25%
Average daily production [(a)]								
Natural gas (mcf)	964,146	744,633	219,513	29%	929,488	717,012	212,476	30%
NGLs (bbls)	56,100	49,130	6,970	14%	57,814	49,405	8,409	17%
Crude oil (bbls)	11,972	10,875	1,097	10%	12,311	11,186	1,125	10%
Total (mcfe) [(b)]	1,372,578	1,104,664	267,914	24%	1,350,243	1,080,562	269,681	25%

(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) received during second quarter 2015 was $2.31 per mcfe compared to $3.73 per mcfe in second quarter 2014. Our average realized price received (including all derivative settlements and third-party transportation costs) was $2.54 per mcfe in the six months ended June 30, 2015 compared to $3.93 per mcfe in the same period of the prior year. Because 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 and compression expense. Our average realized price (including all derivative settlements and third-party transportation costs) calculation also includes all cash settlements for derivatives, whether or not they qualified for hedge accounting. Average sales prices (excluding derivative settlements) do not include derivative settlements or third party transportation costs which are reported in transportation, gathering and compression expense on the accompanying consolidated statements of operations. Average sales 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 price we receive for our natural gas can be more or less than the NYMEX price because of adjustments of delivery location, relative quality and other factors. Average natural gas differentials were $0.68 per mcf below NYMEX in second quarter 2015 compared to $0.60 per mcf below NYMEX in second quarter 2014. We also realized gains on our basis hedging in second quarter 2015 of $0.02 per mcf which is comparable to second quarter 2014. Average natural gas differentials were $0.43 per mcf below NYMEX in the first six months 2015 compared to being equal to NYMEX in the same period of 2014 which was due, in part, to extreme cold weather conditions in first quarter 2014. We also realized losses on our basis hedging of $0.04 per mcf in the first six months 2015 compared to a loss of $0.42 per mcf in the first six months 2014. Average realized price calculations for the three months and six months ended June 30, 2015 and 2014 are shown below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Average Prices				
Average sales prices (excluding derivative settlements):				
Natural gas (per mcf)	$1.96	$4.07	$2.38	$4.79
NGLs (per bbl)	8.02	24.60	9.63	27.45
Crude oil and condensate (per bbl)	41.71	87.79	36.97	86.43
Total (per mcfe) [(a)]	2.07	4.70	2.39	5.33
Average realized prices (including derivative settlements that qualified for hedge accounting):				
Natural gas (per mcf)	$1.96	$4.12	$2.38	$4.83
NGLs (per bbl)	8.02	24.60	9.63	27.45
Crude oil and condensate (per bbl)	41.71	89.09	36.97	87.56
Total (per mcfe) [(a)]	2.07	4.75	2.39	5.37
Average realized prices (including all derivative settlements):				
Natural gas (per mcf)	$2.95	$3.88	$3.23	$4.03
NGLs (per bbl)	9.97	24.34	11.12	25.84
Crude oil and condensate (per bbl)	67.60	80.63	65.79	81.35
Total (per mcfe) [(a)]	3.07	4.49	3.30	4.70
Average realized prices (including all derivative settlements and third party transportation costs paid by Range):				
Natural gas (per mcf)	$2.00	$2.87	$2.28	$3.00
NGLs (per bbl)	7.65	22.43	8.75	23.89
Crude oil and condensate (per bbl)	67.60	80.63	65.79	81.35
Total (per mcfe) [(a)]	2.31	3.73	2.54	3.93

[(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.

Derivative fair value (loss) income was a loss of $34.8 million in second quarter 2015 compared to a loss of $24.1 million in second quarter 2014. Derivative fair value (loss) income was income of $88.0 million in the six months ended June 30, 2015 compared to loss of $171.0 million in the same period of 2014. Through February 28, 2013, some of our derivatives did not qualify for hedge accounting and were accounted for using the mark-to-market accounting method whereby the change in the fair value of our commodity derivative positions and derivative settlements not accounted for as hedges were included in derivative fair value income or loss in the accompanying consolidated statements of operations. Effective March 1, 2013, we discontinued hedge accounting prospectively. Since March 1, 2013, all of our derivatives are accounted for using the mark-to-market accounting method. Mark-to-market accounting treatment results in volatility of our revenues as the change in the fair value of our commodity derivative positions are 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 while losses indicate higher future wellhead revenues. The following table summarizes the impact of our commodity derivatives for the three months and six months ended June 30, 2015 and 2014 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Derivative fair value (loss) income per consolidated statements of operations	$(34,791)	$(24,109)	$88,048	$(170,959)

Non-cash fair value (loss) gain: [1]				
Natural gas derivatives	$(99,274)	$28,435	$(64,984)	$(18,911)
Oil derivatives	(51,734)	(27,131)	(66,620)	(34,412)
NGL derivatives	(9,009)	765	(3,064)	13,126
Total non-cash fair value (loss) gain [1]	$(160,017)	$2,069	$(134,668)	$(40,197)
Net cash receipt (payment) on derivative settlements:				
Natural gas derivatives	$87,059	$(16,637)	$142,928	$(103,745)
Oil derivatives	28,201	(8,376)	64,227	(12,580)
NGL derivatives	9,966	(1,165)	15,561	(14,437)
Total net cash receipt (payment)	$125,226	$(26,178)	$222,716	$(130,762)

(1) Non-cash fair value adjustments on commodity derivatives is a non-GAAP measure. Non-cash fair value adjustments on commodity derivatives only represents 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

27

value adjustments on commodity derivatives is not a measure of financial or operating performance under GAAP, nor should it be considered a substitute for derivative fair value income or loss as reported in our consolidated statements of operations.
Gain (loss) on the sale of assets was a $2.9 million gain in second quarter 2015 compared to a gain of $282.1 million in second quarter 2014. In second quarter 2015, we sold miscellaneous unproved property and inventory for proceeds of $3.6 million and recognized a pre-tax gain of $2.9 million. In second quarter 2014, we recognized a gain related to the Conger Exchange of $280.1 million after selling expenses and received proceeds of $145.0 million. Gain on the sale of assets was $2.7 million in the first six months ended June 30, 2015 compared to a $281.7 million gain in the same period of 2014. The first six months 2015 includes the sale of miscellaneous unproved and proved properties and inventory for cash proceeds of $14.3 million. Included in the $14.3 million of proceeds is $10.5 million received from the sale of certain West Texas properties. In the first six months 2014, in addition to the Conger Exchange, we sold miscellaneous proved and unproved oil and gas properties for proceeds of $1.1 million and recognized an additional gain of $1.6 million.

Brokered natural gas, marketing and other revenue in second quarter 2015 was $21.3 million compared to $30.1 million in second quarter of 2014 with higher volumes offset by significantly lower average sales prices. Brokered natural gas, marketing and other revenues in the first six months 2015 was $35.8 million compared to $62.6 million in the same period of 2014 with higher volumes offset by significantly lower average sales prices. The three months and the six months ended June 30, 2014 also included revenue of $2.7 million from the sale of excess transportation capacity.

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 six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2015	2014	Change	%	2015	2014	Change	%
Direct operating expense	$0.28	$0.35	$(0.07)	(20%)	$0.29	$0.38	$(0.09)	(24%)
Production and ad valorem tax expense	0.07	0.11	(0.04)	(36%)	0.08	0.12	(0.04)	(33%)
General and administrative expense	0.45	0.57	(0.12)	(21%)	0.43	0.54	(0.11)	(20%)
Interest expense	0.35	0.45	(0.10)	(22%)	0.34	0.46	(0.12)	(26%)
Depletion, depreciation and amortization expense	1.22	1.33	(0.11)	(8 %)	1.22	1.34	(0.12)	(9 %)

Direct operating expense was $34.8 million in second quarter 2015 compared to $34.9 million in second quarter 2014. Direct operating expenses include normally recurring expenses to operate and produce our wells, non-recurring well workovers and repair-related expenses. Our production volumes increased 24% but, on an absolute basis, our spending for direct operating expenses for second quarter 2015 was the same as the prior year quarter, with an increase in the number of producing wells and higher water handling and disposal costs offset by lower workover costs, lower well service costs, lower personnel and stock-based compensation costs and the sale of certain non-core assets in the second quarter 2014. We incurred $1.4 million of workover costs in second quarter 2015 compared to $1.9 million in second quarter 2014.

On a per mcfe basis, direct operating expense in second quarter 2015 decreased 20% from the same period of 2014 with the decrease consisting of lower well service costs, lower non-recurring well workovers, lower personnel and stock-based compensation partially offset by higher water handling and disposal costs. We expect to experience lower costs per mcfe as we increase production from our Marcellus Shale wells due to their lower operating cost relative to our other operating areas.

Direct operating expense was $71.9 million in the six months ended June 30, 2015 compared to $74.7 million in the same period of 2014. Our production volumes increased 25% but, on an absolute basis, our spending for direct operating expenses decreased 4% with an increase in the number of producing wells and higher water handling and disposal costs more than offset by lower workover costs, lower well service costs, lower field personnel and stock-based compensation costs and the sale of certain non-core assets in the second quarter 2014. We incurred $2.5 million of workover costs in the six months ended June 30, 2015 compared to $7.4 million in the same period of 2014.

On a per mcfe basis, direct operating expense in the six months ended June 30, 2015 decreased 24% to $0.29 from $0.38 in the same period of 2014, with the decrease consisting of lower well service costs, lower field personnel costs and lower workover costs somewhat offset by higher water handling and disposal costs. Stock-based compensation expense represents the amortization of restricted stock grants as part of the compensation of field employees.

The following table summarizes direct operating expenses per mcfe for the three months and six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2015	2014	Change	%	2015	2014	Change	%
Lease operating expense	$0.26	$0.31	$(0.05)	(16%)	$0.27	$0.33	$(0.06)	(18%)
Workovers	0.01	0.02	(0.01)	(50%)	0.01	0.04	(0.03)	(75%)
Stock-based compensation (non-cash)	0.01	0.02	(0.01)	(50%)	0.01	0.01	¾	¾ %
Total direct operating expense	$0.28	$0.35	$(0.07)	(20%)	$0.29	$0.38	$(0.09)	(24%)

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 $2.8 million in second quarter 2015 compared to $4.3 million in second quarter 2014. On a per mcfe basis, production and ad valorem taxes (excluding the impact fee) were $0.02 in second quarter 2015 compared to $0.04 in first quarter 2014 due to an increase in volumes not subject to production or ad valorem taxes and lower prices. 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 second quarter 2015 is a $6.5 million impact fee ($0.05 per mcfe) compared to $6.5 million ($0.07 per mcfe) in second quarter 2014.

Production and ad valorem taxes (excluding the impact fee) was $6.6 million ($0.03 per mcfe) in the first six months 2015 compared to $9.5 million ($0.05 per mcfe) in the same period of 2014 due to lower prices and an increase in volumes not subject to production taxes. Included in the first six months 2015 is a $12.6 million ($0.05 per mcfe) impact fee compared to $13.0 million ($0.07 per mcfe) in the same period of 2014.

General and administrative ("G&A") expense was $56.0 million in second quarter 2015 compared to $56.9 million for second quarter 2014. The second quarter 2015 decrease of $924,000 when compared to the same period of 2014 is primarily due to lower salaries and benefits, lower stock-based compensation expense which is partially offset by higher legal expenses and higher franchise taxes. The second quarter 2014 stock-based compensation includes awards granted to our prior Executive Chairman for his service in 2013 while he was a Range officer, which were fully vested upon grant. At June 30, 2015, the number of general and administrative employees has remained the same when compared to June 30, 2014. G&A expense for the six months ended June 30, 2015 decreased $1.8 million when compared to the same period in the prior year due to lower stock-based compensation and lower public relations costs partially offset by higher salaries and benefits, higher legal costs and higher franchise taxes. Stock-based compensation expense represents the amortization of restricted stock grants and performance shares granted to our employees and non-employee directors as part of compensation. On a per mcfe basis, second quarter 2015 G&A expense decreased 21% from second quarter 2014 and 20% from the six months ended 2014. The following table summarizes general and administrative expenses per mcfe for the three months and six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2015	2014	Change	%	2015	2014	Change	%
General and administrative	$0.32	$0.36	$(0.04)	(11%)	$0.32	$0.37	$(0.05)	(14%)
Stock-based compensation (non-cash)	0.13	0.21	(0.08)	(38%)	0.11	0.17	(0.06)	(35%)
Total general and administrative expense	$0.45	$0.57	$(0.12)	(21%)	$0.43	$0.54	$(0.11)	(20%)

Interest expense was $43.5 million for second quarter 2015 compared to $45.5 million for second quarter 2014 and was $82.7 million in the six months ended June 30, 2015 compared to $90.9 million in the six months ended June 30, 2014. The following table presents information about interest expense per mcfe for the three months and the six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2015	2014	Change	%	2015	2014	Change	%
Bank credit facility	$0.03	$0.04	$(0.01)	(25%)	$0.04	$0.04	$¾	¾ %
Senior notes	0.04	¾	0.04	¾ %	0.02	¾	0.02	¾ %
Subordinated notes	0.26	0.38	(0.12)	(32%)	0.27	0.39	(0.12)	(31%)
Amortization of deferred financing costs and other	0.02	0.03	(0.01)	(33%)	0.01	0.03	(0.02)	(67%)
Total interest expense	$0.35	$0.45	$(0.10)	(22%)	$0.34	$0.46	$(0.12)	(26%)

29

On an absolute basis, the decrease in interest expense for second quarter 2015 from the same period of 2014 was primarily due to lower average interest rates on our total outstanding debt. In May 2015 we issued $750.0 million of 4.875% senior notes due 2025. In June 2014, we redeemed all of our $300.0 million 8.0% senior subordinated notes due 2019. Average debt outstanding on the bank credit facility for second quarter 2015 was $682.8 million compared to $657.2 million in second quarter 2014 and the weighted average interest rate on the bank credit facility was 1.7% in second quarter 2015 compared to 2.1% in second quarter 2014.

On an absolute basis, the decrease in interest expense for the six months ended June 30, 2015 from the same period of 2014 was primarily due to lower average interest rates on our total outstanding debt. Average debt outstanding on the bank credit facility was $780.3 million for the six months ended June 30, 2015 compared to $634.5 million for the same period of 2014 and the weighted average interest rate on the bank credit facility was 1.7% in the six months ended June 30, 2015 compared to 2.1% in the same period of 2014.

Depletion, depreciation and amortization ("DD&A") expense was $151.9 million in second quarter 2015 compared to $133.4 million in second quarter 2014. This increase is due to a 9% decrease in depletion rates more than offset by a 24% increase in production. Depletion expense, the largest component of DD&A expense, was $1.15 per mcfe in second quarter 2015 compared to $1.26 per mcfe in first quarter 2014. 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 drilling success and continued capital efficiencies in the Marcellus Shale.

DD&A expense was $299.2 million in the six months ended June 30, 2015 compared to $262.0 million in the same period of 2014. Depletion expense was $1.16 per mcfe in the six months ended June 30, 2015 compared to $1.27 per mcfe in the same period of 2014. The following table summarizes DD&A expense per mcfe for the three months and the six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2015	2014	Change	%	2015	2014	Change	%
Depletion and amortization	$1.15	$1.26	$(0.11)	(9%)	$1.16	$1.27	$(0.11)	(9%)
Depreciation	0.03	0.03	¾	¾%	0.02	0.03	(0.01)	(33%)
Accretion and other	0.04	0.04	¾	¾%	0.04	0.04	¾	¾%
Total DD&A expense	$1.22	$1.33	$(0.11)	(8%)	$1.22	$1.34	$(0.12)	(9%)

Transportation, gathering and compression expense was $95.2 million in second quarter 2015 compared to $76.8 million in second quarter 2014. Transportation, gathering and compression expense was $184.6 million in the six months ended June 30, 2015 compared to $151.0 million in the same period of 2014. These third party costs are higher than 2014 due to our production growth in the Marcellus Shale where we have third party gathering, compression and transportation agreements. We have included these costs in the calculation of average realized prices (including all derivative settlements and third party transportation expenses paid by Range).

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, deferred compensation plan expenses and termination costs. 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 six months ended June 30, 2015 and 2014 (in thousands):

	Three Months Ended	Six Months Ended

	June 30,		June 30,	
	2015	2014	2015	2014
Direct operating expense	$654	$1,937	$1,540	$2,789
Brokered natural gas and marketing expense	619	1,130	1,125	1,658
Exploration expense	751	1,222	1,483	2,375
General and administrative expense	15,953	20,696	27,033	32,300
Termination costs	434	¾	1,721	¾
Total stock-based compensation	$18,411	$24,985	$32,902	$39,122

Brokered natural gas and marketing expense was $27.0 million in second quarter 2015 compared to $34.8 million in second quarter 2014. Brokered natural gas and marketing expense was $48.6 million in the six months ended June 30, 2015 compared to $68.9 million in the same period of 2014. These costs were lower in second quarter 2015 when compared to second quarter 2014 with higher brokered gas volumes more than offset by lower purchase prices and higher expenses related to company-owned gathering lines we received as part of the Conger Exchange of $4.8 million. These cost were lower in the six months ended June 30, 2015 when compared to the same period in 2014 with higher brokered gas volumes more than offset by significantly lower purchase prices and higher expenses related to company-owned gathering lines of $9.3 million. The three months and the six months ended June 30, 2015 included $5.3 million of transportation capacity charges where we had taken firm capacity ahead of our production volumes.

Exploration expense was $5.0 million in second quarter 2015 compared to $13.6 million in second quarter 2014 due to lower seismic costs and personnel and stock-based compensation. Exploration expense was $12.9 million in the six months ended June 30, 2015 compared to $28.5 million in the same period of 2014. The following table details our exploration related expenses for the three months and six months ended June 30, 2015 and 2014 (in thousands):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2015	2014	Change	%	2015	2014	Change	%
Seismic	$151	$6,966	$(6,815)	(98%)	$1,575	$12,211	$(10,636)	(87%)
Delay rentals and other	1,026	1,460	(434)	(30%)	2,758	5,554	(2,796)	(50%)
Personnel expense	3,094	3,973	(879)	(22%)	6,989	8,326	(1,337)	(16%)
Stock-based compensation expense	751	1,222	(471)	(39%)	1,483	2,375	(892)	(38%)
Dry hole expense	3	¾	3	¾ %	106	1	105	¾ %
Total exploration expense	$5,025	$13,621	$(8,596)	(63%)	$12,911	$28,467	$(15,556)	(55%)

Abandonment and impairment of unproved properties was $12.3 million in second quarter 2015 compared to $9.3 million in second quarter 2014. Abandonment and impairment of unproved properties was $23.8 million in the six months ended June 30, 2015 compared to $19.3 million in the same period of 2014. 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. 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 will likely be recorded. The increase in second quarter and six months ended June 30, 2015 when compared to the same periods of 2014 is primarily due to higher expected forfeitures in the Midcontinent.

Termination costs were $417,000 in second quarter 2015 and $6.4 million for the six months ended June 30, 2015. These costs include $3.2 million of accrued building lease costs for our Oklahoma City office, additional severance and stock-based compensation for accelerated vesting of restricted stock grants for both our Oklahoma City office employees and other areas where we have determined a need to reduce personnel due, in part, to the low commodity price environment.

Deferred compensation plan expense was a gain of $7.3 million in second quarter 2015 compared to a loss of $10.5 million in second quarter 2014. 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 $52.04 at March 31, 2015 to $49.38 at June 30, 2015. In the same quarter of the prior year, our stock price increased from $82.97 at March 31, 2014 to $86.95 at June 30, 2014. During the six months ended June 30, 2015 deferred compensation was a gain of $12.9 million compared to a loss of $8.5 million in the same period of 2014. Our stock price decreased from $53.45 at December 31, 2014 to $49.38 at June 30, 2015. In the same period of 2014, our stock price increased from $84.31 at December 31, 2013 to $86.95 at June 30, 2014.

Loss on early extinguishment of debt for the second quarter and the six months ended June 30, 2014 was $24.6 million. In June 2014, we redeemed our 8.0% senior subordinated notes due 2019 at 104.0% of par and we recorded a loss on extinguishment of debt of $24.6 million which includes a call premium and expensing of related deferred financing costs on the repurchased debt.

Impairment of proved properties was $25.0 million in the three months and the six months ended June 30, 2014. Impairment expense was recorded related to certain of our natural gas and oil properties in Mississippi, West Texas and North Texas.

Income tax (benefit) expense was a benefit of $62.0 million in second quarter 2015 compared to income tax expense of $118.0 million in second quarter 2014. For the second quarter, the effective tax rate was 34.3% in 2015 compared to 40.8% in 2014. Income tax benefit was $39.6 million in the six months ended June 30, 2015 compared to income tax expense of $136.9 million in the same period of 2014. For the six months ended June 30, 2015 the effective tax rate was 30.3% compared to 40.2% in the six months ended June 30, 2014. The 2015 and 2014 effective tax rates were different than the statutory tax rate due to state income taxes, permanent differences, changes in our valuation allowances related to deferred tax assets associated with senior executives to the extent their estimated future compensation, which includes distributions from the deferred compensation plan, is expected to exceed the $1.0 million annual deductible limit provided under section 162(m) of the Internal Revenue Code and changes to our valuation allowances related to state net operating loss carry forwards. In both the second quarter and the six months ended June 30, 2015, we have increased our valuation allowances for state net operating loss carryforwards and credits. We expect our effective tax rate to be approximately 39% for the remainder of 2015, before any discrete tax items.

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 since 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. We sell a large portion of our production at the wellhead under floating market contracts. 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. Any interim cash needs are funded by borrowings under the bank credit facility. As of June 30, 2015, we have entered into hedging agreements covering 197.4 Bcfe for the remainder of 2015, 260.2 Bcfe for 2016 and 7.3 Bcfe for 2017. We have also entered into basis hedges for 50,565,000 Mmbtu through March 2017.

Net cash provided from operations in first six months 2015 was $370.1 million compared to $441.5 million in first six months 2014. 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 decrease in cash provided from operating activities from 2014 to 2015 reflects a 25% increase in production and lower operating costs more than offset by lower realized prices (a decline of 35%). As of June 30, 2015, we have hedged approximately 80% of our projected total production for the remainder of 2015, with approximately 87% 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 six months 2015 was positive $22.5 million compared to negative $45.2 million for first six months 2014.

Net cash used in investing activities from operations in first six months 2015 was $704.9 million compared to $512.6 million in the same period of 2014.

During the six months ended June 30, 2015, we:

spent $671.2 million on natural gas and oil property additions;
spent $51.4 million on acreage, primarily in the Marcellus Shale; and

- received proceeds from asset sales of $14.3 million.

During the six months ended June 30, 2014, we:

- spent $546.4 million on natural gas and oil property additions;
- spent $110.5 million on acreage, primarily in the Marcellus Shale; and
- received proceeds from asset sales of $146.1 million.

Net cash provided from financing activities in first six months 2015 was $334.8 million compared to $71.0 million in the same period of 2014. Historically, sources of financing have been primarily bank borrowings and capital raised through debt and equity offerings.

During the six months ended June 30, 2015, we:

- borrowed $1.0 billion and repaid $1.4 billion under our bank credit facility, ending the quarter with a $364.0 million outstanding balance on our bank debt;

32

- received proceeds of $750.0 million from issuance of 4.875% senior notes due 2025; and
- paid dividends of $13.5 million.

During the six months ended June 30, 2014, we:

- borrowed $1.2 billion and repaid $1.2 billion under our bank credit facility, ending the quarter with $480.0 million of outstanding balance on our bank debt;
- redeemed all $300.0 million aggregate principal amount of 8.0% senior subordinated notes due 2019, including related expenses;
- received proceeds of $396.7 million from the issuance of 4.56 million shares of common stock; and
- paid dividends of $13.1 million.

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 six months 2015, we significantly reduced our operating costs per unit of production and we entered into additional commodity derivative contracts for 2015, 2016 and 2017 to protect future cash flows. On March 31, 2015, our borrowing base and credit facility commitment were reaffirmed for the period from May 1, 2015 to May 1, 2016 along with various changes to certain financial covenants.

During the first six months 2015, our net cash provided from operating activities of $370.1 million, proceeds received from the issuance of senior notes and proceeds from asset sales were used to fund approximately $724.2 million of capital expenditures (including acreage acquisitions). At June 30, 2015, we had $521,000 in cash and total assets of $8.8 billion.

Long-term debt at June 30, 2015 totaled $3.5 billion, including $364.0 million outstanding on our bank credit facility, $750.0 million of senior notes and $2.4 billion of senior subordinated notes. Our available committed borrowing capacity at June 30, 2015 was $1.5 billion. 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 2015 capital budget is approximately $870.0 million. 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.

Credit Arrangements

As of June 30, 2015, 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 June 30, 2015, the outstanding balance under our credit facility was $364.0 million. Additionally, we had $108.7 million of undrawn letters of credit leaving $1.5 billion of committed borrowing capacity available under the facility.

Our bank credit facility and our senior subordinated notes impose limitations on the payment of dividends and other restricted payments (as defined under our bank credit facility and the agreements relating to our subordinated notes). These agreements also contain customary covenants relating to debt incurrence, liens, investments and financial ratios. We are in compliance with all covenants at June 30, 2015. See Note 8 for additional information regarding our bank debt.

Cash Dividend Payments

On June 1, 2015, our Board of Directors declared a dividend of four cents per share ($6.8 million) on our outstanding common stock, which was paid on June 30, 2015 to stockholders of record at the close of business on June 16, 2015. The amount of future dividends is subject to 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, drilling commitments, derivative obligations, asset retirement obligations and transportation and gathering commitments. As of June 30, 2015, we do not have any capital leases. As of June 30, 2015, 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 June 30, 2015, we had a total of $108.7 million of undrawn letters of credit under our bank credit facility.

Since December 31, 2014, there have been no material changes to our contractual obligations other than a $359.0 million decrease in our outstanding bank credit facility balance, issuance of $750.0 million of 4.875% senior notes, new firm transportation contracts and new delivery commitments. The new firm transportation contracts increased our contractual obligations by approximately $71.5 million over the next nine years.

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 do not utilize complex derivatives, as we typically utilize commodity swap and collar 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 on-going 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 gain of $262.8 million at June 30, 2015. The contracts expire monthly through December 2017. At June 30, 2015, 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			
2015	Collars	145,000 Mmbtu/day	$ 4.07–$ 4.56
2015	Swaps	737,500 Mmbtu/day	$ 3.63
2016	Swaps	630,000 Mmbtu/day	$ 3.42
2017	Swaps	20,000 Mmbtu/day	$ 3.49

Crude Oil			
2015	Swaps	11,250 bbls/day	$ 85.87
2016	Swaps	3,000 bbls/day	$ 70.54
NGLs (C3-Propane)			
2015	Swaps	13,000 bbls/day	$ 0.58/gallon
2016	Swaps	5,500 bbls/day	$ 0.60/gallon
NGLs (NC4-Normal Butane)			
2015	Swaps	3,500 bbls/day	$ 0.72/gallon
2016	Swaps	2,500 bbls/day	$ 0.72/gallon
NGLs (C5-Natural Gasoline)			
2015	Swaps	4,000 bbls/day	$ 1.16/gallon
2016	Swaps	2,500 bbls/day	$ 1.23/gallon

In addition to the collars and swaps discussed above, we have entered into basis swap agreements. The price we received for our gas production can be more or less than the NYMEX 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 gain of $5.9 million at June 30, 2015, the volumes are for 50,565,000 Mmbtu and they expire through March 2017.

Interest Rates

At June 30, 2015, we had approximately $3.5 billion of debt outstanding. Of this amount, $3.1 billion bears interest at fixed rates averaging 5.4%. Bank debt totaling $364.0 million bears interest at floating rates, which averaged 1.5% at June 30, 2015. The 30-day LIBO Rate on June 30, 2015 was approximately 0.2%. A 1% increase in short-term interest rates on the floating-rate debt outstanding on June 30, 2015 would cost us approximately $3.6 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 2015 to continue to be a function of supply and demand and we believe, based on the lower commodity price environment, we will continue to see cost reductions. However, the timing and amount of such cost reductions cannot be predicted.

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. Natural gas and NGLs prices affect us more than oil prices because approximately 97% of our December 31, 2014 proved reserves are natural gas and NGLs. We are also exposed to market risks related to changes in interest rates. These risks did not change materially from December 31, 2014 to June 30, 2015.

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. We do not utilize complex derivatives such as swaptions, knockouts or extendable swaps. 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 also includes collars, which establish a minimum floor price and a predetermined ceiling price. At June 30, 2015, our derivative program includes swaps and collars. These contracts expire monthly through December 2017. The fair value of these contracts, represented by the estimated amount that would be realized upon immediate liquidation as of June 30, 2015, approximated a net unrealized pretax gain of $262.8 million. At June 30, 2015, 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				
2015	Collars	145,000 Mmbtu/day	$ 4.07–$ 4.56	$ 31,149
2015	Swaps	737,500 Mmbtu/day	$ 3.63	$ 98,729
2016	Swaps	630,000 Mmbtu/day	$ 3.42	$ 56,235
2017	Swaps	20,000 Mmbtu/day	$ 3.49	$ 930
Crude Oil				
2015	Swaps	11,250 bbls/day	$ 85.87	$ 52,720
2016	Swaps	3,000 bbls/day	$ 70.54	$ 9,239
NGLs (C3-Propane)				
2015	Swaps	13,000 bbls/day	$ 0.58/gallon	$ 9,732
2016	Swaps	5,500 bbls/day	$ 0.60/gallon	$ 4,234
NGLs (NC4-Normal Butane)				
2015	Swaps	3,500 bbls/day	$ 0.72/gallon	$ 2,057
2016	Swaps	2,500 bbls/day	$ 0.72/gallon	$ 712
NGLs (C5-Natural Gasoline)				
2015	Swaps	4,000 bbls/day	$ 1.16/gallon	$ (2,223)
2016	Swaps	2,500 bbls/day	$ 1.23/gallon	$ (678)

We expect our NGLs production to continue to increase. In our Marcellus Shale operations, propane is a large product component of our NGLs production and we believe NGLs prices are somewhat seasonal. Therefore, the relationship of NGLs prices to NYMEX WTI (or West Texas Intermediate) will vary due to product components, seasonality and geographic supply and demand. We sell NGLs in several regional and global markets. If we are not able to sell or store propane, we may be required to curtail production or shift our drilling activities to dry gas areas.

Currently, there is little demand, or facilities to supply the existing demand elsewhere, for ethane in the Appalachian region. We have previously announced five ethane agreements wherein we have contracted to either sell or transport ethane from our Marcellus Shale area, two of which began operations in late 2013. The Mariner East agreement is expected to begin ethane operations in the second half of 2015. We cannot assure you that this facility will become available. The remaining two contract start dates are still in the planning or construction stage. If we are not able to sell ethane under at least one of these five agreements, we may be required to curtail production or, as we have in the past, purchase natural gas to blend with our rich residue gas.

Other Commodity Risk

We are impacted by basis risk, caused by factors that affect the relationship between commodity futures prices reflected in derivative commodity instruments and the cash market price of the underlying commodity. Natural gas transaction prices are frequently based on industry reference prices that may vary from prices experienced in local markets. If commodity price changes in one region are not reflected in other regions, derivative commodity instruments may no longer provide the expected hedge, resulting in increased basis risk. In addition to the collars and swaps discussed above, we have entered into basis swap agreements. The price we receive for our gas production can be more or less than the NYMEX 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 gain of $5.9 million at June 30, 2015 and they expire monthly through March 2017.

The following table shows the fair value of our collars, swaps and basis swaps and the hypothetical change in fair value that would result from a 10% and a 25% change in commodity prices at June 30, 2015. We remain at risk for possible changes in the market value of commodity derivative instruments; however, such risks should be mitigated by price changes in the underlying physical commodity (in thousands):

		Hypothetical Change in Fair Value Increase of		Hypothetical Change in Fair Value Decrease of	
	Fair Value	10%	25%	10%	25%
Collars	$ 31,149	$ (7,404)	$ (18,059)	$ 7,565	$ 19,113
Swaps	231,687	(156,212)	(388,718)	156,317	390,786
Basis swaps	5,860	2,163	15,228	(15,492)	(28,751)

Our commodity-based contracts expose us to the credit risk of non-performance by the counterparty to the contracts. Our exposure is diversified among major investment grade financial institutions and we have master netting agreements with our counterparties that provide for offsetting payables against receivables from separate derivative contracts. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. At June 30, 2015, our derivative counterparties include seventeen financial institutions, of which all but two are secured lenders in our bank credit facility. Counterparty credit risk is considered when determining the fair value of our derivative contracts. While our counterparties are major investment grade financial institutions, the fair value of our derivative contracts has been adjusted to account for the risk of non-performance by certain of our counterparties, which was immaterial.

Interest Rate Risk

We are exposed to interest rate risk on our bank debt. We attempt to balance variable rate debt, fixed rate debt and debt maturities to manage interest costs, interest rate volatility and financing risk. This is accomplished through a mix of fixed rate senior and senior subordinated debt and variable rate bank debt. At June 30, 2015, we had $3.5 billion of debt outstanding. Of this amount, $3.1 billion bears interest at fixed rates averaging 5.4%. Bank debt totaling $364.0 million bears interest at floating rates, which was 1.5% on June 30, 2015. On June 30, 2015, the 30-day LIBO Rate was approximately 0.2%. A 1% increase in short-term interest rates on the floating-rate debt outstanding on June 30, 2015, would cost us approximately $3.6 million in additional annual interest expense.

ITEM 4.