RANGE RESOURCES CORP
Form 10-Q
July 24, 2013

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

(Mark one)

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2013

OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number: 001-12209

RANGE RESOURCES CORPORATION

(Exact Name of Registrant as Specified in Its Charter)

Delaware	34-1312571

(State or Other Jurisdiction of	(IRS Employer
Incorporation or Organization)	Identification No.)

100 Throckmorton Street, Suite 1200

Fort Worth, Texas	76102
(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

163,396,396 Common Shares were outstanding on July 22, 2013.

RANGE RESOURCES CORPORATION

FORM 10-Q

Quarter Ended June 30, 2013

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 per share data)

	June 30, 2013 (Unaudited)	December 31, 2012
Assets		
Current assets:		
Cash and cash equivalents	$ 284	$ 252
Accounts receivable, less allowance for doubtful accounts of $ 2,493 and $ 2,374	159,981	167,495
Unrealized derivatives	97,052	137,552
Inventory and other	16,131	22,315
Total current assets	273,448	327,614
Unrealized derivatives	30,467	15,715
Equity method investments	132,115	132,449
Natural gas and oil properties, successful efforts method	8,369,641	8,111,775
Accumulated depletion and depreciation	(2,035,850)	(2,015,591)
	6,333,791	6,096,184
Transportation and field assets	116,578	117,717
Accumulated depreciation and amortization	(80,371)	(76,150)
	36,207	41,567
Other assets	124,154	115,206
Total assets	$ 6,930,182	$ 6,728,735
Liabilities		
Current liabilities:		
Accounts payable	$ 303,618	$ 234,651
Asset retirement obligations	2,366	2,470
Accrued liabilities	133,064	139,379
Deferred tax liability	21,312	37,924
Accrued interest	44,016	36,248
Unrealized derivatives		4,471
Total current liabilities	504,376	455,143
Bank debt	309,000	739,000
Subordinated notes	2,639,835	2,139,185
Deferred tax liability	735,166	698,302
Unrealized derivatives		3,463
Deferred compensation liability	207,906	187,604
Asset retirement obligations and other liabilities	148,116	148,646

Total liabilities		4,544,399		4,371,343
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,163,395,396 issued at June 30, 2013 and 162,641,896 issued at December 31, 2012		1,634		1,626
Common stock held in treasury, 101,301 shares at June 30, 2013 and 127,798 shares at December 31, 2012		(3,751)		(4,760)
Additional paid-in capital		1,934,706		1,915,627
Retained earnings		416,306		360,990
Accumulated other comprehensive income		36,888		83,909
Total stockholders equity		2,385,783		2,357,392
Total liabilities and stockholders equity	$	6,930,182	$	6,728,735

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited, in thousands, except per share data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Revenues and other income:				
Natural gas, NGLs and oil sales	$ 437,678	$ 298,349	$ 835,917	$ 615,966
Derivative fair value income	137,760	148,569	37,885	87,736
Gain (loss) on the sale of assets	83,287	(3,227)	83,121	(13,653)
Brokered natural gas, marketing and other	14,631	5,240	35,672	9,837
Total revenues and other income	673,356	448,931	992,595	699,886
Costs and expenses:				
Direct operating	32,636	27,041	62,824	56,063
Transportation, gathering and compression	66,048	44,744	128,464	85,564
Production and ad valorem taxes	11,113	11,786	22,496	48,420
Brokered natural gas and marketing	16,662	6,491	38,977	10,553
Exploration	13,068	15,517	29,848	37,033
Abandonment and impairment of unproved properties	19,156	43,641	34,374	63,930
General and administrative	101,987	44,005	186,045	82,734
Deferred compensation plan	(6,878)	9,333	35,482	1,503
Interest expense	45,071	42,888	87,281	80,093
Loss on early extinguishment of debt	12,280		12,280	
Depletion, depreciation and amortization	120,736	108,802	235,837	208,953
Total costs and expenses	431,879	354,248	873,908	674,846
Income from operations before income taxes	241,477	94,683	118,687	25,040
Income tax expense (benefit)				
Current	(25)			
Deferred	97,519	39,007	50,314	11,164
	97,494	39,007	50,314	11,164
Net income	$ 143,983	$ 55,676	$ 68,373	$ 13,876
Net income per common share:				
Basic	$ 0.88	$ 0.34	$ 0.42	$ 0.09
Diluted	$ 0.88	$ 0.34	$ 0.42	$ 0.09
Dividends per common share	$ 0.04	$ 0.04	$ 0.08	$ 0.08
Weighted average common shares outstanding:				
Basic	160,565	159,412	160,346	159,162
Diluted	161,414	160,030	161,223	159,949

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(Unaudited, in thousands)

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2013	2012	2013	2012
Net income	$ 143,983	$ 55,676	$ 68,373	$ 13,876
Other comprehensive income:				
Realized loss (gain) on hedge derivative contract settlements reclassified into natural gas, NGLs and oil sales from other comprehensive income, net of taxes [1]		(47,934)	(14,840)	(83,376)
Amortization related to de-designated hedges reclassified into natural gas, NGLs and oil sales, net of taxes [2]	(18,616)		(26,041)	
De-designated hedges reclassified to derivative fair value income, net of taxes [3]	(547)		(1,937)	
Change in unrealized deferred hedging (losses) gains, net of taxes [4]		4,813	(4,203)	83,787
Total comprehensive income	$ 124,820	$ 12,555	$ 21,352	$ 14,287

[1] Presented net of income tax expense of $30,647 for the three months ended June 30, 2012 and $9,488 and $52,834 for the six months ended June 30, 2013 and 2012.
[2] Presented net of income tax expense of $11,902 for the three months ended June 30, 2013 and $16,649 for the six months ended June 30, 2013.
[3] Amounts relate to transactions not probable of occurring and are presented net of income tax expense of $350 for the three months ended June 30, 2013 and $1,239 for the six months ended June 30, 2013.
[4] Presented net of income tax benefit of $3,077 for the three months ended June 30, 2012 and $55,184 for the six months ended June 30, 2012. Presented net of income tax expense of $2,687 for the six months ended June 30, 2013.

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited, in thousands)

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Operating activities:		
Net income	$ 68,373	$ 13,876
Adjustments to reconcile net income to net cash provided from operating activities:		
(Gain) loss from equity method investments, net of distributions	(1,552)	2,293
Deferred income tax expense	50,314	11,164
Depletion, depreciation and amortization and impairment	235,837	208,953
Exploration dry hole costs	(159)	817
Mark-to-market on natural gas, NGLs and oil derivatives not designated as hedges	(62,569)	(83,721)
Abandonment and impairment of unproved properties	34,374	63,930
Unrealized derivative loss	3,300	354
Allowance for bad debt	250	
Amortization of deferred financing costs, loss on extinguishment of debt and other	16,662	3,893
Deferred and stock-based compensation	63,325	26,341
(Gain) loss on the sale of assets	(83,121)	13,653
Changes in working capital:		
Accounts receivable	(13,997)	11,611
Inventory and other	1,545	(2,824)
Accounts payable	(10,381)	(21,922)
Accrued liabilities and other	(22,312)	34,528
Net cash provided from operating activities	279,889	282,946
Investing activities:		
Additions to natural gas and oil properties	(592,692)	(781,574)
Additions to field service assets	(2,033)	(1,526)
Acreage purchases	(27,449)	(147,944)
Equity method investments	1,885	
Proceeds from disposal of assets	296,068	15,620
Purchases of marketable securities held by the deferred compensation plan	(20,213)	(7,872)
Proceeds from the sales of marketable securities held by the deferred compensation plan	16,342	3,590
Net cash used in investing activities	(328,092)	(919,706)
Financing activities:		
Borrowing on credit facilities	893,000	697,000
Repayment on credit facilities	(1,323,000)	(649,000)
Issuance of subordinated notes	750,000	600,000
Repayment of subordinated notes	(259,063)	
Dividends paid	(13,057)	(12,972)
Debt issuance costs	(12,324)	(12,455)

Issuance of common stock	343	2,074
Change in cash overdrafts	(1,155)	3,346
Proceeds from the sales of common stock held by the deferred compensation plan	13,491	8,833
Net cash provided from financing activities	48,235	636,826
Increase in cash and cash equivalents	32	66
Cash and cash equivalents at beginning of period	252	92
Cash and cash equivalents at end of period	$ 284	$ 158

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, natura 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 2012 Annual Report on Form 10-K filed on February 27, 2013. The results of operations for the second quarter and the six months ended June 30, 2013 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 Securities and Exchange Commission (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 year s reported amounts in order to conform with the current year presentation. These reclassifications include gas purchases and other marketing costs which were previously reported in other income and are currently reported as a separate operating expense. These reclassifications have no impact on previously reported net income.

Impact Fee

In first quarter 2012, the Pennsylvania legislature passed an impact fee on unconventional natural gas and oil production. The impact fee is a per well annual fee imposed for a period of fifteen years on all unconventional wells drilled in Pennsylvania. The fee is based on the average annual price of natural gas and the Consumer Price Index. The annual fee per well declines each year over the fifteen-year time period as long as the well is producing. In first six months 2012, we recorded a retroactive impact fee of $24.7 million for wells drilled during 2011 and prior. This expense is reflected in our statements of operations as production and ad valorem taxes.

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 will be recognized in earnings immediately each quarter as derivative contracts are settled and marked to market. For second quarter 2013, unrealized gains of $103.8 million and for the six months ended June 30, 2013, unrealized gains of $22.4 million were included in our statements of operations that, prior to March 1, 2013, would have been deferred in accumulated other comprehensive income (AOCI) if we had continued using hedge accounting. Refer to Note 11 for additional information.

(3) NEW ACCOUNTING STANDARDS

Recently Adopted

In December 2011, the Financial Accounting Standards Board (the FASB) issued ASU No. 2011-11, Disclosures about Offsetting Assets and Liabilities requiring additional disclosures about offsetting and related arrangements. ASU 2011-11 is effective retrospectively for annual reporting periods beginning on or after January 1, 2013. Also, in January 2013, the FASB issued ASU No. 2013-01, Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. ASU 2013-01 revised and clarified the disclosures required by ASU No. 2011-11. We adopted these new requirements in first quarter 2013 and they did not have a material effect on our consolidated financial statements.

In February 2013, the FASB issued ASU No. 2013-02, Comprehensive Income (Topic 220): Reporting of Amounts Reclassified out of Accumulated Other Comprehensive Income. ASU 2013-02 requires information to be disclosed about the amounts reclassified out of AOCI by component. We adopted this new requirement in first quarter 2013 and it did not have a material effect on our consolidated financial statements.

(4) DISPOSITIONS

2013 Dispositions

In December 2012, we announced our plan to offer for sale certain of our Delaware and Permian Basin properties in southeast New Mexico and West Texas. On February 26, 2013, we announced we signed a definitive agreement to sell these assets for a price of $275.0 million, subject to normal post-closing adjustments. The agreement had an effective date of January 1, 2013 and consequently, operating net revenues after January 1, 2013 were a downward adjustment to the sales price. We closed this disposition on April 1 and we recognized a gain of approximately $83.5 million in second quarter 2013 related to this sale, before selling expenses of $4.2 million. Also in second quarter 2013, we received $14.2 million of proceeds from the sale of miscellaneous oil and gas properties in Pennsylvania and West Texas and we recognized a gain of $4.0 million on these transactions. In the first six months 2013, we also received $10.0 million of proceeds from the sale of miscellaneous oil and gas property in Pennsylvania.

2012 Dispositions

In June 2012, we sold a suspended well in the Marcellus Shale for proceeds of $2.5 million resulting in a pre-tax loss of $2.5 million. In March 2012, we sold seventy-five percent of a prospect in East Texas which included unproved properties and a suspended exploratory well to a third party for $8.6 million resulting in a pre-tax loss of $10.9 million. As part of this agreement, we retained a carried interest on the first well drilled and an overriding royalty of 2.5% to 5.0% in the prospect.

(5) INCOME TAXES

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Income tax expense	$ 97,494	$ 39,007	$ 50,314	$ 11,164
Effective tax rate	40.4%	41.2%	42.4%	44.6%

We compute our quarterly taxes under the effective tax rate method based on applying an anticipated annual effective rate to our year-to-date income, except for discrete items. Income taxes for discrete items are computed and recorded in the period that the specific transaction occurs. For second quarter and the six months ended June 30, 2013 and 2012, our overall effective tax rate on pre-tax loss from 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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net income, as reported	$143,983	$55,676	$68,373	$13,876
Participating basic earnings [a]	(2,335)	(999)	(1,124)	(246)
Basic net income attributed to common shareholders	141,648	54,677	67,249	13,630
Reallocation of participating earnings [a]	12	3	5	
Diluted net income attributed to common shareholders	$141,660	$54,680	$67,254	$13,630
Net income per common share:				
Basic	$ 0.88	$ 0.34	$ 0.42	$ 0.09
Diluted	$ 0.88	$ 0.34	$ 0.42	$ 0.09

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

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

		Three Months Ended June 30,		Six Months Ended June 30,	
		2013	2012	2013	2012
Denominator:					
Weighted average common shares outstanding	basic	160,565	159,412	160,346	159,162
Effect of dilutive securities:					
Director and employee stock options and SARs		849	618	877	787
Weighted average common shares outstanding	diluted	161,414	160,030	161,223	159,949

Weighted average common shares basic for the three months ended June 30, 2013 excludes 2.6 million shares and the three months ended June 30, 2012 excludes 2.9 million shares of restricted stock held in our deferred compensation plans (although all awards are issued and outstanding upon grant). Weighted average common shares basic for the six months ended June 30, 2013 excludes 2.7 million shares of restricted stock compared to 2.9 million in the same period of 2012. Stock appreciation rights (SARs) of 161,000 for the three months ended June 30, 2013 and 252,000 for the six months ended June 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. SARs of 761,000 for the three months ended June 30, 2012 and 592,000 for the six months ended June 30, 2012 were outstanding but not included in the computations of diluted income from operations 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 six months ended June 30, 2013 and the year ended December 31, 2012 (in thousands except for number of projects):

	June 30, 2013	December 31, 2012
Balance at beginning of period	$ 57,360	$ 93,388
Additions to capitalized exploratory well costs pending the determination of proved reserves	41,405	153,250
Reclassifications to wells, facilities and equipment based on determination of proved reserves	(66,221)	(184,298)
Divested wells		(4,980)
Balance at end of period	32,544	57,360
Less exploratory well costs that have been capitalized for a period of one year or less	(12,025)	(45,965)
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$ 20,519	$ 11,395
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	8	5

As of June 30, 2013, $20.5 million of capitalized exploratory well costs have been capitalized for more than one year with five of the wells waiting on pipelines and three of the wells currently in the completion stage. Four of the wells are not operated by us and seven of the wells are in Pennsylvania. In first six months 2012, we sold a seventy-five percent interest in an East Texas exploratory well. Refer to Note 4 for additional information. The following table provides an aging of capitalized exploratory well costs that have been suspended for more than one year as of June 30, 2013 (in thousands):

	Total	2013	2012	2011	2010	2009	2008
Capitalized exploratory well costs that have been capitalized for more than one year	$ 20,519	$ 3,828	$ 6,965	$ 5,247	$ 72	$ 2,884	$ 1,523

(8) INDEBTEDNESS

We had the following debt outstanding as of the dates shown below (in thousands) (bank debt interest rate at June 30, 2013 is shown parenthetically; no interest was capitalized during the three months or the six months ended June 30, 2013 or 2012):

	June 30, 2013	December 31, 2012
Bank debt (1.8%)	$ 309,000	$ 739,000
Senior subordinated notes:		
7.25% senior subordinated notes due 2018		250,000
8.00% senior subordinated notes due 2019, net of $ 10,165 and $ 10,815 discount, respectively	289,835	289,185
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	
Total debt	$ 2,948,835	$ 2,878,185

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 June 30, 2013, 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 part of our semi-annual bank review completed on April 8, 2013, our borrowing base was reaffirmed at $2.0 billion and our facility amount was also reaffirmed at $1.75 billion. Our current bank group is composed of twenty-eight financial institutions, with no one bank holding more than 9% of the total facility. The 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 payment of a mutually acceptable commitment fee to those banks. As of June 30, 2013, the outstanding balance under our bank credit facility was $309.0 million. Additionally, we had $84.7 million of undrawn letters of credit leaving $1.4 billion of borrowing capacity available under the facility. The bank credit facility matures on February 18, 2016. Borrowings under the bank credit facility can either be at the Alternate Base Rate (as defined) 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 2.2% for the three months ended June 30, 2013 compared to 2.7% for the three months ended June 30, 2012. The weighted average interest rate was 2.1% for the six months ended June 30, 2013 compared to 2.3% for the six months ended June 30, 2012. A commitment fee is paid on the undrawn balance based on an annual rate of 0.375% to 0.50%. At June 30, 2013, the commitment fee was 0.375% and the interest rate margin was 1.5% on our LIBOR loans and 0.5% on our base rate loans. On June 30, 2013, the borrowings under the bank credit facility were at LIBOR.

Senior Subordinated Notes

In March 2013, we issued $750.0 million aggregate principal amount of 5.00% senior subordinated notes due 2023 (the Outstanding Notes) for net proceeds of $738.8 million after underwriting discounts and commissions of $11.2 million. The notes were issued at par. The offering of the Outstanding Notes were only offered to qualified institutional buyers and to Non- U.S. persons outside the United States in compliance with Rule 144A and Regulation S under the Securities Act of 1933 (the Securities Act). On June 19, 2013, substantially all of the Outstanding Notes were exchanged for an equal principal amount of registered 5.00% senior subordinated notes due 2013 pursuant to an effective registration statement on Form S-4 filed on April 26, 2013 under the Securities Act (the Exchange Notes). The Exchange Notes are identical to the Outstanding Notes except that the Exchange Notes are registered under the Securities Act and do not have restrictions on transfer, registration rights or provisions for additional interest. As used in this Form 10-Q, the term 5.00% Notes due 2023 refer to both the Outstanding Notes and the Exchange Notes. Interest on the 5.00% Notes due 2023 is payable semi-annually in March and September and is guaranteed by all of our subsidiary guarantors. We may redeem the 5.00% Notes due 2023, in whole or in part, at any time on or after March 15, 2018, at a redemption price of 102.5% of the principal amount as of March 15, 2018, declining to 100% on March 15, 2021 and thereafter. Before March 15, 2016, we may redeem up to 35% of the original aggregate principal amount of the 5.00% Notes due 2023 at a redemption price equal to 105% of the principal amount thereof, plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings, provided that 65% of the aggregate principal amount of 5.00% Notes due 2023 remains outstanding immediately after the occurrence of such redemption and also provided such redemption shall occur within 60 days of the date of the closing of the equity offering. On closing of the 5.00% Notes due 2023, we used the proceeds to pay down our outstanding bank credit facility balance. We did not receive any proceeds from the issuance of the Exchange 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 April 2, 2013, we announced a call for the redemption of $250.0 million of our outstanding 7.25% senior subordinated notes due 2018 at 103.625% of par which were redeemed on May 2, 2013. In second quarter 2013, we recognized a $12.3 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 of our senior subordinated notes 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 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. We were in compliance with our covenants under the bank credit facility at June 30, 2013.

The indentures governing our senior subordinated notes contain various restrictive covenants that are substantially identical to each other and may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, enter into transactions with affiliates, or change the nature of our business. At June 30, 2013, 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 six months ended June 30, 2013 is as follows (in thousands):

	Six Months Ended June 30, 2013
Beginning of period	$ 146,478

Liabilities incurred		3,846
Liabilities settled		(155)
Disposition of wells		(3,098)
Accretion expense		5,324
Change in estimate		(6,231)
End of period		146,164
Less current portion		(2,366)
Long-term asset retirement obligations	$	143,798

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 2012:

	Six Months Ended June 30, 2013	Year Ended December 31, 2012
Beginning balance	162,514,098	161,131,547
Stock options/SARs exercised	235,369	926,425
Restricted stock granted	401,122	354,674
Restricted stock units vested	117,009	57,824
Treasury shares issued	26,497	43,628
Ending balance	163,294,095	162,514,098

(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. In 2011, we sold NGLs derivative swap contracts (sold swaps) for the natural gasoline (or C5) component of natural gas liquids and in 2012, we entered into purchased derivative swaps (re-purchased swaps) for C5 volumes. These re-purchased swaps were, in some cases, with the same counterparties as our sold swaps. We entered into these re-purchased swaps to lock in certain natural gasoline derivative gains. In second quarter 2012, we also entered into NGL derivative swap contracts for the propane (or C3) component of NGLs. The fair value of these 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), approximated a net unrealized pre-tax gain of $127.5 million at June 30, 2013. These contracts expire monthly through December 2015. The following table sets forth our derivative volumes by year as of June 30, 2013:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price
Natural Gas			

2013	Collars	280,000 Mmbtu/day	$ 4.59	$ 5.05
2014	Collars	447,500 Mmbtu/day	$ 3.84	$ 4.48
2015	Collars	145,000 Mmbtu/day	$ 4.07	$ 4.56
2013	Swaps	296,685 Mmbtu/day	$ 3.79	
2014	Swaps	30,000 Mmbtu/day	$ 4.17	
Crude Oil				
2013	Collars	3,000 bbls/day	$ 90.60	$ 100.00
2014	Collars	2,000 bbls/day	$ 85.55	$ 100.00
2013	Swaps	6,325 bbls/day	$96.77	
2014	Swaps	7,000 bbls/day	$94.14	
2015	Swaps	2,000 bbls day	$90.20	
NGLs (Natural Gasoline)				
2013	Sold Swaps	8,000 bbls/day	$89.64	
2013	Re-purchased Swaps	1,500 bbls/day	$76.30	
NGLs (Propane)				
2013	Swaps	8,000 bbls/day	$36.79	
2014	Swaps	1,000 bbls/day	$40.32	

Every derivative instrument is required to be recorded on the balance sheet as either an asset or a liability measured at its fair value. Fair value is determined based on the difference between the fixed contract price and the underlying market price at the determination date. Changes in the fair value of our derivatives that qualified for hedge accounting are recorded as a component of AOCI 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 June 30, 2013, an unrealized pre-tax derivative gain of $60.5 million was recorded in AOCI. 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 are determined monthly, and are included as increases or decreases to natural gas, NGLs and oil sales in the period the hedged production is 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 $30.5 million of gains in second quarter 2013 compared to gains of $78.6 million in the same period of 2012 related to settled hedging transactions. Natural gas, NGLs and oil sales include $67.0 million of gains in the first six months 2013 compared to gains of $136.2 million in the same period of 2012. Any ineffectiveness associated with these hedge derivatives is reflected in derivative fair value income 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 for the three months ended June 30, 2013 includes no ineffective gains or losses (unrealized and realized) compared to a gain of $1.9 million in the three months ended June 30, 2012. Derivative fair value income for the six months ended June 30, 2013 includes ineffective losses (unrealized and realized) of $2.9 million compared to a gain of $2.1 million in the same period of 2012. During the six months ended June 30, 2013, we recognized a pre-tax gain of $3.2 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 our Delaware and Permian Basin properties in New Mexico and West Texas.

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 marked-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 marked-to-market values included in AOCI as of the de-designation date were frozen and will be reclassified into earnings in future periods as the underlying hedged transactions occur. As of June 30, 2013, we expect to reclassify into earnings $49.5 million of unrealized net gains in the remaining months of 2013 and $10.9 million of unrealized net gains in 2014 from AOCI.

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 marked-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.

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Derivative Fair Value Income

The following table presents information about the components of derivative fair value income for the three months and the six months ended June 30, 2013 and 2012 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Change in fair value of derivatives that did not qualify or were not designated for hedge accounting [(a)]	$159,371	$135,777	$ 62,569	$83,721
Realized loss on settlement natural gas [(a) (b)]	(24,543)		(23,728)	
Realized gain (loss) on settlement oil [(a) (b)]	(111)	768	(213)	(3,854)
Realized gain on settlement NGLs [(a) (b)]	3,043	10,152	2,148	5,760
Hedge ineffectiveness realized	(155)	1,278	409	2,463
unrealized	155	594	(3,300)	(354)
Derivative fair value income	$137,760	$148,569	$ 37,885	$87,736

[(a)] Derivatives that did not qualify or were not designated for hedge accounting. Change in fair value of derivatives line also includes gains of $103.8 million in second quarter 2013 and gains of $22.4 million in the first six months 2013 related to discontinuance of hedge accounting.
[(b)] These amounts represent the realized gains and losses on settled derivatives that did not qualify or were not designated for hedge accounting, which before settlement are included in the category in this same table referred to as change in fair value of derivatives that did not qualify or were not designated for hedge accounting.

Derivative Assets and Liabilities

The combined fair value of derivatives included in the accompanying consolidated balance sheets as of June 30, 2013 and December 31, 2012 is summarized below. The assets and liabilities are netted where derivatives with both gain and loss positions are held by a single counterparty and we have master netting arrangements. The tables below provide additional information relating to our master netting arrangements with our derivative counterparties (in thousands):

June 30, 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	$ 14,255	$ (3,638)	$ 10,617
	collars	88,087	(3,703)	84,384
Crude oil	swaps	15,980		15,980
	collars	1,979		1,979
NGLs	C5 swaps	11,743		11,743
	C3 swaps	3,589	(773)	2,816
		$135,633	$ (8,114)	$ 127,519

		June 30, 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	$(3,638)	$ 3,638	$
	collars	(3,703)	3,703	
NGLs	C3 swaps	(773)	773	
		$(8,114)	$ 8,114	$

		December 31, 2012		
		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	$ 10,746	$ (3,242)	$ 7,504
	collars	128,410	(6,155)	122,255
	basis swaps	993		993
Crude oil	swaps	9,650		9,650
	collars	2,222		2,222
NGLs	C5 swaps	13,055	(2,412)	10,643
		$165,076	$ (11,809)	$ 153,267

		December 31, 2012		
		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	$ (3,242)	$ (221)	$ (3,463)
	collars	(9,618)	9,618	
NGLs	C5 swaps	(137)	2,412	2,275
	C3 swaps	(6,746)		(6,746)
		$(19,743)	$ 11,809	$ (7,934)

The table below provides data about the fair value of our derivative contracts. Derivative assets and liabilities shown below are presented as gross assets and liabilities, without regard to master netting arrangements, which are considered in the presentation of derivative assets and liabilities in the accompanying consolidated balance sheets (in thousands):

June 30, 2013	December 31, 2012

	Assets Carrying Value	(Liabilities) Carrying Value	Net Carrying Value	Assets Carrying Value	(Liabilities) Carrying Value	Net Carrying Value
Derivatives that qualified for cash flow hedge accounting (before discontinuance of hedge accounting):						
Swaps [a]	$11,028	$ (5,952)	$ 5,076	$ 22,236	$ (3,242)	$ 18,994
Collars [a]	64,047	(10,356)	53,691	129,878	(9,721)	120,157
	$75,075	$ (16,308)	$ 58,767	$152,114	$ (12,963)	$139,151
Derivatives that did not qualify or were not designated for hedge accounting:						
Sold swaps [a]	$36,505	$ (2,233)	$ 34,272	$ 7,316	$ (8,904)	$ (1,588)
Re-purchased swaps [a]	1,808		1,808	5,920		5,920
Collars [a]	33,112	(440)	32,672	857		857
Basis swaps [a]				993		993
	$71,425	$ (2,673)	$ 68,752	$ 15,086	$ (8,904)	$ 6,182

[a] Included in unrealized derivatives in the accompanying consolidated balance sheets. See additional discussion above regarding the discontinuance of hedge accounting.

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	Change in Hedge Derivative Fair Value		Realized Gain (Loss) Reclassified from OCI into Revenue [a]		Change in Hedge Derivative Fair Value		Realized Gain (Loss) Reclassified from OCI into Revenue [a]	
	2013	2012	2013	2012	2013	2012	2013	2012
Swaps	$	$ 19,665	$ 3,875	$ 32,335	$ 125	$ 55,836	$ 11,922	$ 51,647
Put options		648		(315)		(914)		(315)
Collars		(12,423)	27,540	46,561	(7,015)	84,048	58,272	84,878
Income taxes		(3,077)	(12,252)	(30,647)	2,687	(55,183)	(27,376)	(52,834)
	$	$ 4,813	$ 19,163	$ 47,934	$(4,203)	$ 83,787	$ 42,818	$ 83,376

[a] For realized gains upon derivative contract settlement, the reduction in AOCI is offset by an increase in revenues, 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 is summarized below (in thousands):

	Three Months Ended June 30,					
	Gain (Loss) Recognized in Income (Non-hedge Derivatives)		Gain (Loss) Recognized in Income (Ineffective Portion)		Derivative Fair Value Income (Loss)	
	2013	2012	2013	2012	2013	2012
Swaps	$ 65,003	$129,313	$	$ 562	$ 65,003	$129,875
Re-purchased swaps	(1,663)	(8,744)			(1,663)	(8,744)
Collars	74,420	7,597		1,310	74,420	8,907
Call options		18,531				18,531

Total	$137,760	$146,697	$	$ 1,872	$137,760	$148,569

	Six Months Ended June 30,					
	Gain (Loss) Recognized in Income (Non-hedge Derivatives)		Gain (Loss) Recognized in Income (Ineffective Portion)		Derivative Fair Value Income (Loss)	
	2013	2012	2013	2012	2013	2012
Swaps	$21,927	$76,328	$ (1,995)	$ 666	$19,932	$76,994
Re-purchased swaps	(478)	(8,744)			(478)	(8,744)
Collars	19,417	5,095	(896)	1,443	18,521	6,538
Call options	(90)	12,948			(90)	12,948
Total	$40,776	$85,627	$ (2,891)	$ 2,109	$37,885	$87,736

(12) FAIR VALUE MEASUREMENTS

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

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

- Level 1 Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

- Level 2 Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.

- Level 3 Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management s best estimate of fair value.

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

Fair Values Recurring

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

		Fair Value Measurements at June 30, 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 June 30, 2013
Trading securities held in the deferred compensation plans		$62,036	$	$	$ 62,036
Derivatives	swaps		41,156		41,156
	collars		86,363		86,363

		Fair Value Measurements at December 31, 2012 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, 2012
Trading securities held in the deferred compensation plans		$57,776	$	$	$ 57,776
Derivatives	swaps		23,326		23,326
	collars		121,014		121,014
	basis swaps		993		993

Our trading securities in Level 1 are exchange-traded and measured at fair value with a market approach using end of period market values. Derivatives in Level 2 are measured at fair value with a market approach using third-party pricing services, which have been corroborated with data from active markets or broker quotes.

Our trading securities held in the deferred compensation plan are accounted for using the mark-to-market accounting method and are included in other assets in the accompanying consolidated balance sheets. We elected to adopt the fair value option to simplify our accounting for the investments in our deferred compensation plan. Interest, dividends, and mark-to-market gains or losses are included in deferred compensation plan expense in the accompanying statement of operations. For second quarter 2013, interest and dividends were $629,000 and the mark-to-market adjustment was a loss of $1.0 million compared to interest and dividends of $125,000 and mark-to-market loss of $2.1 million in the same period of the prior year. For six months ended June 30, 2013, interest and dividends were $668,000 and the mark-to-market adjustment was a gain of $586,000 compared to interest and dividends of $275,000 and mark-to-market gain of $1.9 million in the same period of the prior year.

Fair Values Non-recurring

We review our long-lived assets to be held and used for impairment including proved natural gas and oil properties, whenever events or circumstances indicate the carrying value of those assets may not be recoverable. In second quarter 2013, we evaluated certain surface property we own which included consideration of the potential sale of the assets and recognized an impairment charge of $741,000. The following table presents the fair value of these assets at June 30, 2013 measured at fair value on a non-recurring basis (in thousands):

	Fair Value	Impairment
Surface property	$ 5,550	$ 741

Fair Values Reported

The following table presents the carrying amounts and the fair values of our financial instruments as of June 30, 2013 and December 31, 2012 (in thousands):

	June 30, 2013		December 31, 2012	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:				
Commodity swaps and collars	$ 127,519	$ 127,519	$ 153,267	$ 153,267
Marketable securities[(a)]	62,036	62,036	57,776	57,776
(Liabilities):				
Commodity swaps and collars			(7,934)	(7,934)
Bank credit facility[(b)]	(309,000)	(309,000)	(739,000)	(739,000)
Deferred compensation plan[(c)]	(207,906)	(207,906)	(187,604)	(187,604)
7.25% senior subordinated notes due 2018[(b)]			(250,000)	(262,500)
8.00% senior subordinated notes due 2019[(b)]	(289,835)	(319,500)	(289,185)	(332,250)
6.75% senior subordinated notes due 2020[(b)]	(500,000)	(536,250)	(500,000)	(542,500)
5.75% senior subordinated notes due 2021[(b)]	(500,000)	(515,000)	(500,000)	(535,000)
5.00% senior subordinated notes due 2022[(b)]	(600,000)	(586,500)	(600,000)	(627,000)
5.00% senior subordinated notes due 2023[(b)]	(750,000)	(733,125)		

(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 market values. Refer to Note 8 for additional information.

(c) The fair value of our deferred compensation plan is updated on the closing price on the balance sheet date.

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 incurrence of and expected future insignificance of bad debt expense. Non-financial liabilities initially measured at fair value include asset retirement obligations. Refer to Note 9 for additional information.

Concentrations of Credit Risk

As of June 30, 2013, our primary concentrations of credit risk are the risks of collecting accounts receivable and the risk of 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 $2.5 million at June 30, 2013 and $2.4 million at December 31, 2012. As of June 30, 2013, our derivative contracts consist of swaps and collars. Our exposure is diversified primarily among major investment grade financial institutions, the majority of which we have master netting agreements which provide for offsetting payables against receivables from separate derivative contracts. To manage counterparty risk associated with our derivatives, we select and monitor our counterparties based on our assessment of their financial strength and/or credit ratings. We may also limit the level of exposure with any single counterparty. At June 30, 2013, our derivative counterparties include fifteen financial institutions, of which all but two are secured lenders in our bank credit facility. At June 30, 2013, our net derivative assets include a receivable from the two counterparties not included in our bank credit facility of $7.9 million. For those counterparties who are not secured lenders in our bank credit facility or for which we do not have master netting arrangements, net derivative asset values are determined, in part, by reviewing credit default swap spreads for the counterparties. Net derivative liabilities are determined, in part, by using our market-based credit spread. None of our derivative contracts have margin requirements or collateral provisions that would require funding prior to the scheduled cash settlement date. We have also entered into the International Swaps and Derivatives Association Master Agreements (ISDA Agreements) with our counterparties. The terms of the ISDA Agreements provide us and our counterparties with rights of set off upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. We continue to monitor developments surrounding the derivative regulations adopted under the Dodd-Frank Wall Street Reform and Consumer Protection Act. We do not anticipate any significant changes to our hedging program as a result of this law.

(13) STOCK-BASED COMPENSATION PLANS

Stock-Based Awards

Stock options represent the right to purchase shares of stock in the future at the fair value of the stock on the date of grant. Most stock options granted under our stock option plans vest over a three-year period and expire five years from the date they are granted. Beginning in 2005, we began granting SARs to reduce the dilutive impact of our equity plans. Similar to stock options, 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 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.

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 grants 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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Operating expense	$ 696	$ 692	$ 1,357	$ 1,049
Brokered natural gas and marketing expense	530	408	779	861
Exploration expense	960	994	2,030	1,922
General and administrative expense	13,263	12,540	23,569	20,698
Total	$15,449	$14,634	$27,735	$24,530

Stock and Option Plans

We have two active equity-based stock plans, the 2005 Plan and the Director 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. All awards granted under these plans have been issued at prevailing market prices at the time of the grant. Of the 2.7 million grants outstanding at June 30, 2013, all are grants relating to SARs. Information with respect to SARs activity is summarized below:

	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2012	3,433,362	$ 52.52
Granted	470,617	75.31
Exercised	(1,115,480)	54.01
Expired/forfeited	(42,411)	53.81
Outstanding at June 30, 2013	2,746,088	$ 55.83

Stock Appreciation Right Awards

During first six months 2013, we granted SARs to officers and non-officer employees. The weighted average grant date fair value per share of these SARs, based on our Black-Scholes-Merton assumptions, is shown below:

	Six Months Ended June 30, 2013
Weighted average exercise price per share	$ 75.31
Expected annual dividends per share	0.21%
Expected life in years	3.7
Expected volatility	35%
Risk-free interest rate	0.6%
Weighted average grant date fair value per share	$ 20.19

Restricted Stock Awards

Equity Awards

In first six months 2013, we granted 388,700 restricted stock Equity Awards to employees at an average grant price of $71.05 compared to 359,700 restricted stock Equity Awards granted to employees at an average grant price of $63.37 in the same period of 2012. These awards generally vest over a three-year period. We recorded compensation expense for these Equity Awards of $9.5 million in the first six months 2013 compared to $5.2 million in the same period of 2012. Equity Awards are not issued to employees until they are vested. Employees do not have the option to receive cash.

Liability Awards

In first six months 2013, we granted 406,100 shares of restricted stock Liability Awards as compensation to employees at an average price of $75.45 with vesting generally over a three-year period and 18,300 were granted to non-employee directors at an average price of $77.26 with immediate vesting. In the same period of 2012, we granted 355,400 shares of Liability Awards as compensation to employees at an average price of $63.87 with vesting generally over a three-year period and 14,700 were granted to non-employee directors at an average price of $64.35 with immediate vesting. We recorded compensation expense for Liability Awards of $11.1 million in first six months 2013 compared to $10.2 million in the same period of 2012. 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 summary of the status of our non-vested restricted stock outstanding at June 30, 2013 is summarized below:

	Equity Awards		Liability Awards	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2012	349,156	$ 59.08	423,478	$ 58.91
Granted	388,653	71.05	424,431	75.53
Vested	(153,439)	61.97	(180,503)	60.57
Forfeited	(27,914)	65.02	(21,620)	57.21
Outstanding at June 30, 2013	556,456	$ 66.35	645,786	$ 69.43

Deferred Compensation Plan

Our deferred compensation plan gives non-employees 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 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 income of $6.9 million in second quarter 2013 compared to mark-to-market loss of $9.3 million in second quarter 2012. We recorded mark-to-market loss of $35.5 million in the six months ended June 30, 2013 compared to $1.5 million in the same period of 2012. The Rabbi Trust held 2.9 million shares (2.3 million of vested shares) of Range stock at June 30, 2013 compared to 2.7 million shares (2.3 million of vested shares) at December 31, 2012.

(14) SUPPLEMENTAL CASH FLOW INFORMATION

	Six Months Ended June 30, 2013	2012
	(in thousands)	
Net cash provided from operating activities included:		
Income taxes (refunded) paid to taxing authorities	$ (119)	$ 246
Interest paid	74,940	66,438
Non-cash investing and financing activities included:		
Asset retirement costs (removed) capitalized, net	(2,385)	4,004
Increase (decrease) in accrued capital expenditures	74,428	(29,414)

(15) COMMITMENTS AND CONTINGENCIES

Litigation

James A. Drummond and Chris Parrish v. Range Resources-Midcontinent, LLC et al.; pending in the District Court of Grady County, State of Oklahoma; Case No. CJ-2010-510

Two individuals (one of whom is now deceased), only one of which was a current royalty owner, filed suit against Range Resources Corporation and two of our subsidiaries, including the proper defendant Range Resources-Midcontinent, LLC, in the District Court of Grady County, Oklahoma. This suit is similar to a number of cases filed in Oklahoma asserting claims that royalty owners are entitled to payment of royalties on several different categories of alleged deductions applied by third parties who transport and process natural gas production. The alleged deductions include fuel used by the third party in the transportation and processing of gas, condensate removed by the third party after the point of sale, the contractually agreed natural gas liquids recovery percentages, the percentage of proceeds contracts contractually agreed pricing percentages and other similar alleged deductions. In addition to the claims made with respect to the alleged categories of deductions, the Plaintiffs in this litigation have alleged fraud and the existence of a fiduciary duty to the royalty owners to attempt to support an argument that no statute of limitations applies, and the Plaintiffs also claim that interest accrues on the alleged damages at 12% compounded annually. As previously disclosed, on February 19, 2013, the District Court entered an order certifying a class of royalty owners as requested by the Plaintiffs and we appealed the certification order. While this appeal was pending, the parties successfully mediated the case in May 2013 and we executed a Stipulation and Agreement of Settlement, with an effective date of May 31, 2013, providing for a cash payment to the class in the amount of $87.5 million in settlement of all claims made by the class for the period prior to May 31, 2013. Pursuant to the settlement agreement, on June 28, 2013, we paid $87.5 million into an escrow account. While the settlement is subject to approval by the Court, we currently expect the settlement will ultimately receive final approval.

We are the subject of, or party to, a number of other 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 and Hydraulic Fracturing Services

In the six months ended June 30, 2013, we recognized rate adjustments on certain existing transportation and gathering contracts which increased our transportation and gathering commitments approximately $135.5 million over the next 10 years.

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

	June 30, 2013	December 31, 2012
	(in thousands)	
Natural gas and oil properties:		
Properties subject to depletion	$ 7,645,140	$ 7,368,308
Unproved properties	724,501	743,467
Total	8,369,641	8,111,775
Accumulated depreciation, depletion and amortization	(2,035,850)	(2,015,591)
Net capitalized costs	$ 6,333,791	$ 6,096,184

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

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

	Six Months Ended June 30, 2013	Year Ended December 31, 2012
	(in thousands)	
Acreage purchases	$ 31,049	$ 188,843
Development	500,534	1,049,129
Exploration:		
Drilling	141,838	309,816
Expense	27,818	65,758
Stock-based compensation expense	2,030	4,049
Gas gathering facilities:		
Development	21,081	41,035
Subtotal	724,350	1,658,630
Asset retirement obligations	(2,385)	57,982
Total costs incurred	$721,965	$ 1,716,612

[a] Includes cost incurred whether capitalized or expensed.

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

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. Certain sections of Management s Discussion and Analysis of Financial Condition and Results of Operations include forward-looking statements concerning trends or events potentially affecting our business. These statements contain words such as anticipates, believes, expects, targets, plans, projects, cou 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 forecasts for our existing operations and do not include the potential impact of any future acquisitions. For additional risk factors affecting our business, see Item 1A. Risk Factors as filed with our Annual Report on Form 10-K for the year ended December 31, 2012 as filed with the SEC on February 27, 2013.

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.

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 and crude oil and on our ability to economically find, develop, acquire and produce natural gas, NGLs and crude oil reserves. We include condensate in our crude oil captions below. We use the successful efforts method of accounting for our natural gas, NGLs and oil activities. Our corporate headquarters is located at 100 Throckmorton Street, Fort Worth, Texas.

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 six months ended June 30, 2013 and 2012:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Average NYMEX prices [(a)]				

Natural gas (per mcf)	$ 4.09	$ 2.26	$ 3.73	$ 2.50
Oil (per bbl)	$94.20	$92.27	$94.23	$97.63
Mont Belvieu NGL Composite (per gallon)	$ 0.74	$ 0.88	$ 0.76	$ 0.99

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

Consolidated Results of Operations

Overview of Second Quarter 2013 Results

During second quarter 2013, we achieved the following financial and operating results:

- increased revenue from the sale of natural gas, NGLs and oil by 47% from the same period of 2012;
- achieved 27% production growth from the same period of 2012;
- continued expansion of our activities in the Marcellus Shale in Pennsylvania by growing production, proving up acreage and acquiring additional unproved acreage;
- continued expansion of our activities in the horizontal Mississippian play in Oklahoma by growing production and acquiring additional unproved acreage;
- reduced direct operating expenses per mcfe 5% from the same period of 2012;
- reduced our depletion, depreciation and amortization (DD&A) rate 13% from the same period of 2012;
- received proceeds of $257.9 million primarily from the sale of our New Mexico and West Texas properties;
- redeemed all $250.0 million aggregate principal amount of our 7.25% senior subordinated notes due 2018;
- entered into additional derivative contracts for 2013, 2014 and 2015; and
- realized $78.6 million of cash flow from operating activities (after $87.5 million Oklahoma lawsuit payment).

For the second quarter, total revenues increased $224.4 million or 50% over the same period of 2012. This increase was due to significantly higher production volumes, an increase in the mark-to-market gain from derivatives, higher realized prices and a higher gain on the sale of assets. Our second quarter 2013 production growth was due to the continued success of our drilling program, particularly in the Marcellus Shale. Second quarter 2013 natural gas production increased 24% from the comparable period of 2012 and, as we continue to focus our efforts on the growth of our liquids production, second quarter production for oil and NGLs increased over 35% from the same period of the prior year.

Overview of Six Months 2013 Results

During the six months ending June 30, 2013, we achieved the following financial and operating results:

· increased revenue from the sale of natural gas, NGLs and oil by 36% from the same period of 2012;

· achieved 29% production growth from the same period of 2012;

· reduced direct operating expense per mcfe 13% from the same period of 2012;

· reduced our DD&A rate 13% from the same period of 2012;

· continued our expansion in the Marcellus Shale and the horizontal Mississippian plays;

· issued $750.0 million of new 5% senior subordinated notes due 2023;

· redeemed all $250.0 million aggregate principal amount of our 7.25% senior subordinated notes due 2018;

· received proceeds of $296.1 million from the sale of non-core assets;

· entered into additional derivative contracts for 2013, 2014 and 2015; and

· realized $279.9 million of cash flow from operating activities (after $87.5 million Oklahoma lawsuit payment).

Total revenues increased $292.7 million or 42% in the six months ended June 30, 2013 compared to the same period in 2012. This increase was due to significantly higher production volumes and higher gains on the sale of assets partially offset by a lower mark-to-market gain from derivatives. For the six months ended June 30, 2013, natural gas production increased 28% while liquids production increased 33% from the same period of the prior year.

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, new technology and the level of oil and gas production in North America and worldwide. Although we have entered into derivative contracts covering a portion of our production volumes for the remainder of 2013 and for 2014 and 2015, 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. As a result of relatively higher current prices for oil and NGLs than for natural gas, we continue to focus our capital budget expenditures on higher return oil and liquids-rich gas drilling activities.

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. Revenue from the sale of natural gas, NGLs and oil sales include netback arrangements where we sell natural gas and oil at the wellhead and collect a price, net of transportation 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 deduction. 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 the statement of operations. For more information on revenues from derivative contracts that are not accounted for as hedges, see Derivative fair value income 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 second quarter 2013, natural gas, NGLs and oil sales increased 47% from the same period of 2012 with a 27% increase in production and a 16% increase in realized prices. In the first six months 2013, natural gas, NGLs and oil sales increased 36% from the same period of 2012 with a 29% increase in production and a 5% increase in realized prices. The following table illustrates the primary components of natural gas, NGLs and oil sales for the three months and the six months ended June 30, 2013 and 2012 (in thousands):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2013	2012	Change	%	2013	2012	Change	%
Natural gas, NGLs and oil sales								
Gas wellhead	$268,069	$111,413	$156,656	141%	$485,157	$239,481	$245,676	103%
Gas hedges realized [(a)]	29,345	78,896	(49,551)	(63%)	64,823	136,525	(71,702)	(53%)
Total gas revenue	$297,414	$190,309	$107,105	56%	$549,980	$376,006	$173,974	46%
Total NGLs revenue	$ 66,587	$ 56,280	$ 10,307	18%	$134,158	$132,778	$ 1,380	1%
Oil wellhead	$ 72,504	$ 52,075	$ 20,429	39%	$149,584	$107,497	$ 42,087	39%
Oil hedges realized [(a)]	1,173	(315)	1,488	%	2,195	(315)	2,510	%
Total oil revenue	$ 73,677	$ 51,760	$ 21,917	42%	$151,779	$107,182	$ 44,597	42%
Combined wellhead	$407,160	$219,768	$187,392	85%	768,899	479,756	289,143	60%
Combined hedges [(a)]	30,518	78,581	(48,063)	(61%)	67,018	136,210	(69,192)	(51%)

Total natural gas, NGLs and oil sales	$437,678	$298,349	$139,329	47%	$835,917	$615,966	$219,951	36%

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

Our production continues to grow through drilling success as we place new wells on production offset by the natural decline of our natural gas and oil wells and asset sales. For second quarter 2013, our production volumes increased 34% in our Appalachian region and decreased 8% in our Southwestern region, primarily due to the sale of our Delaware and Permian Basin properties in New Mexico and West Texas, when compared to the same period of 2012. For the first six months 2013, our production volumes increased 38% in our Appalachian region and decreased 7% in our Southwestern region when compared to the same period of 2012. Our production for the three months and the six months ended June 30, 2013 and 2012 is set forth in the following table:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2013	2012	Change	%	2013	2012	Change	%
Production [(a)]								
Natural gas (mcf)	64,926,278	52,293,227	12,633,051	24%	126,950,234	98,926,434	28,023,800	28%
NGLs (bbls)	2,115,489	1,570,593	544,896	35%	4,004,913	3,131,419	873,494	28%
Crude oil (bbls)	864,517	623,026	241,491	39%	1,777,179	1,231,103	546,076	44%
Total (mcfe) [(b)]	82,806,314	65,454,941	17,351,373	27%	161,642,786	125,101,566	36,541,220	29%
Average daily production [(a)]								
Natural gas (mcf)	713,476	574,651	138,825	24%	701,383	543,552	157,831	29%
NGLs (bbls)	23,247	17,259	5,988	35%	22,127	17,206	4,921	29%
Crude oil (bbls)	9,500	6,846	2,654	39%	9,819	6,764	3,055	45%
Total (mcfe) [(b)]	909,959	719,285	190,674	27%	893,054	687,371	205,683	30%

(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 of oil and natural gas prices.

Our average realized price (including all derivative settlements and third-party transportation costs) received during second quarter 2013 was $4.23 per mcfe compared to $4.06 per mcfe in the same period of 2012. Our average realized price (including all derivative settlements and third-party transportation costs) received was $4.24 in the six months ended June 30, 2013 compared to $4.27 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. Average realized price calculations for the three months and the six months ended June 30, 2013 and 2012 are shown below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Average Prices				
Average sales prices (wellhead):				
Natural gas (per mcf)	$ 4.13	$ 2.13	$ 3.82	$ 2.42
NGLs (per bbl)	31.48	35.83	33.50	42.40
Crude oil (per bbl)	83.87	83.58	84.17	87.32
Total (per mcfe) [a]	4.92	3.36	4.76	3.83
Average realized prices (including derivative settlements that qualified for hedge accounting):				
Natural gas (per mcf)	$ 4.58	$ 3.64	$ 4.33	$ 3.80
NGLs (per bbl)	31.48	35.83	33.50	42.40
Crude oil (per bbl)	85.22	83.08	85.40	87.06
Total (per mcfe) [a]	5.29	4.56	5.17	4.92
Average realized prices (including all derivative settlements):				
Natural gas (per mcf)	$ 4.20	$ 3.66	$ 4.15	$ 3.83
NGLs (per bbl)	32.91	42.30	34.03	44.24
Crude oil (per bbl)	85.09	84.31	85.28	83.93
Total (per mcfe) [a]	5.02	4.74	5.04	4.96
Average realized prices (including all derivative settlements and third party transportation costs paid by Range):				
Natural gas (per mcf)	$ 3.23	$ 2.86	$ 3.19	$ 3.01
NGLs (per bbl)	31.36	40.66	32.42	42.68
Crude oil (per bbl)	85.09	84.31	85.28	83.93
Total (per mcfe) [a]	4.23	4.06	4.24	4.27

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

Derivative fair value income was $137.8 million in second quarter 2013 compared to $148.6 million in the same period of 2012. Derivative fair value income was $37.9 million in the six months ended June 30, 2013 compared to $87.7 million in the same period of 2012. Our derivatives that do not qualify or are not designated for hedge accounting are 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 in the accompanying consolidated statements of operations. 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. Hedge ineffectiveness, also included in derivative fair value income, is associated with contracts that qualified for hedge accounting. The ineffective portion is calculated as the difference between the changes in the fair value of the derivative and the estimated change in future cash flows from the item being hedged. Effective March 1, 2013, we elected to discontinue hedge accounting prospectively. After March 1, 2013, all realized and unrealized gains and losses will be recognized in earnings immediately as derivative contracts are settled or marked to market.

The following table presents information about the components of derivative fair value income for the three months and the six months ended June 30, 2013 and 2012 (in thousands):

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Change in fair value of derivatives that did not qualify for hedge accounting [a]	$159,371	$135,777	$ 62,569	$83,721
Realized loss on settlements natural gas [b] [c]	(24,543)		(23,728)	
Realized (loss) gain on settlements oil [b] [c]	(111)	768	(213)	(3,854)
Realized gain on settlements NGLs [b] [c]	3,043	10,152	2,148	5,760
Hedge ineffectiveness realized [c]	(155)	1,278	409	2,463
unrealized [a]	155	594	(3,300)	(354)
Derivative fair value income	$137,760	$148,569	$ 37,885	$87,736

[a] These amounts are unrealized and are not included in average realized price calculations.
[b] These amounts represent realized gains and losses on settled derivatives that did not qualify or were not designated for hedge accounting.
[c] These settlements are included in average realized price calculations (including all derivative settlements and third party transportation costs paid by Range).

Gain (loss) on the sale of assets was a gain of $83.3 million in second quarter 2013 compared to a loss of $3.2 million in the same period of 2012. In second quarter 2013, we recorded a gain on the sale of our New Mexico and West Texas properties of $83.5 million, before selling expenses. In second quarter 2012, we recorded a $2.5 million loss on the sale of a Marcellus exploration well. Gain (loss) on the sale of assets was a gain of $83.1 million in the first six months 2013 compared to a loss of $13.7 million in the same period of 2012. In the first six months 2012, we also sold a seventy-five percent interest in an East Texas prospect which included a suspended exploratory well and unproved properties for proceeds of $8.6 million resulting in a pre-tax loss of $10.9 million.

Brokered natural gas, marketing and other revenue in second quarter 2013 was $14.6 million compared to $5.2 million in the same period of 2012. The second quarter 2013 includes income from equity method investments of $353,000 and revenue from marketing and the sale of brokered gas of $14.4 million. The second quarter 2012 includes income from equity method investments of $502,000 and revenue from marketing and the sale of brokered gas of $5.4 million. Brokered natural gas, marketing and other revenue in the first six months 2013 was $35.7 million compared to $9.8 million in the same period of 2012. The first six months 2013 includes income from equity method investments of $273,000 and $35.5 million of revenue from marketing and the sale of brokered gas. The first six months 2012 includes income from equity method investments of $818,000 and $8.7 million of revenue from marketing and the sale of brokered gas. These revenues are increasing due to an increase in brokered volumes.

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 six months ended June 30, 2013 and 2012:

	Three Months Ended June 30, (per mcfe)				Six Months Ended June 30, (per mcfe)			
	2013	2012	Change	% Change	2013	2012	Change	% Change
Direct operating expense	$0.39	$0.41	$(0.02)	(5%)	$0.39	$0.45	$(0.06)	(13%)
Production and ad valorem tax expense	0.13	0.18	(0.05)	(28%)	0.14	0.39	(0.25)	(64%)
General and administrative expense	1.23	0.67	0.56	84%	1.15	0.66	0.49	74%
Interest expense	0.54	0.66	(0.12)	(18%)	0.54	0.64	(0.10)	(16%)
Depletion, depreciation and amortization expense	1.46	1.66	(0.20)	(12%)	1.45	1.67	(0.22)	(13%)

Direct operating expense was $32.6 million in second quarter 2013 compared to $27.0 million in the same period of 2012. 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. Even though our production volumes increased 27%, on an absolute basis, our spending for direct operating expenses for second quarter 2013 increased 21% with an increase in the number of producing wells, higher workover costs, higher field services and personnel costs and somewhat offset by the sale of certain non-core assets at the beginning of second quarter 2013. We incurred $2.1 million of workover costs in second quarter 2013 compared to $632,000 of workover costs in the same period of 2012.

On a per mcfe basis, direct operating expense in second quarter 2013 declined 5% from the same period of 2012, with the decrease consisting of lower equipment rental and well services partially offset by higher workover and personnel costs. We expect to experience lower costs per mcfe as we increase production from our dry gas Marcellus Shale wells due to their lower operating cost relative to our other operating areas somewhat offset by higher operating costs on our Marcellus Shale liquids-rich wells. Operating costs in the Mississippian play are higher on a per mcfe basis than the Marcellus Shale play. As production increases from the Mississippian play, our direct operating expenses per mcfe are expected to begin to increase.

Direct operating expense was $62.8 million in the six months ended June 30, 2013 compared to $56.1 million in the same period of 2012. Our production volumes increased 29%, on an absolute basis, our spending for direct operating expenses only increased 12% with an increase in the number of producing wells, higher utilities, higher well services, workovers and personnel costs somewhat offset by the sale of certain non-core assets. We incurred $3.5 million of workover costs in the six months ended June 30, 2013 compared to $2.2 million in the same period of 2012. On a per mcfe basis, direct operating expense in the six months ended June 30, 2013 decreased 13% to $0.39 from $0.45 the same period of 2012, with the decrease consisting of lower well services. Stock-based compensation expense represents the amortization of restricted stock grants and SARs as part of the compensation of field employees. The following table summarizes direct operating expenses per mcfe for the three months and the six months ended June 30, 2013 and 2012:

	Three Months Ended June 30, (per mcfe)				Six Months Ended June 30, (per mcfe)			
	2013	2012	Change	% Change	2013	2012	Change	% Change
Lease operating expense	$0.35	$0.39	$ (0.04)	(10%)	$0.36	$0.42	$ (0.06)	(14%)
Workovers	0.03	0.01	0.02	200%	0.02	0.02		%
Stock-based compensation (non-cash)	0.01	0.01		%	0.01	0.01		%
Total direct operating expense	$0.39	$0.41	(0.02)	(5%)	$0.39	$0.45	$ (0.06)	(13%)

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 assessed in 2012. Production and ad valorem taxes (excluding the impact fee) were $4.1 million in second quarter 2013 compared to $4.7 million in the same period of 2012. On a per mcfe basis, production and ad valorem taxes (excluding the impact fee) decreased to $0.05 in second quarter 2013 compared to $0.07 in the same period of 2012 due to an increase in volumes not subject to production taxes and the sale of non-core assets in New Mexico and West Texas partially offset by higher 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 second quarter 2013 is a $7.1 million impact fee ($0.09 per mcfe) compared to $6.4 million ($0.10 per mcfe) in the same period of the prior year. The second quarter 2012 also includes $707,000 ($0.01 per mcfe) retroactive fee which covered wells drilled prior to 2012.

Production and ad valorem taxes (excluding the impact fee) were $8.3 million ($0.05 per mcfe) in the first six months 2013 compared to $11.1 million ($0.09 per mcfe) in the same period of 2012 due to an increase in volumes not subject to production taxes partially offset by higher prices. Included in the six months 2013 is a $14.2 million ($0.09 per mcfe) impact fee compared to $12.6 million ($0.10 per mcfe) in the same period of 2012. The six months ended June 30, 2012 also includes $24.7 million ($0.20 per mcfe) retroactive impact fee which covered wells drilled prior to 2012.

General and administrative (G&A) expense was $102.0 million in second quarter 2013 compared to $44.0 million for the same period of 2012. The 2013 increase of $58.0 million when compared to 2012 is primarily due to a legal settlement related to an Oklahoma lawsuit of $52.5 million, higher salary and benefit expenses of $1.2 million, an increase in stock-based compensation of $723,000 and higher legal and office expenses, including information technology. We continue to incur higher wages which we consider necessary to remain competitive in the industry. G&A expense for the six months ended June 30, 2013 increased $103.3 million or 125% from the same period of the prior year primarily due to a legal settlement related to an Oklahoma lawsuit of $87.5 million (of which $35.0 million was accrued in first quarter 2013), higher salary and benefit expenses of $5.5 million, an increase in stock-based compensation of $2.9 million and higher legal and office expenses, including information technology. Our number of G&A employees increased 8% from June 30, 2012 to June 30, 2013. Stock-based compensation expense represents the amortization of restricted stock grants and SARs granted to our employees and non-employee directors as part of compensation. On a per mcfe basis, G&A expense increased 84% from second quarter 2012 and 74% from the six months ended June 30, 2012 primarily due to the Oklahoma lawsuit. The following table summarizes general and administrative expenses per mcfe for the three months and the six months ended June 30, 2013 and 2012:

	Three Months Ended June 30, (per mcfe)				Six Months Ended June 30, (per mcfe)			
	2013	2012	Change	% Change	2013	2012	Change	% Change
General and administrative	$0.44	$0.48	$ (0.04)	(8%)	$0.46	$0.49	$ (0.03)	(6%)
Oklahoma legal settlement	0.63		0.63	%	0.54		0.54	
Stock-based compensation (non-cash)	0.16	0.19	(0.03)	(16%)	0.15	0.17	(0.02)	(12%)
Total general and administrative expenses	$1.23	$0.67	0.56	84%	$1.15	$0.66	$ 0.49	74%

Interest expense was $45.1 million for second quarter 2013 compared to $42.9 million for second quarter 2012 and was $87.3 million in the six months ended June 30, 2013 compared to $80.1 million in the six months ended June 30, 2012. The following table presents information about interest expense for the three months and six months ended June 30, 2013 and 2012 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Bank credit facility	$ 2,686	$ 2,140	$ 7,590	$ 4,660
Subordinated notes	40,061	38,344	75,072	71,022
Amortization of deferred financing costs and other	2,324	2,404	4,619	4,411

Total interest expense	$45,071	$42,888	$87,281	$80,093

The increase in interest expense for second quarter 2013 from the same period of 2012 was primarily due to an increase in outstanding debt balances. In March 2013, we issued $750.0 million of 5.00% senior subordinated notes due 2023. We used the proceeds to repay our outstanding bank debt which carries a lower interest rate. In March 2012, we issued $600.0 million of 5.00% senior subordinated notes due 2022. We used the proceeds to repay $350.0 million of our outstanding credit facility balance and for general corporate purposes. The 2013 and 2012 note issuances were 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 second quarter 2013 was $163.5 million compared to $91.3 million in the same period of 2012 and the weighted average interest rate on the bank credit facility was 2.2% in second quarter 2013 compared to 2.7% in the same period of 2012.

The increase in interest expense for the six months ended June 30, 2013 from the same period of 2012 was due to an increase in outstanding debt balances. Average debt outstanding on the bank credit facility was $424.6 million compared to $172.2 million for 2012 and the weighted average interest rate on the bank credit facility was 2.1% in the six months ended June 30, 2013 compared to 2.3% in the same period of 2012.

Depletion, depreciation and amortization (DD&A) was $120.7 million in second quarter 2013 compared to $108.8 million in the same period of 2012. The increase in second quarter 2013 when compared to the same period of 2012 is due to a 13% decrease in depletion rates more than offset by a 27% increase in production. Depletion expense, the largest component of DD&A, was $1.38 per mcfe in second quarter 2013 compared to $1.58 per mcfe in the same period of 2012. We have historically adjusted our depletion rates in the fourth quarter of each year based on the year-end reserve report and other times during the year when circumstances indicate there has been a significant change in reserves or costs. The second quarter and the six months ended June 30, 2013 also includes $741,000 impairment related to surface acreage in North Texas.

DD&A was $235.8 million in the six months ended June 30, 2013 compared to $209.0 million in the same period of 2012. Depletion expense was $1.38 per mcfe in the six months ended June 30, 2013 compared to $1.59 per mcfe in the same period of 2012. The following table summarizes DD&A expense per mcfe for the three months and six months ended June 30, 2013 and 2012:

	Three Months Ended June 30, (per mcfe)				Six Months Ended June 30, (per mcfe)			
	2013	2012	Change	% Change	2013	2012	Change	% Change
Depletion and amortization	$1.38	$1.58	$(0.20)	(13%)	$1.38	$1.59	$(0.21)	(13%)
Depreciation	0.04	0.05	(0.01)	(20%)	0.04	0.05	(0.01)	(20%)
Accretion and other	0.04	0.03	0.01	33%	0.03	0.03		%
Total DD&A expense	$1.46	$1.66	(0.20)	(12%)	$1.45	$1.67	$(0.22)	(13%)

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, loss on extinguishment of debt and deferred compensation plan expenses. Stock-based compensation includes the amortization of restricted stock grants 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 the six months ended June 30, 2013 and 2012 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Direct operating expense	$ 696	$ 692	$ 1,357	$ 1,049
Brokered natural gas and marketing expense	530	408	779	861
Exploration expense	960	994	2,030	1,922
General and administrative expense	13,263	12,540	23,569	20,698
Total	$15,449	$14,634	$27,735	$24,530

Transportation, gathering and compression expense was $66.0 million in second quarter 2013 compared to $44.7 million in the same period of 2012. Transportation, gathering and compression expense was $128.5 million in the six months ended June 30, 2013 compared to $85.6 million in the same period of 2012. These third party costs are higher than 2012 due to our production growth in the Marcellus Shale where we have third party gathering and compression agreements. We have included these costs in the calculation of average realized prices (including all derivative settlements and third party transportation expenses paid by Range).

Brokered natural gas and marketing expense was $16.7 million in second quarter 2013 compared to $6.5 million in the same period of 2012. Brokered natural gas and marketing expense was $39.0 million in the six months ended June 30, 2013 compared to $10.6 million in the same period of 2012. These costs are higher than 2012 primarily due to an increase in brokered volumes.

Exploration expense was $13.1 million in second quarter 2013 compared to $15.5 million in the same period of 2012. Exploration expense was lower in second quarter 2013 when compared to 2012 due to lower seismic and dry hole costs. The six months ended June 30, 2013 also includes lower seismic and dry hole costs compared to the same period of 2012. The following table details our exploration related expenses for the three months and six months ended June 30, 2013 and 2012 (in thousands):

	Three Months Ended June 30, (per mcfe)				Six Months Ended June 30, (per mcfe)			
	2013	2012	Change	% Change	2013	2012	Change	% Change
Seismic	$ 6,077	$ 9,096	$(3,019)	(33%)	$13,245	$19,768	$(6,523)	(33%)
Delay rentals and other	2,052	1,886	166	9%	7,102	7,589	(487)	(6%)
Personnel expense	3,978	3,434	544	16%	7,629	6,938	691	10%
Stock-based compensation expense	960	993	(33)	(3%)	2,030	1,921	109	6%
Dry hole expense	1	108	(107)	(99%)	(158)	817	(975)	(119%)
Total exploration expense	$13,068	$15,517	(2,449)	(16%)	$29,848	$37,033	$(7,185)	(19%)

Abandonment and impairment of unproved properties was $19.2 million in second quarter 2013 compared to $43.6 million in the same period of 2012. Abandonment and impairment was $34.4 million in the six months ended June 30, 2013 compared to $63.9 million in the same period of 2012. 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. In second quarter 2012, we impaired individually significant unproved properties in Pennsylvania for $23.1 million because we determined that we were not going to drill in the area.

Deferred compensation plan expense was a gain of $6.9 million in second quarter 2013 compared to a loss of $9.3 million in the same period of 2012. 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 $81.04 at March 31, 2013 to $77.32 at June 30, 2013. In the same quarter of the prior year, our stock price increased from $58.14 at March 31, 2012 to $61.87 at June 30, 2012. During the six months ended June 30, 2013 deferred compensation plan expense was $35.5 million compared to $1.5 million in the same period of 2012. Our stock price increased from $62.83 at December 31, 2012 to $77.32 at June 30, 2013. In the same six months of 2012, our stock price decreased from $61.94 at December 31, 2011 to $61.87 at June 30, 2012.

Loss on extinguishment of debt for the second quarter and the six months ended June 30, 2013 was $12.3 million. On May 2, 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 on the repurchased debt.

Income tax expense was $97.5 million in second quarter 2013 compared to $39.0 million in second quarter 2012. The increase in income taxes in second quarter 2013 reflects a 155% increase in income from operations when compared to the same period of 2012. For the second quarter, the effective tax rate was 40.4% in 2013 compared to 41.2% in 2012. Income tax expense was $50.3 million in the six months ended June 30, 2013 compared to $11.2 million in the same period of 2012. For the six months ended June 30, 2013, the increase in income taxes reflects a 374% increase in income from operations when compared to the prior year period. For the six months June 30, 2013, the effective tax rate was 42.4% compared to 44.6% in the six months ended June 30, 2012. The 2013 and 2012 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 our deferred tax asset for future deferred compensation plan distributions to senior executives to the extent their estimated future compensation (including these distributions) would exceed the $1.0 million deductible limit provided under section 162 (m) of the Internal Revenue Code. We expect our effective tax rate to be approximately 40% for the remainder of 2013. Our effective tax rate may be reduced in the third quarter 2013 by tax legislation passed in the Commonwealth of Pennsylvania that may allow us to revise a valuation allowance we currently have recorded for our Pennsylvania net operating loss carryforward.

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

Cash Flow

Cash flows from operations are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivatives. Our cash flows from operations are also impacted by changes in working capital. We generally maintain low cash and cash equivalent balances because we use available funds to reduce our bank debt. Short-term liquidity needs are satisfied by borrowings under our bank credit facility. Because of this, and since our principal source of operating cash flows (proved reserves to be produced in the following year) cannot be reported as working capital, we often have low or negative working capital. We sell a large portion of our production at the wellhead under floating market contracts. From time to time, we enter into various derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future natural gas, NGLs and oil production. The production we hedge has varied and will continue to vary from year to year depending on, among other things, our expectation of future commodity prices. Any payments due to counterparties under our derivative contracts should ultimately be funded by prices received from the sale of our production. Production receipts, however, often lag payments to the counterparties. Any interim cash needs are funded by borrowings under the bank credit facility. As of June 30, 2013, we have entered into hedging agreements covering 132.4 Bcfe for 2013, 196.2 Bcfe for 2014 and 57.3 Bcfe for 2015.

Net cash provided from operations in the first six months 2013 was $279.9 million compared to $282.9 million in the same period of 2012. Cash provided from continuing operations is largely dependent upon commodity prices and production, net of the effects of settlement of our derivative contracts. The decrease in cash provided from operating activities from 2012 to 2013 reflects a 29% increase in production offset by lower realized prices (a decline of 1%) and higher operating costs, including the payment of the Oklahoma lawsuit. As of June 30, 2013, we have hedged approximately 77% of our projected production for the remainder of 2013, with approximately 77% of our projected natural gas production hedged. Net cash provided from continuing operations is also affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital (as reflected in our consolidated statements of cash flows) for first six months 2013 was a negative $45.1 million compared to positive $21.4 million for the same period of 2012.

Net cash used in investing activities from operations in first six months 2013 was $328.1 million compared to $919.7 million in the same period of 2012.

During the six months ended June 30, 2013, we:

· spent $592.7 million on natural gas and oil property additions;

· spent $27.4 million on acreage primarily in the Marcellus Shale and the Mississippian; and

· received proceeds from asset sales of $296.1 million.

During the six months ended June 30, 2012, we:

· spent $781.6 million on natural gas and oil property additions;

· spent $147.9 million on acreage primarily in the Marcellus Shale; and

· received proceeds from asset sales of $15.6 million.

Net cash provided from financing activities in first six months 2013 was $48.2 million compared to $636.8 million in the same period of 2012. Historically, sources of financing have been primarily bank borrowings and capital raised through equity and debt offerings.

During the six months ended June 30, 2013, we:

· borrowed $893.0 million and repaid $1.3 billion under our bank credit facility, ending the quarter with a $309.0 million outstanding balance on our bank debt;

· issued $750.0 million aggregate 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 amount of 7.25% senior subordinated notes due 2018 including related expenses; and

· spent $12.3 million related to debt issuance costs.

During the six months ended June 30, 2012, we:

- borrowed $697.0 million and repaid $649.0 million under our bank credit facility, ending the period with $235.0 million outstanding borrowings under our bank credit facility;

- issued $600.0 million principal amount of 5.00% senior subordinated notes due 2022, at par, with net proceeds of approximately $589.5 million; and

- spent $12.5 million related to debt issuance costs.

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 continue to take steps to ensure adequate capital resources and liquidity to fund our capital expenditure program. In first six months 2013, we entered into additional commodity derivative contracts for 2013, 2014 and 2015 to protect future cash flows. In March 2013, we issued $750.0 million of new 5.00% ten-year senior subordinated notes due 2023. On April 2, 2013, we called for redemption the entire $250.0 million outstanding principal amount of our 7.25% senior subordinated notes due 2018 which were redeemed on May 2, 2013.

During the first six of months 2013, our net cash provided from continuing operations of $279.9 million, proceeds from the sale of assets of $296.1 million, proceeds from the issuance of our 5.00% senior subordinated notes due 2023 and borrowings under our bank credit facility were used to fund $622.2 million of capital expenditures (including acreage acquisitions). At June 30, 2013, we had $284,000 in cash and total assets of $6.9 billion.

Long-term debt at June 30, 2013 totaled $2.9 billion, including $309.0 million outstanding on our bank credit facility and $2.6 billion of senior subordinated notes. Our available committed borrowing capacity at June 30, 2013 was $1.4 billion. Cash is required to fund capital expenditures necessary to offset inherent declines in production and reserves that are typical in the oil and natural gas industry. Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding or acquiring additional reserves. We currently believe that net cash generated from operating activities, unused committed borrowing capacity under the bank credit facility and proceeds from asset sales combined with our natural gas, NGLs and oil derivatives contracts currently in place will be adequate to satisfy near-term financial obligations and liquidity needs. To the extent our capital requirements exceed our internally generated cash flow and proceeds from asset sales, debt or equity securities may be issued to fund these requirements. Long-term cash flows are subject to a number of variables including the level of production and prices as well as various economic conditions that have historically affected the oil and natural gas business. A 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 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.

Our expectations concerning liquidity and our ability to avail ourselves in the future of the financing options mentioned in the above forward-looking statements are based on currently available information. If this information proves to be inaccurate, future availability of financing may be adversely affected. Factors that affect the availability of financing include our performance, the state of the worldwide debt and equity markets, investor perceptions and expectations of past and future performance, the global financial climate and, in particular, with respect to borrowings, the level of our working capital or outstanding debt and credit ratings by rating agencies.

Credit Arrangements

As of June 30, 2013, we maintained a $2.0 billion revolving credit facility, which we refer to as our bank credit facility. The bank credit facility is secured by substantially all of our assets and has a maturity date of February 18, 2016. Availability under the bank credit facility is subject to a borrowing base set by the lenders semi-annually with an option to set more often in certain circumstances. The borrowing base is dependent on a number of factors but primarily on the lenders   assessment of future cash flows. Redeterminations of the borrowing base require approval of two thirds of the lenders; increases to the borrowing base require 97% lender approval. On April 8, 2013, the facility amount on our bank credit facility was reaffirmed at $1.75 billion and our borrowing base was reaffirmed at $2.0 billion. Our current bank group is currently composed of twenty-eight financial institutions.

Our bank 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 were in compliance with all covenants at June 30, 2013.

Capital Requirements

Our primary capital requirements are for exploration, development and acquisition of natural gas and oil properties, repayment of principal and interest on outstanding debt and payment of dividends. During the first six months of 2013, $672.2 million of capital was expended on drilling projects. Also in the first six months of 2013, $31.0 million was expended on acquisitions of unproved acreage, primarily in the Marcellus Shale and in the horizontal Mississippian oil play. Our 2013 capital program, excluding acquisitions, is expected to be funded by net cash flow from operations, our prior debt offering, proceeds from asset sales and borrowings under our bank credit facility. Our capital expenditure budget for 2013 is currently set at $1.3 billion, excluding proved property acquisitions. To the extent capital requirements exceed internally generated cash flow, proceeds from asset sales and our committed capacity under our bank credit facility will be used to fund these requirements. In addition, debt or equity may also be issued in capital market transactions to fund these requirements. We monitor our capital expenditures on an ongoing basis, adjusting the amount up or down and also between our operating regions, depending on commodity prices, cash flow and projected returns. Also, our obligations may change due to acquisitions, divestitures and continued growth. We may issue additional shares of stock, subordinated notes or other debt securities to fund capital expenditures, acquisitions, extend maturities or to repay debt.

The forward-looking statements about our capital budget are based on current expectations, estimates and projections and are not guarantees of future performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially include prices of and demand for natural gas and oil, actions of competitors, disruptions or interruptions of our production and unforeseen hazards such as weather conditions, acts of war or terrorists acts and the government or military response, and other operating and economic considerations.

Cash Dividend Payments

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. On June 1, 2013, the Board of Directors declared a dividend of four cents per share ($6.5 million) on our common stock, which was paid on June 28, 2013 to stockholders of record at the close of business on June 14, 2013.

Cash Contractual Obligations

Our contractual obligations include long-term debt, operating leases, drilling commitments, derivative obligations, asset retirement obligations and transportation and gathering commitments. As of June 30, 2013, we do not have any capital leases. As of June 30, 2013, we do not have any significant off-balance sheet debt or other such unrecorded obligations and we have not guaranteed any debt of any unrelated party. As of June 30, 2013, we had a total of $84.7 million of undrawn letters of credit under our bank credit facility.

Since December 31, 2012, there have been no material changes to our contractual obligations other than a $430.0 million reduction to our outstanding bank credit facility balance, an issuance of $750.0 million of new 5.00% senior subordinated notes due 2023, a redemption of $250.0 million 7.25% senior subordinated notes due 2018 and adjustments to certain transportation and gathering contracts which increased these commitments $135.5 million over the next 10 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. In 2011, we also entered into sold NGL derivative swap contracts for the natural gasoline component of NGLs and in 2012 we entered into re-purchased derivative swaps for the natural gasoline component of NGLs. In addition, in second quarter 2012, we entered into NGL derivative swap contracts for propane. 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.

At June 30, 2013, we had open swap contracts covering 65.5 Bcf of natural gas at prices averaging $3.85 per mcf, 4.4 million barrels of oil at prices averaging $94.18 per barrel, 1.2 million net barrels of NGLs (the C5 component of NGLs) at prices averaging $92.72 per barrel and 1.8 million barrels of NGLs (the C3 component of NGLs) at prices averaging $37.49 per barrel. We had collars covering 267.8 Bcf of natural gas at weighted average floor and cap prices of $4.03 to $4.61 per mcf and 1.3 million barrels of oil at weighted average floor and cap prices of $87.72 to $100.00 per barrel. The fair value of these contracts, represented by the estimated amount that would be realized or payable on termination, based on a comparison of the contract price and a reference price, generally NYMEX, approximated a pretax gain of $127.5 million at June 30, 2013. The contracts expire monthly through December 2015.

At June 30, 2013, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price
Natural Gas			
2013	Collars	280,000 Mmbtu/day	$ 4.59 $ 5.05

2014	Collars	447,500 Mmbtu/day	$ 3.84	$ 4.48
2015	Collars	145,000 Mmbtu/day	$ 4.07	$ 4.56
2013	Swaps	296,685 Mmbtu/day	$3.79	
2014	Swaps	30,000 Mmbtu/day	$4.17	
Crude Oil				
2013	Collars	3,000 bbls/day	$ 90.60	$ 100.00
2014	Collars	2,000 bbls/day	$ 85.55	$ 100.00
2013	Swaps	6,325 bbls/day	$96.77	
2014	Swaps	7,000 bbls/day	$94.14	
2015	Swaps	2,000 bbls/day	$90.20	
NGLs (Natural Gasoline)				
2013	Sold Swaps	8,000 bbls/day	$89.64	
2013	Re-purchased Swaps	1,500 bbls/day	$76.30	
NGLs (Propane)				
2013	Swaps	8,000 bbls/day	$36.79	
2014	Swaps	1,000 bbls/day	$40.32	

Interest Rates

At June 30, 2013, we had approximately $2.9 billion of debt outstanding. Of this amount, $2.7 billion bears interest at fixed rates averaging 5.8%. Bank debt totaling $309.0 million bears interest at floating rates, which averaged 1.8% at June 30, 2013. The 30-day LIBOR rate on June 30, 2013 was approximately 0.2%. A 1% increase in short-term interest rates on the floating-rate debt outstanding on June 30, 2013 would cost us approximately $3.1 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 2013 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 derivatives 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 74% of our December 31, 2012 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, 2012 to June 30, 2013.

Commodity Price Risk

We use commodity-based derivative contracts to manage exposures to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. We do not utilize complex derivatives such as swaptions, knockouts or extendable swaps. At times, certain of our derivatives are swaps where we receive a fixed price for our production and pay market prices to the counterparty. Our derivatives program also includes collars, which establish a minimum floor price and a predetermined ceiling price. At June 30, 2013, our derivatives program includes swaps (both purchased and sold NGL swaps) and collars. As of June 30, 2013, we had open swap contracts covering 65.5 Bcf of natural gas at prices averaging $3.85 per mcf, 4.4 million barrels of oil at prices averaging $94.18 per barrel, 1.2 million net barrels of NGLs (the C5 component of NGLs) at prices averaging $92.72 per barrel and 1.8 million barrels of NGLs (the C3 component of NGLs) at prices averaging $37.49 per barrel. We had collars covering 267.8 Bcf of natural gas at weighted average floor and cap prices of $4.03 to $4.61 per mcf and 1.3 million barrels of oil at weighted average floor and cap prices of $87.72 to $100.00 per barrel. These contracts expire monthly through December 2015. The fair value of these contracts, represented by the estimated amount that would be realized upon immediate liquidation as of June 30, 2013, approximated a net unrealized pretax gain of $127.5 million.

At June 30, 2013, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price	Fair Market Value (in thousands)

Natural Gas				
2013	Collars	280,000 Mmbtu/day	$ 4.59 $ 5.05	$50,512
2014	Collars	447,500 Mmbtu/day	$ 3.84 $ 4.48	$28,084
2015	Collars	145,000 Mmbtu/day	$ 4.07 $ 4.56	$5,787
2013	Swaps	296,685 Mmbtu/day	$3.79	$7,772
2014	Swaps	30,000 Mmbtu/day	$4.17	$2,845
Crude Oil				
2013	Collars	3,000 bbls/day	$ 90.60 $ 100.00	$249
2014	Collars	2,000 bbls/day	$ 85.55 $ 100.00	$1,730
2013	Swaps	6,325 bbls/day	$96.77	$2,006
2014	Swaps	7,000 bbls/day	$94.14	$10,621
2015	Swaps	2,000 bbls/day	$90.20	$3,354
NGLs (Natural Gasoline)				
2013	Sold Swaps	8,000 bbls/day	$89.64	$9,935
2013	Re-purchased Swaps	1,500 bbls/day	$76.30	$1,808
NGLs (Propane)				
2013	Swaps	8,000 bbls/day	$36.79	$1,030
2014	Swaps	1,000 bbls/day	$40.32	$1,786

We expect our NGL production to continue to increase. In our Marcellus Shale operations, propane is a large product component of our NGL production and we believe NGL prices are somewhat seasonal. Therefore, the percentage of NGL 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 markets. Approximately 70% of our NGL production is in the Marcellus Shale.

The relationship between the price of oil and the price of natural gas is at an unprecedented spread. Normally, natural gas liquids production is a by-product of natural gas production. Due to the current differences in prices, we and other producers may choose to sell natural gas at or below cost or otherwise dispose of natural gas to allow for the sale of only natural gas liquids.

Currently, because there is little demand, or facilities to supply the existing demand, for ethane in the Appalachian region, for our Appalachian production volumes, ethane remains in the natural gas stream. We currently have waivers from two transmission pipelines that allow us to leave ethane in the residue natural gas. We have announced three ethane agreements where we have contracted to either sell or transport ethane from our Marcellus Shale area, which are expected to begin operations in late 2013, early 2014 and early 2015. We cannot assure you that these facilities will become available. If we are not able to sell ethane, we may be required to curtail production 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. At times, 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 in the past that effectively fix the basis adjustments. We currently have no financial basis swap agreements outstanding.

The following table shows the fair value of our collars and swaps and the hypothetical change in fair value that would result from a 10% and a 25% change in commodity prices at June 30, 2013. 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	$ 86,363	$(91,107)	$(231,935)	$92,111	$243,130
Swaps	41,156	(80,166)	(199,440)	80,724	201,810

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 June 30, 2013, 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 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 June 30, 2013, we had $2.9 billion of debt outstanding. Of this amount, $2.7 billion bears interest at fixed rates averaging 5.8%. Bank debt totaling $309.0 million bears interest at floating rates, which was 1.8% on June 30, 2013. On June 30, 2013, the 30-day LIBOR rate was approximately 0.2%. A 1% increase in short-term interest rates on the floating-rate debt outstanding on June 30, 2013, would cost us approximately $3.1 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 June 30, 2013 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 June 30, 2013 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

Litigation

James A. Drummond and Chris Parrish v. Range Resources-Midcontinent, LLC et al.; pending in the District Court of Grady County, State of Oklahoma; Case No. CJ-2010-510

Two individuals (one of whom is now deceased), only one of which was a current royalty owner, filed suit against Range Resources Corporation and two of our subsidiaries, including the proper defendant Range Resources-Midcontinent, LLC, in the District Court of Grady County, Oklahoma. This suit is similar to a number of cases filed in Oklahoma asserting claims that royalty owners are entitled to payment of royalties on several different categories of alleged deductions applied by third parties who transport and process natural gas production. The alleged deductions include fuel used by the third party in the transportation and processing of gas, condensate removed by the third party after the point of sale, the contractually agreed natural gas liquids recovery percentages, the percentage of proceeds contracts contractually agreed pricing percentages and other similar alleged deductions. In addition to the claims made with respect to the alleged categories of deductions, the Plaintiffs in this litigation have alleged fraud and the existence of a fiduciary duty to the royalty owners to attempt to support an argument that no statute of limitations applies, and the Plaintiffs also claim that interest accrues on the alleged damages at 12% compounded annually. As previously disclosed, on February 19, 2013, the District Court entered an order certifying a class of royalty owners as requested by the Plaintiffs and we appealed the certification order. While the appeal was pending, the parties successfully mediated the case in May 2013 resulting in a settlement and we executed a Stipulation and Agreement of Settlement, with an effective date of May 31, 2013, providing for a cash payment to the class in the amount of $87.5 million in settlement of all claims made by the class for the period prior to May 31, 2013. Pursuant to the settlement agreement, on June 28, 2013, we paid $87.5 million into an escrow account. While the settlement is subject to the approval by the Court, we currently expect the settlement will receive final approval.

We are the subject of, or party to, a number of other pending or threatened legal actions 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.

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, 2012. There have been no material changes from the risk factors previously disclosed in that Form 10-K.

ITEM 6. EXHIBITS

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 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 28, 2005) and the Certificate of Second Amendment to the 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 (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)
4.1	Form of 5.00% Senior Subordinated Notes due 2023 (incorporated by reference to Exhibit A to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on March 19, 2013)
4.2	Indenture dated March 18, 2013 among Range Resources Corporation, as issuer, the Subsidiary Guarantors (as defined therein) as guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on March 19, 2013)
4.3	Registration Rights Agreement dated March 18, 2013 by and among Range Resources Corporation, the Initial Guarantors (as defined therein), and the Representatives (as defined therein) (incorporated by reference to Exhibit 4.2 on our Form 8-K (File No. 001-12209) as filed with the SEC on March 19, 2013)
10.1*	Stipulation and agreement of Settlement effective May 31, 2013
31.1*	Certification by the President and Chief Executive Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification by the President and Chief Executive Officer of Range 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 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

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: July 24, 2013

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

Date: July 24, 2013

RANGE RESOURCES CORPORATION
By: /s/ DORI A. GINN
Dori A. Ginn
Principal Accounting Officer and Vice President Controller

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