RANGE RESOURCES CORP
Form 10-Q
April 27, 2011

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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 March 31, 2011

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 o No þ

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

160,703,877 Common Shares were outstanding on April 25, 2011.

RANGE RESOURCES CORPORATION
FORM 10-Q
Quarter Ended March 31, 2011

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
(Unaudited, in thousands, except per share data)

	March 31, 2011	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 1,681	$ 2,848
Accounts receivable, less allowance for doubtful accounts of $4,285 and $5,001	75,530	76,683
Unrealized derivative gain	62,286	123,255
Assets of discontinued operations	856,195	876,304
Inventory and other	18,605	21,352
Deferred tax asset	1,639	
Total current assets	1,015,936	1,100,442
Equity method investments	142,353	155,105
Natural gas and oil properties, successful efforts method	5,669,791	5,390,391
Accumulated depletion and depreciation	(1,373,652)	(1,306,378)
	4,296,139	4,084,013
Transportation and field assets	121,274	134,980
Accumulated depreciation and amortization	(61,303)	(60,931)
	59,971	74,049
Other assets	100,848	84,977
Total assets	$ 5,615,247	$ 5,498,586
Liabilities		
Current liabilities:		
Accounts payable	$ 245,446	$ 289,109
Asset retirement obligations	4,020	4,020
Accrued liabilities	44,629	60,082
Deferred tax liability		11,848
Accrued interest	39,496	32,189
Unrealized derivative loss	593	352
Current liabilities of discontinued operations	16,288	32,962
Total current liabilities	350,472	430,562
Bank debt	480,000	274,000

Subordinated notes		1,686,816		1,686,536
Deferred tax liability		646,427		672,041
Unrealized derivative loss		30,242		13,412
Deferred compensation liability		169,278		134,488
Asset retirement obligations and other liabilities		66,168		59,885
Long-term liabilities of discontinued operations		2,226		3,901
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, 160,668,296 issued at March 31, 2011 and 160,113,608 issued at December 31, 2010		1,607		1,601
Common stock held in treasury, 196,016 shares at March 31, 2011 and 204,556 shares at December 31, 2010		(7,190)		(7,512)
Additional paid-in capital		1,835,261		1,820,503
Retained earnings		310,246		341,699
Accumulated other comprehensive income		43,694		67,470
Total stockholders equity		2,183,618		2,223,761
Total liabilities and stockholders equity	$	5,615,247	$	5,498,586

See the accompanying notes.

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

	Three Months Ended March 31, 2011	2010
Revenues and other income		
Natural gas, NGL and oil sales	$ 226,881	$ 187,673
Transportation and gathering	313	2,081
Derivative fair value (loss) income	(40,834)	42,333
Gain on the sale of assets	139	67,913
Other	1,077	(1,575)
Total revenues and other income	187,576	298,425
Costs and expenses		
Direct operating	28,717	21,836
Production and ad valorem taxes	6,879	6,542
Exploration	27,187	14,139
Abandonment and impairment of unproved properties	16,537	6,551
General and administrative	33,959	28,170
Termination costs		7,938
Deferred compensation plan	30,630	(5,712)
Interest expense	24,779	20,931
Depletion, depreciation and amortization	72,216	64,807
Impairment of proved properties		6,505
Total costs and expenses	240,904	171,707
(Loss) income from continuing operations before income taxes	(53,328)	126,718
Income tax (benefit) expense		
Current		
Deferred	(19,897)	49,012
Total income tax (benefit) expense	(19,897)	49,012
(Loss) income from continuing operations	(33,431)	77,706
Discontinued operations, net of taxes	8,398	(127)
Net (loss) income	$ (25,033)	$ 77,579
(Loss) income per common share		
Basic-(loss) income from continuing operations	$ (0.21)	$ 0.50

-discontinued operations		0.05		
-net (loss) income	$	(0.16)	$	0.50
Diluted-(loss) income from continuing operations	$	(0.21)	$	0.48
-discontinued operations		0.05		
-net (loss) income	$	(0.16)	$	0.48
Dividends per common share	$	0.04	$	0.04
Weighted average common shares outstanding				
Basic		157,545		156,393
Diluted		157,545		160,292

See the accompanying notes.

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

	Three Months Ended March 31,	
	2011	**2010**
Operating activities		
Net (loss) income	$ (25,033)	$ 77,579
Adjustments to reconcile net cash provided from operating activities:		
(Gain) loss from discontinued operations	(8,398)	127
Loss from equity method investments, net of distributions	14,738	1,621
Deferred income tax (benefit) expense	(19,897)	49,012
Depletion, depreciation, amortization and proved property impairment	72,216	71,312
Exploration dry hole costs	10	
Mark-to-market loss (gain) on gas and oil derivatives not designated as hedges	40,036	(46,578)
Abandonment and impairment of unproved properties	16,537	6,551
Unrealized derivative (gain) loss	(568)	249
Allowance for bad debts	(688)	
Deferred and stock-based compensation	40,650	7,277
Amortization of deferred financing costs and other	(78)	1,167
Gain on sale of assets	(139)	(67,913)
Changes in working capital:		
Accounts receivable	1,689	8,111
Inventory and other	3,574	(700)
Accounts payable	2,302	17,452
Accrued liabilities and other	(18,210)	(8,998)
Net cash provided from continuing operations	118,741	116,269
Net cash provided from discontinued operations	21,881	36,605
Net cash provided from operating activities	140,622	152,874
Investing activities		
Additions to oil and gas properties	(250,766)	(153,971)
Additions to field service assets	(1,022)	(6,355)
Acreage and proved property purchases	(24,316)	(19,849)
Other assets		(45)
Investing activities of discontinued operations	(8,219)	(12,273)
Proceeds from disposal of assets	15,197	301,648
Purchase of marketable securities held by the deferred compensation plan	(6,260)	(3,690)
Proceeds from the sales of marketable securities held by the deferred compensation plan	3,557	2,613
Net cash (used in) provided from investing activities	(271,829)	108,078
Financing activities		
Borrowing on credit facilities	372,826	148,000
Repayment on credit facilities	(166,826)	(118,000)

Dividends paid	(6,420)	(6,373)
Issuance of common stock	503	5,437
Debt issuance costs	(12,356)	
Change in cash overdrafts	(60,979)	(5,162)
Proceeds from the sales of common stock held by the deferred compensation plan	3,292	893
Net cash provided from financing activities	130,040	24,795
(Decrease) increase in cash and equivalents	(1,167)	285,747
Cash and cash equivalents at beginning of period	2,848	767
Cash and cash equivalents at end of period	$ 1,681	$ 286,514

See the accompanying notes.

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

	Three Months Ended March 31,	
	2011	**2010**
Net (loss) income	$ (25,033)	$ 77,579
Other comprehensive (loss) income:		
Realized gain on hedge derivative contract settlements reclassified into earnings from other comprehensive income, net of taxes	(23,889)	(753)
Change in unrealized deferred hedging gains (losses), net of taxes	113	52,582
Total comprehensive (loss) income	$ (48,809)	$ 129,408

See the accompanying notes.

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RANGE RESOURCES CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

(1) ORGANIZATION AND NATURE OF BUSINESS

We are a Fort Worth, Texas-based independent natural gas and oil company engaged in the exploration, development and acquisition of natural gas and oil properties, mostly in the Appalachia and the Southwest regions of the United States. Our objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. Range 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 the Range Resources Corporation 2010 Annual Report on Form 10-K filed on March 1, 2011. 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.

In February 2011, we entered into an agreement to sell our Barnett Shale assets. Accordingly, we have classified the assets and liabilities as discontinued operations in the accompanying consolidated balance sheets along with the historic results of operations of our Barnett Shale operations as discontinued operations, net of tax, in the accompanying consolidated statements of operations. See also Note 4 and 5.

(3) NEW ACCOUNTING STANDARDS

There have been no developments to recently issued accounting standards, including the expected dates of adoption and estimated effects on our consolidated financial statements, from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2010.

(4) DISPOSITIONS

2011 Asset Sales

In February 2011, we entered into an agreement to sell our Barnett Shale natural gas properties in North Central Texas for a price of $900.0 million, which also includes the assumption of certain derivative contracts by the buyer and is subject to normal post closing adjustments. The completion of the sale is dependent upon customary prospective buyer due diligence procedures. We expect to complete the sale by the end of April 2011. As of March 31, 2011, we have classified these assets and liabilities held for sale as discontinued operations. As of February 28, 2011, the carrying value of the asset group, which excludes the derivative contracts to be sold, was approximately $827.9 million. As indicated in Note 2, our Barnett operations are presented as discontinued operations.

2010 Asset Sales

In February 2010, we entered into an agreement to sell our tight gas sand properties in Ohio. We closed approximately 90% of the sale in March 2010 and closed the remainder in June 2010. Proceeds received in first quarter 2010 were approximately $300.0 million and we recorded a gain of $67.0 million in continuing operations. The agreement had an effective date of January 1, 2010, and consequently operating net revenues after January 1, 2010 were a downward adjustment to the selling price. The proceeds we received were placed in a like-kind exchange account and in June 2010, we used a portion of the proceeds to purchase proved and unproved natural gas properties in Virginia. In September 2010, the like-kind exchange account was closed and the balance of these proceeds ($135.0 million) was used to repay amounts outstanding under our bank credit facility.

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(5) DISCONTINUED OPERATIONS

The following table presents the components of our Barnett operations as discontinued operations for the three months ended March 31, 2011 and 2010 (in thousands):

	Three Months Ended March 31,	
	2011	**2010**
Revenues and other income		
Natural gas, NGL and oil sales	$ 42,257	$ 49,087
Transportation and gathering	5	12
Gain on the sale of assets		955
Other	4	
Total revenues and other income	42,266	50,054
Costs and expenses		
Direct operating	8,277	9,204
Production and ad valorem taxes	1,066	1,528
Exploration	32	496
Abandonment and impairment of unproved properties		5,856
Interest expense [(a)]	11,076	9,356
Depletion, depreciation and amortization	8,880	23,819
Total costs and expenses	29,331	50,259
Income (loss) from discontinued operations before income taxes	12,935	(205)
Income tax expense (benefit)		
Current		
Deferred	4,537	(78)
Total income tax expense (benefit)	4,537	(78)
Net income (loss) from discontinued operations	$ 8,398	$ (127)
Production:		
Natural gas (mcf)	8,885,498	9,378,392
NGLs (bbls)	158,843	207,662
Crude oil (bbls)	6,988	9,577
Total (mcfe) [(b)]	9,880,483	10,681,826

(a) Interest expense is allocated to discontinued operations based on the ratio of the net assets of discontinued operations to our consolidated net assets plus long-term debt.

(b) NGLs and oil are converted at a rate of one barrel equals six mcf.

The carrying values of our Barnett operations are included in discontinued operations in the accompanying consolidated balance sheets which is comprised of the following (in thousands):

	March 31, 2011	December 31, 2010
Composition of assets of discontinued operations:		
Natural gas and oil properties, net	$ 827,172	$ 838,044
Transportation and field assets, net	666	684
Accounts receivable	28,276	29,300
Unrealized derivative gain		8,195
Inventory and other	81	81
Total assets of discontinued operations	$ 856,195	$ 876,304

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	March 31, 2011	December 31, 2010
Composition of liabilities of discontinued operations:		
Account payable	$ 9,514	$ 23,366
Accrued liabilities	6,774	9,596
Total current liabilities of discontinued operations	$ 16,288	$ 32,962
Asset retirement obligations	$ 2,025	$ 1,980
Other liabilities	201	1,921
Total long-term liabilities of discontinued operations	$ 2,226	$ 3,901

(6) INCOME TAXES

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

	Three Months Ended March 31,	
	2011	2010
Income tax (benefit) expense	$(19,897)	$49,012
Effective tax rate	37.3%	38.7%

We compute our quarterly taxes under the effective tax rate method based on applying an anticipated annual effective rate to our year-to-date income, except for discrete items. Income taxes for discrete items are computed and recorded in the period that the specific transaction occurs. For the three months ended March 31, 2011 and 2010, 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, valuation allowances and other permanent differences.

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(7) (LOSS) INCOME FROM CONTINUING OPERATIONS PER COMMON SHARE

Basic income or loss from continuing operations per share is computed as (i) income or loss from continuing operations (ii) less income allocable to participating securities (iii) divided by weighted average basic shares outstanding. Diluted income or loss from continuing operations per share is computed as (i) basic income or loss from continuing operations attributable to common shareholders (ii) plus diluted adjustments to income allocable to participating securities (iii) divided by weighted average diluted shares outstanding. The following table sets forth a reconciliation of income (loss) from continuing operations to basic income (loss) from continuing operations attributable to common shareholders and to diluted income (loss) from continuing operations attributable to common shareholders and a reconciliation of basic weighted average common shares outstanding to diluted weighted average common shares outstanding (in thousands except per share amounts):

	Three Months Ended March 31,	
	2011	2010
Numerator:		
(Loss) income from continuing operations	$ (33,431)	$ 77,706
Less: Basic income allocable to participating securities [(a)]		
Basic (loss) income from continuing operations attributable to common shareholders	(33,431)	77,706
Diluted adjustments to income allocable to participating securities [(a)]		
Diluted (loss) income from continuing operations attributable to common shareholders	$ (33,431)	$ 77,706
Denominator:		
Weighted average common shares outstanding basic	157,545	156,393
Effect of dilutive securities:		
Employee stock options, SARs, restricted stock units and stock held in the deferred compensation plan		3,899
Weighted average common shares diluted	157,545	160,292
(Loss) income from continuing operations per common share:		
Basic net (loss) income	$ (0.21)	$ 0.50
Diluted net (loss) income	$ (0.21)	$ 0.48

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

The weighted average common shares basic for the three months ended March 31, 2011 excludes 2.9 million shares of restricted stock compared to 2.7 million shares of restricted stock excluded at March 31, 2010 which are held in our deferred compensation plans (although all restricted stock is issued and outstanding upon grant). Due to our loss from continuing operations for the three months ended March 31, 2011, we excluded all outstanding stock options, stock appreciation rights (SARs) and restricted stock from computations of diluted net income per share because the effect would have been anti-dilutive to the computations. SARs of 1.1 million for the three months ended March 31, 2010 were outstanding but not included in the computations of diluted income from continuing operations per share because the grant prices of the SARs were greater than the average market price of the common shares.

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(8) SUSPENDED EXPLORATORY WELL COSTS

The following table reflects the changes in capitalized exploratory well costs for the three months ended March 31, 2011 and the year ended December 31, 2010 (in thousands):

	March 31, 2011	December 31, 2010
Beginning balance at January 1	$ 23,908	$ 19,052
Additions to capitalized exploratory well costs pending the determination of proved reserves	15,329	28,897
Reclassifications based on determination of proved reserves	(11,619)	(24,041)
Capitalized exploratory well costs charged to expense		
Balance at end of period	27,618	23,908
Less exploratory well costs that have been capitalized for a period of one year or less	(22,388)	(13,181)
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$ 5,230	$ 10,727
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	3	4

As of March 31, 2011 the $5.2 million of capitalized exploratory well costs that have been capitalized for more than one year, all are Marcellus Shale wells and are waiting on the completion of pipelines. The following provides an aging of capitalized exploratory well costs that have been suspended for more than one year as of March 31, 2011 (in thousands):

	Total	2011	2010	2009	2008
Capitalized exploratory well costs that have been capitalized for more than one year	$ 5,230	$ 252	$ 334	$ 3,065	$ 1,579

(9) INDEBTEDNESS

We had the following debt outstanding as of the dates shown below (in thousands) (bank debt interest rate at March 31, 2011 is shown parenthetically). No interest expense was capitalized during the three months ended March 31, 2011 and 2010.

	March 31, 2011	December 31, 2010
Bank debt (1.9%)	$ 480,000	$ 274,000
Subordinated debt:		
6.375% Senior Subordinated Notes due 2015	150,000	150,000
7.5% Senior Subordinated Notes due 2016, net of discount	249,695	249,683
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	287,121	286,853
6.75% Senior Subordinated Notes due 2020	500,000	500,000

Total debt	$ 2,166,816	$ 1,960,536

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Bank Debt

In February 2011, we entered into an amended and restated revolving bank facility, which we refer to as our bank debt or our bank credit facility, which is secured by substantially all of our assets. Our new borrowing base was set without our Barnett shale assets, which are presented as held for sale at March 31, 2011. The bank credit facility provides for an initial commitment equal to the lesser of the facility amount or the borrowing base. On March 31, 2011, the borrowing base was $2.0 billion and our facility amount was $1.5 billion. The bank credit facility provides for a borrowing base subject to redeterminations semi-annually and for event-driven unscheduled redeterminations. Our current bank group is comprised of twenty-seven commercial banks, with no one bank holding more than 7% of the total facility. 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 March 31, 2011, the outstanding balance under the bank credit facility was $480.0 million and we had $8.3 million of undrawn letters of credit leaving $1.0 billion of borrowing capacity available under the facility amount. The loan matures in February 2016. Borrowing under the bank credit facility can either be the Alternate Base Rate (as defined) plus a spread ranging from 0.50% to 1.50% or LIBOR borrowings at the Adjusted LIBO Rate (as defined) plus a spread ranging from 1.50% to 2.50%. 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 2.3% for the three months ended March 31, 2011 compared to 2.1% for the three months ended March 31, 2010. A commitment fee is paid on the undrawn balance based on an annual rate of between 0.375% and 0.50%. At March 31, 2011, the commitment fee was 0.375% and the interest rate margin was 1.5% on our LIBOR loans and 0.5% on our base rate loans.

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 4.25 to 1.0 and a current ratio (as defined in the credit agreement) of no less than 1.0 to 1.0. We were in compliance with our covenants under the bank credit facility at March 31, 2011.

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 March 31, 2011, we were in compliance with these covenants.

(10) ASSET RETIREMENT OBLIGATIONS

Our asset retirement obligations primarily represent 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 three months ended March 31, 2011 is as follows (in thousands):

	Three Months Ended March 31, 2011
Beginning of period	$ 62,673
Liabilities incurred	699
Liabilities settled	(622)
Liabilities reclassified to discontinued operations	(2,025)
Accretion expense continuing operations	1,193
Accretion expense discontinued operations	45

Change in estimate		1,584
End of period	$	63,547

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

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(11) 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 2010:

	Three Months Ended March 31, 2011	Year Ended December 31, 2010
Beginning balance	159,909,052	158,118,937
Stock options/SARs exercised	439,558	991,988
Restricted stock grants	115,130	405,127
Treasury shares issued	8,540	12,771
Shares issued for acreage purchases		380,229
Ending balance	160,472,280	159,909,052

Treasury Stock

The Board of Directors has approved up to $10.0 million of repurchases of common stock based on market conditions and opportunities and on March 31, 2011, we have $6.8 million remaining under this authorization.

(12) DERIVATIVE ACTIVITIES

We use commodity based derivative contracts to manage exposure to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. We do not utilize complex derivatives such as swaptions, knockouts or extendable swaps. We typically utilize commodity swap, collar or call option contracts to (1) reduce the effect of price volatility of the commodities we produce and sell and (2) support our annual capital budget and expenditure plans. Historically, our derivative activities have consisted of collars and fixed price swaps. At March 31, 2011, we had open swap contracts covering 25.6 Bcf of natural gas at prices averaging $5.00 per mcf and 1.5 million barrels of NGLs at prices averaging $101.88 per barrel. At March 31, 2011, we had collars covering 195.3 Bcf of natural gas at weighted average floor and cap prices of $5.42 to $6.27 per mcf and 0.7 million barrels of oil at weighted average floor and cap prices of $70.00 to $80.00 per barrel. At March 31, 2011, we also had sold call options for 3.2 million barrels of oil at a weighted average price of $82.66. In first quarter 2011, we entered into NGL derivative swap contracts for the natural gasoline (or C5) component of natural gas liquids. The fair value of these commodity derivatives, 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 March 31, 2011, was a net unrealized pre-tax gain of $31.4 million. These contracts expire monthly through December 2013.

The following table sets forth our derivative volumes and average hedge prices as of March 31, 2011:

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural Gas			
2012	Swaps	70,192 Mmbtu/day	$5.00
2011	Collars	418,236 Mmbtu/day	$5.52-$6.45
2012	Collars	119,641 Mmbtu/day	$5.50-$6.25
2013	Collars	100,000 Mmbtu/day	$5.00-$5.73
Crude Oil			
2012	Collars	2,000 bbls/day	$70.00-$80.00
2011	Call options	5,500 bbls/day	$80.00

2012	Call options	4,700 bbls/day	$85.00
NGLs			
2011	Swaps	2,676 bbls/day	$102.80
2012	Swaps	2,000 bbls/day	$100.96

Every derivative instrument is recorded on the accompanying balance sheets 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 market price at the determination date. Changes in the fair value of derivatives that qualify for hedge accounting are recorded as a component of accumulated other comprehensive income (AOCI) in the stockholders equity section of the accompanying consolidated balance sheets, which is later transferred to natural gas, NGL and oil sales when the underlying physical transaction occurs and the hedging contract is settled. Amounts included in AOCI at March 31, 2011 and December 31, 2010 relate solely to our commodity derivative activities. As of March 31, 2011, an unrealized pre-tax derivative gain of $69.9 million was recorded in AOCI. This gain is expected to be reclassified into earnings as a $68.6 million gain in 2011, a $4.3 million gain in 2012 and a $2.9 million loss in 2013. 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 natural gas, NGL and oil sales in the period the hedged production is sold. Natural gas, NGL and oil sales include $29.6 million of gains in the three months ended March 31, 2011 compared to gains of $1.2 million in the same period of 2010 related to settled hedging transactions. Any ineffectiveness associated with these hedge derivatives is included in derivative fair value income (loss) in the accompanying consolidated statements of operations. 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 March 31, 2011 includes ineffective gains (unrealized and realized) of $1.5 million compared to losses of $606,000 in the same period of 2010.

Through March 31, 2011, we have elected to designate our commodity derivative instruments that qualify for hedge accounting as cash flow hedges. 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 natural gas, NGL and oil 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 derivative fair value income (loss) in the accompanying consolidated statements of operations. During the first three months of 2011 or 2010 there were no gains or losses recorded due to the discontinuance of hedge accounting treatment for these derivatives.

Some of our derivatives do not qualify for hedge accounting or are not designated as a hedge but provide an economic hedge of our exposure to commodity price risk associated with anticipated future natural gas and oil 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 derivative fair value (loss) income in the accompanying consolidated statements of operations (for additional information see table below).

Derivative Fair Value (Loss) Income

The following table presents information about the components of derivative fair value (loss) income in the three months ended March 31, 2011 and 2010 (in thousands):

	Three Months Ended March 31,	
	2011	2010
Hedge ineffectiveness realized	$ 946	$ (357)
unrealized	568	(249)
Change in fair value of derivatives that do not qualify for hedge accounting[(a)]	(40,036)	46,578
Realized loss on settlements gas[(a) (b)]	(394)	(3,639)

Realized loss on settlements oil [a] [b]	(1,918)	
Derivative fair value (loss) income	$ (40,834)	$ 42,333

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

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

The combined fair value of derivatives included in the accompanying consolidated balance sheets as of March 31, 2011 and December 31, 2010 is summarized below (in thousands). We conduct commodity derivative activities with nine financial institutions, all 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. In our accompanying consolidated balance sheets, derivative assets and liabilities are netted where derivatives with both gain and loss positions are held by a single counterparty.

	March 31, 2011	December 31, 2010
Derivative assets:		
Natural gas collars	$ 122,843	$ 163,354
swaps	(524)	
Crude oil collars	(5,172)	
call options	(53,799)	(31,904)
NGL swaps	(1,062)	
	$ 62,286	$ 131,450
Derivative liabilities:		
Natural gas collars	$ 18,015	$ 27,032
basis swaps		(352)
swaps	(881)	
Crude oil collars	(14,866)	(12,051)
call options	(32,301)	(28,393)
NGL swaps	(802)	
	$ (30,835)	$ (13,764)

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 accompanying consolidated balance sheets (in thousands):

	March 31, 2011			December 31, 2010		
	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:						
Swaps [(1)]	$	$ (1,405)	$ (1,405)	$	$	$
Collars[(1)]	136,578	(3,390)	133,188	173,128		173,128
	$ 136,578	$ (4,795)	$ 131,783	$ 173,128	$	$ 173,128

Derivatives that do not qualify for hedge accounting:						
Swaps [1]	$	$ (1,864)	$ (1,864)	$	$	$
Collars[1]	7,844	(20,211)	(12,367)	17,259	(12,052)	5,207
Call options[1]		(86,101)	(86,101)		(60,297)	(60,297)
Basis swaps[1]					(352)	(352)
	$ 7,844	$ (108,176)	$ (100,332)	$ 17,259	$ (72,701)	$ (55,442)

(1) Included in unrealized derivative gain or loss in the accompanying consolidated balance sheets.

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

	Three Months Ended March 31,			
	Change in Hedge Derivative Fair Value		Realized Gain Reclassified from AOCI into Revenue [a]	
	2011	2010	2011	2010
Swaps	$ (2,540)	$	$	$
Collars	(387)	84,811	38,223	1,215
Income taxes	3,040	(32,229)	(14,334)	(462)
	$ 113	$ 52,582	$ 23,889	$ 753

[a] For realized gains upon contract settlement, the reduction in AOCI is offset by an increase in natural gas, NGL and oil sales. For realized losses upon contract settlement, the increase in AOCI is offset by a decrease in natural gas, NGL and oil sales.

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

	Three Months Ended March 31,					
	Gain (Loss) Recognized in Income (Non-hedge Derivatives)		Gain Recognized in Income (Ineffective Portion)		Derivative Fair Value (Loss) Income	
	2011	2010	2011	2010	2011	2010
Swaps	$ (1,864)	$	$	$	$ (1,864)	$
Collars	(7,586)	46,956	1,514	(606)	(6,072)	46,350
Call options	(32,855)				(32,855)	
Basis swaps	(43)	(4,017)			(43)	(4,017)
Total	$ (42,348)	$ 42,939	$ 1,514	$ (606)	$ (40,834)	$ 42,333

(13) FAIR VALUE MEASUREMENTS

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

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

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

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

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

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

Fair Values-Recurring

We use a market approach for our 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 March 31, 2011 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 March 31, 2011
Trading securities held in our deferred compensation plans	$ 52,682	$	$	$ 52,682
Derivatives swaps		(3,269)		(3,269)
collars		120,821		120,821
call options		(86,101)		(86,101)

Our trading securities in Level 1 are exchange-traded and measured at fair value with a market approach using March 31, 2011 market values. Derivatives in Level 2 are measured at fair value with a market approach using third-party pricing services, which have been corroborated with data from active markets or broker quotes.

Our trading securities held in the deferred compensation plan are accounted for using the mark-to-market accounting method and are included in other assets in our accompanying consolidated balance sheets. We elected to adopt the fair value option to simplify our accounting for the investments in our deferred compensation plan. Interest, dividends and mark-to-market gains/losses are included in deferred compensation plan expense in our consolidated statements of operations. For the three months ended March 31, 2011, interest and dividends were $35,000 and mark-to-market was a gain of $1.3 million. For the three months ended March 31, 2010, interest and dividends were $32,000 and mark-to-market was a gain of $596,000. For additional information on the accounting for our deferred compensation plan, see Note 14.

Fair Values-Nonrecurring

We review our long-lived assets to be held and used, including proved natural gas and oil properties, whenever events or circumstances indicate the carrying value of those assets may not be recoverable. Several long-lived assets held for use were evaluated for impairment during 2010 due to reductions in estimated reserves and natural gas prices. The fair value of our onshore Gulf Coast assets in 2010 was measured using an income approach based upon internal estimates of future production levels, prices, drilling and operating costs and discount rates, which are Level 3 inputs. Our projected undiscounted cash flows associated with these assets was less than their carrying value and therefore, we recorded an impairment of $6.5 million in 2010 related to our onshore Gulf Coast proved properties.

The following table presents the value of these assets measured at fair value on a nonrecurring basis (in thousands):

	Three Months Ended March 31,			
	2011		2010	
	Fair Value	Impairment	Fair Value	Impairment

Natural gas and oil properties	$	$	$16,075	$6,505

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Fair Values-Reported

The following table presents the carrying amounts and the fair values of our financial instruments as of March 31, 2011 and December 31, 2010 (in thousands):

	March 31, 2011		December 31, 2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:				
Commodity swaps, collars, call options and basis swaps	$ 62,286	$ 62,286	$ 131,450	$ 131,450
Marketable securities[(a)]	52,682	52,682	47,794	47,794
Liabilities:				
Commodity swaps, collars, call options and basis swaps	(30,835)	(30,835)	(13,764)	(13,764)
Bank credit facility [(b)]	(480,000)	(480,000)	(274,000)	(274,000)
6.375% senior subordinated notes due 2015 [(b)]	(150,000)	(153,000)	(150,000)	(153,000)
7.5% senior subordinated notes due 2016 [(b)]	(249,695)	(259,375)	(249,683)	(259,375)
7.5% senior subordinated notes due 2017 [(b)]	(250,000)	(266,250)	(250,000)	(263,438)
7.25% senior subordinated notes due 2018 [(b)]	(250,000)	(267,500)	(250,000)	(263,750)
8.0% senior subordinated notes due 2019 [(b)]	(287,121)	(330,750)	(286,853)	(326,625)
6.75% senior subordinated notes due 2020 [(b)]	(500,000)	(532,500)	(500,000)	(515,625)

(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 deemed necessary to limit risk of loss. Our allowance for uncollectible receivables was $4.3 million at March 31, 2011 and $5.0 million at December 31, 2010. Commodity-based contracts expose us to the credit risk of nonperformance by the counterparty to the contracts. As of March 31, 2011, these contracts consist of swaps, collars and call options. 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 nine financial institutions, all of which are secured lenders in our bank credit facility. Our natural gas and oil properties provide collateral under our credit facility and our derivative exposure. None of our derivative contracts have margin requirements or collateral provisions that would require funding prior to the scheduled cash settlement date.

(14) EMPLOYEE BENEFIT AND EQUITY PLANS

We have two active equity-based stock plans. Under these plans, incentive and non-qualified stock options, SARs, restricted stock, restricted stock units, phantom stock and various other awards may be issued to employees and directors 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. Information with respect to stock option/SARs activity is summarized below:

	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2010	6,461,839	$ 37.20
Granted	317,451	49.18
Exercised	(1,169,831)	26.63
Expired/forfeited	(147,375)	55.94
Outstanding at March 31, 2011	5,462,084	$ 39.65

The weighted average fair value of a SAR to purchase one share of common stock granted during 2011 was $17.60. The fair value of each SAR granted during 2011 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 1.7%; dividend yield of 0.3%; expected volatility of 47% and an expected life of 3.6 years. Of the 5.5 million stock option/SARs outstanding at March 31, 2011, 671,000 are stock options and 4.8 million are SARs.

Equity Awards-Restricted Stock Units

Beginning in first quarter 2011, the compensation committee began granting restricted stock units under our equity-based stock plans. These restricted stock units vest over a three-year period. All awards granted have been issued at prevailing market prices at the time of grant and the vesting of these shares is based upon an employee s continued employment with us. Net shares will be issued to employees as the restricted stock units vest. A summary of the outstanding restricted stock unit awards at March 31, 2011 is presented below:

	Shares	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2010		$
Granted	297,349	49.18
Exercised	(1,054)	49.18
Expired/forfeited	(2,555)	49.18
Outstanding at March 31, 2011	293,740	$ 49.18

Liability Awards-Restricted Stock

These restricted stock shares are placed into our deferred compensation plan when granted. During the first three months of 2011, 130,000 shares of restricted stock (or non-vested shares) were issued to certain employees at an average price of $49.14 with a three-year vesting period. In the first three months of 2010, we issued 172,000 shares of restricted stock as compensation to employees at an average price of $46.45 with a three-year vesting period. All restricted stock awards held in our deferred compensation plans are classified as a liability award and remeasured at fair value each reporting period. This mark-to-market is included in deferred compensation plan expense in our accompanying consolidated statements of operations (see additional 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 March 31, 2011 is presented below:

	Shares	Weighted Average Grant Date Fair Value
Non-vested restricted stock outstanding at December 31, 2010	582,751	$ 44.81
Granted	129,602	49.14
Vested	(101,300)	46.47
Forfeited	(4,268)	40.63
Non-vested restricted stock outstanding at March 31, 2011	606,785	$ 45.48

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. Our stock granted and held in the Rabbi Trust is treated as a liability award as employees are allowed to take withdrawals either in cash or in Range stock. The liability associated with the vested portion of the stock is adjusted to fair value each reporting period by a charge or credit to deferred compensation plan expense on our consolidated statements of operations. The assets of the Rabbi Trust, other than Range common stock, are invested in marketable securities and reported at market value in other assets in the accompanying consolidated balance sheets. Changes in the market value of the marketable securities are charged or credited to deferred compensation plan expense each quarter. The deferred compensation liability included in our consolidated balance sheets 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 $30.6 million in the three months ended March 31, 2011 compared to income of $5.7 million in the same period of 2010.

(15) SUPPLEMENTAL CASH FLOW INFORMATION

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
	(in thousands)	
Non-cash investing and financing activities included:		
Asset retirement costs capitalized, net	$ 2,284	$ 376
Unproved property purchased with stock[a]	$	$20,000
Net cash provided from operating activities included:		
Interest paid	$24,240	$15,625
Income taxes paid (refunded)	$ 300	$ (1,684)

[a] Three months ended March 31, 2010 included shares that were issued in January 2010 while the value was accrued and included in costs incurred for the year ended December 31, 2009.

(16) COMMITMENTS AND CONTINGENCIES

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.

Transportation Contracts

During the first quarter 2011, we entered into additional transportation agreement in Appalachia which total approximately $100.0 million over the next seven years.

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

	March 31, 2011	December 31, 2010
	(in thousands)	
Natural gas and oil properties:		
Properties subject to depletion	$ 5,023,170	$ 4,742,248
Unproved properties	646,621	648,143
Total	5,669,791	5,390,391
Accumulated depreciation, depletion and amortization	(1,373,652)	(1,306,378)
Net capitalized costs	$ 4,296,139	$ 4,084,013

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

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

	Three Months Ended March 31, 2011	Year Ended December 31, 2010
	(in thousands)	
Acquisitions:		
Unproved leasehold	$	$ 3,697
Proved properties		130,767
Asset retirement obligations		556
Acreage purchases	18,816	166,677
Development	237,954	784,153
Exploration:		
Drilling	29,441	50,737
Expense	25,890	56,879
Stock-based compensation expense	1,329	4,209
Gas gathering facilities:		
Development	5,610	20,726
Subtotal	319,040	1,218,401
Asset retirement obligations	2,284	(6,523)
Total costs incurred	$ 321,324	$ 1,211,878

(a) Includes costs incurred whether capitalized or expensed and include our Barnett operations.

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(19) OFFICE CLOSING AND EXIT ACTIVITIES

In February 2010, we entered into an agreement to sell our natural gas properties in Ohio. We closed approximately 90% of the sale in March 2010 and closed the remainder of the sale in June 2010. The first quarter 2010 includes $5.1 million accrued severance costs, which is reflected in termination costs in the accompanying consolidated statements of operations. As part of their severance agreement, our Ohio employees vesting of SARs and restricted stock grants was accelerated, increasing termination costs for stock compensation expense in first quarter 2010 by approximately $2.8 million.

The following table details our exit activities, which are included in accrued liabilities in the accompanying consolidated balance sheets as of March 31, 2011 and December 31, 2010 (in thousands):

	Three Months Ended March 31, 2011	Year Ended December 31, 2010
	(in thousands)	
Balance at beginning of period	$ 1,092	$ 1,568
Accrued one-time termination costs		5,138
Office lease		514
Payments	(323)	(6,128)
Balance at end of period	$ 769	$ 1,092

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

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. Certain sections of Management s Discussion and Analysis of Financial Condition and Results of Operations include forward-looking statements concerning trends or events potentially affecting our business. These statements typically contain words such as anticipates, believes, estimates, expects, targets, pla could, may, should, would or similar words indicating that future outcomes are uncertain. In accordance with safe harbor provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in forward-looking statements. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future revenues and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions. For additional risk factors affecting our business, see Item 1A. Risk Factors as filed with our Annual Report on Form 10-K for the year ended December 31, 2010 filed with the SEC on March 1, 2011.

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 our Annual Report on Form 10-K for the year ended December 31, 2010. We have identified the following critical accounting policies and estimates used in the preparation of our financial statements: accounting for natural gas, NGL and oil revenue, natural gas and oil properties, stock-based compensation, derivative financial instruments, asset retirement obligations and deferred income taxes.

Market Conditions

Prices for various quantities of natural gas, natural gas liquids (NGLs) and oil that we produce significantly impact our revenues and cash flows. Commodity prices have been volatile in recent years. The following table lists average New York Mercantile Exchange (NYMEX) prices for natural gas and oil for the three months ended March 31, 2011 and 2010.

	Three Months Ended March 31,	
	2011	2010
Average NYMEX prices[(a)]		
Natural gas (per mcf)	$ 4.12	$ 5.37
Oil (per bbl)	$ 94.67	$ 78.82

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

Consolidated Results of Operations

Overview

We are an independent natural gas and oil company engaged in the exploration, development and acquisition of natural gas and oil properties, mostly in the Appalachia and Southwest regions of the United States. Our objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. Our strategy to achieve our objective is to increase reserves and production through internally generated drilling projects occasionally coupled with complementary acquisitions. Our revenues, profitability and future growth depend substantially on prevailing prices for natural gas and oil and on our ability to economically find, develop, acquire and produce natural gas and oil reserves. We use the successful efforts method of accounting for our natural gas, NGLs and oil activities. Our corporate headquarters is located in Fort Worth, Texas.

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Discontinued operations consists of our Barnett Shale properties which are reported as discontinued operations as of March 31, 2011. Unless otherwise indicated, the information included herein relates to our continuing operations.

During the first three months of 2011, we achieved the following financial and operating results:

- recorded our 33rd consecutive quarter of sequential production growth;
- achieved 26% year-over-year production growth;
- daily production now exceeds 435.0 mmcfe per day;
- natural gas, NGL and oil sales increased 21% from first quarter 2010;
- reduced our DD&A rate 12% from first quarter 2010;
- year-over-year direct operating expense per mcfe increased 4% while production and ad valorem tax expense per mcfe declined 14% and general and administrative expense per mcfe declined 3%;
- entered into additional commodity derivative contracts for 2011, 2012 and 2013; and
- renewed our bank credit facility, with a borrowing base of $2.0 billion.

Total revenues decreased $110.8 million, or 37% for first quarter 2011 over the same period of 2010. The decrease includes a $39.2 million increase in natural gas, NGL and oil sales offset by a decrease in derivative fair value income (loss) of $83.2 million and a lower gain on sale of assets of $67.8 million. Natural gas, NGL and oil sales vary due to changes in volumes of production sold and realized commodity prices. Realized prices declined from the same period of the prior year, which was more than offset by an increase in production, including a 81% increase in NGL production primarily due to increased liquids-rich production in our Appalachia area. For first quarter 2011, production increased 26% from the same period of the prior year while realized prices (including all derivative settlements) declined 3%. We believe natural gas, NGL and oil 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. Although we have entered into derivative contracts covering a portion of our production volumes for 2011, 2012 and 2013, a sustained lower price environment would result in lower realized prices for unprotected volumes and reduce the prices we can enter into derivative contracts for additional volumes in the future.

Natural Gas, NGL and Oil Sales Production and Realized Price Calculation

Our natural gas, NGL and oil sales vary from quarter to quarter as a result of changes in realized commodity prices and volumes of production sold. Hedges included in natural gas, NGL and oil sales reflect settlements on those derivatives that qualify for hedge accounting. Cash settlements of derivative contracts that are not accounted for as hedges are included in derivative fair value (loss) income in the accompanying consolidated statements of operations. The following table summarizes the primary components of natural gas, NGL and oil sales for the three months ended March 31, 2011 and 2010 (in thousands):

	Three Months Ended March 31,			
	2011	2010	Change	%
Gas wellhead	$ 106,283	$ 123,270	$ (16,987)	(14%)
Gas hedges realized	29,616	1,215	28,401	2,338%
Total gas sales	135,899	124,485	11,414	9%

NGL	54,475	28,024	26,451	94%
Oil wellhead	36,507	35,164	1,343	4%
Oil hedges realized				%
Total oil sales	36,507	35,164	1,343	4%
Combined wellhead	197,265	186,458	10,807	6%
Combined hedges realized	29,616	1,215	28,401	2,338%
Total natural gas, NGL and oil sales	$ 226,881	$ 187,673	$ 39,208	21%

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Our production continues to grow through continued drilling success as we place new wells into production, partially offset by the natural decline of our wells and asset sales. For first quarter 2011, total production volumes, when compared to the same period of the prior year, increased 40% in our Appalachia area and remained the same in our Southwest area. For first quarter 2011, NGL production increased 81% from the same period of the prior year primarily due to increased liquids-rich gas production in our Appalachia area along with an increase in processing capacity in the region. Our production for the three months ended March 31, 2011 and 2010 is shown below:

	Three Months Ended March 31,			
	2011	2010	Change	%
Production[(a)]:				
Natural gas (mcf)	29,805,523	24,372,167	5,433,356	22%
NGLs (bbls)	1,131,565	623,474	508,091	81%
Crude oil (bbls)	436,132	505,101	(68,969)	(14%)
Total (mcfe)[(b)]	39,211,706	31,143,617	8,068,089	26%
Average daily production[(a)]:				
Natural gas (mcf)	331,172	270,802	60,370	22%
NGLs (bbls)	12,573	6,927	5,646	81%
Crude oil (bbls)	4,846	5,612	(766)	(14%)
Total (mcfe)[(b)]	435,686	346,040	89,646	26%

(a) Represents volumes sold regardless of when produced.

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

Our average realized price (including all derivative settlements) received was $5.75 per mcfe in first quarter 2011 compared to $5.90 per mcfe in the same period of the prior year. Our average realized price calculation (including all derivative settlements) includes all cash settlements for derivatives, whether or not they qualify for hedge accounting. Average price calculations for the three months ended March 31, 2011 and 2010 are shown below:

	Three Months Ended March 31,	
	2011	2010
Average sales prices (wellhead):		
Natural gas (per mcf)	$ 3.57	$ 5.06
NGLs (per bbl)	48.14	44.95
Crude oil (per bbl)	83.71	69.62
Total (per mcfe)[(a)]	5.03	5.99
Average realized price (including derivatives that qualify for hedge accounting):		
Natural gas (per mcf)	$ 4.56	$ 5.11
NGLs (per bbl)	48.14	44.95
Crude oil (per bbl)	83.71	69.62
Total (per mcfe)[(a)]	5.79	6.02
Average realized price (including all derivative settlements):		
Natural gas (per mcf)	4.58	4.94
NGLs (per bbl)	48.14	44.95

Crude oil (per bbl)	79.31	69.62
Total (per mcfe)[(a)]	5.75	5.90

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

Derivative fair value income (loss) was a loss of $40.8 million in first quarter 2011 compared to a gain of $42.3 million in the same period of 2010. Some of our derivatives do not qualify for hedge accounting and are accounted for using the mark-to-market accounting method whereby all realized and unrealized gains and losses related to these contracts are included in derivative fair value (loss) income in the accompanying consolidated statements of operations. Mark-to-market 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 accumulated other comprehensive income in the accompanying consolidated balance sheets. Hedge ineffectiveness, also included in this statement of operations category, is associated with our hedging contracts that qualify for hedge accounting.

The following table presents information about the components of derivative fair value (loss) income for the three months ended March 31, 2011 and 2010 (in thousands):

	Three Months Ended March 31,	
	2011	2010
Hedge ineffectiveness realized[a]	$ 946	$ (357)
unrealized[a]	568	(249)
Change in fair value of derivatives that do not qualify for hedge accounting[a]	(40,036)	46,578
Realized loss on settlements gas[b][c]	(394)	(3,639)
Realized loss on settlements oil[b][c]	(1,918)	
Derivative fair value (loss) income	$ (40,834)	$ 42,333

(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).

Gain on the sale of assets for first quarter 2011 decreased $67.8 million from the same period of the prior year. For the three months ended March 31, 2010, we recorded a total gain of $67.0 million from the sale of our properties in Ohio and we received proceeds of $300.0 million.

Other income (loss) for first quarter 2011 was income of $1.1 million compared to a loss of $1.6 million in the same period of 2010. First quarter 2011 includes income from equity method investments of $262,000. The first quarter of 2010 includes a loss from equity method investments of $1.6 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 a per mcfe basis for the three months ended March 31, 2011 and 2010:

	Three Months Ended March 31,			
	2011	2010	Change	%
Direct operating expense	$0.73	$0.70	$ 0.03	4%
Production and ad valorem tax expense	0.18	0.21	(0.03)	(14%)
General and administrative expense	0.87	0.90	(0.03)	(3%)
Interest expense	0.63	0.67	(0.04)	(6%)
Depletion, depreciation and amortization expense	1.84	2.08	(0.24)	(12%)

Direct operating expense increased $6.9 million in first quarter 2011 to $28.7 million. We experience increases in operating expenses as we add new wells and maintain production from existing properties. We incurred $390,000 ($0.01 per mcfe) of workover costs in first quarter 2011 versus $777,000 ($0.02 per mcfe) in 2010. On a per mcfe basis, direct operating expenses for first quarter 2011 increased $0.03, or 4%, from the same period of 2010 with the increase primarily due to higher water hauling and disposal costs ($0.04 per mcfe) and higher equipment rental ($0.02 per mcfe) somewhat offset by the impact of the sale of certain higher operating cost assets during 2010. In the future, we expect to experience lower costs per mcfe as we increase production from our Marcellus Shale wells due to their lower operating costs relative to our other operating areas. 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 ended March 31, 2011 and 2010:

	Three Months Ended March 31,			
	2011	2010	Change	%
Lease operating expense	$ 0.71	$ 0.67	$ 0.04	6%
Workovers	0.01	0.02	(0.01)	(50%)
Stock-based compensation (non-cash)	0.01	0.01		%
Total direct operating expenses	$ 0.73	$ 0.70	$ 0.03	4%

Production and ad valorem taxes are paid based on market prices and not hedged prices. For first quarter 2011, these taxes increased $337,000 or 5% from the same period of the prior year due to a decrease in the number of wells receiving high cost tax credits which was partially offset by an increase in production volumes not subject to production taxes and lower prices. On a per mcfe basis, production and ad valorem taxes decreased from $0.21 per mcf in first quarter 2010 to $0.18 per mcfe in 2011.

General and administrative expense for first quarter 2011 increased $5.8 million or 21% from the same period of the prior year due primarily to higher community relations costs ($1.3 million), higher salaries and benefits ($3.0 million), higher legal costs ($1.7 million) and higher office expenses, including information technology somewhat offset by lower bad debt expense ($688,000). 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 months ended March 31, 2011 and 2010:

	Three Months Ended March 31,			
	2011	2010	Change	%
General and administrative	$ 0.68	$ 0.65	$ 0.03	5%
Stock-based compensation (non-cash)	0.19	0.25	(0.06)	(24%)
Total general and administrative expenses	$ 0.87	$ 0.90	$ (0.03)	(3%)

Interest expense for first quarter 2011 increased $3.8 million from the same period of the prior year due to the refinancing of certain debt from floating to higher fixed rates and higher overall debt balances. In August 2010, we issued $500.0 million of 6.75% senior subordinated notes due 2020, which added $8.4 million of interest costs in first quarter 2011. The proceeds from the issuance were used to retire our 7.375% senior subordinated notes due 2013 and to lower our floating interest rate bank debt, which better matches the maturities of our debt with the life of our properties and gives us greater liquidity for the near term. Average debt outstanding on the bank credit facility for first quarter 2011 was $421.1 million compared to $359.6 million for the same period of the prior year and the weighted average interest rate was 2.3% in first quarter 2011 compared to 2.1% in the same period of the prior year.

Depletion, depreciation and amortization (DD&A) increased $7.4 million, or 11%, to $72.2 million in first quarter 2011. The increase was due to a 26% increase in production partially offset by a 10% decrease in depletion rates. On a per mcfe basis, DD&A decreased from $2.08 in first quarter 2010 to $1.84 in first quarter 2011. Depletion rates are declining due to our lower finding and development costs and the mix of our production. The following table summarizes DD&A expense per mcfe for the three months ended March 31, 2011 and 2010:

	Three Months Ended March 31,			
	2011	2010	Change	%
Depletion and amortization	$ 1.71	$ 1.89	$ (0.18)	(10%)
Depreciation	0.10	0.15	(0.05)	(33%)

Accretion and other	0.03	0.04	(0.01)	(25%)
Total DD&A expense	$ 1.84	$ 2.08	$ (0.24)	(12%)

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, termination costs, deferred compensation plan expenses and impairment of proved properties. In the three months ended March 31, 2011 and 2010, stock-based compensation represents the amortization of restricted stock grants and expenses related to SAR grants. In first quarter 2011, stock-based compensation is a component of direct operating expense ($310,000), exploration expense ($1.3 million) and general and administrative expense ($7.5 million) for a total of $9.6 million. In first quarter 2010, stock-based compensation was a component of direct operating expense ($362,000), exploration expense ($1.1 million) and general and administrative expense ($7.8 million) for a total of $9.7 million.

Exploration expense increased $13.0 million in first quarter 2011 with higher seismic costs and higher delay rental expense. The higher delay rental payments, or costs to defer the commencement of drilling, are primarily attributed to our Marcellus Shale operations. The following table details our exploration-related expenses for the three months ended March 31, 2011 and 2010 (in thousands):

	Three Months Ended March 31,			
	2011	2010	Change	%
Dry hole expense	$ 10	$	$ 10	%
Seismic	13,172	7,213	5,959	83%
Personnel expense	4,026	2,730	1,296	47%
Stock-based compensation expense	1,329	1,136	193	17%
Delay rentals and other	8,650	3,060	5,590	183%
Total exploration expense	$ 27,187	$ 14,139	$ 13,048	92%

Abandonment and impairment of unproved properties expense was $16.5 million during the three months ended March 31, 2011 compared to $6.6 million during the same period of 2010. We assess individually significant unproved properties for impairment on a quarterly basis and recognize a loss where circumstances indicate an impairment in value. In determining whether a significant unproved property is impaired we consider numerous factors including, but not limited to, current exploration plans, favorable or unfavorable activity on the property being evaluated and/or adjacent properties, our geologists evaluation of the property and the remaining months in the lease term for the property. Impairment of individually insignificant unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. The increase from the prior year is primarily due to increasing expirations in the Marcellus Shale.

Termination costs in the first three months of 2010 includes severance costs of $5.1 million related to the sale of our properties in Ohio and $2.8 million of non-cash stock-based compensation expense related to the accelerated vesting of SARs and restricted stock as part of the severance agreement for our Ohio personnel.

Deferred compensation plan expense was $30.6 million in first quarter 2011 compared to income of $5.7 million in the same period of the prior year. 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 in the accompanying statements of operations. Our stock price increased from $44.98 at December 31, 2010 to $58.46 at March 31, 2011. During the same period in the prior year, our stock price decreased from $49.85 at December 31, 2009 to $46.87 at March 31, 2010.

Impairment of proved properties in the first three months of 2010 of $6.5 million was recognized due to declining gas prices and is related to a portion of our onshore Gulf Coast properties. Our estimated fair value of producing properties is generally calculated as the discounted present value of future net cash flows. Our estimates of cash flow were based on the latest available proved reserve and production information and management s estimates of future product prices and costs, based on available information such as forward strip prices, at the time of the impairment.

Income tax (benefit) expense for first quarter 2011 decreased to a benefit of $19.9 million from income tax expense of $49.0 million in first quarter 2010, reflecting a 142% decrease in income from continuing operations before taxes compared to the same period of 2010. First quarter 2011 provided for tax benefit at an effective rate of 37.3% compared to tax expense at an effective rate of 38.7% in the same period of 2010. We expect our effective tax rate to be approximately 40% for the remainder of 2011.

Liquidity, Capital Resources and Financial Conditions

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. We continue to take steps to ensure adequate capital resources and liquidity to fund our capital expenditure program. In February 2011, we announced we had entered into a definitive agreement to sell our Barnett Shale properties along with certain derivative contracts for $900.0 million. The sale is expected to close at the end of April 2011. For additional information, see Notes 4 and 5 to the accompanying consolidated financial statements. In the first three months of 2011, we also entered into additional commodity derivative contracts for 2011, 2012 and 2013 to protect future cash flows. On February 18, 2011, we announced we had entered into an amended and restated revolving bank credit facility, which replaced our previous credit facility. At closing, the facility amount was $1.5 billion and the borrowing base was $2.0 billion.

During the three months ended March 31, 2011, our cash provided from operating activities was $140.6 million and we spent $260.0 million on capital expenditures and $24.3 million on proved and unproved property purchases. At March 31, 2011, we had $1.7 million in cash, total assets of $5.6 billion and a debt-to-capitalization ratio of 49.8%. Long-term debt at March 31, 2011 totaled $2.2 billion, which included $480.0 million of bank credit facility debt and $1.7 billion of senior subordinated notes. Available committed borrowing capacity under the bank credit facility at March 31, 2011 was $1.0 billion.

In June 2009, we filed a universal shelf registration statement with the Securities and Exchange Commission, under which we, as a well-known seasoned issuer, have the ability, subject to market conditions, to issue and sell an indeterminate amount of various types of registered debt and equity securities.

We establish a capital budget at the beginning of each calendar year. Our 2011 capital budget (excluding acquisitions) now stands at $1.38 billion and focuses on projects we believe will generate and lay the foundation for economic, long-term production growth. In the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. We continue to screen for attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable.

Cash is required to fund capital expenditures necessary to offset inherent declines in production and reserves that are typical in the oil and natural gas industry. Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding or acquiring additional reserves. We 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, our 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 natural gas and oil business. Sustained lower 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 operate in an environment with numerous financial and operating risks, including, but not limited to, the inherent risks of the search for, development and production of natural gas, NGLs and oil, the ability to buy properties and sell production at prices, which provide an attractive return and the highly competitive nature of the industry. Our ability to expand our reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, bank borrowings, asset sales or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to offset inherent declines in production and proven reserves.

Our 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. Estimates may differ from actual results. 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 outstanding debt and credit ratings by rating agencies.

Credit Arrangements

On March 31, 2011, the bank credit facility had a $2.0 billion borrowing base and a $1.5 billion facility amount. The borrowing base represents an amount approved by the bank group that can be borrowed based on our assets, while our $1.5 billion facility amount is the amount we have requested that the banks commit 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 was $924.0 million on April 25, 2011. Our bank group is comprised of twenty-seven commercial banks, with no one bank holding more than 7.0% 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 $1.5 billion commitment up to the $2.0 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 4.25 to 1.0 and a current ratio (as defined in the credit agreement) of no less than 1.0 to 1.0. We were in compliance with these covenants at March 31, 2011. Please see Note 9 to the accompanying consolidated financial statements for additional information.

Cash Flow

Cash flows from operating activities 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 natural gas, NGL and oil production at the wellhead under floating market contracts. However, we generally hedge a substantial, but varying, portion of our anticipated future natural gas and oil production for the next 12 to 36 months. Any payments due to counterparties under our derivative contracts should ultimately be funded by prices received from the sale of our production. Production receipts, however, often lag payments to the counterparties. Any interim cash needs are funded by borrowing under the credit facility. As of March 31, 2011, we have entered into derivative agreements covering 128.5 Bcfe for 2011, 88.5 Bcfe for 2012 and 36.5 Bcfe for 2013.

Net cash provided from continuing operations for the three months ended March 31, 2011 was $118.7 million compared to $116.3 million in the three months ended March 31, 2010. Cash flow from continuing operations for the first three months of 2011 was higher than the same period of the prior year, as higher production from development activity and a $15.0 million equity method investment distribution was more than offset by lower realized prices and higher operating costs. Net cash provided from operating activities is also affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital (as reflected in our consolidated statements of cash flows) in the three months ended March 31, 2011 was a decrease of $10.6 million compared to a increase of $15.9 million in the same period of the prior year.

Net cash used in investing activities for the three months ended March 31, 2011 was $271.8 million compared to net cash provided from investing activities of $108.1 million in the same period of 2010. During the three months ended March 31, 2011, we:

- spent $250.8 million on natural gas and oil property additions;
- spent $24.3 million on acreage primarily in the Marcellus Shale;
- received proceeds of $15.2 million primarily from the sale of a low pressure pipeline; and
- spent $8.2 million on discontinued operations.

During the three months ended March 31, 2010, we:

- spent $154.0 million on natural gas and oil property additions;
- spent $19.8 million on acreage primarily in the Marcellus Shale;
- received proceeds of $301.6 million primarily from the sale of Ohio oil and gas properties; and
- spent $12.3 million on discontinued operations.

Net cash provided from financing activities for the three months ended March 31, 2011 was $130.0 million compared to $24.8 million in the same period of 2010. During the three months ended March 31, 2011, we:

- borrowed $372.8 million and repaid $166.8 million under our bank credit facility, ending the period with a $206.0 million higher bank credit facility balance.
- spent $12.4 million related to debt issuance costs; and
- recorded as decrease of $61.0 million in cash overdrafts.

During the three months ended March 31, 2010, we:

- borrowed $148.0 million and repaid $118.0 million under our bank credit facility, ending the period with a $30.0 million higher bank credit facility balance.

Dividends

On March 1, 2011, the Board of Directors declared a dividend of four cents per share ($6.4 million) on our common stock, which was paid on March 31, 2011 to stockholders of record at the close of business on March 15, 2011.

Capital Requirements and Contractual Cash Obligations

We currently estimate our 2011 capital spending will approximate $1.38 billion (excluding acquisitions) and based on current projections is expected to be funded with internal cash flow, property sales and our bank credit facility. Acreage purchases during the first three months include $14.7 million of purchases in the Marcellus Shale, which were funded with borrowings under our credit facility. For the three months ended March 31, 2011, $294.6 million of our development and exploration spending was funded with internal cash flow and borrowings under our bank credit facility. 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 choose to 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.

Our contractual obligations include long-term debt, operating leases, drilling commitments, derivative obligations, transportations commitments and other purchase obligations. Since December 31, 2010, there have been no material changes to our contractual obligations other than our outstanding bank credit facility amount increased to $480.0 million at March 31, 2011 and the credit facility loan maturity was extended to 2016. In addition, we entered into additional transportation agreements in Appalachia which totals approximately $100.0 million over the next seven years.

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   Natural Gas and Oil 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. Historically, these contracts consisted 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 have employed a strategy to hedge a portion of our production looking out 12 to 36 months from each quarter. At March 31, 2011, we had open swap contracts covering 25.6 Bcf of natural gas at prices averaging $5.00 and $1.5 million barrels of NGLs at an average price of $101.88 per barrel. At March 31, 2011, we had collars covering 195.3 Bcf of natural gas at weighted average floor and cap prices of $5.42 and $6.27 per mcf and 0.7 million barrels of oil at weighted average floor and cap prices of $70.00 and $80.00 per barrel. At March 31, 2011, we also had sold call options covering 3.2 million barrels of oil at a weighted average price of $82.66. The fair value of all of our derivative contracts, 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 March 31, 2011 was a net unrealized pre-tax gain of $31.5 million. The contracts expire monthly through December 2013. Settled transaction gains and losses for derivatives that qualify for hedge accounting are determined monthly and are included as increases or decreases in natural gas, NGLs and oil sales in the period the hedged production is sold. In the first three months of 2011, natural gas, NGLs and oil sales included realized hedging gains of $29.6 million compared to gains of $1.2 million in the same period of 2010.

At March 31, 2011, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural Gas			
2012	Swaps	70,192 Mmbtu/day	$5.00
2011	Collars	418,236 Mmbtu/day	$5.52-$6.45
2012	Collars	119,641 Mmbtu/day	$5.50-$6.25

2013	Collars	100,000 Mmbtu/day	$5.00-$5.73
Crude Oil			
2012	Collars	2,000 bbls/day	$70.00-$80.00
2011	Call options	5,500 bbls/day	$80.00
2012	Call options	4,700 bbls/day	$85.00
NGLs			
2011	Swaps	2,676 bbls/day	$102.80
2012	Swaps	2,000 bbsl/day	$100.96

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Some of our derivatives do not qualify for hedge accounting or are not designated as a hedge but provide an economic hedge of our exposure to commodity price risk associated with anticipated future natural gas and oil production. These contracts are accounted for using the mark-to-market accounting method. Under this method, the contracts are carried at their fair value as unrealized derivative gains and losses in the accompanying consolidated balance sheets. We recognize all unrealized and realized gains and losses related to these contracts as derivative fair value income or loss in our consolidated statements of operations. As of March 31, 2011, derivatives on 56.0 Bcfe no longer qualify or are not designated for hedge accounting.

Interest Rates

At March 31, 2011, we had $2.2 billion of debt outstanding. Of this amount, $1.7 billion bore interest at fixed rates averaging 7.2%. Bank debt totaling $480.0 million bears interest at floating rates, which approximated 1.9% at March 31, 2011. The 30-day LIBOR rate on March 31, 2011 was 0.2%.

Inflation and Changes in Prices

Our revenues, the value of our assets and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in natural gas and oil prices and the costs to produce our reserves. Natural gas and oil prices are subject to fluctuations that are beyond our ability to control or predict. During first quarter 2011, we received an average of $3.57 per mcf of gas and $83.71 per barrel of oil before derivative contracts compared to $5.06 per mcf of gas and $69.62 per barrel of oil in the same period 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 accelerated through the middle 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. Due to the decline in commodity prices since then, costs have generally moderated but are increasing in areas with high levels of drilling activity that utilize specialized services for horizontal drilling and completions. We expect costs in 2011 to continue to be a function of supply and demand.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in 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.

Market Risk

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

Commodity Price Risk

We periodically enter into derivative arrangements with respect to our natural gas, oil and NGL production. These arrangements are intended to reduce the impact of natural gas and oil price fluctuations. Some of our derivatives have been 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. We have also entered into call option derivative contracts under which we sold call options in exchange for a premium from the counterparty. Historically, we applied hedge accounting to derivatives utilized to manage price risk associated with our natural gas and oil production. Accordingly, we recorded the change in the fair value of our swap and collar contracts under the balance sheet caption accumulated other comprehensive income and into natural gas, NGLs and oil 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 in derivative fair value income or loss in our consolidated statements of operations. 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 natural gas, oil and NGL production. These contracts are accounted for using the mark-to-market accounting method. Under this method, the contracts are carried at their fair value in unrealized derivative gains and losses in our consolidated balance sheets. We recognize all unrealized and realized gains and losses related to these contracts in derivative fair value (loss) income in our consolidated statements of operations. 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 nine financial institutions, all of which are in our bank group. None of our derivative contracts have margin requirements or collateral provisions that would require funding prior to the scheduled cash settlement date.

As of March 31, 2011, we had swaps covering 25.6 Bcf of natural gas and 1.5 million barrels of NGLs, collars covering 195.3 Bcf of natural gas and 0.7 million barrels of oil and oil call options for 3.2 million barrels of oil. These contracts expire monthly through December 2013. The fair value, represented by the estimated amount that would be realized upon immediate liquidation as of March 31, 2011, approximated a net unrealized pre-tax gain of $31.5 million.

We expect our NGL production to continue to increase. In the first quarter 2011, we entered into NGL swap contracts for the natural gasoline component of NGLs. In our Marcellus Shale operations, propane is a large product component of our NGL production, we believe NGL prices are somewhat seasonal. Therefore, the percentage of NGL prices to NYMEX WTI (or West Texas Intermediate) will vary due to product components, seasonality and geographic supply and demand.

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At March 31, 2011, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price	Fair Market Value as of March 31, 2011 Asset (Liability) (in thousands)
Natural Gas				
2012	Swaps	70,192 Mmbtu/day	$5.00	$(1,405)
2011	Collars	418,236 Mmbtu/day	$5.52-$6.45	$116,271
2012	Collars	119,641 Mmbtu/day	$5.50-$6.25	$27,532
2013	Collars	100,000 Mmbtu/day	$5.00-$5.73	$(2,945)
Crude Oil				
2012	Collars	2,000 bbls/day	$70.00-$80.00	$(20,037)
2011	Call options	5,500 bbls/day	$80.00	$(42,949)
2012	Call options	4,700 bbls/day	$85.00	$(43,152)
NGLs				
2011	Swaps	2,676 bbls/day	$102.80	$(1,104)
2012	Swaps	2,000 bbls/day	$100.96	$(760)

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. We currently have not entered into any basis derivatives.

The following table shows the fair value of our swaps, collars and call options and the hypothetical change in the fair value that would result from a 10% and a 25% change in commodity prices at March 31, 2011 (in thousands):

		Hypothetical Change in Fair Value Increase of		Hypothetical Change in Fair Value Decrease of	
	Fair Value	10%	25%	10%	25%
Swaps	$ (3,269)	$(12,592)	$ (31,487)	$12,792	$ 32,020
Collars	120,821	(86,266)	(210,057)	89,681	229,520
Call options	(86,101)	(30,695)	(79,080)	28,395	62,831

Interest rate risk. At March 31, 2011, we had $2.2 billion of debt outstanding. Of this amount, $1.7 billion bore interest at fixed rates averaging 7.2%. Senior bank debt totaling $480.0 million bore interest at floating rates averaging 1.9%. A 1% increase or decrease in short-term interest rates would affect interest expense by approximately $4.8 million per year.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure 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 March 31, 2011 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

There was no change in our system of internal control over financial reporting (as defined in Rules 13a-15(f) and 15-d-15(f) under the Exchange Act) during the quarter ended March 31, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II OTHER INFORMATION

ITEM 1A. RISK FACTORS

We are subject to various risks and uncertainties in the course of our business. In addition to the factors discussed elsewhere in this report, you should carefully consider the risks and uncertainties described under Item 1A. Risk Factors filed in our Annual Report on Form 10-K for the year ended December 31, 2010. There have been no material changes from the risk factors previously disclosed in that Form 10-K.

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ITEM 6. EXHIBITS
(a) EXHIBITS

Exhibit Number	Exhibit 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 Second Amendment to Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 28, 2005) and the Certificate of Second Amendment to the Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 24, 2008)
3.2	Amended and Restated By-laws of Range (incorporated by reference to Exhibit 3.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 20, 2010)
10.1*	Purchase and Sale Agreement between Range Texas Production, LLC, Energy Assets Operating Company, LLC and Range Resources Corporation as Seller and Legend Natural Gas IV, LP as Buyer dated February 28, 2011
10.2	Fourth Amended and Restated Credit Agreement dated February 18, 2011 (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12009) as filed with the SEC on February 22, 2011)
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. INS	XBRL Instance Document
101. SCH	XBRL Taxonomy Extension Schema
101. CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101. DEF	XBRL Taxonomy Extension Definition Linkbase Document
101. LAB	XBRL Taxonomy Extension Label Linkbase Document
101. PRE	XBRL Taxonomy Extension Presentation Linkbase Document

* filed herewith

** furnished herewith

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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: April 27, 2011

RANGE RESOURCES CORPORATION

By: /s/ ROGER S. MANNY

Roger S. Manny

Executive Vice President and Chief Financial Officer

Date: April 27, 2011

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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