RANGE RESOURCES CORP
Form 10-Q
October 29, 2014

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 September 30, 2014

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 (State or Other Jurisdiction of Incorporation or Organization)	34-1312571 (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

168,700,876 Common Shares were outstanding on October 29, 2014

RANGE RESOURCES CORPORATION

FORM 10-Q

Quarter Ended September 30, 2014

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

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PART I – FINANCIAL INFORMATION

ITEM 1. Financial Statements
RANGE RESOURCES CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands, except share data)

	September 30, 2014 (Unaudited)	December 31, 2013
Assets		
Current assets:		
Cash and cash equivalents	$468	$348
Accounts receivable, less allowance for doubtful accounts of $2,704 and $2,494	172,429	179,667
Derivative assets	44,774	4,421
Deferred tax asset	2,010	51,414
Inventory and other	16,961	12,451
Total current assets	236,642	248,301
Derivative assets	17,034	9,233
Equity method investments	—	129,034
Natural gas and oil properties, successful efforts method	10,102,115	9,032,881
Accumulated depletion and depreciation	(2,472,030)	(2,274,444)
	7,630,085	6,758,437
Transportation and field assets	125,638	118,625
Accumulated depreciation and amortization	(87,083)	(85,841)
	38,555	32,784
Other assets	112,134	121,297
Total assets	$8,034,450	$7,299,086
Liabilities		
Current liabilities:		
Accounts payable	$266,702	$258,431
Asset retirement obligations	5,037	5,037
Accrued liabilities	171,345	161,520
Accrued interest	23,328	44,375
Derivative liabilities	—	26,198
Total current liabilities	466,412	495,561
Bank debt	649,000	500,000
Subordinated notes	2,350,000	2,640,516
Deferred tax liability	948,904	771,980
Derivative liabilities	—	25
Deferred compensation liability	197,277	247,537
Asset retirement obligations and other liabilities	253,940	229,015
Total liabilities	4,865,533	4,884,634
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, 168,700,022 issued at September 30, 2014 and 163,441,414 issued at December 31, 2013	1,687	1,634
Common stock held in treasury, 82,954 shares at September 30, 2014 and 98,520 shares at December 31, 2013	(3,088)	(3,637)
Additional paid-in capital	2,389,491	1,959,636
Retained earnings	781,049	450,583
Accumulated other comprehensive (loss) income	(222)	6,236
Total stockholders' equity	3,168,917	2,414,452
Total liabilities and stockholders' equity	$ 8,034,450	$ 7,299,086

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited, in thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Revenues and other income:				
Natural gas, NGLs and oil sales	$446,067	$431,214	$1,495,601	$1,267,131
Derivative fair value income (loss)	142,057	(40,355)	(28,902)	(2,470)
Gain on the sale of assets	167	6,008	281,878	89,129
Brokered natural gas, marketing and other	28,324	45,171	90,904	80,843
Total revenues and other income	616,615	442,038	1,839,481	1,434,633
Costs and expenses:				
Direct operating	37,792	30,907	112,522	93,731
Transportation, gathering and compression	84,777	60,958	235,747	189,422
Production and ad valorem taxes	10,110	11,454	32,632	33,950
Brokered natural gas and marketing	28,706	51,117	97,610	90,094
Exploration	11,443	20,496	39,910	50,344
Abandonment and impairment of unproved properties	13,444	11,692	32,771	46,066
General and administrative	54,963	44,919	161,063	230,964
Deferred compensation plan	(46,198)	(2,225)	(37,714)	33,257
Interest expense	39,188	44,321	130,077	131,602
Loss on early extinguishment of debt	—	—	24,596	12,280
Depletion, depreciation and amortization	142,450	130,343	404,493	365,439
Impairment of proved properties and other assets	—	7,012	24,991	7,753
Total costs and expenses	376,675	410,994	1,258,698	1,284,902
Income from operations before income taxes	239,940	31,044	580,783	149,731
Income tax expense				
Current	—	—	5	—
Deferred	93,522	11,866	230,450	62,180
	93,522	11,866	230,455	62,180
Net income	$146,418	$19,178	$350,328	$87,551
Net income per common share:				
Basic	$0.87	$0.12	$2.11	$0.54
Diluted	$0.86	$0.12	$2.10	$0.53
Dividends paid per common share	$0.04	$0.04	$0.12	$0.12
Weighted average common shares outstanding:				
Basic	165,841	160,500	162,866	160,398
Diluted	166,460	161,374	163,685	161,321

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited, in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net income	$146,418	$19,178	$350,328	$87,551
Other comprehensive income:				
Realized gain on hedge derivative contract settlements reclassified into natural gas, NGLs and oil sales from other comprehensive income, net of taxes [1]	—	—	—	(14,840)
De-designated hedges reclassified into natural gas, NGLs and oil sales, net of taxes [2]	(2,172)	(16,717)	(6,458)	(42,758)
De-designated hedges reclassified to derivative fair value income, net of taxes [3]	—	(438)	—	(2,376)
Change in unrealized deferred hedging gains, net of taxes [4]	—	—	—	(4,203)
Total comprehensive income	$144,246	$2,023	$343,870	$23,374

(1) Amount is net of income tax benefit of $9,488 for the nine months ended September 30, 2013.

(2) Amounts are net of income tax benefit of $1,332 for the three months ended September 30, 2014 and $4,122 for the nine months ended September 30, 2014. Amounts are net of income tax benefit of $10,688 for the three months ended September 30, 2013 and $27,337 for the nine months ended September 30, 2013.

(3) Amounts relate to transactions not probable of occurring and are presented net of income tax benefit of $279 for the three months ended September 30, 2013 and $1,518 for the nine months ended September 30, 2013.

(4) Amount is net of income tax benefit of $2,687 for the nine months ended September 30, 2013.

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited, in thousands)

	Nine Months Ended September 30, 2014	2013
Operating activities:		
Net income	$350,328	$87,551
Adjustments to reconcile net income to net cash provided from operating activities:		
Loss (gain) from equity method investments, net of distributions	3,096	(1,174)
Deferred income tax expense	230,450	62,180
Depletion, depreciation and amortization and impairment	429,484	373,192
Exploration dry hole costs	1	3,904
Abandonment and impairment of unproved properties	32,771	46,066
Derivative fair value loss	28,902	2,470
Cash settlements on derivative financial instruments that do not qualify for hedge accounting	(113,859)	(28,335)
Allowance for bad debt	250	250
Amortization of deferred financing costs, loss on extinguishment of debt and other	31,430	19,735
Deferred and stock-based compensation	15,486	74,187
Gain on the sale of assets	(281,878)	(89,129)
Changes in working capital:		
Accounts receivable	13,098	6,508
Inventory and other	(5,335)	3,259
Accounts payable	(13,355)	(29,234)
Accrued liabilities and other	(65,931)	(28,564)
Net cash provided from operating activities	654,938	502,866
Investing activities:		
Additions to natural gas and oil properties	(867,285)	(907,813)
Additions to field service assets	(9,492)	(4,326)
Acreage purchases	(145,543)	(70,187)
Equity method investments	1,103	3,799
Proceeds from disposal of assets	147,126	311,748
Purchases of marketable securities held by the deferred compensation plan	(23,053)	(23,729)
Proceeds from the sales of marketable securities held by the deferred compensation plan	25,206	19,375
Net cash used in investing activities	(871,938)	(671,133)
Financing activities:		
Borrowing on credit facilities	1,682,000	1,310,000
Repayment on credit facilities	(1,533,000)	(1,622,000)
Issuance of subordinated notes	—	750,000
Repayment of subordinated notes	(312,000)	(259,063)
Dividends paid	(19,862)	(19,593)
Debt issuance costs	—	(12,448)

Issuance of common stock, net of offering expenses	396,580	343
Change in cash overdrafts	(12,305)	4,704
Proceeds from the sales of common stock held by the deferred compensation plan	15,707	16,327
Net cash provided from financing activities	217,120	168,270
Increase in cash and cash equivalents	120	3
Cash and cash equivalents at beginning of period	348	252
Cash and cash equivalents at end of period	$468	$255

See accompanying notes.

RANGE RESOURCES CORPORATION

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 Southwestern 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

Presentation

These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Range Resources Corporation 2013 Annual Report on Form 10-K filed with the Securities and Exchange Commission (the "SEC") on February 26, 2014. The results of operations for the third quarter and the nine months ended September 30, 2014 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. Certain reclassifications have been made to prior years reported amounts in order to conform with the current year presentation including reclassifications between accounts payable and accrued liabilities within cash flow from operating activities and a change in the presentation for our derivative activities. These reclassifications have no impact on previously reported net income, stockholders' equity or cash flows.

De-designation of Commodity Derivative Contracts

Effective March 1, 2013, we elected to discontinue hedge accounting prospectively. After March 1, 2013, both realized and unrealized gains and losses are recognized in derivative fair value income or loss immediately each quarter as derivative contracts are settled and marked to market. For additional information, see Note 11.

(3) NEW ACCOUNTING STANDARDS

Not Yet Adopted

In May 2014, an accounting standards update was issued 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. The new guidance is effective for us for the reporting period beginning January 1, 2017, with early application not permitted. We are evaluating our existing revenue recognition policies to determine whether any contracts will be affected by the new requirements.

Recently Adopted

In February 2013, an accounting standards update was issued to provide guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date, except for obligations such as asset retirement and environmental obligations, contingencies, guarantees, income taxes and retirement benefits, which are separately addressed within U.S. GAAP. An entity is required to measure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date as the sum of (1) the amount the entity agreed to pay on the basis of its arrangement among its co-obligors and (2) any amount the entity expects to pay on behalf of its co-obligors. Disclosure of the nature of the obligation, including how the liability arose, the relationship with other co-obligors and the terms and conditions of the arrangement is required. In addition, the total outstanding amount under the arrangement, not reduced by the effect of any amounts that may be recoverable from other entities, plus the carrying amount of any liability or receivable recognized must be disclosed. This accounting standards update is effective for us beginning in first quarter 2014 and should be applied retrospectively for those in-scope obligations resulting from joint and several liability arrangements that exist at the beginning of 2014. Early adoption was permitted and we adopted this new standard in first quarter 2014 which did not have an impact on our consolidated results of operations, financial position or cash flows.

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 sale or (3) is classified as held for sale. This accounting standards update is effective for annual periods beginning on or after December 15, 2014 and is applied prospectively. Early adoption is permitted but only for disposals (or classifications that are held for sale) that have 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 defined and described in more detail below, is not reported as a discontinued operation.

(4) ACQUISITIONS AND DISPOSITIONS

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 other EQT assets in Virginia and $145.0 million in cash ("Conger Exchange"). We closed the exchange transaction on June 16, 2014. The assets exchanged meet the definition of a business under accounting standards and was recorded at fair value. We recognized a pre-tax gain of $275.2 million related to this exchange, before selling expenses of $5.0 million, which is recognized as a gain on sale of assets in our consolidated statement of operations for the nine months ended September 30, 2014. The combined carrying amount of our Conger assets prior to the exchange was $271.8 million. We are in the process of identifying and determining the fair value of the assets acquired and liabilities assumed as part of the Conger Exchange. The following table presents a preliminary estimate of the fair value of assets acquired and liabilities assumed in the transaction, pending final closing adjustments (in thousands):

	Conger Exchange
Consideration	
Fair value of net assets transferred	$ 550,273
Fair value of assets acquired and liabilities assumed	
Cash	$ 145,000
Working capital – Nora Gathering, LLC	14,244
Natural gas and oil properties	407,255
Transportation and field assets	7,793
Other liabilities-firm transportation contract	(12,092)
Asset retirement obligations	(11,927)
Fair value of net assets acquired and liabilities assumed	$ 550,273

In connection with the Conger Exchange, we acquired the remaining 50% interest held by EQT in Nora Gathering, LLC ("NGLLC"), a natural gas gathering operation, which we had previously accounted for using the equity method of accounting. As of June 16, 2014, we have consolidated NGLLC into our consolidated financial statements. Our previous 50% membership interest in NGLLC was remeasured to fair value on the acquisition date, resulting in a gain of $10.0 million which is recognized in gain on sale of assets in our consolidated statement of operations for the nine months ended September 30, 2014. We assumed trade receivables as part of the acquisition of NGLLC of $5.5 million, all of which we expect to collect.

For the period from June 16, 2014 through September 30, 2014, we recognized $18.4 million of natural gas, oil and NGLs sales and we recognized $14.6 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) from the property interests acquired in the Conger Exchange.

Conger Exchange Fair Value

Accounting standards define fair value as 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 (often referred to as the “exit price”). The fair value measurement is based on the assumptions of market participants and not those of the reporting entity. Therefore, entity-specific intentions do not impact the measurement of fair value unless those assumptions are consistent with market participant views.

The fair value of the Conger Exchange described above was based on an income approach which was supplemented by a market approach. For the natural gas and oil properties, the income approach uses significant inputs not observable in the market, which are Level 3 inputs. The significant inputs assumed include future production and capital, commodity prices, risk-adjusted discount rates, natural gas and oil pricing differentials, and projected reserve recovery factors. The market approach uses inputs such as recent market transactions in a similar geographic region and with similar production. The income approach for the natural gas gathering operations was based on a discounted future net cash flow model, which uses Level 3 inputs and was supplemented by a market approach.

Other 2014 Dispositions

In addition to the Conger Exchange above, in the nine months ended September 30, 2014, we sold miscellaneous proved property and inventory for proceeds of $2.1 million resulting in a pre-tax gain of $1.7 million.

2013 Dispositions

In September 2013, we sold our equity method investment in a drilling company for proceeds of $7.0 million and recognized a gain of $4.4 million. In addition, in third quarter 2013 we sold unproved leases in West Texas for proceeds of $2.6 million where we recognized a gain of $1.7 million and sold surface acreage in North Texas for proceeds of $5.3 million with a loss of $253,000 recognized.

In the nine months ended September 30, 2013, we completed the sale of certain of our Delaware and Permian Basin properties in southeast New Mexico and West Texas for a price of $275.0 million and we recognized pre-tax gain of $83.3 million, before selling expenses of $4.2 million. In addition, we also sold miscellaneous proved and unproved properties and inventory for proceeds of $26.0 million resulting in a pre-tax gain of $4.1 million.

(5) INCOME TAXES

Income tax expense from operations was as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Income tax expense	$93,522	$11,866	$230,455	$62,180
Effective tax rate	39.0 %	38.2 %	39.7 %	41.5 %

We compute our quarterly taxes under the effective tax rate method based on applying an anticipated annual effective rate to our year-to-date income, except for discrete items. Income taxes for discrete items are computed and recorded in the period that the specific transaction occurs. For third quarter and the nine months ended September 30, 2014 and 2013, our overall effective tax rate on operations was different than the federal statutory rate of 35% due primarily to state income taxes, valuation allowances and other permanent differences.

(6) 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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net income, as reported	$146,418	$19,178	$350,328	$87,551
Participating basic earnings [a]	(2,479)	(341)	(5,940)	(1,479)
Basic net income attributed to common shareholders	143,939	18,837	344,388	86,072
Reallocation of participating earnings [a]	9	1	28	6
Diluted net income attributed to common shareholders	$143,948	$18,838	$344,416	$86,078
Net income per common share:				
Basic	$0.87	$0.12	$2.11	$0.54
Diluted	$0.86	$0.12	$2.10	$0.53

[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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Denominator:				
Weighted average common shares outstanding – basic	165,841	160,500	162,866	160,398
Effect of dilutive securities:				
Director and employee stock options and SARs	619	874	819	923
Weighted average common shares outstanding – diluted	166,460	161,374	163,685	161,321

Weighted average common shares-basic for both the three months ended September 30, 2014 and 2013 excludes 2.9 million shares held in our deferred compensation plans (although all awards are issued and outstanding upon grant). Weighted average common shares-basic for both the nine months ended September 30, 2014 and 2013 excludes 2.8 million shares of restricted stock. Stock appreciation rights (“SARs”) of 351,000 for the three months ended September 30, 2014 were outstanding but not included in the computations of diluted income from operations per share because the grant prices of the SARs were greater than the average market price of the common stock. All SARs for the nine months ended September 30, 2014 were included in the computations of diluted income from operations per share because the grant prices of the SARs were all less than the average market price of the common stock. SARs of 796 for the three months ended September 30, 2013 and 181,000 for the nine months ended September 30, 2013 were outstanding but not included in the computations of diluted income from operations per share because the grant prices of the SARs were greater than the average market price of the common shares.

(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. The following table reflects the changes in capitalized exploratory well costs for the nine months ended September 30, 2014 and the year ended December 31, 2013 (in thousands except for number of projects):

	September 30, 2014	December 31, 2013
Balance at beginning of period	$ 6,964	$ 57,360
Additions to capitalized exploratory well costs pending the determination of proved reserves	90,767	39,832
Reclassifications to wells, facilities and equipment based on determination of proved reserves	(15,735)	(84,840)
Capitalized exploratory well costs charged to expense	—	—
Divested wells	—	(5,388)
Balance at end of period	81,996	6,964
Less exploratory well costs that have been capitalized for a period of one year or less	(46,412)	—
	$ 35,584	$ 6,964

Capitalized exploratory well costs that have been capitalized for a period greater than one year		
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	5	1

As of September 30, 2014, $35.6 million of capitalized exploratory well costs have been capitalized for more than one year which relates to one well in our Marcellus Shale area where we continue to evaluate pipeline options and opportunities and four wells, also in our Marcellus Shale area, which are expected to be producing in fourth quarter 2014. The following table provides an aging of capitalized exploratory well costs that have been suspended for more than one year as of September 30, 2014 (in thousands):

	Total	2014	2013	2012	2011
Capitalized exploratory well costs that have been capitalized for more than one year	$35,584	$24,484	$4,246	$6,801	$ 53

(8) INDEBTEDNESS

We had the following debt outstanding as of the dates shown below (bank debt interest rate at September 30, 2014 is shown parenthetically) (in thousands). No interest was capitalized during the three months or the nine months ended September 30, 2014 or 2013:

	September 30, 2014	December 31, 2013
Bank debt (2.2%)	$649,000	$ 500,000
Senior subordinated notes:		
8.00% senior subordinated notes due 2019, net of $9,484 discount	¾	290,516
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	$2,999,000	$ 3,140,516

Bank Debt

In February 2011, 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. The bank credit facility provides for an initial commitment equal to the lesser of the facility amount or the borrowing base. On September 30, 2014, the facility amount was $1.75 billion and the borrowing base was $2.0 billion. The bank credit facility provides for a borrowing base subject to redeterminations semi-annually and for event-driven unscheduled redeterminations. As of September 30, 2014, our bank group was composed of twenty-eight financial institutions with no bank holding more than 9% of the total facility. The bank credit facility amount may be increased to the borrowing base amount with twenty days notice, 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 September 30, 2014, the outstanding balance under our bank credit facility was $649.0 million. Additionally, we had $104.0 million of undrawn letters of credit leaving $997.0 million of borrowing capacity available under the facility. As of September 30, 2014, borrowings under the bank credit facility can either be at the Alternate Base Rate (as defined in the bank credit facility) plus a spread ranging from 0.50% to 1.5% or LIBOR borrowings at the Adjusted LIBO Rate (as defined in the bank credit facility) plus a spread ranging from 1.5% to 2.5%. The applicable spread is dependent upon borrowings relative to the borrowing base. We may elect, from time to time, to convert all or any part of our LIBOR loans to base rate loans or to convert all or any of the base rate loans to LIBOR loans. The weighted average interest rate was 2.1% for the three months ended September 30, 2014 compared to 1.9% for the three months ended September 30, 2013. The weighted average interest rate was 2.1% for the nine months ended September 30, 2014 and compared to 2.0% for the nine months ended September 30, 2013. A commitment fee is paid on the undrawn balance based on an annual rate of 0.375% to 0.50%. At September 30, 2014, the commitment fee was 0.375% and the interest rate margin was 1.75% on our LIBOR loans and 0.75% on our base rate loans.

Subsequent Development

On October 16, 2014, we entered into an amended and restated revolving bank credit facility, which replaced our previous bank credit facility and which we refer to as our new bank credit facility. The new bank credit facility, secured by substantially all of our assets, provides for an initial commitment equal to the lesser of the facility amount or the borrowing base. At closing, the facility amount was $2.0 billion and the borrowing base was $3.0 billion. The new bank credit facility provides for a borrowing base subject to redetermination annually each May and for event-driven unscheduled redeterminations. The new bank group is composed of twenty-nine financial institutions, with no one bank holding more than 6% of the total facility. The facility amount may be increased to the borrowing base amount subject to payment of a mutually acceptable commitment fee to those banks agreeing to participate in the facility increase. The facility matures on October 16, 2019. During a non-investment grade period, borrowings under the new bank credit facility can either be at the alternate base rate ("ABR," as defined in the new bank credit facility) plus a spread ranging from 0.25% to 1.25% or LIBOR borrowings 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. A commitment fee is paid on the undrawn balance based on an annual rate of 0.30% to 0.375%. At closing, the commitment fee was 0.30% and the interest rate margin was 1.50% on our LIBOR loans and 0.50% 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 certain other restrictive covenants will become less restrictive, and an additional financial covenant (as defined in the new bank credit facility) will be temporarily 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 LIBOR borrowings plus a spread ranging from 1.125% to 1.75% depending on our debt rating. The commitment fee paid on the undrawn balance ranges from 0.15% to 0.30%.

Senior Subordinated Notes

If we experience a change of control, bondholders may require us to repurchase all or a portion of all 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 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 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 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 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 and Maturity

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 debt to EBITDAX (as defined in the credit agreement) of no greater than 4.25 to 1.0 and a current ratio (as defined in the credit agreement) of no less than 1.0 to 1.0. During an investment grade period in which Range has only one investment grade rating, an additional covenant is imposed whereby 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 to 1.0. We were in compliance with applicable covenants under the bank credit facility at September 30, 2014.

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 September 30, 2014, 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 life. The inputs are calculated based on historical data as well as current estimated costs. A reconciliation of our liability for plugging and abandonment costs for the nine months ended September 30, 2014 is as follows (in thousands):

	Nine Months Ended September 30, 2014
Beginning of period	$ 230,077
Liabilities incurred	5,475
Acquisitions	11,927
Disposition of wells	(12,121)
Liabilities settled	(3,301)
Change in estimate	2,455
Accretion expense	11,206
End of period	245,718
Less current portion	(5,037)
Long-term asset retirement obligations	$ 240,681

Accretion expense is recognized as a component of depreciation, depletion and amortization expense in the accompanying statements of 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 2013:

	Nine Months Ended September 30, 2014	Year Ended December 31, 2013
Beginning balance	163,342,894	162,514,098
Public offering	4,560,000	¾
SARs exercised	188,649	278,916
Restricted stock granted	269,506	401,122
Restricted stock units vested	240,453	119,480
Treasury shares issued	15,566	29,278
Ending balance	168,617,068	163,342,894

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(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") or Mont Belvieu for NGLs, approximated a net unrealized pre-tax gain of $63.3 million at September 30, 2014. These contracts expire monthly through December 2016. The following table sets forth our commodity-based derivative volumes by year as of September 30, 2014, excluding our basis swaps which are discussed separately below:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price
Natural Gas			
2014	Collars	447,500 Mmbtu/day	$ 3.84–$ 4.48
2015	Collars	145,000 Mmbtu/day	$ 4.07–$ 4.56
2014	Swaps	260,000 Mmbtu/day	$ 4.18
2015	Swaps	307,432 Mmbtu/day	$ 4.21
2016	Swaps	90,000 Mmbtu/day	$ 4.21
Crude Oil			
2014	Collars	2,000 bbls/day	$ 85.55–$ 100.00
2014	Swaps	9,500 bbls/day	$ 94.35
2015	Swaps	9,626 bbls day	$ 90.57
2016	Swaps	1,000 bbls/day	$ 91.43
NGLs (C3-Propane)			
2014	Swaps	12,000 bbls/day	$ 1.02/gallon
2015 -first six months	Swaps	1,000 bbls/day	$ 1.10/gallon
NGLs (NC4-Normal Butane)			
2014	Swaps	4,000 bbls/day	$ 1.34/gallon
NGLs (C5-Natural Gasoline)			
2014	Swaps	3,500 bbls/day	$ 2.17/gallon
2015 - first quarter	Swaps	500 bbls/day	$ 2.14/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. Through February 28, 2013, changes in the fair value of our derivatives that qualified for hedge accounting were recorded as a component of accumulated other comprehensive income or loss ("AOCI" or "AOCL") in the stockholders' equity section of the accompanying consolidated balance sheets, which is later transferred to natural gas, NGLs and oil sales when the underlying physical transaction occurs and the hedging contract is settled. As of September 30, 2014, an unrealized pre-tax derivative loss of $358,000 ($222,000 after tax) was recorded in AOCL. See additional discussion below regarding the discontinuance of hedge accounting. 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 in derivative fair value income or loss.

For those derivative instruments that qualified or were designated for hedge accounting, settled transaction gains and losses were determined monthly, and were included as increases or decreases to natural gas, NGLs and oil sales in the period the hedged production was sold. Through February 28, 2013, we had elected to designate our commodity derivative instruments that qualified for hedge accounting as cash flow hedges. Natural gas, NGLs and oil sales include $3.5 million of gains in third quarter 2014 compared to gains of $27.4 million in the same period of 2013 related to settled hedging transactions. Natural gas, NGLs and oil sales include $10.6 million of gains in first nine months 2014 compared to gains of $94.4 million in the same period of 2013 related to settled hedging transactions. Any ineffectiveness associated with these hedge derivatives is reflected in derivative fair value income or loss in the accompanying statements of operations. The ineffective portion is generally calculated as the difference between the changes in fair value of the derivative and the estimated change in future cash flows from the item hedged. Derivative fair value income or loss for the three months and the nine months ended September 30, 2014 includes no ineffective gains or losses compared to a loss of $39,000 in the three months ended September 30, 2013 and a loss of $2.9 million in the nine months ended September 30, 2013. During the nine months ended September 30, 2013, we recognized a pre-tax gain of $3.9 million in derivative fair value income as a result of the discontinuance of hedge accounting where we determined the transaction was probable not to occur primarily due to the sale of certain of our Delaware and Permian Basin properties in New Mexico and West Texas.

Basis Swap Contracts

In addition to the collars and swaps above, at September 30, 2014, 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 are for an average of 70,593 Mmbtu/day and settle monthly through October 2015. The fair value of these contracts was a loss of $1.5 million on September 30, 2014.

Discontinuance of Hedge Accounting

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. AOCI included $103.6 million ($63.2 million after tax) of unrealized net gains, representing the mark-to-market value of the effective portion of our cash flow hedges as of February 28, 2013. As a result of discontinuing hedge accounting, the mark-to-market values included in AOCI as of the de-designation date were frozen and will be reclassified into earnings in natural gas, NGLs and oil sales in future periods as the underlying hedged transactions occur. As of September 30, 2014, we expect to reclassify into earnings $358,000 of unrealized losses in the remaining months of 2014.

With the election to de-designate hedging instruments, all of our derivative instruments continue to be recorded at fair value with unrealized gains and losses recognized immediately in earnings rather than in AOCI. These mark-to-market adjustments will produce a degree of earnings volatility that can be significant from period to period, but such adjustments will have no cash flow impact relative to changes in market prices. The impact to cash flow occurs upon settlement of the underlying contract.

Derivative Assets and Liabilities

The combined fair value of derivatives included in the accompanying consolidated balance sheets as of September 30, 2014 and December 31, 2013 is summarized below. The assets and liabilities are netted where derivatives with both gain and loss positions are held by a single counterparty and we have master netting arrangements. The tables below provide additional information relating to our master netting arrangements with our derivative counterparties (in thousands):

		September 30, 2014		
		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	$29,609	$(339)	$ 29,270
	–collars	15,295	(1,447)	13,848
	–basis swaps	8,720	(10,189)	(1,469)
Crude oil	–swaps	15,504	(7)	15,497
	–collars	123	—	123
NGLs	–C3 swaps	1,499	(2,268)	(769)
	–NC4 swaps	1,942	—	1,942
	–C5 swaps	3,366	—	3,366
		$76,058	$(14,250)	$ 61,808

		September 30, 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	–swaps	$ (339)	$ 339	$ —
	–collars	(1,447)	1,447	—
	–basis swaps	(10,189)	10,189	—
Crude oil	–swaps	(7)	7	—
NGLs	–C3 swaps	(2,268)	2,268	—
		$ (14,250)	$ 14,250	$ —

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		December 31, 2013 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	$4,240	$(1,218)	$ 3,022
	–collars	16,057	(7,671)	8,386
	–basis swaps	7,686	(7,686)	—
Crude oil	–swaps	3,567	(1,321)	2,246
NGLs	–C3 swaps	826	(826)	—
	–NC4 swaps	863	(863)	—
	–C5 swaps	121	(121)	—
		$33,360	$(19,706)	$ 13,654

		December 31, 2013 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	$(4,790)	$1,218	$ (3,572)
	–collars	(13,345)	7,671	(5,674)
	–basis swaps	(3,756)	7,686	3,930
Crude oil	–swaps	(4,711)	1,321	(3,390)
	–collars	(398)	—	(398)
NGLs	–C3 swaps	(18,172)	826	(17,346)
	–NC4 swaps	(757)	863	106
	–C5 swaps	—	121	121
		$(45,929)	$19,706	$ (26,223)

The effects of our cash flow hedges (or those derivatives that previously qualified for hedge accounting) on AOCI in the accompanying consolidated balance sheets are summarized below (in thousands):

	Three Months Ended September 30, Change in Hedge Derivative Fair Value		Realized Gain (Loss) Reclassified from OCI into Revenue (a)		Nine Months Ended September 30, Change in Hedge Derivative Fair Value		Realized Gain (Loss) Reclassified from OCI into Revenue (a)	
	2014	2013	2014	2013	2014	2013	2014	2013
Swaps	$ —	$ ¾	$ 1,255	$ 2,765	$¾	$ 125	$ 3,144	$ 14,687
Collars	—	¾	2,249	25,357	¾	(7,015)	7,436	83,630
Income taxes	—	¾	(1,332)	(10,967)	¾	2,687	(4,122)	(38,343)

$ —	$ ¾	$ 2,172	$ 17,155	$¾	$(4,203)	$ 6,458	$ 59,974

(a) For realized gains upon derivative contract settlement, the reduction in AOCI is offset by an increase in natural gas, NGLs and oil sales. For realized losses upon derivative contract settlement, the increase in AOCI is offset by a decrease in revenues. See additional discussion above regarding the discontinuance of hedge accounting.

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

	Three Months Ended September 30,					
	Gain (Loss) Recognized in Income (Non-hedge Derivatives)		Gain (Loss) Recognized in Income (Ineffective Portion)		Derivative Fair Value Income (Loss)	
	2014	2013	2014	2013	2014	2013
Swaps	$105,767	$(48,277)	$ —	$ (39)	$105,767	$(48,316)
Re-purchased swaps	—	1,595	—	—	—	1,595
Collars	30,119	6,366	—	—	30,119	6,366
Basis swaps	6,171	—	—	—	6,171	—
Total	$142,057	$(40,316)	$ —	$ (39)	$142,057	$(40,355)

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	Nine Months Ended September 30,					
	Gain (Loss) Recognized in Income (Non-hedge Derivatives)		Gain (Loss) Recognized in Income (Ineffective Portion)		Derivative Fair Value Income (Loss)	
	2014	2013	2014	2013	2014	2013
Swaps	$23,173	$(26,350)	$ —	$ (2,034)	$23,173	$(28,384)
Re-purchased swaps	—	1,117	—	—	—	1,117
Collars	(7,997)	25,783	—	(896)	(7,997)	24,887
Basis swaps	(44,078)	(90)	—	—	(44,078)	(90)
Total	$(28,902)	$460	$ —	$ (2,930)	$(28,902)	$(2,470)

(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 September 30, 2014 using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of September 30, 2014
Trading securities held in the deferred compensation plans	$66,874	$ —	$ —	$ 66,874
Derivatives –swaps	—	49,305	—	49,305
–collars	—	13,972	—	13,972
–basis swaps	—	(2,461)	992	(1,469)

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	Fair Value Measurements at December 31, 2013 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, 2013
Trading securities held in the deferred compensation plans	$67,766	$ —	$ —	$ 67,766
Derivatives –swaps	—	(18,812)	—	(18,812)
–collars	—	2,314	—	2,314
–basis swaps	—	3,381	548	3,929

Our trading securities in Level 1 are exchange-traded and measured at fair value with a market approach using end of period market values. Derivatives in Level 2 are measured at fair value with a market approach using third-party pricing services, which have been corroborated with data from active markets or broker quotes. As of September 30, 2014, we have four natural gas basis swaps categorized as Level 3 due to the forward price curve being unavailable for the regional sales point. We based the fair value on the most similar regional forward natural gas basis curve received from a third party pricing service along with assumed basis differentials based on historical trends.

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 statement of operations. For third quarter 2014, interest and dividends were $151,000 and the mark-to-market adjustment was a loss of $1.2 million compared to interest and dividends of $111,000 and mark-to-market gain of $3.2 million in the same period of the prior year. For the nine months ended September 30, 2014, interest and dividends were $322,000 and the mark-to-market adjustment was a gain of $1.3 million compared to interest and dividends of $779,000 and mark-to-market adjustment of a gain of $3.8 million in the same period of 2013.

Fair Values—Non-recurring

In the nine months ended September 30, 2014, due to declines in estimated reserves, there were indications that the carrying values of certain of our oil and gas properties may be impaired and undiscounted future cash flows attributed to these assets indicated their carrying amounts were not expected to be recovered. Their fair value was measured using an income approach based upon internal estimates of future production levels, prices, drilling and operating costs and discount rates, which are Level 3 inputs. We recorded non-cash charges during the nine months ended September 30, 2014 of $25.0 million related to natural gas and oil properties in Mississippi, West Texas and North Texas. In third quarter 2013, we recognized an impairment expense of $7.0 million on certain of our oil and gas properties in South Texas due to a reduction in reserves from a failed well recompletion. Also, in the nine months ended September 30, 2013 we evaluated certain surface property we owned which included a consideration for the potential sale of these assets and we recognized an impairment charge of $741,000. The following table presents the value of these assets measured at fair value on a non-recurring basis at the time impairment was recorded (in thousands):

Three Months Ended	Nine Months Ended
September 30,	September 30,

	2014 Fair Value	Impairment	2013 Fair Value	Impairment	2014 Fair Value	Impairment	2013 Fair Value	Impairment
Natural gas and oil properties	$¾	$¾	$500	$7,012	$18,086	$24,991	$500	$7,012
Surface property	$¾	$¾	$¾	$¾	$¾	$¾	$5,550	$741

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Fair Values—Reported

The following table presents the carrying amounts and the fair values of our financial instruments as of September 30, 2014 and December 31, 2013 (in thousands):

	September 30, 2014		December 31, 2013	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:				
Commodity swaps, collars and basis swaps	$61,808	$61,808	$13,654	$13,654
Marketable securities[a]	66,874	66,874	67,766	67,766
(Liabilities):				
Commodity swaps, collars and basis swaps	—	—	(26,223)	(26,223)
Bank credit facility[b]	(649,000)	(649,000)	(500,000)	(500,000)
Deferred compensation plan[c]	(232,120)	(232,120)	(271,738)	(271,738)
8.00% senior subordinated notes due 2019[b]	¾	¾	(290,516)	(319,500)
6.75% senior subordinated notes due 2020[b]	(500,000)	(525,000)	(500,000)	(541,250)
5.75% senior subordinated notes due 2021[b]	(500,000)	(523,125)	(500,000)	(530,625)
5.00% senior subordinated notes due 2022[b]	(600,000)	(613,500)	(600,000)	(588,750)
5.00% senior subordinated notes due 2023[b]	(750,000)	(770,625)	(750,000)	(732,188)

(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 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 September 30, 2014, our primary concentrations of credit risk are the risks of collecting accounts receivable and the risk of a counterparties' 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 $2.7 million at September 30, 2014 and $2.5 million at December 31, 2013. As of September 30, 2014, 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 September 30, 2014, our derivative counterparties include fifteen financial institutions, of which all but two are secured lenders in our bank credit facility. At September 30, 2014, our net derivative assets include a net receivable from these two counterparties that are not included in our bank credit facility of $5.5 million.

(13) STOCK-BASED COMPENSATION PLANS

Stock-Based Awards

In 2005, we began granting SARs to reduce the dilutive impact of our equity plans. SARs 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 also 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 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 PSU awards vest at the end of three years. 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 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 that is allocated to functional expense categories (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Operating expense	$720	$699	$3,509	$2,056
Brokered natural gas and marketing expense	656	531	2,314	1,310
Exploration expense	1,033	983	3,408	3,013
General and administrative expense	11,556	11,031	43,856	34,600
Total	$13,965	$13,244	$53,087	$40,979

Stock Appreciation Right Awards

We have two active equity-based stock plans, the 2005 Plan and the 2004 Non-Employee Director Stock Option Plan. Under these plans, incentive and non-qualified stock options, SARs, restricted stock units 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. Of the 2.0 million grants outstanding at September 30, 2014, all are grants relating to SARs. Information with respect to SARs activity is summarized below:

	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2013	2,582,074	$ 56.36
Granted	1,104	81.74
Exercised	(578,110)	45.17
Expired/forfeited	(66)	46.44

Outstanding at September 30, 2014	2,005,002	$ 59.60

During first nine months 2014, we granted SARs to our non-executive chairman in conjunction with his retirement from Range as an employee. The weighted average grant date fair value of these SARs, based on our Black-Scholes-Merton assumptions, is shown below:

	Nine Months Ended September 30, 2014	
Weighted average exercise price per share	$ 81.74	
Expected annual dividends per share	0.20	%
Expected life in years	4.3	
Expected volatility	33	%
Risk-free interest rate	1.4	%
Weighted average grant date fair value	$ 23.17	

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Performance Share Unit Awards

The following is a summary of our non-vested PSU awards outstanding at September 30, 2014:

	Units	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2013	—	$ —
Units granted [(a)]	227,929	86.14
Units vested [(b)]	(69,411)	86.30
Outstanding at September 30, 2014	158,518	$ 86.07

[(a)] Amounts granted reflect the number of performance units granted. The actual payout of shares may 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 vesting date.

[(b)] Primarily represents PSU awards granted to our prior executive chairman for the 2013 calendar year while he was a Range officer.

The following assumptions were used to estimate the fair value of PSUs granted during the first nine months 2014:

	Nine Months Ended September 30, 2014	
Risk-free interest rate	0.77	%
Expected annual volatility	32.5	%
Grant date fair value per unit	$ 86.14	

We recorded PSU compensation expense of $6.1 million in the first nine months 2014 compared to none in the same period of 2013.

Restricted Stock Awards

Equity Awards

In first nine months 2014, we granted 355,000 restricted stock Equity Awards to employees at an average grant price of $84.96 compared to 394,100 restricted stock Equity Awards granted to employees at an average grant price of $71.13 in the same period of 2013. These awards generally vest over a three-year period. We recorded compensation expense for these Equity Awards of $21.0 million in first nine months 2014 compared to $14.6 million in the same period of 2013. Equity Awards are not issued to employees until they are vested. Employees do not have the option to receive cash.

Liability Awards

In first nine months 2014, we granted 208,000 shares of restricted stock Liability Awards as compensation to employees at an average price of $87.24 with vesting generally over a three-year period and 64,000 shares were granted to non-employee directors at an average price of $87.97 with immediate vesting. In the same period of 2013, we granted 406,300 shares of Liability Awards as compensation to employees at an average price of $75.45 with vesting generally over a three-year period and 18,300 shares were granted to non-employee directors at an average price of $77.26 with immediate vesting. We recorded compensation expense for Liability Awards of $19.8 million in first nine months 2014 compared to $16.0 million in the same period of 2013. Substantially all of these awards are held in our deferred compensation plan, are classified as a liability and are remeasured at fair value each reporting period. This mark-to-market adjustment is reported as deferred compensation expense in our consolidated statements of operations (see additional discussion below). A following is a summary of the status of our non-vested restricted stock and restricted stock units outstanding at September 30, 2014:

	Equity Awards		Liability Awards	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2013	385,063	$ 68.24	389,013	$ 71.02
Granted	355,094	84.96	271,438	87.41
Vested	(276,461)	72.60	(275,054)	75.54
Forfeited	(24,195)	75.56	(90)	71.03
Outstanding at September 30, 2014	439,501	$ 78.61	385,307	$ 79.35

Deferred Compensation Plan

Our deferred compensation plan gives non-employee directors, officers and key employees 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 plans 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 $46.2 million in third quarter 2014 compared to mark-to-market gain of $2.2 million in third quarter 2013. We recorded mark-to-market gain of $37.7 million in the nine months ended September 30, 2014 compared to mark-to-market loss of $33.3 million in the same period of 2013. The Rabbi Trust held 2.8 million shares (2.4 million of vested shares) of Range stock at September 30, 2014 compared to 2.8 million shares (2.4 million of vested shares) at December 31, 2013.

(14) SUPPLEMENTAL CASH FLOW INFORMATION

	Nine Months Ended September 30,	
	2014	2013
	(in thousands)	
Net cash provided from operating activities included:		
Income taxes paid to (refunded from) taxing authorities	$41	$(237)
Interest paid	144,596	129,043
Non-cash investing and financing activities included:		
Increase (decrease) in asset retirement costs capitalized	7,815	(964)
Increase in accrued capital expenditures	41,707	32,776

(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 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 will continue to evaluate our litigation quarterly and will establish and adjust any litigation reserves as appropriate to reflect our assessment of the then current status of litigation.

Transportation and Gathering Contracts

In the nine months ended September 30, 2014, our transportation and gathering commitments increased by approximately $992.0 million over the next 25 years primarily from new firm transportation contracts. We also have entered into additional agreements which are contingent on certain pipeline and gathering modifications and/or construction that will range between five and twenty year terms and are expected to begin in fourth quarter 2014 through 2017. Based on these new contracts, we will have additional transportation and gathering obligations for a range of natural gas volumes from 25,000 mcfe per day to 400,000 mcfe per day through the end of the contract term.

Delivery Commitments

In the nine months ended September 30, 2014, we entered into new agreements with several pipeline companies and end users to deliver natural gas and ethane volumes from our production that are contingent upon pipeline and gathering modifications and/or construction which includes the construction of ethane crackers. The new agreements to deliver 50,000 mmbtu per day to 80,000 mmbtu per day of natural gas will range between five and ten years and are expected to begin in 2016 through 2019. The new ethane delivery agreements for 5,000 bbls per day to 10,000 bbls per day are for three to fifteen year terms and are expected to begin in 2017 through 2018.

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

	September 30, 2014	December 31, 2013
	(in thousands)	
Natural gas and oil properties:		
Properties subject to depletion	$9,193,442	$ 8,225,859
Unproved properties	908,673	807,022
Total	10,102,115	9,032,881
Accumulated depreciation, depletion and amortization	(2,472,030)	(2,274,444)
Net capitalized costs	$7,630,085	$ 6,758,437

[a] Includes capitalized asset retirement costs and the associated accumulated amortization.

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

	Nine Months Ended September 30, 2014	Year Ended December 31, 2013
	(in thousands)	
Acquisitions [b]	$409,331	$ ¾
Acreage purchases	143,850	137,538
Development	775,570	938,668
Exploration:		
Drilling	114,942	189,742
Expense	36,502	60,384
Stock-based compensation expense	3,408	4,025
Gas gathering facilities:		
Development	12,986	47,086
Subtotal	1,496,589	1,377,443
Asset retirement obligations	7,815	76,373
Total costs incurred	$1,504,404	$ 1,453,816

[a] Includes costs incurred whether capitalized or expensed.

[b] See also Note 4 for additional information related to the Conger Exchange. Includes $134.8 million of gas gathering assets.

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, 2013, as filed with the SEC on February 26, 2014.

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 Southwestern 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 objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. Our strategy to achieve our 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; and
- the quantity of natural gas, NGLs and oil we can economically produce.

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. 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 the nine months ended September 30, 2014 and 2013:

	Three Months Ended	Nine Months Ended

	September 30,		September 30,	
	2014	2013	2014	2013
Average NYMEX prices [a]				
Natural gas (per mcf)	$4.05	$3.60	$4.52	$3.68
Oil (per bbl)	96.99	105.87	99.51	98.47
Mont Belvieu NGL composite (per gallon)	0.76	0.78	0.83	0.77

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

Consolidated Results of Operations

Overview of Third Quarter 2014 Results

During third quarter 2014, we achieved the following financial and operating results:

- increased revenue from the sale of natural gas, NGLs and oil by 3% from the same period of 2013;
- achieved 26% production growth over the same period of 2013;
- 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 3% from the same period of 2013;
- reduced our depletion, depreciation and amortization (“DD&A”) rate per mcfe by 14% from the same period of 2013;
- entered into additional derivative contracts for 2015 and 2016; and
- realized $213.4 million of cash flow from operating activities.

Our third quarter 2014 net income was $146.4 million, or $0.86 per diluted common share compared to $19.2 million, or $0.12 per diluted common share in the same period of 2013. We experienced an increase in revenue from the sale of natural gas, NGLs and oil driven by 26% higher production volumes compared to third quarter 2013. Our third quarter 2014 production growth was due to the continued success of our drilling program, particularly in the Marcellus Shale including an increase in ethane sales from the Marcellus Shale. Third quarter 2014 production for NGLs increased 109% from the same period of 2013 due to increased sales of ethane based on our new ethane sales/transport agreements which commenced initial deliveries in late 2013. When comparing third quarter 2014 to the same period of 2013, we also reported a favorable non-cash fair value adjustment on our commodity derivatives, a non-GAAP measure, along with a favorable non-cash mark-to-market adjustment related to our deferred compensation plans and lower realized prices. 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 $0.71 per mcf below NYMEX in third quarter 2014 compared to $0.17 per mcf below NYMEX in the same quarter of 2013. This decrease was partially offset by realized gains on our basis hedging in third quarter 2014 of $0.22 per mcf.

Overview of the First Nine Months 2014 Results

During the nine months ended September 30, 2014, we achieved the following financial and operating results:

- increased revenue from the sale of natural gas, NGLs and oil by 18% from the same period of 2013;
- achieved 23% production growth from the same period of 2013;
- reduced direct operating expense per mcfe by 3% from the same period of 2013;
- reduced our DD&A rate by 10% from the same period of 2013;
- issued 4.56 million shares of common stock in a public offering where we received net proceeds of $396.6 million;
- redeemed all $300.0 million aggregate principal amount of our 8.00% senior subordinated notes due 2019;
- completed the Conger Exchange and received total proceeds of $147.1 million from the sale of non-core assets;
- entered into additional firm transportation commitments over the next 25 years along with delivery commitments which begin in 2016;
- entered into additional derivative contracts for 2014, 2015 and 2016; and
- realized $654.9 million of cash flow from operating activities.

Net income for the nine months ended September 30, 2014 was $350.3 million or $2.10 per diluted common share compared to $87.6 million or $0.53 per diluted common share in the same period of 2013. In the first nine months 2014, we recognized a $280.1 million gain related to the Conger Exchange compared to a gain on the sale of our New Mexico and certain of our West Texas properties of $79.1 million in the same period of 2013. We also experienced increased revenues from the sale of natural gas, NGLs and oil driven by 23% higher production volumes compared to the same period of 2013. When comparing the first nine months 2014 to the same period of 2013, we also reported a favorable non-cash fair value adjustment on our commodity derivatives, a non-GAAP measure, a favorable non-cash mark-to-market adjustment related to our deferred compensation plans and lower general and administrative expenses which were offset by lower realized prices and higher non-cash proved property impairment. Realized prices include the impact of basis differentials. Average natural gas differentials were $0.26 per mcf below NYMEX in the first nine months 2014 compared to differentials being equal to NYMEX in the same period of 2013. We were also impacted by realized losses on our basis hedging during the first nine months 2014 of $0.19 per mcf.

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 regional and aggregate 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 2014 and for 2015 and 2016, 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, production volumes and the value of certain of our derivative contracts. 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 get our commodity to the delivery point are reported in transportation, gathering and compression expense. Hedges included in natural gas, NGLs and oil sales reflect settlements on those derivatives that qualified for hedge accounting. Cash settlements and changes in the market value of derivative contracts that are not accounted for as hedges are included in derivative fair value income or loss in our statements of operations. For more information on revenues from derivative contracts that are not accounted for as hedges, see the derivative fair value income (loss) discussion below. 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. Refer to Note 11 to the consolidated financial statements for more information.

In third quarter 2014, natural gas, NGLs and oil sales increased 3% compared to the same period of 2013 with a 26% increase in production partially offset by a 18% decrease in realized prices. In the nine months ended September 30, 2014, natural gas, NGLs and oil sales increased 18% compared to the same period of 2013 with a 23% increase in production and a 4% decrease in realized prices. NGLs revenues in the nine months ended September 30, 2014 were negatively impacted by maintenance down time at a third party NGLs processing facility and a weather event which caused a decline in processing ability and efficiency at that same plant. The following table illustrates the primary components of natural gas, NGLs, oil and condensate sales for the three months and the nine months ended September 30, 2014 and 2013 (in thousands):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2014	2013	Change	%	2014	2013	Change	%
Natural gas, NGLs and oil sales								
Gas wellhead	$252,562	$233,019	$19,543	8 %	$874,514	$718,176	$156,338	22 %
Gas hedges realized [a]	1,966	25,870	(23,904)	(92%)	6,760	90,693	(83,933)	(93%)
Total gas revenue	$254,528	$258,889	$(4,361)	(2 %)	$881,274	$808,869	$72,405	9 %
Total NGLs revenue	$109,858	$77,317	$32,541	42 %	$355,360	$211,475	$143,885	68 %
Oil wellhead	$80,144	$93,473	$(13,329)	(14%)	$255,146	$243,057	$12,089	5 %
Oil hedges realized [a]	1,537	1,535	2	¾ %	3,821	3,730	91	2 %
Total oil revenue	$81,681	$95,008	$(13,327)	(14%)	$258,967	$246,787	$12,180	5 %
Combined wellhead	$442,564	$403,809	$38,755	10 %	1,485,020	1,172,708	312,312	27 %
Combined hedges [a]	3,503	27,405	(23,902)	(87%)	10,581	94,423	(83,842)	(89%)
Total natural gas, NGLs and oil sales	$446,067	$431,214	$14,853	3 %	$1,495,601	$1,267,131	$228,470	18 %

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

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Our production continues to grow through drilling success as we place new wells on production partially offset by the natural decline of our natural gas and oil wells and asset sales. When compared to the same period of 2013, our third quarter 2014 production volumes increased 35% in our Appalachian region and decreased 31% in our Southwestern region. For the first nine months 2014, our production volumes increased 28% in our Appalachian region and decreased 13% in our Southwestern region when compared to the same period of 2013. When compared to the same periods of 2013, our Marcellus production volumes increased 34% for the third quarter of 2014 and 31% for the nine months ended September 30, 2014. Ethane production volumes are reported with NGLs in the table below. Our production for the three months and the nine months ended September 30, 2014 and 2013 is set forth in the following table:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2014	2013	Change	%	2014	2013	Change	%
Production [a]								
Natural gas (mcf)	75,665,182	68,024,813	7,640,369	11 %	205,444,379	194,975,047	10,469,332	5 %
NGLs (bbls)	4,934,882	2,362,340	2,572,542	109%	13,877,217	6,367,253	7,509,964	118%
Crude oil (bbls)	985,300	1,018,013	(32,713)	(3 %)	3,010,054	2,795,192	214,862	8 %
Total (mcfe) [b]	111,186,274	88,306,931	22,879,343	26 %	306,768,005	249,949,717	56,818,288	23 %
Average daily production [a]								
Natural gas (mcf)	822,448	739,400	83,048	11 %	752,544	714,194	38,350	5 %
NGLs (bbls)	53,640	25,678	27,962	109%	50,832	23,323	27,509	118%
Crude oil (bbls)	10,710	11,065	(355)	(3 %)	11,026	10,239	787	8 %
Total (mcfe) [b]	1,208,546	959,858	248,688	26 %	1,123,692	915,567	208,125	23 %

(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 necessarily indicative of the relationship between oil and natural gas prices.

Our average realized price (including all derivative settlements and third-party transportation costs) received during third quarter 2014 was $3.40 per mcfe compared to $4.11 per mcfe in the same period of 2013. Our average realized price (including all derivative settlements and third-party transportation costs) received was $3.74 per mcfe in the nine months ended September 30, 2014 compared to $4.20 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 (wellhead) do not include derivative settlements or third party transportation costs which are reported in transportation, gathering and compression expense on the accompanying statements of operations. Average sales prices (wellhead) do include transportation costs where we receive net revenue proceeds from purchasers. Average realized price calculations for the three months and nine months ended September 30, 2014 and 2013 are shown below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013

Average Prices				
Average sales prices (wellhead):				
Natural gas (per mcf)	$3.34	$3.43	$4.26	$3.68
NGLs (per bbl)	22.26	32.73	25.61	33.21
Crude oil and condensate (per bbl)	81.34	91.82	84.76	86.96
Total (per mcfe) [(a)]	3.98	4.57	4.84	4.69
Average realized prices (including derivative settlements that qualified for hedge accounting):				
Natural gas (per mcf)	$3.36	$3.81	$4.29	$4.15
NGLs (per bbl)	22.26	32.73	25.61	33.21
Crude oil and condensate (per bbl)	82.90	93.33	86.03	88.29
Total (per mcfe) [(a)]	4.01	4.88	4.88	5.07
Average realized prices (including all derivative settlements):				
Natural gas (per mcf)	$3.63	$3.88	$3.88	$4.05
NGLs (per bbl)	22.53	31.08	24.66	32.94
Crude oil and condensate (per bbl)	78.66	85.46	80.47	85.35
Total (per mcfe) [(a)]	4.16	4.80	4.50	4.96
Average realized prices (including all derivative settlements and third party transportation costs paid by Range):				
Natural gas (per mcf)	$2.67	$3.03	$2.88	$3.13
NGLs (per bbl)	19.98	29.64	22.50	31.39
Crude oil and condensate (per bbl)	78.66	85.46	80.47	85.35
Total (per mcfe) [(a)]	3.40	4.11	3.74	4.20

(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 income (loss) was income of $142.1 million in third quarter 2014 compared to a loss of $40.4 million in the same period of 2013. Derivative fair value income (loss) was a loss of $28.9 million in the nine months ended September 30, 2014 compared to loss of $2.5 million in the same period of 2013. 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 all realized and unrealized gains and losses related to these contracts are 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 unrealized gains and losses from derivatives 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.

Gain on the sale of assets was $167,000 in third quarter 2014 compared to $6.0 million in the same period of 2013. In third quarter 2013, we sold our equity method investment in a drilling company for proceeds of $7.0 million and recognized a gain of $4.4 million. In addition, in third quarter 2013, we sold unproved leases in West Texas for proceeds of $2.6 million and recognized a gain of $1.7 million and sold surface acreage in North Texas for proceeds of $5.3 million with a loss of $253,000 recognized. Gain on the sale of assets was $281.9 million in the first nine months ended September 30, 2014 compared to $89.1 million in the same period of 2013. In second quarter 2014, we recognized a gain related to the Conger Exchange of $280.1 million, after selling expenses. In second quarter 2013, we recognized a gain of $79.4 million, after selling expenses on the sale of our New Mexico and certain of our West Texas properties. In addition to the Conger Exchange and the New Mexico sale mentioned above, in the first nine months 2014 and 2013, we also sold miscellaneous proved and unproved oil and gas properties and inventory for proceeds received of $2.1 million in first nine months 2014 compared to $26.0 million in the same period of 2013 and recognized a gain of $1.7 million in 2014 compared to a gain of $4.1 million in 2013.

Brokered natural gas, marketing and other revenue in third quarter 2014 was $28.3 million compared to $45.2 million in the same period of 2013. The third quarter 2014 includes $28.1 million of revenue from marketing and the sale of brokered gas which includes revenue of $6.8 million from the release of transportation capacity where we have taken firm transportation capacity ahead of production volumes. The third quarter 2013 includes $45.5 million of revenue from marketing and the sale of brokered gas and income from equity method investments of $268,000. The third quarter 2013 includes volumes purchased (and sold) to blend our rich residue gas from the Southwest Marcellus Shale which was discontinued in late 2013. Brokered natural gas, marketing and other revenues in first nine months 2014 was $90.9 million compared to $80.8 million in the same period of 2013. The first nine months 2014 includes a loss from equity method investments of $277,000 and $91.6 million of revenue from marketing and the sale of brokered gas which includes revenue of $9.5 million from the release of transportation capacity where we have taken firm transportation capacity ahead of production volumes. The first nine months ended September 30, 2013 includes income from equity method investments of $541,000 and $81.0 million of revenue from marketing and sale of brokered gas. Effective with the closing of the Conger Exchange on June 16, 2014, we no longer have income or loss from equity method investments.

We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per mcfe, basis. The following presents information about certain of our expenses on a per mcfe basis for the three months and the nine months ended September 30, 2014 and 2013:

	Three Months Ended September 30, (per mcfe)			Nine Months Ended September 30, (per mcfe)		
	2014	2013	Change	2014	2013	Change

				% Change				% Change
Direct operating expense	$0.34	$0.35	$(0.01)	(3%)	$0.37	$0.38	$(0.01)	(3%)
Production and ad valorem tax expense	0.09	0.13	(0.04)	(31%)	0.11	0.14	(0.03)	(21%)
General and administrative expense	0.49	0.51	(0.02)	(4%)	0.53	0.92	(0.39)	(42%)
Interest expense	0.35	0.50	(0.15)	(30%)	0.42	0.53	(0.11)	(21%)
Depletion, depreciation and amortization expense	1.28	1.48	(0.20)	(14%)	1.32	1.46	(0.14)	(10%)

Direct operating expense was $37.8 million in third quarter 2014 compared to $30.9 million in the same period of 2013. We experience increases in operating expenses as we add new wells and manage existing properties. 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 26% but, on an absolute basis, our spending for direct operating expenses for third quarter 2014 only increased 22% with an increase in the number of producing wells, higher water handling and disposal costs and higher field personnel and compressor costs somewhat offset by the sale of certain non-core assets at the end of second quarter 2014. We incurred $1.3 million of workover costs in third quarter 2014 compared to $2.0 million in the same period of 2013.

On a per mcfe basis, direct operating expense in third quarter 2014 decreased 3% from the same period of 2013 with the decrease consisting of lower non-recurring well workovers and lower nitrogen blending 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 $112.5 million in the nine months ended September 30, 2014 compared to $93.7 million in the same period of 2013. Our production volumes increased 23%, and on an absolute basis, our spending for direct operating expenses increased 20% with an increase in the number of producing wells, higher water handling and disposal costs, higher well services, well workovers, field personnel costs and stock-based compensation somewhat offset by the sale of certain non-core assets. We incurred $8.7 million of workover costs in the nine months ended September 30, 2014 compared to $5.5 million in the same period of 2013. On a per mcfe basis, direct operating expense in the nine months ended September 30, 2014 decreased 3% to $0.37 from $0.38 in the same period of 2013, with the decrease consisting of lower well services somewhat offset by higher workover 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 the nine months ended September 30, 2014 and 2013:

	Three Months Ended September 30, (per mcfe)				Nine Months Ended September 30, (per mcfe)			
	2014	2013	Change	% Change	2014	2013	Change	% Change
Lease operating expense	$0.32	$0.32	$ ¾	¾ %	$0.33	$0.35	$ (0.02)	(6 %)
Workovers	0.01	0.02	(0.01)	(50 %)	0.03	0.02	0.01	50 %
Stock-based compensation (non-cash)	0.01	0.01	¾	¾ %	0.01	0.01	¾	¾ %
Total direct operating expense	$0.34	$0.35	$ (0.01)	(3 %)	$0.37	$0.38	$ (0.01)	(3 %)

Production and ad valorem taxes are paid based on market prices, not hedged prices. This expense category also includes the Pennsylvania impact fee that was initially assessed in 2012. Production and ad valorem taxes (excluding the impact fee) were $3.6 million in third quarter 2014 compared to $4.5 million in the same period of 2013. On a per mcfe basis, production and ad valorem taxes (excluding the impact fee) were $0.03 in third quarter 2014 compared to $0.05 in third quarter 2013 from 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” on unconventional natural gas and oil production which includes the Marcellus Shale. Included in third quarter 2014 is a $6.5 million impact fee ($0.06 per mcfe) compared to $7.0 million ($0.08 per mcfe) in the same period of the prior year.

Production and ad valorem taxes (excluding the impact fee) was $13.1 million ($0.04 per mcfe) in the first nine months 2014 compared to $12.8 million ($0.05 per mcfe) in the same period of 2013 with higher prices partially offset by an increase in volumes not subject to production or ad valorem taxes. Included in the first nine months 2014 is a $19.3 million ($0.06 per mcfe) impact fee compared to $21.2 million ($0.08 per mcfe) in the same period of 2013.

General and administrative ("G&A") expense was $55.0 million in third quarter 2014 compared to $44.9 million for the same period of 2013. The third quarter 2014 increase of $10.0 million when compared to 2013 is primarily due to the $4.2 million previously announced fine for water impoundment leaks, and higher salaries, benefits and legal and office expenses, including information technology. G&A expense for the nine months ended September 30, 2014 decreased $69.9 million when compared to the same period of 2013 primarily due to lower lawsuit settlements partially offset by higher salaries, benefits and stock-based compensation. At September 30, 2014, the number of general and administrative employees increased 5% from 2013. 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. In the nine months ended September 30, 2014, our stock-based compensation expense increased $9.3 million from the same period of 2013 primarily due to awards granted to our prior executive chairman for his service in 2013 while he was a Range officer, which were fully vested upon grant. On a per mcfe basis, G&A expense decreased 42% from the nine months ended September 30, 2013 primarily due to a legal settlement in 2013. The following table summarizes general and administrative expenses per mcfe for the three and nine months ended September 30, 2014 and 2013:

	Three Months Ended September 30, (per mcfe)				Nine Months Ended September 30, (per mcfe)			
	2014	2013	Change	% Change	2014	2013	Change	% Change
General and administrative	$0.39	$0.39	$ ¾	¾ %	$0.39	$0.43	$ (0.04)	(9 %)
Legal settlement	¾	¾	¾	¾ %	¾	0.35	(0.35)	(100 %)
Stock-based compensation (non-cash)	0.10	0.12	(0.02)	(17 %)	0.14	0.14	¾	¾ %
Total general and administrative expense	$0.49	$0.51	$ (0.02)	(4 %)	$0.53	$0.92	$ (0.39)	(42 %)

Interest expense was $39.2 million for third quarter 2014 compared to $44.3 million for third quarter 2013 and was $130.1 million in the nine months ended September 30, 2014 compared to $131.6 million in the nine months ended September 30, 2013. The following table presents information about interest expense per mcfe for the three months and nine months ended September 30, 2014 and 2013:

	Three Months Ended September 30, (per mcfe)				Nine Months Ended September 30, (per mcfe)			
	2014	2013	Change	% Change	2014	2013	Change	% Change
Bank credit facility	$0.04	$0.04	$ ¾	¾ %	$0.04	$0.04	$ ¾	¾ %
Subordinated notes	0.29	0.44	(0.15)	(34 %)	0.35	0.45	(0.10)	(22 %)
Amortization of deferred financing costs and other	0.02	0.02	¾	¾ %	0.03	0.04	(0.01)	(25 %)
Total interest expense	$0.35	$0.50	$ (0.15)	(30 %)	$0.42	$0.53	$ (0.11)	(21 %)

On an absolute basis, the decrease in interest expense for third quarter 2014 from the same period of 2013 was primarily due to lower average interest rates on our total outstanding debt. In June 2014, we redeemed all of our $300.0 million 8.0% senior subordinated notes due 2019. In March 2013, we issued $750.0 million of 5.0% senior subordinated notes due 2023. We used the proceeds to partially repay our outstanding bank debt which carries a lower interest rate. The 2013 note issuance was undertaken to better match the maturities of our debt with the life of our properties and to give us greater liquidity for the near term. Average debt outstanding on the bank credit facility for third quarter 2014 was $599.3 million compared to $409.8 million in the same period of 2013 and the weighted average interest rate on the bank credit facility was 2.1% in third quarter 2014 compared to 1.9% in the same period of 2013.

On an absolute basis, the decrease in interest expense for the nine months ended September 30, 2014 from the same period of 2013 was primarily due to lower average interest rates on our total outstanding debt. Average debt outstanding on the bank credit facility was $622.8 million for 2014 compared to $419.6 million for 2013 and the weighted average interest rate on the bank credit facility was 2.1% in the nine months ended September 30, 2014 compared to 2.0% in the same period of 2013.

Depletion, depreciation and amortization ("DD&A") expense was $142.5 million in third quarter 2014 compared to $130.3 million in the same period of 2013. This increase is due to a 13% decrease in depletion rates more than offset by a 26% increase in production. Depletion expense, the largest component of DD&A expense, was $1.22 per mcfe in third quarter 2014 compared to $1.41 per mcfe in the same period of 2013. 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 our drilling success in the Marcellus Shale.

DD&A expense was $404.5 million in the nine months ended September 30, 2014 compared to $365.4 million in the same period of 2013. Depletion expense was $1.25 per mcfe in the nine months ended September 30, 2014 compared to $1.39 per mcfe in the same period of 2013. The following table summarizes DD&A expense per mcfe for the three months and nine months ended September 30, 2014 and 2013:

	Three Months Ended September 30, (per mcfe)				Nine Months Ended September 30, (per mcfe)			
	2014	2013	Change	% Change	2014	2013	Change	% Change
Depletion and amortization	$1.22	$1.41	$(0.19)	(13%)	$1.25	$1.39	$(0.14)	(10%)
Depreciation	0.03	0.04	(0.01)	(25%)	0.03	0.04	(0.01)	(25%)
Accretion and other	0.03	0.03	¾	¾ %	0.04	0.03	0.01	33 %
Total DD&A expense	$1.28	$1.48	$(0.20)	(14%)	$1.32	$1.46	$(0.14)	(10%)

Other Operating Expenses

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include stock-based compensation, transportation, gathering and compression expense, brokered natural gas and marketing expense, exploration expense, abandonment and impairment of unproved properties and deferred compensation plan expense. Stock-based compensation includes the amortization of restricted stock grants, PSUs and SARs grants. The following table details the allocation of stock-based compensation that is allocated to functional expense categories for the three months and nine months ended September 30, 2014 and 2013 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Direct operating expense	$720	$699	$3,509	$2,056
Brokered natural gas and marketing expense	656	531	2,314	1,310
Exploration expense	1,033	983	3,408	3,013
General and administrative expense	11,556	11,031	43,856	34,600
Total	$13,965	$13,244	$53,087	$40,979

Transportation, gathering and compression expense was $84.8 million in third quarter 2014 compared to $61.0 million in the same period of 2013. Transportation, gathering and compression expense was $235.7 million in the nine months ended September 30, 2014 compared to $189.4 million in the same period of 2013. These third party costs are higher than 2013 due to our production growth in the Marcellus Shale where we have third party gathering, compression and transportation agreements. Third quarter and the nine months ended September 30, 2014 also include the impact of an ethane transportation contract which commenced initial deliveries in late 2013. We have included these costs in the calculation of average realized prices (including all derivative settlements and third party transportation expenses paid by Range).

Brokered natural gas and marketing expense was $28.7 million in third quarter 2014 compared to $51.1 million in the same period of 2013. Brokered natural gas and marketing expense was $97.6 million in the nine months ended September 30, 2014 compared to $90.1 million in the same period of 2013. These costs were lower in third quarter 2014 when compared to third quarter 2013 due to the 2013 purchase (and sale) of natural gas used to blend our rich residue gas from the Southern Marcellus Shale which was discontinued in late 2013 upon commencement of ethane sales partially offset by $3.5 million of transportation capacity charges where we have taken firm transportation capacity ahead of production volumes and higher expenses related to company owned gathering lines. Brokered natural gas and marketing expenses for the nine months ended September 30, 2014 are higher than the same period of 2013 primarily due to an increase in transportation capacity charges where we have taken firm transportation capacity ahead of production volumes of $8.8 million, an increase in salaries, benefits and stock-based compensation for our marketing staff and higher expenses related to company owned gathering lines partially offset by lower broker purchases.

Exploration expense was $11.4 million in third quarter 2014 compared to $20.5 million in the same period of 2013 due to lower dry hole costs and lower delay rental payments and seismic costs. The nine months ended September 30, 2014 includes lower seismic costs, lower dry hole and lower delay rental payments when compared to the same period of 2013. The following table details our exploration related expenses for the three months and nine months ended September 30, 2014 and 2013 (in thousands):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2014	2013	Change	% Change	2014	2013	Change	% Change
Seismic	$5,827	$7,621	$(1,794)	(24%)	$18,038	$20,866	$(2,828)	(14%)
Delay rentals and other	1,267	4,337	(3,070)	(71%)	6,821	11,439	(4,618)	(40%)
Personnel expense	3,316	3,493	(177)	(5%)	11,642	11,122	520	5%
Stock-based compensation expense	1,033	983	50	5%	3,408	3,013	395	13%
Dry hole expense	¾	4,062	(4,062)	(100%)	1	3,904	(3,903)	(100%)
Total exploration expense	$11,443	$20,496	$(9,053)	(44%)	$39,910	$50,344	$(10,434)	(21%)

Abandonment and impairment of unproved properties was $13.4 million in third quarter 2014 compared to $11.7 million in the same period of 2013. Abandonment and impairment of unproved properties was $32.8 million in the nine months ended September 30, 2014 compared to $46.1 million in the same period of 2013. 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 the three months ended September 30, 2014 when compared to the same period of 2013 is primarily due to higher expected forfeiture rates in Midcontinent as we continue to review our acreage position in our development area. The decline in the nine months ended September 30, 2014 when compared to the same period of 2013 is primarily due to lower than expected forfeiture rates in the Marcellus Shale.

Deferred compensation plan income was $46.2 million in third quarter 2014 compared to $2.2 million in the same period of 2013. 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 $86.95 at June 30, 2014 to $67.81 at September 30, 2014. In the same quarter of the prior year, our stock price decreased from $77.32 at June 30, 2013 to $75.89 at September 30, 2013. During the nine months ended September 30, 2014 deferred compensation income was $37.7 million compared to expense of $33.3 million in the same period of 2013. Our stock price decreased from $84.31 at December 31, 2013 to $67.81 at September 30, 2014. In the same period of 2013, our stock price increased from $62.83 at December 31, 2012 to $75.89 at September 30, 2013.

Loss on extinguishment of debt for the nine months ended September 30, 2014 was $24.6 million. On June 26, 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 the expensing of related deferred financing costs on the repurchased debt. In the first nine months 2013, we redeemed our 7.25% senior subordinated notes due 2018 at 103.625% of par and we recorded a loss on extinguishment of debt of $12.3 million which includes a call premium and the expensing of related deferred financing costs.

Impairment of proved properties and other assets was zero for the third quarter 2014 compared to $7.0 million in the same period of 2013 and was $25.0 million in the nine months ended September 30, 2014 compared to $7.8 million in the nine months ended September 30, 2013. In the nine months ended September 30, 2014, impairment expense was recorded related to certain of our natural gas and oil properties in Mississippi, West Texas and North Texas. Our analysis of these properties determined that undiscounted cash flows were less than their carrying values. These assets were evaluated for impairment due to declining reserve estimates and changes in projected capital spending in these areas. Impairment of proved properties and other assets for the three months and the nine months ended September 30, 2013 includes $741,000 impairment expense related to surface acreage in North Texas and impairment expense of $7.0 million related to certain natural gas and oil properties in South Texas due to a reduction in reserves due to a failed well recompletion.

Income tax expense was $93.5 million in third quarter 2014 compared to $11.9 million in third quarter 2013. The increase in income taxes in third quarter 2014 reflects a 673% increase in income from operations when compared to the same period of 2013. For the third quarter, the effective tax rate was 39.0% in 2014 compared to 38.2% in 2013. Income tax expense was $230.5 million in the nine months ended September 30, 2014 compared to $62.2 million in the same period of 2013. For the nine months ended September 30, 2014, the increase in income tax expense reflects a 288% increase in income from operations when compared to the prior year. For the nine months ended September 30, 2014, the effective tax rate was 39.7% compared to 41.5% in the nine months ended September 30, 2013. The 2014 and 2013 effective tax rates were different than the statutory tax rate due to state income taxes, permanent differences and 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. We expect our effective tax rate to be approximately 39% for the remainder of 2014, 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 September 30, 2014, we have entered into hedging agreements covering 82.2 Bcfe for the remainder of 2014, 187.6 Bcfe for 2015 and 35.1 Bcfe for 2016. We have also entered into basis hedges for an average of 70,593 Mmbtu/day through October 2015.

Net cash provided from operations in first nine months 2014 was $654.9 million compared to $502.9 million in the same period of 2013. Cash provided from continuing operations is largely dependent upon commodity prices and production volumes, net of the effects of settlement of our derivative contracts. The increase in cash provided from operating activities from 2013 to 2014 reflects a 23% increase in production and lower lawsuit settlements offset by lower realized prices (a decline of 11%) and higher operating costs. As of September 30, 2014, we have hedged approximately 66% of our projected production for the remainder of 2014, with approximately 76% of our projected natural gas production hedged. Net cash provided from continuing operations is affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital (as reflected in our consolidated statements of cash flows) for first nine months 2014 was negative $71.5 million compared to negative $48.0 million for the same period of 2013.

Net cash used in investing activities from operations in first nine months 2014 was $871.9 million compared to $671.1 million in the same period of 2013.

During the nine months ended September 30, 2014, we:

spent $867.3 million on natural gas and oil property additions;
spent $9.5 million on field service assets;

- spent $145.5 million on acreage, primarily in the Marcellus Shale; and
- received proceeds from asset sales of $147.1 million.

During the nine months ended September 30, 2013, we:

- spent $907.8 million on natural gas and oil property additions;
- spent $4.2 million on field service assets;
- spent $70.2 million on acreage primarily in the Marcellus Shale and the Mississippian; and
- received proceeds from asset sales of $311.7 million.

Net cash provided from financing activities in first nine months 2014 was $217.1 million compared to $168.3 million in the same period of 2013. Historically, sources of financing have been primarily bank borrowings and capital raised through equity and debt offerings.

During the nine months ended September 30, 2014, we:

- borrowed $1.7 billion and repaid $1.5 billion under our bank credit facility, ending the quarter with a $649.0 million 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 $396.6 million from the issuance of 4.56 million shares of common stock; and
- paid dividends of $19.9 million.

During the nine months ended September 30, 2013, we:

- borrowed $1.3 billion and repaid $1.6 billion under our bank credit facility, ending the quarter with $427.0 million outstanding borrowings under our bank credit facility;
- issued $750.0 million principal amount of 5.00% senior subordinated notes due 2023, at par, with net proceeds of approximately $738.8 million;
- redeemed all $250.0 million aggregate principal amounts of 7.25% senior subordinated notes due 2018 including related expenses;
- spent $12.4 million related to debt issuance costs; and
- paid dividends of $19.6 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 nine months 2014, we entered into additional commodity derivative contracts for 2014, 2015 and 2016 to protect future cash flows. On October 16, 2014, we entered into an amended and restated bank credit facility, which replaced our previous bank credit facility, to increase liquidity and extend the maturity.

During first nine months 2014, our net cash provided from operating activities of $654.9 million, borrowing under our bank credit facility, an equity offering and proceeds from asset sales were used to fund approximately $1.0 billion of capital expenditures (including acreage acquisitions) and the redemption of our 8.0% senior subordinated notes due 2019. At September 30, 2014, we had $468,000 in cash and total assets of $8.0 billion.

Long-term debt at September 30, 2014 totaled $3.0 billion, including $649.0 million outstanding on our bank credit facility and $2.4 billion of senior subordinated notes. Our available committed borrowing capacity at September 30, 2014 was $997.0 million. Cash is required to fund capital expenditures necessary to offset inherent declines in production and reserves that are typical in the oil and natural gas industry. Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding or acquiring additional reserves. We currently believe that net cash generated from operating activities, unused committed borrowing capacity under the bank credit facility and proceeds from asset sales combined with our natural gas, NGLs and oil derivatives contracts currently in place will be adequate to satisfy near-term financial obligations and liquidity needs. To the extent our capital requirements exceed our internally generated cash flow and proceeds from asset sales, debt or equity securities may be issued to fund these requirements. Long-term cash flows are subject to a number of variables including the level of production and prices as well as various economic conditions that have historically affected the oil and natural gas business. A material drop 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 remain profitable. We establish a capital budget at the beginning of each calendar year and review it during the course of the year. Our 2014 capital budget is approximately $1.52 billion. We operate in an environment with numerous financial and operating risks, including, but not limited to, the inherent risks of the search for, development and production of natural gas, NGLs and oil, the ability to buy properties and sell production at prices which provide an attractive return and the highly competitive nature of the industry. Our ability to expand our reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, bank borrowings, asset sales or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to offset inherent declines in production and proven reserves.

Credit Arrangements

As of September 30, 2014, we maintained a $2.0 billion revolving credit facility, which we refer to as our bank credit facility. The bank credit facility was secured by substantially all of our assets. Availability under the bank credit facility was subject to a borrowing base set by the lenders semi-annually with an option to set more often in certain circumstances. As of September 30, 2014, the outstanding balance under our credit facility was $649.0 million. Additionally, we had $104.0 million of undrawn letters of credit leaving $997.0 million of borrowing capacity available under the facility.

On October 16, 2014, we entered into an amended and restated bank credit facility, which replaced our previous bank credit facility and which we refer to as our new bank credit facility. The new bank credit facility is secured by substantially all of our assets and provides for an initial commitment equal to the lesser of the facility amount or the borrowing base. As of October 16, 2014, the facility amount was $2.0 billion, the borrowing base was $3.0 billion and there was $1.2 billion of borrowing capacity available. The new bank credit facility provides for a borrowing base subject to redetermination annually each May and for event-driven unscheduled redeterminations. The borrowing base is dependent on a number of factors but primarily on the lenders' assessment of future cash flows. The new bank group is composed of twenty-nine financial institutions. The new bank credit facility matures on October 16, 2019.

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 security requirements, including the borrowing base requirement, and restrictive covenants will cease to apply, certain other restrictive covenants will become less restrictive and an additional financial covenant will be temporarily imposed. During the investment grade period, borrowings under the new credit facility can either be at the Alternate Base Rate plus a spread ranging from 0.125% to 0.75% or LIBOR borrowing plus a spread ranging from 1.125% to 1.75% depending on our debt rating. The commitment fee paid on the undrawn balance ranges from 0.15% to 0.30%.

Our bank credit debt and our subordinated notes impose limitations on the payment of dividends and other restricted payments (as defined under the debt agreements for our bank debt and our subordinated notes). The debt agreements also contain customary covenants relating to debt incurrence, working capital, dividends and financial ratios. We are in compliance with all covenants at September 30, 2014.

See Note 8 for additional information regarding our bank debt.

Cash Dividend Payments

On August 29, 2014, the Board of Directors declared a dividend of four cents per share ($6.7 million) on our common stock, which was paid on September 30, 2014 to stockholders of record at the close of business on September 15, 2014. 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 September 30, 2014, we do not have any capital leases. As of September 30, 2014, we do not have any significant off-balance sheet debt or other such unrecorded obligations and we have not guaranteed any debt of any unrelated party. As of September 30, 2014, we had a total of $104.0 million of undrawn letters of credit under our bank credit facility.

Since December 31, 2013, there have been no material changes to our contractual obligations other than a $149.0 million increase in our outstanding bank credit facility balance, the redemption of our 8.0% senior subordinated notes due 2019 and new firm transportation contracts. The new firm transportation contracts increased our contractual obligations by approximately $922.0 million over the next 25 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, approximated a pretax gain of $63.3 million at September 30, 2014. The contracts expire monthly through December 2016. At September 30, 2014, 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			
2014	Collars	447,500 Mmbtu/day	$3.84–$4.48
2015	Collars	145,000 Mmbtu/day	$4.07–$4.56
2014	Swaps	260,000 Mmbtu/day	$4.18
2015	Swaps	307,432 Mmbtu/day	$4.21
2016	Swaps	90,000 Mmbtu/day	$4.21
Crude Oil			
2014	Collars	2,000 bbls/day	$85.55–$100.00
2014	Swaps	9,500 bbls/day	$94.35
2015	Swaps	9,626 bbls/day	$90.57

2016	Swaps	1,000 bbls/day	$91.43
NGLs (C3-Propane)			
2014	Swaps	12,000 bbls/day	$1.02/gallon
2015 -first six months	Swaps	1,000 bbls/day	$1.10/gallon
NGLs (NC4-Normal Butane)			
2014	Swaps	4,000 bbls/day	$1.34/gallon
NGLs (C5-Natural Gasoline)			
2014	Swaps	3,500 bbls/day	$2.17/gallon
2015 - first quarter	Swaps	500 bbls/day	$2.14/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 that 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 loss of $1.5 million at September 30, 2014, the volumes are for an average of 70,593 Mmbtu/day and they expire through October 2015.

Interest Rates

At September 30, 2014, we had approximately $3.0 billion of debt outstanding. Of this amount, $2.4 billion bears interest at fixed rates averaging 5.5%. Bank debt totaling $649.0 million bears interest at floating rates, which averaged 2.2% at September 30, 2014. The 30-day LIBO Rate on September 30, 2014 was approximately 0.2%. A 1% increase in short-term interest rates on the floating-rate debt outstanding on September 30, 2014 would cost us approximately $6.5 million in additional annual interest expense.

Off-Balance Sheet Arrangements

We do not currently utilize any 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 2014 to continue to be a function of supply and demand.

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 prices affect us more than oil prices because approximately 69% of our December 31, 2013 proved reserves are natural gas. We are also exposed to market risks related to changes in interest rates. These risks did not change materially from December 31, 2013 to September 30, 2014.

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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 September 30, 2014, our derivatives program includes swaps and collars. These contracts expire monthly through December 2016. The fair value of these contracts, represented by the estimated amount that would be realized upon immediate liquidation as of September 30, 2014, approximated a net unrealized pretax gain of $63.3 million. At September 30, 2014, 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				
2014	Collars	447,500 Mmbtu/day	$ 3.84–$ 4.48	$ 1,559
2015	Collars	145,000 Mmbtu/day	$ 4.07–$ 4.56	$ 12,290
2014	Swaps	260,000 Mmbtu/day	$ 4.18	$ 1,964
2015	Swaps	307,432 Mmbtu/day	$ 4.21	$ 22,941
2016	Swaps	90,000 Mmbtu/day	$ 4.21	$ 4,364
Crude Oil				
2014	Collars	2,000 bbls/day	$ 85.55–$ 100.00	$ 123
2014	Swaps	9,500 bbls/day	$ 94.35	$ 3,632
2015	Swaps	9,626 bbls/day	$ 90.57	$ 9,883
2016	Swaps	1,000 bbls/day	$ 91.43	$ 1,982
NGLs (C3-Propane)				
2014	Swaps	12,000 bbls/day	$ 1.02/gallon	$ (1,330)
2015 -first six months	Swaps	1,000 bbls/day	$1.10/gallon	$ 561
NGLs (NC4-Normal Butane)				
2014	Swaps	4,000 bbls/day	$ 1.34/gallon	$ 1,942
NGLs (C5-Natural Gasoline)				
2014	Swaps	3,500 bbls/day	$ 2.17/gallon	$ 2,946
2015 -first quarter	Swaps	500 bbls/day	$ 2.14/gallon	$ 420

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.

Currently, there is little demand, or facilities to supply the existing demand, 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 and propane operations in the first half of 2015. We cannot assure you that this last 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 agreements, we may be required to curtail production or purchase natural gas to blend with our rich residue gas, which will adversely affect our revenues.

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 loss of $1.5 million at September 30, 2014, the volumes are for an average of 70,593 Mmbtu/day and they expire monthly through October 2015.

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 September 30, 2014. 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	$ 13,971	$(25,686)	$(72,909)	$27,952	$79,545
Swaps	49,306	(118,873)	(295,907)	120,073	300,179
Basis swaps	(1,469)	(1,225)	(3,101)	1,274	3,184

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 the majority of 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 September 30, 2014, our derivative counterparties include fifteen 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 have 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 subordinated debt and variable rate bank debt. At September 30, 2014, we had $3.0 billion of debt outstanding. Of this amount, $2.4 billion bears interest at fixed rates averaging 5.5%. Bank debt totaling $649.0 million bears interest at floating rates, which was 2.2% on September 30, 2014. On September 30, 2014, the 30-day LIBO Rate was approximately 0.2%. A 1% increase in short-term interest rates on the floating-rate debt outstanding on September 30, 2014, would cost us approximately $6.5 million in additional annual interest expense.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedure

As required by Rule 13a-15(b) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of September 30, 2014 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

There was no change in our system of internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the quarter ended September 30, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

See Note 15 to our unaudited consolidated financial statements entitled “Commitments and Contingencies” included in Part I Item 1 above for a summary of our legal proceedings, such information being incorporated herein by reference.

ITEM 1A. RISK FACTORS

We are subject to various risks and uncertainties in the course of our business. In addition to the factors discussed elsewhere in this report, you should carefully consider the risks and uncertainties described under Item 1A. Risk Factors filed in our Annual Report on Form 10-K for the year ended December 31, 2013. There have been no material changes from the risk factors previously disclosed in that Form 10-K.

ITEM 6. EXHIBITS

Exhibits included in this report are set forth in the Index to Exhibits which immediately precedes such exhibits, and are incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Date: October 29, 2014

RANGE RESOURCES CORPORATION

By: /s/ ROGER S. MANNY
Roger S. Manny
Executive Vice President and Chief Financial Officer

Date: October 29, 2014

RANGE RESOURCES CORPORATION

By: /s/ DORI A. GINN
Dori A. Ginn
Senior Vice President – Controller and Principal Accounting Officer

Exhibit index

Exhibit Number	Exhibit Description
3.1	Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on May 5, 2004, as amended by the Certificate of First Amendment to Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 28, 2005) and the Certificate of Second Amendment to Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 24, 2008)
3.2	Amended and Restated By-laws of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 20, 2010)
10.1	Fifth Amended and Restated Credit Agreement, dated as of October 16, 2014, among Range Resources Corporation (as borrower) and the institutions named therein as lenders. JPMorgan Chase Bank, N.A., as Administrative Agent and a Letter of Credit Issuer, and each other Letter of Credit Issuer from time to time party thereto (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on October 20, 2014)
31.1*	Certification by the President and Chief Executive Officer of Range Resources Corporation Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer of Range Resources Corporation Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification by the President and Chief Executive Officer of Range Resources Corporation Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification by the Chief Financial Officer of Range Resources Corporation Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101. INS*	XBRL Instance Document
101. SCH*	XBRL Taxonomy Extension Schema
101. CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101. DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101. LAB*	XBRL Taxonomy Extension Label Linkbase Document
101. PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* filed herewith
** furnished herewith