RANGE RESOURCES CORP
Form 10-Q
October 22, 2009

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark one)

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

For the quarterly period ended September 30, 2009

or

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

For the transition period from __________ to __________

Commission file number 001-12209

RANGE RESOURCES CORPORATION

(Exact name of registrant as specified in its charter)

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

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 o

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

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

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

Yes o No þ

157,733,941 Common Shares were outstanding on October 20, 2009.

RANGE RESOURCES CORPORATION
FORM 10-Q
Quarter Ended September 30, 2009

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 shares)

	September 30, 2009 (Unaudited)	December 31, 2008
Assets		
Current assets:		
Cash and equivalents	$ 859	$ 753
Accounts receivable, less allowance for doubtful accounts of $1,888 and $954	97,172	162,201
Unrealized derivative gain	78,410	221,430
Inventory and other	20,735	19,927
Total current assets	197,176	404,311
Unrealized derivative gain		5,231
Equity method investments	151,824	147,126
Oil and gas properties, successful efforts method	6,300,946	6,028,980
Accumulated depletion and depreciation	(1,429,007)	(1,186,934)
	4,871,939	4,842,046
Transportation and field assets	164,102	142,662
Accumulated depreciation and amortization	(69,824)	(56,434)
	94,278	86,228
Other assets	81,165	66,937
Total assets	$ 5,396,382	$ 5,551,879
Liabilities		
Current liabilities:		
Accounts payable	$ 135,881	$ 250,640
Asset retirement obligations	2,118	2,055
Accrued liabilities	59,328	47,309
Deferred tax liability	2,462	32,984
Accrued interest	37,002	20,516
Unrealized derivative loss	9,573	10
Total current liabilities	246,364	353,514
Bank debt	398,000	693,000
Subordinated notes and other long term debt	1,383,480	1,097,668

Deferred tax liability		759,406		779,218
Unrealized derivative loss		5,301		
Deferred compensation liability		132,517		93,247
Asset retirement obligations and other liabilities		85,985		83,890
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, 157,591,936 issued at September 30, 2009 and 155,609,387 issued at December 31, 2008		1,576		1,556
Common stock held in treasury, 233,900 shares at September 30, 2009 and December 31, 2008		(8,557)		(8,557)
Additional paid-in capital		1,743,276		1,695,268
Retained earnings		629,632		685,568
Accumulated other comprehensive income		19,402		77,507
Total stockholders equity		2,385,329		2,451,342
Total liabilities and stockholders equity	$	5,396,382	$	5,551,879

See accompanying notes.

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RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited, in thousands, except per share data)

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Revenues				
Oil and gas sales	$ 202,122	$ 347,720	$ 597,834	$ 1,002,726
Transportation and gathering	2,444	1,537	4,091	3,890
Derivative fair value (loss) income	(482)	272,869	65,209	(47,582)
Other	(443)	544	(6,624)	20,777
Total revenues	203,641	622,670	660,510	979,811
Costs and expenses				
Direct operating	31,111	36,532	101,480	106,710
Production and ad valorem taxes	7,600	15,210	23,421	45,106
Exploration	11,102	19,149	35,809	55,204
Abandonment and impairment of unproved properties	24,053	5,055	84,579	10,653
General and administrative	30,568	24,650	84,581	66,000
Deferred compensation plan	16,445	(37,515)	29,635	(9,365)
Interest expense	30,633	25,373	86,817	72,361
Depletion, depreciation and amortization	97,208	76,690	270,241	218,938
Total costs and expenses	248,720	165,144	716,563	565,607
(Loss) income from operations	(45,079)	457,526	(56,053)	414,204
Income tax (benefit) expense				
Current	(695)	2,374	(76)	4,209
Deferred	(14,566)	170,202	(18,884)	152,551
Total income tax (benefit) expense	(15,261)	172,576	(18,960)	156,760
Net (loss) income	$ (29,818)	$ 284,950	$ (37,093)	$ 257,444
(Loss) income per common share:				
Basic	$ (0.19)	$ 1.87	$ (0.24)	$ 1.71
Diluted	$ (0.19)	$ 1.81	$ (0.24)	$ 1.65

Dividends per common share	$	0.04	$	0.04	$	0.12	$	0.12
Weighted average common shares outstanding:								
Basic		154,653		152,765		154,257		150,487
Diluted		154,653		157,729		154,257		155,896

See accompanying notes.

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RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited, in thousands)

	Nine Months Ended September 30,	
	2009	**2008**
Operating activities:		
Net (loss) income	$ (37,093)	$ 257,444
Adjustments to reconcile net cash provided from operating activities:		
Loss (gain) from equity method investments	6,548	(170)
Deferred income tax (benefit) expense	(18,884)	152,551
Depletion, depreciation and amortization	270,241	218,938
Exploration dry hole costs	342	9,337
Mark-to-market on oil and gas derivatives not designated as hedges	83,393	3,184
Abandonment and impairment of unproved properties	84,579	10,653
Unrealized derivative loss (gain)	483	(1,862)
Deferred and stock-based compensation	58,844	13,413
Amortization of deferred financing costs and other	3,742	2,137
Loss (gain) on sale of assets and other	2,660	(19,415)
Changes in working capital:		
Accounts receivable	38,373	(64,468)
Inventory and other	(807)	(5,263)
Accounts payable	(67,076)	2,927
Accrued liabilities and other	18,423	20,982
Net cash provided from operating activities	443,768	600,388
Investing activities:		
Additions to oil and gas properties	(425,376)	(646,403)
Additions to field service assets	(21,959)	(20,651)
Acreage purchases	(118,724)	(733,767)
Investment in equity method investment	(6,099)	(25,460)
Other assets	8,604	(25,496)
Proceeds from disposal of assets	182,230	66,693
Purchase of marketable securities held by the deferred compensation plan	(6,932)	(9,300)
Proceeds from the sales of marketable securities held by the deferred compensation plan	3,155	6,605
Net cash used in investing activities	(385,101)	(1,387,779)
Financing activities:		
Borrowing on credit facilities	582,000	1,219,000
Repayment on credit facilities	(877,000)	(972,500)
Dividends paid	(18,843)	(18,404)
Debt issuance costs	(6,399)	(5,710)

Issuance of subordinated notes		285,201		250,000
Issuance of common stock		8,368		288,643
Change in cash overdrafts		(37,690)		20,785
Proceeds from the sales of common stock held by the deferred compensation plan		6,049		5,135
Purchases of common stock held by the deferred compensation plan and other treasury stock purchases		(247)		(3,311)
Net cash (used in) provided from financing activities		(58,561)		783,638
Increase (decrease) in cash and equivalents		106		(3,753)
Cash and equivalents at beginning of period		753		4,018
Cash and equivalents at end of period	$	859	$	265

See accompanying notes.

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RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited, in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
Net (loss) income	$ (29,818)	$ 284,950	$ (37,093)	$ 257,444
Other comprehensive (loss) income:				
Realized loss (gain) on hedge derivative contract settlements reclassified into earnings from other comprehensive (loss) income	(34,248)	25,538	(100,070)	53,300
Change in unrealized deferred hedging gains (losses)	(1,218)	222,569	41,965	(60,157)
Total comprehensive (loss) income	$ (65,284)	$ 533,057	$ (95,198)	$ 250,587

See accompanying notes.

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RANGE RESOURCES CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

(1) ORGANIZATION AND NATURE OF BUSINESS

We are engaged in the exploration, development and acquisition of oil and gas properties primarily in the Southwestern and the Appalachian regions of the United States. We seek to increase our reserves and production primarily through drilling and complementary acquisitions. Range Resources Corporation is a Delaware corporation with our common stock listed and traded on the New York Stock Exchange under the symbol RRC.

(2) BASIS OF PRESENTATION

These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in our current report on Form 8-K filed on August 10, 2009 (see additional information below). 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 disclosed otherwise. These consolidated financial statements, including selected notes, have been prepared in accordance with the applicable rules of the Securities and Exchange Commission (SEC) and do not include all of the information and disclosures required by accounting principles generally accepted in the United States of America for complete financial statements. We have evaluated events or transactions that occurred subsequent to September 30, 2009 through the date and time this quarterly report on Form 10-Q was filed.

In second quarter 2009, we identified certain mineral leases amounting to $8.2 million that expired in 2006, 2007, and 2008, which were not expensed as required. Based on Staff Accounting Bulletin No. 108 (SAB 108), we determined that these amounts were immaterial to each of the periods affected and, therefore, we were not required to amend our previously filed reports. However, if these adjustments were recorded in 2009, we believe the impact could be material to this year. Therefore, on August 10, 2009, we adjusted our previously reported results for 2006, 2007, and 2008 for these immaterial amounts (as required by SAB 108), by filing on Form 8-K revised consolidated financial statements for 2006, 2007 and 2008. In addition to recording additional mineral lease expirations, we made four other adjustments to prior year numbers to correct other immaterial items, which included the following adjustments: (1) tax expense of $3.5 million for discrete tax items recorded in 2008 related to 2007 (2) expense for volumetric ineffectiveness related to our derivative positions of $1.7 million recorded in 2008 related to 2007 (3) dry hole expense of $2.4 million not recorded in 2007 and (4) deferred compensation income of $7.1 million recorded in 2007 related to 2006 and prior years. The balance sheet as of December 31, 2008 has been adjusted to reflect the cumulative impact of such adjustments. As a result, oil and gas properties decreased by $10.7 million, deferred tax liability decreased $4.2 million and retained earnings decreased by $6.5 million. The effect of these adjustments on the three months and the nine months September 30, 2008 was to decrease net income $374,000 in the third quarter 2008 and increase net income $5.0 million for the nine months ended September 30, 2008.

We follow Financial Accounting Standards Board (FASB) Accounting Standards Codification Topic 932 Extractive Activities-Oil and Gas for recognizing impairment of capitalized costs related to unproved properties. These costs are capitalized and periodically evaluated (at least quarterly) as to recoverability based on changes brought about by economic factors and potential shifts in business strategy employed by management. We also consider time, geologic and engineering factors to evaluate the need for impairment of these costs. We continue to experience an increase in lease expirations and impairment expense caused by (1) current economic conditions, which have impacted our future drilling plans thereby increasing the amount of expected lease expirations and (2) the expansion of our unproved property positions in new shale plays. As economic conditions change and we continue to evaluate unproved properties, our estimates of expirations will likely change and we may increase or decrease impairment expense. We recorded abandonment and impairment expense in the three and nine months ended September 30, 2009 of $24.1 million and $84.6 million compared to $5.1 million and $10.7 million in the same periods of the prior year. The nine months ended September 30, 2009 includes the expiration of certain sizeable Barnett Shale leases.

(3) NEW ACCOUNTING STANDARDS

In February 2008, the FASB issued Accounting Standards Codification (ASC) 820 10 (formerly Financial Staff Position SFAS No. 157-2), which delayed the effective date of ASC 820 - 10 (formerly SFAS No. 157) for all non-financial assets and non-financial liabilities except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). This deferral primarily applied to our asset retirement obligation, which uses fair value measures at the date incurred to determine our liability and any property impairments that may occur. We adopted the provisions of this standard effective January 1, 2009 and the adoption did not have a material effect on our consolidated results of operations or financial position.

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In June 2008, the FASB issued ASC 260 10 (formerly Staff Position No. EITF 03-6-1), Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities, which provides that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and, therefore, need to be included in the earnings allocation in computing earnings per share under the two class method. We adopted the provisions of this standard on January 1, 2009 with no impact on our reported earnings per share.

In March 2008, the FASB issued ASC 815- 10 (formerly SFAS No. 161), which amends and expands disclosure requirements with the intent to provide users of financial statements with an enhanced understanding of: (i) how and why any entity uses derivative instruments; (ii) how derivative instruments and related hedged items are accounted for; and (iii) how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. The provisions of this standard were adopted on January 1, 2009. See Note 11 for additional disclosures about our derivative instruments and hedging activities.

In December 2007, the FASB issued ASC 805-10 (formerly SFAS No. 141(R)), Business Combinations, which retains the purchase method of accounting for acquisitions, but requires a number of changes, including changes in the way assets and liabilities are recognized in the purchase method of accounting. It changes the recognition of assets acquired and liabilities assumed arising from contingencies, requires the capitalization of in-process research and development at fair value, and requires the expensing of acquisition-related costs as incurred. The provisions of this standard will apply prospectively to business combinations occurring in our fiscal year beginning January 1, 2009 and the adoption did not have an impact on our financial position or results of operations.

In April 2009, the FASB issued additional application guidance and enhancements to disclosures regarding fair value measurements. ASC 825-10 (formerly FASB Staff Position No. FAS 107-1 and APB 28-1), Interim Disclosures about Fair Value of Financial Instruments, enhances consistency in financial reporting by increasing the frequency of fair value disclosures. ASC 820 10 (formerly FASB Staff Position No. FAS 157-4), Determining Fair Value when the Volume and Level of Activity for the Asset or Liability have Significantly Decreased and Identifying Transactions that are Not Orderly, provides guidelines for making fair value measurements more consistent. We adopted the provisions of these standards for the period ended June 30, 2009, which did not have an impact on our financial position or results of operations.

In May 2009, the FASB issued ASC 855-10 (formerly SFAS No. 165), Subsequent Events, which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. We adopted this standard upon issuance with no impact on our financial position or results of operations.

In June 2009, the FASB issued ASC 105-10 (formerly SFAS No. 168), Accounting Standards Codification™ and the Hierarchy of Generally Accepted Accounting Principles. The FASB Accounting Standards Codification™ (Codification) has become the source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in accordance with GAAP. All existing accounting standard documents are superseded by the Codification and any accounting literature not included in the Codification will not be authoritative. However, rules and interpretive releases of the SEC issued under the authority of federal securities laws will continue to be the source of authoritative generally accepted accounting principles for SEC registrants. Effective September 30, 2009, all references made to GAAP in our consolidated financial statements will include the new Codification numbering system along with original references. The Codification does not change or alter existing GAAP and, therefore, will not have an impact on our financial position, results of operations or cash flows.

(4) DISPOSITIONS

In second quarter 2009, we sold certain oil properties located in West Texas for proceeds of $182.0 million. The proceeds from the sale of these properties were credited to oil and gas properties, with no gain or loss recognized, as the disposition did not materially impact the depletion rate of the remaining properties in the amortization base. In first quarter 2008, we sold East Texas properties for proceeds of $64.4 million and recorded a gain of $20.1 million.

(5) INCOME TAXES

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Income tax (benefit) expense	$(15,261)	$172,576	$(18,960)	$156,760
Effective tax rate	33.9%	37.7%	33.8%	37.8%

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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 (loss), except for discrete items. Income taxes for discrete items are computed and recorded in the period that the specific transaction occurs. For the three months ended September 30, 2009, our overall effective tax rate on pre-tax loss from operations was different than the statutory rate of 35% due primarily to state income taxes, valuation allowances and other permanent differences. For the three months ended September 30, 2008, our overall effective tax rate on pre-tax income from operations was different than the statutory rate of 35% due primarily to state income taxes and valuation allowance. For the nine months ended September 30, 2009, our overall effective tax rate on loss from operations was different than the statutory rate of 35% due primarily to state income taxes, valuation allowance and other permanent differences. For the nine months September 30, 2008, our overall effective tax rate on income from operations was different than the statutory rate due primarily to state income taxes.

(6) EARNINGS (LOSS) PER COMMON SHARE

Basic income (loss) per share is based on weighted average number of common shares outstanding. Diluted income (loss) per share includes restricted stock, the exercise of stock options, stock appreciation rights (or SARs), provided the effect is not anti-dilutive. The following table sets forth the computation of basic and diluted earnings (loss) per common share (in thousands except per share amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Numerator:				
Net (loss) income	$ (29,818)	$ 284,950	$ (37,093)	$ 257,444
Denominator:				
Weighted average common shares outstanding basic	154,653	152,765	154,257	150,487
Effect of dilutive securities:				
Employee stock options, SARs and stock held in the deferred compensation plan		4,964		5,409
Weighted average common shares diluted	154,653	157,729	154,257	155,896
Loss per common share:				
Basic net (loss) income	$ (0.19)	$ 1.87	$ (0.24)	$ 1.71
Diluted net (loss) income	$ (0.19)	$ 1.81	$ (0.24)	$ 1.65

The weighted average common shares basic amount excludes 2.7 million shares at September 30, 2009 and 2.3 million shares at September 30, 2008, of restricted stock that is held in our deferred compensation plan (although all restricted stock is issued and outstanding upon grant). Due to our net loss from operations for the three months and the nine months ended September 30, 2009, we excluded 7.6 million of outstanding stock options/SARs and 2.7 million of restricted stock held in our deferred compensation plans from the computations of diluted net loss per share because the effect would have been anti-dilutive. Stock appreciation rights for 1.1 million shares for the three months ended September 30, 2008 and 187,000 shares for the nine months ended September 30, 2008 were outstanding but not included in the computations of diluted net income per share because the grant prices of the SARs were greater than the average market price of the common shares and would be anti-dilutive to the computations.

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(7) SUSPENDED EXPLORATORY WELL COSTS

The following table reflects the changes in capitalized exploratory well costs for the nine months ended September 30, 2009 and the year ended December 31, 2008 (in thousands):

	September 30, 2009	December 31, 2008
Beginning balance at January 1	$ 47,623	$ 15,053
Additions to capitalized exploratory well costs pending the determination of proved reserves	35,377	43,968
Reclassifications to wells, facilities and equipment based on determination of proved reserves	(12,234)	(3,847)
Capitalized exploratory well costs charged to expense		(7,551)
Balance at end of period	70,766	47,623
Less exploratory well costs that have been capitalized for a period of one year or less	(44,470)	(41,681)
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$ 26,296	$ 5,942
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	13	3

The $70.8 million of capitalized exploratory well costs at September 30, 2009 was incurred in 2009 ($21.3 million), in 2008 ($43.5 million) and in 2007 ($6.0 million). Of the thirteen projects that have exploratory costs capitalized for more than one year, twelve projects are Marcellus Shale wells, which are waiting on the completions of pipelines.

(8) INDEBTEDNESS

We had the following debt outstanding as of the dates shown below (in thousands) (bank debt interest rate at September 30, 2009 is shown parenthetically). No interest expense was capitalized during the three months or the nine months ended September 30, 2009 and 2008.

	September 30, 2009	December 31, 2008
Bank debt (2.2%)	$ 398,000	$ 693,000
Subordinated debt:		
7.375% Senior Subordinated Notes due 2013, net of discount	198,262	197,968
6.375% Senior Subordinated Notes due 2015	150,000	150,000
7.5% Senior Subordinated Notes due 2016, net of discount	249,626	249,595
7.5% Senior Subordinated Notes due 2017	250,000	250,000
7.25% Senior Subordinated Notes due 2018	250,000	250,000
8.0% Senior Subordinated Notes due 2019, net of discount	285,592	
Other		105

Total debt	$ 1,781,480	$ 1,790,668

Bank Debt

In October 2006, we entered into an amended and restated revolving bank facility, which we refer to as our bank debt or our bank credit facility, which is secured by substantially all of our assets. The bank credit facility provides for an initial commitment equal to the lesser of the facility amount or the borrowing base. On September 30, 2009, the borrowing base was $1.5 billion and our facility amount was $1.25 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 September 30, 2009, our borrowing base was reaffirmed at $1.5 billion and our facility amount was also reaffirmed at $1.25 billion. Our current bank group is comprised of twenty-six commercial banks each holding between 2.4% and 5.0% of the total facility. Of those twenty-six banks, thirteen are domestic banks and thirteen are foreign banks or wholly owned subsidiaries of foreign banks. The facility amount may be increased up to the borrowing base amount with twenty days notice, subject to payment of a mutually acceptable commitment fee to those banks agreeing to participate in the facility amount increase. At September 30, 2009, the outstanding balance under the bank credit facility was $398.0 million and there was $852.0 million of borrowing capacity available under the facility amount. The loan matures October 25, 2012. Borrowing under the bank credit facility can either be the Alternate Base Rate (as defined) plus a spread ranging from 0.875% to 1.625% or LIBOR borrowings at the adjusted LIBO Rate (as defined) plus a spread ranging from 1.75% 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 part of the base rate loans to LIBOR loans. The weighted average interest rate on the bank credit facility was 2.2% for the three months ended September 30, 2009 compared to 4.3% for the three months ended September 30, 2008. The weighted average interest rate on the bank credit facility was 2.5% for the nine months ended September 30, 2009 compared to 4.7% in the same period of the prior year. A commitment fee is paid on the undrawn balance based on an annual rate of between 0.375% and 0.50%. At September 30, 2009, the commitment fee was 0.375% and the interest rate margin was 1.75% on our LIBOR loans and 0.875% on our base rate loans. At October 20, 2009, the interest rate (including applicable margin) was 2.1%.

Senior Subordinated Notes

In May 2009, we issued $300.0 million aggregate principal amount of 8.0% senior subordinated notes due 2019 (8.0% Notes). The 8.0% Notes were issued at a discount, which is being amortized over the life of the 8.0% Notes. Interest on the 8.0% Notes is payable semi-annually, in May and November, and is guaranteed by certain of our subsidiaries. We may redeem the 8.0% Notes, in whole or in part, at any time on or after May 15, 2014, at redemption prices of 104.0% of the principal amount as of May 15, 2014 declining to 100.0% on May 15, 2017 and thereafter. Before May 15, 2012, we may redeem up to 35% of the original aggregate principal amount of the 8.0% Notes at a redemption price equal to 108.0% of the principal amount thereof, plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings, provided that at least 65% of the original aggregate principal amount of the 8.0% Notes remain 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.

Debt Covenants

Our bank credit facility contains negative covenants that limit our ability, among other things, to pay cash dividends, incur additional indebtedness, sell assets, enter into certain hedging contracts, change the nature of our business or operations, merge, consolidate, or make investments. In addition, we are required to maintain a ratio of debt to EBITDAX (as defined in the credit agreement) of no greater than 4.0 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 September 30, 2009.

The indentures governing our senior subordinated notes contain various restrictive covenants that are substantially identical to each other and may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, enter into transactions with affiliates, or change the nature of our business. At September 30, 2009, we were in compliance with these covenants.

(9) ASSET RETIREMENT OBLIGATIONS

Our asset retirement obligation primarily represents the estimated present value of the amount 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. A reconciliation of our liability for plugging, abandonment and remediation costs for the nine months ended September 30, 2009 is as follows (in thousands):

	Nine Months Ended September 30, 2009
Beginning of period	$ 83,457
Liabilities incurred	1,364
Liabilities settled	(533)

Liabilities sold		(7,287)
Accretion expense		4,431
Change in estimate		2,551
End of period	$	83,983

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Accretion expense is recognized as a component of depreciation, depletion and amortization on our consolidated statement of operations.

(10) CAPITAL STOCK

We have authorized capital stock of 485 million shares, which includes 475 million shares of common stock and 10 million shares of preferred stock. The following is a summary of changes in the number of common shares outstanding since the beginning of 2008:

	Nine Months Ended September 30, 2009	Year Ended December 31, 2008
Beginning balance	155,375,487	149,511,997
Public offering		4,435,300
Stock options/SARs exercised	1,032,671	1,339,536
Restricted stock grants	475,306	167,054
Treasury shares		(78,400)
Issued for acreage purchases	474,572	
Ending balance	157,358,036	155,375,487

Treasury Stock

The Board of Directors has approved up to $10.0 million of repurchases of common stock based on market conditions and opportunities. During 2008, we repurchased 78,400 shares of common stock at an average price of $41.11 for a total of $3.2 million. We have $6.8 million remaining under this authorization.

(11) DERIVATIVE ACTIVITIES

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. These contracts consist of collars and fixed price swaps. We do not utilize complex derivatives such as swaptions, knockouts or extendable swaps. At September 30, 2009, we had open swap contracts covering 7.1 Bcf of gas at prices averaging $8.16 per mcf. We also had collars covering 78.9 Bcf of gas at weighted average floor and cap prices of $5.96 to $7.70 per mcf and 0.6 million barrels of oil at weighted average floor and cap prices of $63.43 to $76.01 per barrel. Their fair value, represented by the estimated amount that would be realized upon termination, based on a comparison of the contract prices and a reference price, generally New York Mercantile Exchange (NYMEX), on September 30, 2009, was a net unrealized pre-tax gain of $80.5 million. These contracts expire monthly through December 2010.

The following table sets forth our derivative volumes and average hedge prices as of September 30, 2009:

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural Gas			
2009	Swaps	76,739 Mmbtu/day	$8.16
2009	Collars	184,837 Mmbtu/day	$7.64-$8.53
2010	Collars	169,671 Mmbtu/day	$5.50-$7.47
Crude Oil			
2009	Collars	6,000 bbl/day	$63.43-$76.01

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As required by the Derivatives and Hedging Topic of the Codification, every derivative instrument is recorded on the balance sheet as either an asset or a liability measured at its fair value. Fair value is generally determined based on the difference between the fixed contract price and the underlying estimated market price at the determination date. Changes in the fair value of effective cash flow hedges are recorded as a component of Accumulated other comprehensive income (loss), (AOCI) on our consolidated balance sheet which is later transferred to earnings when the underlying physical transaction occurs. Amounts included in AOCI at September 30, 2009 and December 31, 2008 relate solely to our derivative activities. If the derivative does not qualify as a hedge or is not designated as a hedge, changes in fair value of the derivative are recognized in earnings. As of September 30, 2009, an unrealized pre-tax derivative gain of $30.8 million was recorded in AOCI. This gain is expected to be reclassified into earnings as a $38.3 million gain in 2009 and as a $7.5 million loss in 2010. The actual reclassification to earnings will be based on market prices at the contract settlement date.

For those derivative instruments that qualify for hedge accounting, settled transaction gains and losses are determined monthly, and are included as increases or decreases to oil and gas sales in the period the hedged production is sold. Oil and gas sales include $54.4 million of gains in the three months ended September 30, 2009 compared to losses of $41.2 million in the three months ended September 30, 2008 related to settled hedging transactions. For the nine months ended September 30, 2009, oil and gas sales include $158.8 million of gains compared to losses of $86.0 million in the same period of the prior period related to settled hedging transactions. Any ineffectiveness associated with these hedges is reflected in the statement of operations caption called Derivative fair value income (loss). The ineffective portion is calculated as the difference between the change in fair value of the derivative and the estimated change in future cash flows from the item hedged. The three months ended September 30, 2009 include ineffective unrealized losses of $386,000 compared to unrealized gains of $4.6 million in the same period of 2008. The nine months ended September 30, 2009 include ineffective unrealized losses of $483,000 compared to unrealized gains of $1.9 million in the same period of 2008.

To designate a derivative as a cash flow hedge, we document at the hedge s inception our assessment that the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. This assessment, which is updated at least quarterly, is generally based on the most recent relevant historical correlation between the derivative and the item hedged. The ineffective portion of the hedge is calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged. If, during the derivative s term, we determine the hedge is no longer highly effective, hedge accounting is prospectively discontinued and any remaining unrealized gains or losses, based on the effective portion of the derivative at that date, are reclassified to earnings as oil or gas sales when the underlying transaction occurs. If it is determined that the designated hedge transaction is not probable to occur, any unrealized gains or losses are recognized immediately in the statement of operations as a Derivative fair value income or loss. During the first nine months of 2009, there were gains of $5.4 million reclassified into earnings as a result of the discontinuance of hedge accounting treatment for these derivatives. Due to the sale of certain West Texas oil properties in the second quarter 2009, we liquidated four oil commodity contracts and received proceeds of $119,000 in July 2009.

Some of our derivatives do not qualify for hedge accounting but provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and gas production. These contracts are accounted for using the mark-to-market accounting method. We recognize all unrealized and realized gains and losses related to these contracts in the consolidated statement of operations caption called Derivative fair value income (loss) (see table below).

In addition to the swaps and collars discussed above, we have entered into basis swap agreements, which do not qualify for hedge accounting and are marked to market. The price we receive for our gas production can be more or less than the NYMEX price because of adjustments for delivery location (basis), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix a portion of our basis adjustments. The fair value of the basis swaps was a net unrealized pre-tax loss of $16.9 million at September 30, 2009 and these basis swaps expire through 2011.

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Derivative Fair Value (Loss) Income

The following table presents information about the components of derivative fair value (loss) income in the three months and the nine months ended September 30, 2009 and 2008 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Hedge ineffectiveness realized	$ 1,581	$ (213)	$ 3,159	$ 2
unrealized	(386)	4,553	(483)	1,862
Change in fair value of derivatives that do not qualify for hedge accounting[a]	(53,323)	294,317	(83,393)	(3,184)
Realized gain (loss) on settlements gas[a] [b]	51,619	(18,520)	138,361	(30,192)
Realized gain (loss) on settlements oil[a] [b]	27	(7,268)	7,565	(16,070)
Derivative fair value (loss) income	$ (482)	$ 272,869	$ 65,209	$ (47,582)

[a] Derivatives that do not qualify for hedge accounting.

[b] These amounts represent the realized gains and losses on settled derivatives that do not qualify for hedge accounting, which before settlement are included in the category above called change in fair value of derivatives that do not qualify for hedge accounting.

The combined fair value of derivatives included in our consolidated balance sheets as of September 30, 2009 and December 31, 2008 is summarized below (in thousands). We conduct derivative activities with thirteen financial institutions, eleven of which are secured lenders in our bank credit facility. We believe all of these institutions are acceptable credit risks. At times, such risks may be concentrated with certain counterparties. The credit worthiness of our counterparties is subject to periodic review. On our balance sheet, derivative assets and liabilities are netted where derivatives with both gain and loss positions are held by a single counterparty.

	September 30, 2009	December 31, 2008
Derivative assets:		
Natural gas swaps	$ 24,698	$ 57,280
collars	59,680	121,781
basis swaps	(5,406)	12,434
Crude oil collars	(562)	35,166
	$ 78,410	$ 226,661
Derivative liabilities:		
Natural gas swaps	$	$
collars	(3,306)	
basis swaps	(11,511)	(10)
Crude oil collars	(57)	
	$ (14,874)	$ (10)

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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 our consolidated balance sheets (in thousands):

	September 30, 2009			December 31, 2008		
	Assets	(Liabilities)		Assets	(Liabilities)	
	Carrying Value	Carrying Value	Net Carrying Value	Carrying Value	Carrying Value	Net Carrying Value
Derivatives that qualify for cash flow hedge accounting:						
Collars[1]	$ 44,848	$ (1,964)	$ 42,884	$ 124,193	$	$ 124,193
	$ 44,848	$ (1,964)	$ 42,884	$ 124,193	$	$ 124,193
Derivatives that do not qualify for hedge accounting:						
Swaps[1]	$ 24,697	$	$ 24,697	$ 57,280	$	$ 57,280
Collars[1]	13,190	(318)	12,872	32,754		32,754
Basis swaps[1]	594	(17,511)	(16,917)	12,481	(57)	12,424
	$ 38,481	$ (17,829)	$ 20,652	$ 102,515	$ (57)	$ 102,458

(1) Included in unrealized derivative gain/(loss) on our balance sheet.

The effects of our cash flow hedges on accumulated other comprehensive income (loss) on the consolidated balance sheets are summarized below:

	Three Months Ended September 30,			
	Change in Hedge Derivative Fair Value		Realized Gain (Loss) Reclassified from OCI into Revenue[a]	
	2009	2008	2009	2008
Swaps	$	$ 26,398	$	$ (22,893)
Collars	(1,934)	332,584	54,362	(18,298)
Income taxes	716	(136,413)	(20,114)	15,653
	$ (1,218)	$ 222,569	$ 34,248	$ (25,538)

	Nine Months Ended September 30,			
	Change in Hedge Derivative Fair Value		Realized Gain (Loss) Reclassified from OCI into Revenue[(a)]	
	2009	2008	2009	2008
Swaps	$	$ (39,276)	$	$ (19,765)
Collars	67,386	(57,750)	158,842	(66,203)
Income taxes	(25,421)	36,869	(58,772)	32,668
	$ 41,965	$ (60,157)	$ 100,070	$ (53,300)

(a) For realized gains upon contract settlement, the reduction in other comprehensive income is offset by an increase in oil and gas revenue. For realized losses upon contract settlement, the increase in other comprehensive income is offset by a decrease in oil and gas revenue.

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The effects of our non-hedge derivatives and the ineffective portion of our hedge derivatives on our consolidated statement of operations is summarized below:

	Three Months Ended September 30,					
	Gain (Loss) Recognized in Income (Non-Hedge)		Gain (Loss) Recognized in Income (Ineffective Portion)		Derivative Fair Value Income (Loss)	
	2009	2008	2009	2008	2009	2008
Swaps	$ 6,540	$ 194,821	$	$ 802	$ 6,540	$ 195,623
Collars	4,976	70,819	1,195	3,538	6,171	74,357
Basis Swaps	(13,193)	2,889			(13,193)	2,889
Total	$ (1,677)	$ 268,529	$ 1,195	$ 4,340	$ (482)	$ 272,869

	Nine Months Ended September 30,					
	Gain (Loss) Recognized in Income (Non-Hedge)		Gain (Loss) Recognized in Income (Ineffective Portion)		Derivative Fair Value Income (Loss)	
	2009	2008	2009	2008	2009	2008
Swaps	$ 60,098	$ (43,080)	$	$ (655)	$ 60,098	$ (43,735)
Collars	29,846	(19,731)	2,676	2,519	32,522	(17,212)
Basis Swaps	(27,411)	13,365			(27,411)	13,365
Total	$ 62,533	$ (49,446)	$ 2,676	$ 1,864	$ 65,209	$ (47,582)

(12) FAIR VALUE MEASUREMENTS

We use a market approach for our fair value measurements and endeavor to use the best information available. Accordingly, valuation techniques that maximize the use of observable impacts are favored. The following presents the fair value hierarchy table for assets and liabilities measured at fair value, on a recurring basis (in thousands):

	Fair Value Measurements at September 30, 2009 Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of September 30, 2009
Trading securities held in the deferred compensation plans	$ 44,428	$	$	$ 44,428

Derivatives swaps	24,698	24,698
collars	55,755	55,755
basis swaps	(16,917)	(16,917)

These items 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. Our trading securities in Level 1 are exchange-traded and measured at fair value with a market approach using September 30, 2009 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 the balance sheet category called other assets. 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/losses are included in the statement of operations category called Deferred compensation plan expense. For the three months ended September 30, 2009, interest and dividends were $45,000 and mark-to-market was a gain of $5.7 million. For the three months ended September 30, 2008, interest and dividends were $52,000 and the mark-to-market was a loss of $6.3 million. For the nine months ended September 30, 2009, interest and dividends were $138,000 and mark-to-market was a gain of $9.1 million. For the nine months ended September 30, 2008, interest and dividends were $319,000 and the mark-to-market was a loss of $11.5 million.

The following table presents the carrying amounts and the fair values of our financial instruments as of September 30, 2009 and December 31, 2008 (in thousands):

	September 30, 2009		December 31, 2008	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:				
Commodity swaps and collars	$ 78,410	$ 78,410	$ 226,661	$ 226,661
Marketable securities[(a)]	44,428	44,428	33,473	33,473
Liabilities:				
Commodity swaps and collars	(14,874)	(14,874)	(10)	(10)
Long-term debt[(b)]	(1,781,480)	(1,789,230)	(1,790,668)	(1,621,793)

(a) Marketable securities are held in our deferred compensation plans.

(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.

Concentration of Credit Risk

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 necessary to limit risk of loss. Our allowance for uncollectible receivables was $1.9 million at September 30, 2009 and $954,000 at December 31, 2008. Commodity-based contracts expose us to the credit risk of nonperformance by the counterparty to the contracts. These contracts consist of collars and fixed price swaps. This exposure is diversified among major investment grade financial institutions and we have master netting agreements with the counterparties that provide for offsetting payables against receivables from separate derivative contracts. Our derivative counterparties include thirteen financial institutions, eleven of which are secured lenders in our bank credit facility. Mitsui & Co. and J. Aron & Company are the two counterparties not in our bank group. At September 30, 2009, our net derivative asset includes a payable to J. Aron & Company of $965,000 and a receivable from Mitsui & Co. for $4.9 million. None of our derivative contracts have margin requirements or collateral provisions that would require funding prior to the scheduled cash settlement date.

(13) EMPLOYEE BENEFIT AND EQUITY PLANS

We have two active equity-based stock plans. Under these plans, incentive and nonqualified options, SARs and annual cash incentive awards may be issued to directors and employees pursuant to decisions of the Compensation Committee, which is made up of non-employee, independent directors from the Board of Directors. All awards granted have been issued at prevailing market prices at the time of the grant. Since the middle of 2005, only SARs have been granted under the plans to limit the dilutive impact of our equity plans. Information with respect to stock option and SARs activities is summarized below:

	Shares	Weighted Average Exercise Price
Outstanding on December 31, 2008	7,248,666	$ 26.15
Granted	1,705,429	36.85
Exercised	(1,287,291)	13.44
Expired/forfeited	(61,548)	40.08
Outstanding on September 30, 2009	7,605,256	$ 30.58

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The following table shows information with respect to outstanding stock options and SARs at September 30, 2009:

	Outstanding			Exercisable	
Range of Exercise Prices	Shares	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
$1.29 $9.99	933,036	2.18	$ 3.39	933,036	$ 3.39
10.00 19.99	1,390,634	0.65	16.79	1,390,634	16.79
20.00 29.99	1,150,961	1.48	24.30	1,140,261	24.28
30.00 39.99	2,424,333	3.34	34.14	767,380	34.42
40.00 49.99	619,437	4.59	41.73	55,485	41.69
50.00 59.99	713,440	3.39	58.49	214,387	58.57
60.00 69.99	26,677	3.63	65.40	8,529	65.33
70.00 75.00	346,738	3.64	75.00	122,563	75.00
Total	7,605,256	2.54	$ 30.58	4,632,275	$ 22.72

The weighted average fair value of an option/SAR to purchase one share of common stock granted during 2009 was $15.41. The fair value of each stock option/SAR granted during 2009 was estimated as of the date of grant using the Black-Scholes-Merton option-pricing model based on the following average assumptions: risk-free interest rate of 1.5%; dividend yield of 0.4%; expected volatility of 59%; and an expected life of 3.5 years.

As of September 30, 2009, the aggregate intrinsic value (the difference in value between exercise and market price) of the awards outstanding was $158.6 million. The aggregate intrinsic value and weighted average remaining contractual life of stock option awards currently exercisable was $128.7 million and 1.7 years. As of September 30, 2009, the number of fully vested awards and awards expected to vest was 7.5 million. The weighted average exercise price and weighted average remaining contractual life of these awards was $30.35 and 2.5 years and the aggregate intrinsic value was $157.2 million. As of September 30, 2009, unrecognized compensation cost related to the awards was $32.1 million, which is expected to be recognized over a weighted average period of 1.2 years. Of the 7.6 million stock option/SARs outstanding at September 30, 2009, 1.6 million are stock options and 6.0 million are SARs.

Restricted Stock Grants

During the first nine months of 2009, 539,000 shares of restricted stock (or non-vested shares) were issued to employees at an average price of $37.83 with a three-year vesting period and 22,700 shares were granted to our directors at an average price of $41.60 with immediate vesting. In the first nine months of 2008, we issued 314,000 shares of restricted stock as compensation to employees at an average price of $65.40 with a three-year vesting period and 10,800 shares were granted to our directors at a price of $75.00 with immediate vesting. We recorded compensation expense related to restricted stock grants which is based upon the market value of the shares on the date of grant of $13.1 million in the first nine months of 2009 compared to $10.7 million in the nine-month period ended September 30, 2008. As of September 30, 2009, unrecognized compensation cost related to restricted stock awards was $25.9 million, which is expected to be recognized over the weighted average period of 1.2 years (not including the mark-to-market expense (income) that would also be recognized over that same time period see Deferred Compensation Plan discussion below). All of our restricted stock grants are held in our deferred compensation plans (see also discussion below). All awards granted have been issued at prevailing market prices at the time of the grant and the vesting of these shares is based upon an employee s continued employment with us.

A summary of the status of our non-vested restricted stock outstanding at September 30, 2009 is presented below:

	Weighted Average Grant

	Shares		Date Fair Value
Non-vested shares outstanding at December 31, 2008	473,547	$	48.50
Granted	561,267		37.98
Vested	(367,700)		40.45
Forfeited	(7,767)		38.32
Non-vested shares outstanding at September 30, 2009	659,347	$	44.16

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Deferred Compensation Plan

Our deferred compensation plan gives directors, officers and key employees the ability to defer all or a portion of their salaries and bonuses and invest such amounts in Range common stock or make other investments at the individual s discretion. The assets of the plan are held in a grantor trust, which we refer to as the Rabbi Trust, and are therefore available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Our stock granted and 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 associated with the vested portion of the stock held in the Rabbi Trust is adjusted to fair value each reporting period by a charge or credit to deferred compensation plan expense on our consolidated statement of operations. The assets of the Rabbi Trust, other than Range common stock, are invested in marketable securities and reported at market value under the caption other assets on our consolidated balance sheet. Changes in the market value of the securities are charged or credited to deferred compensation plan expense each quarter. The deferred compensation liability on our balance sheet reflects the vested market value of the marketable securities and Range common stock held in the Rabbi Trust. We recorded non-cash, mark-to-market expense related to our deferred compensation plan of $16.4 million in the third quarter 2009 and $29.6 million in the first nine months of 2009 compared to mark-to-market income of $37.5 million in the third quarter 2008 and $9.4 million in the first nine months of 2008.

(14) SUPPLEMENTAL CASH FLOW INFORMATION

	Nine Months Ended September 30,	
	2009	2008
	(in thousands)	
Non-cash investing and financing activities included:		
Asset retirement costs (removed) capitalized, net	$ (3,373)	$ (7,389)
Unproved property purchased with stock	$20,548	$
Net cash provided from operating activities included:		
Interest paid	$66,556	$59,590
Income taxes paid (refunded)	$ (493)	$ 4,554

(15) COMMITMENTS AND CONTINGENCIES

Transportation Contracts

We have entered firm transportation contracts with various pipelines. Under these contracts, we are obligated to transport minimum daily gas volumes, as calculated on a monthly basis, or pay for any deficiencies at a specified reservation fee rate. In most cases, our production committed to these pipelines is expected to exceed the minimum daily volumes provided in the contracts. As of September 30, 2009, future minimum transportation fees under our gas transportation commitments are as follows (in thousands):

2009 remaining	$ 8,891
2010	34,663
2011	34,180
2012	31,220
2013	30,349
2014	27,070
Thereafter	207,240
	$ 373,613

Litigation

We are involved in various legal actions and claims arising in the ordinary course of our business. While the outcome of these lawsuits cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations.

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(16) CAPITALIZED COSTS AND ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION[a]

	September 30, 2009	December 31, 2008
	(in thousands)	
Oil and gas properties:		
Properties subject to depletion	$ 5,534,009	$ 5,271,021
Unproved properties	766,937	757,959
Total	6,300,946	6,028,980
Accumulated depreciation, depletion and amortization	(1,429,007)	(1,186,934)
Net capitalized costs	$ 4,871,939	$ 4,842,046

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

(17) COSTS INCURRED FOR PROPERTY ACQUISITIONS, EXPLORATION AND DEVELOPMENT[a]

	Nine Months Ended September 30, 2009	Year Ended December 31, 2008
	(in thousands)	
Acquisitions:		
Unproved leasehold	$	$ 99,446
Proved oil and gas properties	445	251,471
Asset retirement obligations		251
Acreage purchases[b]	123,421	494,341
Development	376,254	729,268
Exploration:		
Drilling	41,063	133,116
Expense	32,878	63,560
Stock-based compensation expense	2,933	4,130
Gas gathering facilities	19,959	47,056
Subtotal	596,953	1,822,639
Asset retirement obligations	(3,373)	4,647
Total costs incurred	$ 593,580	$ 1,827,286

(a) Includes costs incurred whether capitalized or expensed.

(b) The nine months ended September 30, 2009 includes 474,572 shares of stock issued to purchase $20.5 million of Marcellus acreage.

(18) OFFICE CLOSING

We have announced the closing of our Gulf Coast Area administrative and operations office in Houston, Texas. The properties will be operated out of our Southwest Area office in Fort Worth effective November 1, 2009. As of September 30, 2009, we have accrued $840,000 of severance costs. At the time of closure, employee severance costs, and lease termination costs are not expected to be material. Expenses related to lease termination and severance costs are included in general and administrative expenses in our consolidated statement of operations.

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(19) ACCOUNTING STANDARDS NOT YET ADOPTED

In December 2008, the SEC announced that it had approved revisions to its oil and gas reporting disclosures. The new disclosure requirements include provisions that:

- Introduce a new definition of oil and gas producing activities. This new definition allows companies to include in their reserve base volumes from unconventional resources. Such unconventional resources include bitumen extracted from oil sands and oil and gas extracted from coal beds and shale formations.
- Require companies to report oil and gas reserves using an unweighted average price using the prior 12-month period, based on the closing prices on the first day of each month, rather than year-end prices. The SEC indicated they will continue to communicate with the FASB staff to align FASB s accounting standards with these rules. The FASB currently requires a single-day, year-end price for accounting purposes.
- Permit companies to disclose their probable and possible reserves on a voluntary basis. In the past, proved reserves were the only reserves allowed in the disclosures.
- Require companies to provide additional disclosure regarding the aging of proved undeveloped reserves.
- Permit the use of reliable technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes.
- Replace the existing certainty test for areas beyond one offsetting drilling unit from a productive well with a reasonable certainty test.
- Require additional disclosures regarding the qualifications of the chief technical person who oversees the company s overall reserve estimation process. Additionally, disclosures regarding internal controls over reserve estimation, as well as a report addressing the independence and qualifications of its reserves preparer or auditor will be mandatory.

We will begin complying with the disclosure requirements in our annual report on Form 10-K for the year ending December 31, 2009. The new rules may not be applied to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required. We are currently in the process of evaluating the new requirements.

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

The following discussion should be read in conjunction with management s discussion and analysis contained in our 2008 Annual Report on Form 10-K, as well as the consolidated financial statements and notes thereto included in this Quarterly Report on Form 10-Q. Statements in our discussion may be forward-looking. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. For additional risk factors affecting our business, see the information in Item 1A. Risk Factors, in our 2008 Annual Report on Form 10-K and subsequent filings. The three months and the nine months ended September 30, 2008 have been adjusted for certain immaterial amounts. See also Note 2 of this report.

Critical Accounting Estimates and Policies

The preparation of financial statements in accordance with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Actual results could differ from the estimates and assumptions used. These policies and estimates are described in the 2008 Form 10-K except as updated below. We have identified the following critical accounting policies and estimates used in the preparation of our financial statements: accounting for oil and gas revenue, oil and gas properties, stock-based compensation, derivative financial instruments, asset retirement obligations and deferred taxes.

We adhere to FASB Accounting Standards Codification Topic 932 Extractive Activities Oil and Gas, for recognizing impairment of capitalized costs related to unproved properties. These costs are capitalized and periodically evaluated (at least quarterly) as to recoverability based on changes brought about by economic factors and potential shifts in business strategy employed by management. We also consider time, geologic and engineering factors to evaluate the need for impairment of these costs. We continue to experience an increase in lease expirations and impairment expense caused by (1) current economic conditions, which have impacted our future drilling plans thereby increasing the amount of expected lease expirations, and (2) the rapid expansion of our unproved property positions in new shale plays. As economic conditions change and we continue to evaluate unproved properties, our estimates of expirations likely will change and we may increase or decrease impairment expense. We recorded abandonment and impairment expense in the three and nine months ended September 30, 2009 of $24.1 million and $84.6 million compared to $5.1 million and $10.7 million in the same periods of the prior year.

Results of Continuing Operations

Overview

Total revenues declined $419.0 million, or 67% for third quarter 2009 over the same period of 2008. The decrease includes a $273.4 million decrease in derivative fair value (loss) income and a $145.6 million decrease in oil and gas sales. Oil and gas sales vary due to changes in volumes of production sold and realized commodity prices. Due to volatility in oil and gas prices, realized prices dropped sharply from the same period of the prior year, which was partially offset by an increase in production. For third quarter 2009, production increased 13% from the same period of the prior year while realized prices declined 30%. For the nine months ended September 30, 2009, production also increased 13% from the same period of the prior year while realized prices declined 31%. We believe oil and gas prices will remain volatile and will be affected by, among other things, weather, the U.S. and worldwide economy, new regulations, new technology, and the level of oil and gas production in North America and worldwide.

Despite a 13% increase in production volumes, oil and gas sales declined 42% when compared to the same period in the prior year. The oil and gas commodity price decline, which began during the second half of 2008, has continued through the first nine months of 2009, especially with regard to natural gas prices. However, signs of possible economic improvement have recently resulted in higher oil prices and a slight increase in natural gas prices. With the lower commodity price environment, we have focused our efforts on improving our operating efficiency. These efforts resulted in 25% lower direct operating expense per mcfe for the third quarter and 16% lower for the nine months ended September 30, 2009 when compared to the same periods of the prior year. However, as we continue to expand our Marcellus Shale team to meet the needs of this developing asset, we have seen upward pressure on our general and administrative costs per mcfe. To mitigate this trend, we have announced the closing of our Gulf Coast business unit office in Houston, Texas, effective November 1, 2009. The operations will be combined with and operated out of our Southwestern Area office in Fort Worth. We also continue to see higher fixed interest expense per mcfe due to the issuances of new fixed rate senior subordinated notes at higher interest rates than our floating rate bank credit facility.

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Oil and Gas Sales, Production and Realized Price Calculation

Our oil and gas sales vary from quarter to quarter as a result of changes in realized commodity prices and volumes of production sold. Hedges included in oil and gas sales reflect settlement on those derivatives that qualify for hedge accounting. Cash settlement of derivative contracts that are not accounted for as hedges are included in the consolidated statement of operations caption called Derivative fair value income (loss). The following table summarizes the primary components of oil and gas sales for the three months and the nine months ended September 30, 2009 and 2008 (in thousands):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2009	2008	Change	%	2009	2008	Change	%
Oil wellhead	$ 33,869	$ 86,506	$ (52,637)	(61%)	$ 101,892	$ 257,640	$ (155,748)	(60%)
Oil hedges realized	240	(28,003)	28,243	101%	12,247	(76,428)	88,675	116%
Total oil sales	34,109	58,503	(24,394)	(42%)	114,139	181,212	(67,073)	(37%)
Gas wellhead	97,004	282,243	(185,239)	(66%)	300,646	775,813	(475,167)	(61%)
Gas hedges realized	54,122	(13,188)	67,310	510%	146,594	(9,540)	156,134	1,637%
Total gas sales	151,126	269,055	(117,929)	(44%)	447,240	766,273	(319,033)	(42%)
NGL	16,887	20,162	(3,275)	(16%)	36,455	55,241	(18,786)	(34%)
Combined wellhead	147,760	388,911	(241,151)	(62%)	438,993	1,088,694	(649,701)	(60%)
Combined hedges	54,362	(41,191)	95,553	232%	158,841	(85,968)	244,809	285%
Total oil and gas sales	$ 202,122	$ 347,720	$ (145,598)	(42%)	$ 597,834	$ 1,002,726	$ (404,892)	(40%)

Our production continues to grow through continued drilling success as we place new wells into production. For third quarter 2009, our production volumes increased, from the same period of the prior year, 32% in our Appalachian Area, 4% in our Southwestern Area and decreased 33% in our Gulf Coast Area. For the nine months ended September 30, 2009, our production volumes increased, from the same period of the prior year, 23% in our Appalachia Area, 8% in our Southwestern Area and decreased 11% in our Gulf Coast Area. Crude oil production declined primarily due to the sale of certain oil properties in West Texas effective June 30, 2009. Our production for the three months and the nine months ended September 30, 2009 and 2008 is shown below:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2009	2008	Change	%	2009	2008	Change	%
Production:								

Crude oil (bbls)	534,399	759,449	(225,050)	(30%)	1,987,603	2,343,138	(355,535)	(15%)
NGLs (bbls)	543,005	345,635	197,370	57%	1,492,259	993,366	498,893	50%
Natural gas (mcf)	33,747,972	29,053,832	4,694,140	16%	96,205,898	84,029,611	12,176,287	14%
Total (mcfe)[a]	40,212,396	35,684,336	4,528,060	13%	117,085,070	104,048,635	13,036,435	13%
Average daily production:								
Crude oil (bbls)	5,809	8,255	(2,446)	(30%)	7,281	8,552	(1,271)	(15%)
NGLs (bbls)	5,902	3,757	2,145	57%	5,466	3,625	1,841	51%
Natural gas (mcf)	366,826	315,803	51,023	16%	352,403	306,677	45,726	15%
Total (mcfe)[a]	437,091	387,873	49,218	13%	428,883	379,740	49,143	13%

[a] Oil and NGLs are converted at the rate of one barrel equals six mcfe.

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Our average realized price (including all derivative settlements) received for oil and gas was $6.35 per mcfe in third quarter 2009 compared to $9.02 per mcfe in the same period of the prior year. Our average realized price calculation (including all derivative settlements) includes all cash settlement for derivatives, whether or not they qualify for hedge accounting. Average price calculations for the three months and the nine months ended September 30, 2009 and 2008 are shown below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Average sales prices (wellhead):				
Crude oil (per bbl)	$63.38	$113.91	$51.26	$109.95
NGLs (per bbl)	$31.10	$ 58.34	$24.43	$ 55.61
Natural gas (per mcf)	$ 2.87	$ 9.72	$ 3.13	$ 9.23
Total (per mcfe)[a]	$ 3.67	$ 10.90	$ 3.75	$ 10.46
Average realized price (including derivatives that qualify for hedge accounting):				
Crude oil (per bbl)	$63.83	$ 77.03	$57.43	$ 77.34
NGLs (per bbl)	$31.10	$ 58.34	$24.43	$ 55.61
Natural gas (per mcf)	$ 4.48	$ 9.26	$ 4.65	$ 9.12
Total (per mcfe)[a]	$ 5.03	$ 9.74	$ 5.11	$ 9.64
Average realized price (including all derivative settlements):				
Crude oil (per bbl)	$63.88	$ 67.40	$61.24	$ 70.06
NGLs (per bbl)	$31.10	$ 58.34	$24.43	$ 55.61
Natural gas (per mcf)	$ 6.05	$ 8.62	$ 6.12	$ 8.77
Total (per mcfe)[a]	$ 6.35	$ 9.02	$ 6.38	$ 9.19
Average NYMEX prices[b]				
Oil (per bbl)	$68.18	$117.83	$56.01	$113.66
Natural gas (per mcf)	$ 3.41	$ 10.08	$ 3.93	$ 9.67

(a) Oil and NGLs are converted at the rate of one barrel equals six mcfe.

(b) Based on average of bid week prompt month prices.

Derivative fair value (loss) income is a loss of $482,000 in third quarter 2009 compared to income of $272.9 million in the same period of 2008. Some of our derivatives do not qualify for hedge accounting but provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and gas production. These contracts are accounted for using the mark-to-market accounting method. All unrealized and realized gains and losses related to these contracts are included in the consolidated statement of operations caption Derivative fair value income (loss). We have also entered into basis swap agreements, which do not qualify for hedge accounting and are also marked to market. Not using hedge accounting treatment creates volatility in our revenues as unrealized gains and losses from non-hedge derivatives are included in total revenues and are not included in our balance sheet caption Accumulated other comprehensive income (loss). Hedge ineffectiveness, also included in this statement of operations category, is associated with our hedging contracts that qualify for hedge accounting under the Derivatives and Hedging Topic of the Codification.

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The following table presents information about the components of derivative fair value income (loss) for the three months and the nine months ended September 30, 2009 and 2008 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Hedge ineffectiveness realized[a]	$ 1,581	$ (213)	$ 3,159	$ 2
unrealized[a]	(386)	4,553	(483)	1,862
Change in fair value of derivatives that do not qualify for hedge accounting[a]	(53,323)	294,317	(83,393)	(3,184)
Realized gain (loss) on settlements gas[b][c]	51,619	(18,520)	138,361	(30,192)
Realized gain (loss) on settlements oil[b][c]	27	(7,268)	7,565	(16,070)
Derivative fair value (loss) income	$ (482)	$ 272,869	$ 65,209	$ (47,582)

(a) These amounts are unrealized and are not included in average sales price calculations.

(b) These amounts represent realized gains and losses on settled derivatives that do not qualify for hedge accounting.

(c) These settlements are included in average realized price calculations (average realized price including all derivative settlements).

Other revenue for third quarter 2009 decreased to a loss of $443,000 compared to income of $544,000 in the same period of 2008. Third quarter 2009 includes a loss from equity method investments of $1.0 million compared to income of $151,000 in the same period of the prior year. Other revenue for the first nine months of 2009 decreased to a loss of $6.6 million from a gain of $20.8 million in the same period of the prior year. The first nine months of 2009 includes a loss from equity method investments of $6.5 million. The first nine months of 2008 includes a gain on the sale of certain East Texas properties of $20.1 million.

We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per mcfe, basis. The following presents information about these expenses on an mcfe basis for the three months and the nine months ended September 30, 2009 and 2008:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2009	2008	Change	%	2009	2008	Change	%
Direct operating expense	$0.77	$1.02	$(0.25)	(25%)	$0.87	$1.03	$(0.16)	(16%)
Production and ad valorem tax expense	0.19	0.43	(0.24)	(56%)	0.20	0.43	(0.23)	(53%)
General and administrative expense	0.76	0.69	0.07	10%	0.72	0.63	0.09	14%
Interest expense	0.76	0.71	0.05	7%	0.74	0.70	0.04	6%
Depletion, depreciation and amortization expense	2.42	2.15	0.27	13%	2.31	2.10	0.21	10%

Direct operating expense declined $5.4 million in third quarter 2009 to $31.1 million. We experience increases in operating expenses as we add new wells and maintain production from existing properties. In the third quarter 2009, this effect was more than offset by lower overall industry costs, lower workovers and asset sales. On an absolute dollar basis, our spending for direct operating expense (excluding workovers) is virtually unchanged for the three months and the nine months ended September 30, 2009 despite higher production levels, due to cost containment measures and lower overall industry costs. We incurred $2.7 million ($0.07 per mcfe) of workover costs in third quarter 2009 versus $3.7 million ($0.10 per mcfe) in 2008. On a per mcfe basis, direct operating expenses for third quarter 2009 decreased $0.25 or 25% from the same period of 2008 with the decrease consisting primarily of lower workover costs ($0.03 per mcfe) and lower utility costs ($0.04 per mcfe) and lower well service costs. Direct operating expense was $101.5 million in the first nine months of 2009 compared to $106.7 million in the same period of the prior year. We incurred $5.3 million ($0.05 per mcfe) of workover costs in the first nine months of 2009 versus $9.1 million ($0.09 per mcfe) in 2008. On a per mcfe basis, direct operating expenses for the first nine months of 2009 decreased $0.16 or 16% from the same time period of 2008 with the decrease consisting primarily of lower workover costs ($0.04 per mcfe), lower utility costs ($0.02 per mcfe) and lower well service costs. Stock-based compensation included in this category represents amortization of restricted stock grants and expense related to SAR grants. The following table summarizes direct operating expenses per mcfe for the three months and the nine months ended September 30, 2009 and 2008:

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	Three Months Ended September 30, 2009	2008	Change	%	Nine Months Ended September 30, 2009	2008	Change	%
Lease operating expense	$ 0.68	$ 0.90	$ (0.22)	(24%)	$ 0.80	$ 0.92	$ (0.12)	(13%)
Workovers	0.07	0.10	(0.03)	(30%)	0.05	0.09	(0.04)	(44%)
Stock-based compensation (non-cash)	0.02	0.02		%	0.02	0.02		%
Total direct operating expenses	$ 0.77	$ 1.02	$ (0.25)	(25%)	$ 0.87	$ 1.03	$ (0.16)	(16%)

Production and ad valorem taxes are paid based on market prices and not hedged prices. For the third quarter, these taxes decreased $7.6 million or 50% from the same period of the prior year due to the significant decline in wellhead prices. On a per mcfe basis, production and ad valorem taxes decreased to $0.19 in third quarter 2009 from $0.43 in the same period of 2008 primarily due to a 66% decrease in pre-hedge prices. For the first nine months of 2009, these taxes decreased $21.7 million or 48% from the same period of the prior year due to the significant decline in pre-hedge prices, which declined 64%.

General and administrative expense for third quarter 2009 increased $5.9 million from the same period of the prior year due primarily to higher salaries and benefits ($2.4 million) reflecting salary increases and an increase in the number of employees as we continue the expansion of our Marcellus Shale team, higher stock-based compensation ($2.0 million) and higher office expenses, including rent and information technology. Third quarter 2009 also includes $840,000 ($0.02 per mcfe) accrued severance costs related to the closing of our Houston office and $1.1 million ($0.03 per mcfe) bad debt expense. We have increased our employee count by 3% from September 2008. General and administrative expense for the nine months ended September 30, 2009 increased $18.6 million or 28% from the same period of the prior year due primarily to higher salaries and benefits ($10.3 million), higher stock-based compensation ($5.6 million) and higher office expenses, including rent costs and an increase in legal expenses. Stock-based compensation included in this category represents amortization of restricted stock grants and expense related to SAR grants. The following table summarizes general and administrative expenses per mcfe for the three and nine months ended September 30, 2009 and 2008:

	Three Months Ended September 30, 2009	2008	Change	%	Nine Months Ended September 30, 2009	2008	Change	%
General and administrative	$ 0.57	$ 0.53	$ 0.04	8%	$ 0.53	$ 0.47	$ 0.06	13%
Stock-based compensation (non-cash)	0.19	0.16	0.03	19%	0.19	0.16	0.03	19%
Total general and administrative expenses	$ 0.76	$ 0.69	$ 0.07	10%	$ 0.72	$ 0.63	$ 0.09	14%

Interest expense for third quarter 2009 increased $5.3 million from the same period of the prior year to $30.6 million due to the refinancing of certain debt from floating to higher fixed rates combined with higher overall debt balances. In May 2009, we issued $300.0 million of 8.0% senior subordinated notes due 2019, which added $6.0 million of interest costs in third quarter 2009. The proceeds from the issuance were used to retire lower floating interest rate bank debt, to better match the maturities of our debt with the life of our properties and to give us greater liquidity for the near term. Average debt outstanding on the bank credit facility for third quarter 2009 was $430.7 million compared to $384.6 million for the same period of the prior year and the weighted average interest rates were 2.2% in third quarter 2009 compared to 4.3% in the same period of the prior year. Interest expense for the nine months ended September 30, 2009 increased $14.5 million or 20% also due to the refinancing of certain debt from floating to higher fixed rates and higher overall debt balances. Average debt outstanding on the bank credit facility for the first nine months of 2009 was $644.5 million compared to $425.5 million for the first nine months of 2008 and the weighted average interest rate was 2.5% in the first nine months 2009 compared to 4.7% in the same period of 2008.

Depletion, depreciation and amortization (DD&A) increased $20.5 million, or 27%, to $97.2 million in third quarter 2009 with a 13% increase in production and an 12% increase in depletion rates. On a per mcfe basis, DD&A increased from $2.15 in third quarter 2008 to $2.42 in third quarter 2009. In the first nine months of 2009, DD&A increased $51.3 million to $270.2 million with a 13% increase in production and an 9% increase in depletion rates. The increase in DD&A per mcfe is primarily due to significant early stage exploratory and development costs associated with our shale plays and the mix of our production. We generally adjust our D,D&A rates in the fourth quarter of each year. The following table summarizes DD&A expenses per mcfe for the three months and the nine months ended September 30, 2009 and 2008:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2009	2008	Change	%	2009	2008	Change	%
Depletion and amortization	$ 2.26	$ 2.01	$ 0.25	12%	$ 2.15	$ 1.97	$ 0.18	9%
Depreciation	0.12	0.11	0.01	9%	0.12	0.10	0.02	20%
Accretion and other	0.04	0.03	0.01	33%	0.04	0.04		%
Total DD&A expense	$ 2.42	$ 2.15	$ 0.27	13%	$ 2.31	$ 2.11	$ 0.20	9%

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include stock-based compensation, exploration expense, abandonment and impairment of unproved properties and deferred compensation plan expenses. In the three months and the nine months ended September 30, 2009 and 2008, stock-based compensation represents the amortization of restricted stock grants and expenses related to SAR grants. In third quarter 2009, stock-based compensation is a component of direct operating expense ($798,000), exploration expense ($979,000) and general and administrative expense ($7.5 million) for a total of $9.5 million. In third quarter 2008, stock-based compensation was a component of direct operating expense ($762,000), exploration expense ($1.0 million) and general and administrative expense ($5.5 million) for a total of $7.4 million. In the nine months ended September 30, 2009, stock-based compensation is a component of directing operating expense ($2.4 million), exploration expense ($2.9 million) and general and administrative expense ($22.7 million) for a total of $28.7 million. In the nine months ended September 30, 2008, stock based compensation is a component of direct operating expense ($2.1 million) exploration expense ($3.1 million) and general and administrative expense ($17.1 million) for a total of $22.6 million.

Exploration expense decreased $8.0 million in third quarter 2009 primarily due to lower seismic costs. Exploration expense declined $19.4 million in the first nine months 2009 due to lower dry hole and seismic costs. The following table details our exploration-related expenses for the three months and the nine months ended September 30, 2009 and 2008 (in thousands):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2009	2008	Change	%	2009	2008	Change	%
Dry hole expense	$ 212	$ 81	$ 131	162%	$ 343	$ 9,337	$ (8,994)	(96%)
Seismic	6,267	14,090	(7,823)	(56%)	20,182	30,616	(10,434)	(34%)
Personnel expense	2,727	2,736	(9)	%	8,432	8,291	141	2%
Stock-based compensation expense	979	1,020	(41)	(4%)	2,933	3,128	(195)	(6%)
Delay rentals and other	917	1,222	(304)	(25%	3,919	3,832	88	2%
Total exploration expense	$ 11,102	$ 19,149	$ (8,046)	(42%)	$ 35,809	$ 55,204	$ (19,394)	(35%)

Abandonment and impairment of unproved properties expense was $24.1 million and $84.6 million during the three and nine months ended September 30, 2009 as compared to $5.1 million and $10.7 million during the same respective periods of 2008. In the first nine months of 2009, abandonment and impairment expense of $84.6 million includes the expiration of certain Barnett Shale leases. We continue to experience increases in lease expirations and impairment expenses caused by (1) current economic conditions, which have impacted our future drilling plans thereby increasing the amount of expected lease expirations and (2) the expansion of our unproved property positions in new shale plays.

Deferred compensation plan expense was $16.4 million in the third quarter 2009 compared to income of $37.5 million in the same period of the prior year. Our stock price increased from $41.41 at June 30, 2009 to $49.36 at September 30, 2009. During the same period in the prior year, our stock price decreased from $65.54 at June 30, 2008 to $42.87 at September 30, 2008. This non-cash expense relates to the increase or decrease in value of the liability associated with our common stock that is vested and held in the deferred compensation plan. Our deferred compensation liability is adjusted to fair value by a charge or a credit to deferred compensation plan expense. Deferred compensation expense for the nine months ended September 30, 2009 was $29.6 million compared to income of $9.4 million in the same period of the prior year. Our stock price increased from $34.39 at December 31, 2008 to $49.36 at September 30, 2009. During the same nine-month period of 2008, our stock price decreased from $51.36 at December 31, 2007 to $42.87 at September 30, 2008.

Income tax (benefit) expense for third quarter 2009 decreased to a benefit of $15.3 million from expense of $172.6 million in third quarter 2008, reflecting a 110% decrease in income from operations before taxes compared to the same period of 2008. Third quarter 2009 provided for a tax benefit at an effective rate of 33.9% compared to tax expense at an effective rate of 37.7% in the same period of 2008. Current income taxes in third quarter 2009 and the nine months ended September 30, 2009 are related to state income taxes and include a $1.0 million federal income tax refund. Income tax benefit for the nine months ended September 30, 2009, decreased from an expense of $156.8 million to a benefit of $19.0 million reflecting a 114% decline in income from operations before taxes when compared to the same period of 2008. We expect our effective tax rate to be approximately 36% for 2009.

Liquidity and Capital Resources

Our main sources of liquidity and capital resources are internally generated cash flow from operations, a bank credit facility with both uncommitted and committed availability, asset sales and access to both the debt and equity capital markets. In a continuing effort to mitigate the effect of the deterioration in the capital markets and the decline in oil and gas commodity prices, which began in mid 2008, we have taken additional measures during the first nine months of 2009 to enhance our liquidity. In May 2009 we issued $300.0 million of 8.0% senior subordinated notes due 2019 at a discount. We used the $285.2 million of proceeds received from the issuance of the 8.0% senior subordinated notes to repay outstanding bank debt, increasing the availability of our credit line. Also in 2009, we entered into commodity derivative contracts covering 61.9 Bcf for the 2010 year at weighted average floor and cap prices of $5.50 to $7.47 per mcfe to protect our cash flow. We also sold certain West Texas oil properties for proceeds of $182.0 million with the proceeds used to repay outstanding bank debt. We currently estimate our 2009 capital spending will approximate $740.0 million, excluding acquisitions, which incorporates significantly reduced spending in all areas except our Marcellus Shale play. As part of our semi-annual bank review completed September 30, 2009, our borrowing base and facility amounts were reaffirmed at $1.5 billion and $1.25 billion.

During the nine months ended September 30, 2009, our cash provided from operating activities was $443.8 million and we spent $447.3 million on capital expenditures and $118.7 million of acreage purchases. We sold certain West Texas oil properties for proceeds of $182.0 million. At September 30, 2009, we had $859,000 in cash, total assets of $5.4 billion and a debt-to-capitalization ratio of 42.8%. Long-term debt at September 30, 2009 totaled $1.8 billion including $398.0 million of bank credit facility debt and $1.4 billion of senior subordinated notes. Available committed borrowing capacity under the bank credit facility at September 30, 2009 was $852.0 million.

Cash is required to fund capital expenditures necessary to offset inherent declines in production and proven reserves, which is typical in the capital-intensive oil and 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 believe that net cash generated from operating activities, unused committed borrowing capacity under the bank credit facility and proceeds from asset sales will be adequate to satisfy near-term financial obligations and liquidity needs. However, 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 gas business. Sustained lower oil and gas prices or a reduction in production and reserves would reduce our ability to fund capital expenditures, reduce debt, meet financial obligations and remain profitable. We currently have approximately 48% of our 2010 production subject to hedging agreements. 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 oil and gas, 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 opinions 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

On September 30, 2009, the bank credit facility had a $1.5 billion borrowing base and a $1.25 billion facility amount. The borrowing base represents an amount approved by the bank group that can be borrowed based on our assets, while our $1.25 billion facility amount is the amount the banks have committed to fund pursuant to the credit agreement. The bank credit facility provides for a borrowing base subject to redeterminations semi-annually each April and October and for event-driven unscheduled redeterminations. Remaining credit availability is $829.0 million on October 20, 2009. Our bank group is comprised of twenty-six commercial banks, with no one bank holding more than 5.0% of the bank credit facility. We believe our large number of banks and relatively low hold levels allow for significant lending capacity should we elect to increase our $1.25 billion commitment up to the $1.5 billion borrowing base and also allow for flexibility should there be additional consolidation within the banking sector.

Our bank credit facility and our indentures governing our senior subordinated notes all contain covenants that, among other things, limit our ability to pay dividends, incur additional indebtedness, sell assets, enter into hedging contracts change the nature of our business or operations, merge or consolidate or make certain investments. In addition, we are required to maintain a ratio of debt to EBITDAX (as defined in the credit agreement) of no greater than 4.0 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 these covenants at September 30, 2009. Please see Note 8 to our consolidated financial statements for additional information.

Cash Flow

Cash flows from operations primarily are affected by production and commodity prices, net of the effects of settlements of our derivatives. Our cash flows from operating activities also are impacted by changes in working capital. We sell substantially all of our oil and gas production at the wellhead under floating market contracts. However, we generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 12 to 24 months. Any payments due to counterparties under our derivative contracts should ultimately be funded by higher prices received from the sale of our production. Production receipts, however, often lag payments to the counterparties. Any interim cash needs are funded by borrowing under the credit facility. As of September 30, 2009, we have entered into hedging agreements covering 27.4 Bcfe for 2009 and 61.9 Bcfe for 2010.

Net cash provided from operating activities for the nine months ended September 30, 2009 was $443.8 million compared to $600.4 million in the nine months ended September 30, 2008. Cash flow from operating activities for the first nine months of 2009 was lower than same period of the prior year, as higher production from development activity was more than offset by lower prices. 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 the consolidated statement of cash flows) in the nine months ended September 30, 2009 was a negative $11.1 million compared to a negative $45.8 million in the same period of the prior year.

Net cash used in investing for the nine months ended September 30, 2009 was $385.1 million compared to $1.4 billion in the same period of 2008. The first nine months of 2009 included $425.4 million of additions to oil and gas properties and $118.7 million of acreage purchases offset by proceeds of $182.2 million from asset sales. Acquisitions for the first nine months of 2009 include the purchase of certain Marcellus Shale leasehold acreage for $77.4 million and Barnett Shale acreage for $14.1 million. The first nine months of 2008 included $646.4 million of additions to oil and gas properties and $805.4 million of acreage purchases and other investments, offset by proceeds of $66.7 million from asset sales.

Net cash used in financing for the nine months ended September 30, 2009 was $58.6 million compared to net cash provided from financing activities of $783.6 million in the first nine months of 2008. The prior year included net proceeds from a public stock offering of $282.2 million. In the first nine months of 2009, we borrowed $582.0 million under our bank credit facility compared to borrowings of $1.2 billion in the same period of the prior year. During the first nine months of 2009, total debt decreased $9.2 million. In the first nine months of 2008, total debt increased $496.8 million.

Dividends

On September 1, 2009, the Board of Directors declared a dividend of four cents per share ($6.3 million) on our common stock, which was paid on September 30, 2009 to stockholders of record at the close of business on September 15, 2009.

Capital Requirements, Contractual Cash Obligations and Off-Balance Sheet Arrangements

We currently estimate our 2009 capital spending will approximate $740.0 million (excluding proved property acquisitions) and based on current projections, is expected to be funded with internal cash flow and property sales. We may, from time to time during 2009, make borrowings under our credit facility but expect that for all of 2009 to require no significant incremental borrowing from ending 2008 levels. Acreage purchases during the year include $77.4 million of purchases in the Marcellus Shale and $14.1 million in the Barnett Shale which were funded with borrowings under the credit facility. In addition, in second and third quarter 2009, we issued 474,572 shares of stock to purchase $20.5 million of additional Marcellus acreage. For the nine months ended September 30, 2009, $453.1 million of development and exploration spending was funded with internal cash flow and proceeds from asset sales. We monitor our capital expenditures on a regular basis, adjusting the amount up or down and 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 sell assets, issue subordinated notes or other debt securities, or issue additional shares of stock to fund capital expenditures or acquisitions, extend maturities or repay debt.

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Our contractual obligations include long-term debt, operating leases, drilling commitments, derivative obligations, transportation commitments and other liabilities. Since December 31, 2008, the material changes to our contractual obligations included the issuance of $300.0 million of 8.0% senior subordinated notes due 2019 and an increase in our transportation commitments (see table and discussion below).

We have entered into firm transportation contracts with various pipelines. Under these contracts, we are obligated to transport minimum daily gas volumes, as calculated on a monthly basis, or pay for any deficiencies at a specified reservation fee rate. As of September 30, 2009, future minimum transportation fees under our gas transportation commitments were as follows (in thousands):

2009 remaining	$ 8,891
2010	34,663
2011	34,180
2012	31,220
2013	30,349
2014	27,070
Thereafter	207,240
	$ 373,613

Other Contingencies

We are involved in various legal actions and claims arising in the ordinary course of business. We believe the resolution of these proceedings will not have a material adverse effect on our liquidity or consolidated financial position.

Hedging Oil and Gas Prices

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. These contracts consist of collars and fixed price swaps. We do not utilize complex derivatives such as swaptions, knockouts or extendable swaps. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital program. Our decision on the quantity and price at which we choose to hedge our future production is based in part on our view of current and future market conditions. In light of current worldwide economic uncertainties, we recently have employed a strategy to hedge a portion of our production looking out 12 to 15 months from each quarter. At September 30, 2009, we had open swap contracts covering 7.1 Bcf of gas at prices averaging $8.16 per mcf. We also have collars covering 78.9 Bcf of gas at weighted average floor and cap prices of $5.96 and $7.70 per mcf and 0.6 million barrels of oil at weighted average floor and cap prices of $63.43 and $76.01 per barrel. Their fair value, represented by the estimated amount that would be realized upon termination, based on a comparison of contract prices and a reference price, generally NYMEX, on September 30, 2009 was a net unrealized pre-tax gain of $80.5 million. The contracts expire monthly through December 2010. Settled transaction gains and losses for derivatives that qualify for hedge accounting are determined monthly and are included as increases or decreases in oil and gas sales in the period the hedged production is sold. In the first nine months of 2009, oil and gas sales included realized hedging gains of $158.8 million compared to losses of $86.0 million in the first nine months of 2008.

At September 30, 2009, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural Gas			
2009	Swaps	76,739 Mmbtu/day	$ 8.16

2009	Collars	184,837 Mmbtu/day	$ 7.64-$8.53
2010	Collars	169,671 Mmbtu/day	$ 5.50-$7.47
Crude Oil			
2009	Collars	6,000 bbl/day	$63.43-$76.01

Some of our derivatives do not qualify for hedge accounting but provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and gas production. These contracts are accounted for using the mark-to-market accounting method. Under this method, the contracts are carried at their fair value on our balance sheet under the captions Unrealized derivative gains and losses. We recognize all unrealized and realized gains and losses related to these contracts in our consolidated statement of operations caption called Derivative fair value income (loss). As of September 30, 2009, derivatives on 21.7 Bcfe no longer qualify or are not designated for hedge accounting.

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In addition to the swaps and collars above, we have entered into basis swap agreements that do not qualify for hedge accounting and are marked to market. The price we receive for our production can be less than NYMEX price because of adjustments for delivery location (basis), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix the basis adjustments. The fair value of the basis swaps was a net unrealized pre-tax loss of $16.9 million at September 30, 2009.

Interest Rates

At September 30, 2009, we had $1.8 billion of debt outstanding. Of this amount, $1.4 billion bore interest at fixed rates averaging 7.4%. Bank debt totaling $398.0 million bears interest at floating rates, which averaged 2.2% at September 30, 2009. The 30-day LIBOR rate on September 30, 2009 was 0.2%.

Debt Ratings

We receive debt credit ratings from Standard & Poor s Ratings Group, Inc. (S&P) and Moody s Investor Services, Inc. (Moody s), which are subject to regular reviews. S&P s rating for us is BB with a stable outlook. Moody s rating for us is Ba2 with a stable outlook. We believe that S&P and Moody s consider many factors in determining our ratings including: production growth opportunities, liquidity, debt levels, asset, and proved reserve mix. A reduction in our debt ratings could negatively impact our ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing.

Inflation and Changes in Prices

Our revenues, the value of our assets, our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in oil and gas prices and the costs to produce our reserves. Oil and gas prices are subject to fluctuations that are beyond our ability to control or predict. During third quarter 2009, we received an average of $63.38 per barrel of oil and $2.87 per mcf of gas before derivative contracts compared to $113.91 per barrel of oil and $9.72 per mcf of gas in the same period of the prior year. During the first nine months of 2009, we received an average of $51.26 per barrel of oil and $3.13 per mcf of gas before derivative contracts compared to $109.95 per barrel and $9.23 per mcf in the first nine months of the prior year. Although certain of our costs are affected by general inflation, inflation does not normally have a significant effect on our business. In a trend that began in 2004 and continued through the first six months of 2008, commodity prices for oil and gas increased significantly. The higher prices led to increased activity in the industry and, consequently, rising costs. These cost trends put pressure not only on our operating costs but also on capital costs. The last half of 2008 and the first nine months of 2009 we have experienced declines in commodity prices and while we have realized some cost savings, operating costs have not decreased at the same rate as commodity prices. We expect to see further cost reductions in 2009 but we are uncertain how quickly costs will decline and by how much.

Accounting Standards Not Yet Adopted

In December 2008, the SEC announced that it had approved revisions to its oil and gas reporting disclosures. The new disclosure requirements include provisions that:

Introduce a new definition of oil and gas producing activities. This new definition allows companies to include in their reserve base volumes from unconventional resources. Such unconventional resources include bitumen extracted from oil sands and oil and gas extracted from coal beds and shale formations.

Require companies to report oil and gas reserves using an unweighted average price using the prior 12-month period, based on the closing prices on the first day of each month, rather than year-end prices. The SEC indicated they will continue to communicate with the FASB staff to align FASB s accounting standards with these rules. The FASB currently requires a single-day, year-end price for accounting purposes.

Permit companies to disclose their probable and possible reserves on a voluntary basis. In the past, proved reserves were the only reserves allowed in the disclosures.

Require companies to provide additional disclosure regarding the aging of proved undeveloped reserves.

Permit the use of reliable technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes.

Replace the existing certainty test for areas beyond one offsetting drilling unit from a productive well with a reasonable certainty test.

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Require additional disclosures regarding the qualifications of the chief technical person who oversees the company s overall reserve estimation process. Additionally, disclosures regarding internal controls over reserve estimation, as well as a report addressing the independence and qualifications of its reserves preparer or auditor will be mandatory.

We will begin complying with the disclosure requirements in our annual report on Form 10-K for the year ending December 31, 2009. The new rules may not be applied to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required. We are currently in the process of evaluating the new requirements.

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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 oil and gas prices and interest rates. The disclosures are not meant to be 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 exposures. All of our market-risk sensitive instruments were entered into for purposes other than trading. All accounts are U.S. dollar denominated.

Financial Market Risk

The debt and equity markets have exhibited adverse conditions since late 2007. The unprecedented volatility and upheaval in the capital markets may increase costs associated with issuing debt instruments due to increased spreads over relevant interest rate benchmarks and affect our ability to access those markets. At this point, we do not believe our liquidity has been materially affected by the recent events in the global markets and we do not expect our liquidity to be materially impacted in the near future. We will continue to monitor our liquidity and the capital markets. Additionally, we will continue to monitor events and circumstances surrounding each of our twenty-six lenders in the bank credit facility.

Market Risk

Our major market risk is exposure to oil and gas prices. Realized prices are primarily driven by worldwide prices for oil and spot market prices for North American gas production. Oil and gas prices have been volatile and unpredictable for many years.

Commodity Price Risk

We periodically enter into derivative arrangements with respect to our oil and gas production. These arrangements are intended to reduce the impact of oil and gas price fluctuations. 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. Historically, we applied hedge accounting to derivatives utilized to manage price risk associated with our oil and gas production. Accordingly, we recorded change in the fair value of our swap and collar contracts under the balance sheet caption Accumulated other comprehensive income (loss) and into oil and gas sales when the forecasted sale of production occurred. Any hedge ineffectiveness associated with contracts qualifying for and designated as a cash flow hedge is reported currently each period under our consolidated statement of operations caption Derivative fair value income (loss). Some of our derivatives do not qualify for hedge accounting but provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and gas production. These contracts are accounted for using the mark-to-market accounting method. Under this method, the contracts are carried at their fair value on our consolidated balance sheet under the captions Unrealized derivative gains and losses. We recognize all unrealized and realized gains and losses related to these contracts in our consolidated statement of operations under the caption Derivative fair value income (loss). Generally, derivative losses occur when market prices increase, which are offset by gains on the underlying physical commodity transaction. Conversely, derivative gains occur when market prices decrease, which are offset by losses on the underlying commodity transaction. Our derivative counterparties include thirteen financial institutions, eleven of which are in our bank group. Mitsui & Co. and J. Aron & Company are the two counterparties not in our bank group. At September 30, 2009, our net derivative asset includes a payable to J. Aron & Company of $965,000 and a receivable from Mitsui & Co. for $4.9 million. None of our derivative contracts have margin requirements or collateral provisions that would require funding prior to the scheduled cash settlement date.

As of September 30, 2009, we had swaps in place covering 7.1 Bcf of gas. We also had collars covering 78.9 Bcf of gas and 0.6 million barrels of oil. These contracts expire monthly through December 2010. The fair value, represented by the estimated amount that would be realized upon immediate liquidation as of September 30, 2009, approximated a net unrealized pre-tax gain of $80.5 million.

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At September 30, 2009, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price	Fair Market Value (in thousands)
Natural Gas				
2009	Swaps	76,739 Mmbtu/day	$ 8.16	$ 24,698
2009	Collars	184,837 Mmbtu/day	$ 7.64-$8.53	$ 51,011
2010	Collars	169,671 Mmbtu/day	$ 5.50-$7.47	$ 5,362
Crude Oil				
2009	Collars	6,000 bbl/day	$ 63.43-$76.01	$ (618)

Other Commodity Risk

We are impacted by basis risk, caused by factors that affect the relationship between commodity futures prices reflected in derivative commodity instruments and the cash market price of the underlying commodity. Natural gas transaction prices are frequently based on industry reference prices that may vary from prices experienced in local markets. If commodity price changes in one region are not reflected in other regions, derivative commodity instruments may no longer provide the expected hedge, resulting in increased basis risk. In addition to the collars and swaps detailed above, we have entered into basis swap agreements, which do not qualify for hedge accounting and are marked to market. The price we receive for our gas production can be less than the NYMEX price because of adjustments for delivery location (basis), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix the basis adjustments. The fair value of the basis swaps was a net realized pre-tax loss of $16.9 million at September 30, 2009.

The following table shows the fair value of our swaps and collars and the hypothetical change in the fair value that would result from a 10% change in commodity prices at September 30, 2009. The hypothetical change in fair value would be a gain or loss depending on whether prices increase or decrease (in thousands):

	Fair Value	Hypothetical Change in Fair Value
Swaps	$24,698	$ 3,300
Collars	$55,755	$ 34,000

Interest rate risk. At September 30, 2009, we had $1.8 billion of debt outstanding. Of this amount, $1.4 billion bore interest at fixed rates averaging 7.4%. Senior bank debt totaling $398.0 million bore interest at floating rates averaging 2.2%. A 1% increase or decrease in short-term interest rates would affect interest expense by approximately $4.0 million per year.

Item 4. CONTROLS AND PROCEDURES

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

SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of September 30, 2009 at the reasonable assurance level.

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PART II OTHER INFORMATION
Item 6. Exhibits
(a) EXHIBITS

Exhibit Number	Description
3.1	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 May 5, 2004, as amended by the Certificate of First Amendment to Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 28, 2005) and the Certificate of Second Amendment to 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, 2007)
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 February 17, 2009)
10.1*	Eighth Amendment to the Third Amended and Restated Credit Agreement dated October 26, 2006 among Range (as borrower) and J.P.Morgan Chase Bank, N.A. and institutions named (therein) as lenders, J.P.Morgan Chase as Administrative Agent
31.1*	Certification by the Chairman 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 Chairman 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*	XBRL documents

* filed herewith

** furnished herewith

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SIGNATURES

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

Date: October 21, 2009

RANGE RESOURCES CORPORATION

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

Date: October 21, 2009

RANGE RESOURCES CORPORATION

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

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Exhibit index

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