SM Energy Co
Form 10-Q
May 03, 2011

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2011

Commission File Number 001-31539

SM ENERGY COMPANY

(Exact name of registrant as specified in its charter)

Delaware	**41-0518430**
(State or other jurisdiction	(I.R.S. Employer

of incorporation or organization)	Identification No.)
1775 Sherman Street, Suite 1200, Denver, Colorado	**80203**
(Address of principal executive offices)	(Zip Code)

(303) 861-8140

(Registrant s telephone number, including area code)

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 x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

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

Large accelerated filer x	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 x

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date.

As of April 26, 2011 the registrant had 63,626,866 shares of common stock, $0.01 par value, outstanding.

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

SM ENERGY COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(In thousands, except share amounts)

	March 31, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 191,294	$ 5,077
Accounts receivable	146,805	163,190
Refundable income taxes	4,752	8,482
Prepaid expenses and other	18,565	45,522
Derivative asset	33,571	43,491
Deferred income taxes	8,503	8,883
Total current assets	403,490	274,645
Property and equipment (successful efforts method), at cost:		
Land	1,526	1,491
Proved oil and gas properties	3,553,287	3,389,158
Less - accumulated depletion, depreciation, and amortization	(1,427,181)	(1,326,932)
Unproved oil and gas properties	92,375	94,290
Wells in progress	183,737	145,327
Materials inventory, at lower of cost or market	18,215	22,542
Oil and gas properties held for sale (note 3)	122,838	86,811
Other property and equipment, net of accumulated depreciation of $16,447 in 2011 and $15,480 in 2010	45,859	21,365
	2,590,656	2,434,052
Other noncurrent assets:		
Derivative asset	12,325	18,841
Other noncurrent assets	47,053	16,783
Total other noncurrent assets	59,378	35,624
Total Assets	**$ 3,053,524**	**$ 2,744,321**
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 375,721	$ 417,654
Derivative liability	114,228	82,044
Deposit associated with oil and gas properties held for sale		2,355
Total current liabilities	489,949	502,053
Noncurrent liabilities:		
Long-term credit facility		48,000
	277,942	275,673

3.50% senior convertible notes, net of unamortized discount of $9,558 in 2011 and $11,827 in 2010				
6.625% senior notes		350,000		
Asset retirement obligation		70,979		69,052
Asset retirement obligation associated with oil and gas properties held for sale		122		2,119
Net Profits Plan liability		147,403		135,850
Deferred income taxes		425,029		443,135
Derivative liability		64,574		32,557
Other noncurrent liabilities		15,078		17,356
Total noncurrent liabilities		1,351,127		1,023,742
Commitments and contingencies (note 7)				
Stockholders equity:				
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued: 63,720,176 shares in 2011 and 63,412,800 shares in 2010; outstanding, net of treasury shares: 63,617,930 shares in 2011 and 63,310,165 shares in 2010		637		634
Additional paid-in capital		206,304		191,674
Treasury stock, at cost: 102,246 shares in 2011 and 102,635 shares in 2010		(386)		(423)
Retained earnings		1,020,448		1,042,123
Accumulated other comprehensive loss		(14,555)		(15,482)
Total stockholders equity		1,212,448		1,218,526
Total Liabilities and Stockholders Equity	**$**	**3,053,524**	**$**	**2,744,321**

The accompanying notes are an integral part of these consolidated financial statements.

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SM ENERGY COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

(In thousands, except per share amounts)

	For the Three Months Ended March 31, 2011	2010
Operating revenues and other income:		
Oil, gas, and NGL production revenue	$ 276,313	$ 212,887
Realized hedge gain (loss)	(1,375)	2,595
Gain on divestiture activity (note 3)	24,915	120,978
Marketed gas system and other operating revenue	15,476	23,675
Total operating revenues and other income	315,329	360,135
Operating expenses:		
Oil, gas, and NGL production expense	65,812	48,340
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	105,356	77,765
Exploration	12,712	13,898
Abandonment and impairment of unproved properties	3,079	904
General and administrative	25,861	23,486
Change in Net Profits Plan liability	14,195	(27,272)
Unrealized and realized derivative (gain) loss	88,429	(7,735)
Marketed gas system and other expense	19,857	22,998
Total operating expenses	335,301	152,384
Income (loss) from operations	(19,972)	207,751
Nonoperating income (expense):		
Interest income	128	129
Interest expense	(9,714)	(6,787)
Income (loss) before income taxes	(29,558)	201,093
Income tax benefit (expense)	11,055	(74,915)
Net income (loss)	**$ (18,503)**	**$ 126,178**
Basic weighted-average common shares outstanding	63,447	62,792
Diluted weighted-average common shares outstanding	63,447	64,377
Basic net income (loss) per common share	**$ (0.29)**	**$ 2.01**
Diluted net income (loss) per common share	**$ (0.29)**	**$ 1.96**

The accompanying notes are an integral part of these consolidated financial statements.

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SM ENERGY COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME (LOSS) (UNAUDITED)

(In thousands, except share amounts)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Treasury Stock Shares	Treasury Stock Amount	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholders Equity
Balances, January 1, 2011	**63,412,800**	**$ 634**	**$ 191,674**	**(102,635)**	**$ (423)**	**$ 1,042,123**	**$ (15,482)**	**$ 1,218,526**
Comprehensive loss, net of tax:								
Net loss						(18,503)		(18,503)
Reclassification to earnings							927	927
Total comprehensive loss								(17,576)
Cash dividends, $ 0.05 per share						(3,172)		(3,172)
Issuance of common stock upon vesting of RSUs, net of shares used for tax withholdings, including income tax benefit of RSUs	18,836		(644)					(644)
Sale of common stock, including income tax benefit of stock option exercises	288,540	3	9,760					9,763
Stock-based compensation expense			5,514	389	37			5,551
Balances, March 31, 2011	**63,720,176**	**$ 637**	**$ 206,304**	**(102,246)**	**$ (386)**	**$ 1,020,448**	**$ (14,555)**	**$ 1,212,448**
Balances, January 1, 2010	**62,899,122**	**$ 629**	**$ 160,516**	**(126,893)**	**$ (1,204)**	**$ 851,583**	**$ (37,954)**	**$ 973,570**
Comprehensive income, net of tax:								
Net income						126,178		126,178
Change in derivative instrument fair value							33,702	33,702
Reclassification to earnings							(1,945)	(1,945)
Minimum pension liability adjustment							2	2
Total comprehensive income								157,937
Cash dividends, $ 0.05 per share						(3,141)		(3,141)
Issuance of common stock upon vesting of RSUs, net of shares used for tax withholdings, including income tax cost of RSUs	33,458	1	(647)					(646)
Sale of common stock, including income tax benefit	18,214		268					268

of stock option exercises								
Stock-based compensation expense			5,578		25			5,603
Balances, March 31, 2010	**62,950,794**	**$ 630**	**$ 165,715**	**(126,893)**	**$ (1,179)**	**$ 974,620**	**$ (6,195)**	**$ 1,133,591**

The accompanying notes are an integral part of these consolidated financial statements.

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SM ENERGY COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(In thousands)

	For the Three Months Ended March 31, 2011	2010
Cash flows from operating activities:		
Net income (loss)	$ (18,503)	$ 126,178
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Gain on divestiture activity	(24,915)	(120,978)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	105,356	77,765
Exploratory dry hole expense	40	163
Abandonment and impairment of unproved properties	3,079	904
Stock-based compensation expense	5,551	5,603
Change in Net Profits Plan liability	14,195	(27,272)
Unrealized derivative (gain) loss	82,012	(7,735)
Amortization of debt discount and deferred financing costs	3,620	3,291
Deferred income taxes	(18,174)	64,608
Other	(2,006)	(1,285)
Changes in current assets and liabilities:		
Accounts receivable	16,385	(13,244)
Refundable income taxes	3,730	13,003
Prepaid expenses and other	20,959	1,489
Accounts payable and accrued expenses	(28,341)	31,402
Excess income tax benefit from the exercise of stock awards	(6,303)	
Net cash provided by operating activities	**156,685**	**153,892**
Cash flows from investing activities:		
Net proceeds from sale of oil and gas properties	39,023	239,247
Capital expenditures	(309,691)	(132,445)
Deposits to restricted cash		(36,160)
Other	(2,355)	(6,500)
Net cash (used in) provided by investing activities	**(273,023)**	**64,142**
Cash flows from financing activities:		
Proceeds from credit facility	102,000	177,559
Repayment of credit facility	(150,000)	(365,559)
Net proceeds from 6.625% senior notes	341,435	
Proceeds from sale of common stock	3,460	268
Excess income tax benefit from the exercise of stock awards	6,303	
Other	(643)	(527)
Net cash provided by (used in) financing activities	**302,555**	**(188,259)**
Net change in cash and cash equivalents	186,217	29,775
Cash and cash equivalents at beginning of period	5,077	10,649
Cash and cash equivalents at end of period	**$ 191,294**	**$ 40,424**

The accompanying notes are an integral part of these consolidated financial statements.

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SM ENERGY COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED) (Continued)

Supplemental schedule of additional cash flow information and noncash investing and financing activities:

	For the Three Months Ended March 31, 2011		2010	
	(In thousands)			
Cash paid for interest	$	1,015	$	2,136
Net cash refunded for income taxes	$	(3,309)	$	(3,553)

Dividends of approximately $3.2 million have been declared by the Company s Board of Directors, but not paid, as of March 31, 2011.

For the three months ended March 31, 2011, and 2010, $222.8 million, and $104.6 million, respectively, are included as additions to oil and gas properties and accounts payable and accrued expenses. These oil and gas property additions are reflected in cash used in investing activities in the periods that the payables are settled.

The accompanying notes are an integral part of these consolidated financial statements.

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SM ENERGY COMPANY AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

Note 1 The Company and Business

SM Energy Company (SM Energy or the Company) is an independent energy company engaged in the acquisition, exploration, exploitation, development, and production of crude oil, natural gas, and natural gas liquids (NGLs) in North America, with a focus on oil and liquids-rich resource plays.

Note 2 Basis of Presentation and Significant Accounting Policies

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements of SM Energy have been prepared in accordance with accounting principles generally accepted in the United States for interim financial information and the instructions to Form 10-Q and Regulation S-X. They do not include all information and notes required by generally accepted accounting principles for complete financial statements. However, except as disclosed herein, there has been no material change in the information disclosed in the notes to consolidated financial statements included in SM Energy s Annual Report on Form 10-K for the year ended December 31, 2010 (the 2010 Form 10-K). In the opinion of management, all adjustments, consisting of normal recurring accruals that are considered necessary for a fair presentation of the interim financial information, have been included. Operating results for the periods presented are not necessarily indicative of expected results for the full year. In connection with the preparation of its condensed consolidated financial statements, the Company evaluated subsequent events after the balance sheet date of March 31, 2011, through the filing date of this report.

Other Significant Accounting Policies

The accounting policies followed by the Company are set forth in Note 1 to the Company s consolidated financial statements in the 2010 Form 10-K, and are supplemented throughout the notes to condensed consolidated financial statements in this report. It is suggested that these condensed consolidated financial statements be read in conjunction with the consolidated financial statements and notes included in the 2010 Form 10-K. As discussed in Note 10 Derivative Financial Instruments, as of January 1, 2011, the Company elected to discontinue cash flow hedge accounting on a prospective basis.

Recently Issued Accounting Standards

There are no new significant accounting standards applicable to SM Energy that have been issued but not yet adopted as of the quarter ended March 31, 2011.

Note 3 Divestitures and Assets Held for Sale

Rockies Divestiture

In January 2011 the Company completed the divestiture of certain non-strategic assets located in its Rocky Mountain region that were classified as assets held for sale at December 31, 2010. Total cash received, before marketing costs and Net Profits Interest Bonus Plan (Net Profits Plan) payments, was $44.4 million. The final sale price is subject to post-closing adjustments and is expected to be finalized during the second quarter of 2011. The estimated gain on this divestiture is approximately $26.1 million and may be impacted by post-closing adjustments mentioned above. The Company determined that the sale

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did not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

Assets Held for Sale

Assets are classified as held for sale when the Company commits to a plan to sell the assets and there is reasonable certainty that the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted and a measurement for impairment is performed to expense any excess of carrying value over fair value less costs to sell. Subsequent changes to estimated fair value less the cost to sell will impact the measurement of assets held for sale for assets for which fair value is determined to be less than the carrying value of the assets.

As of March 31, 2011, the accompanying condensed consolidated balance sheets (accompanying balance sheets) include $122.8 million in book value of assets held for sale, net of accumulated depletion, depreciation and amortization. The corresponding asset retirement obligation liability of $122,000 is also separately presented. The above assets held for sale and asset retirement obligation liability amounts include amounts for certain assets located in Pennsylvania, the Company s Mid-Continent region, as well as the Company s gathering assets in its South Texas & Gulf Coast region. The Company began marketing these Pennsylvania and Mid-Continent region assets in the third quarter of 2010 and the South Texas & Gulf Coast region assets in the first quarter of 2011. The Company determined that these planned asset sales do not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

Note 4 Income Taxes

Income tax benefit (expense) for the three-month periods ended March 31, 2011, and 2010, differs from the amounts that would be provided by applying the statutory U.S. federal income tax rate to income (loss) before income taxes as a result of the estimated effect of the domestic production activities deduction, percentage depletion, the effect of state income taxes, and other permanent differences.

The provision for income taxes consists of the following:

	For the Three Months Ended March 31,	
	2011	**2010**
	(in thousands)	
Current portion of income tax (expense):		
Federal	$ (6,944)	$ (9,975)
State	(175)	(332)
Deferred portion of income tax benefit (expense)	18,174	(64,608)
Total income tax benefit (expense)	$ 11,055	$ (74,915)
Effective tax rate	37.4%	37.3%

A change in the Company s effective tax rate between reported periods will generally reflect differences in its estimated highest marginal state tax rate due to changes in the composition of income from Company activities among state tax jurisdictions. The rate is also impacted period to period by estimates for the domestic production activities deduction, percentage depletion, and for potential permanent state tax items which affect the presented periods differently due to oil and gas price variability and the impact of non-core asset sales.

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The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction and in various states. With few exceptions, the Company is no longer subject to U.S. federal or state income tax examinations by these tax authorities for years before 2007. During the first quarter of 2010, the Internal Revenue Service initiated an audit of the Company for the 2006 tax year as a result of a net operating loss carryback from the Company s 2008 tax year. The audit was successfully concluded in the second quarter of 2010 with no changes to Company reported amounts. During the first quarter of 2011, the Company received an anticipated $5.5 million refund from its 2006 tax year net operating loss carryback claim. The Company s remaining refundable income tax balance at March 31, 2011, reflects an additional net operating loss carryback claim to the 2006 tax year from filing a revised income tax return for the 2009 tax year prior to the extended return due date. In the fourth quarter of 2010, the Internal Revenue Service began an audit of the Company s 2009 tax year. The audit is still in progress at March 31, 2011.

Note 5 Long-Term Debt

3.50% Senior Convertible Notes Due 2027

On April 4, 2007, the Company issued $287.5 million in aggregate principal amount of 3.50% Senior Convertible Notes Due 2027 (the 3.50% Senior Convertible Notes). The 3.50% Senior Convertible Notes mature on April 1, 2027, unless converted prior to maturity, redeemed, or purchased by the Company.

Holders of the 3.50% Senior Convertible Notes may elect to surrender all or a portion of their notes for conversion under certain circumstances, including during a calendar quarter if the closing price of the Company s common stock was more than 130 percent of the conversion price of $54.42 per share for at least 20 trading days in the 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter. As of December 31, 2010, the 3.50% Senior Convertible Notes were not convertible. Since the closing price of the Company s common stock was more than the conversion trigger price of $70.75 per share for at least 20 trading days in the 30 consecutive trading days ending on the last trading day in the quarter ended March 31, 2011, the holders of the 3.50% Senior Convertible Notes have the right to convert all or a portion of their notes during the second quarter ending June 30, 2011. If holders elect to convert all or a portion of their notes, they will receive cash, or shares of the Company s common stock, or any combination thereof as may be elected by the Company under the indenture for the 3.50% Senior Convertible Notes. Based on the secondary market trading price of the 3.50% Senior Convertible Notes, the estimated fair value of the notes was approximately $410 million as of March 31, 2011.

6.625% Senior Notes Due 2019

On February 7, 2011, the Company issued $350.0 million in aggregate principal amount of 6.625% Senior Notes Due 2019 (the 6.625% Senior Notes). The 6.625% Senior Notes were issued at par and mature on February 15, 2019. The Company received net proceeds of approximately $341.4 million after deducting fees of approximately $8.6 million, which will be amortized as deferred financing costs over the life of the 6.625% Senior Notes. The net proceeds were used to repay borrowings under the Company s credit facility, with the remainder to be used for the Company s ongoing capital expenditure program and general corporate purposes.

Prior to February 15, 2014, the Company may redeem up to 35 percent of the aggregate principal amount of the 6.625% Senior Notes with the net cash proceeds of one or more equity offerings at a redemption price of 106.625% of the principal amount thereof, plus accrued and unpaid interest.

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The Company may also redeem all or, from time to time, a part of the 6.625% Senior Notes on or after February 15, 2015, at the prices set forth below, expressed as a percentage of the principal amount redeemed, plus accrued and unpaid interest:

2015	103.313%
2016	101.656%
2017 and thereafter	100.000%

The 6.625% Senior Notes are unsecured senior obligations and rank equal in right of payment with all of the Company s existing and any future unsecured senior debt and are senior in right of payment to any future subordinated debt. There are no subsidiary guarantors of the 6.625% Senior Notes. The Company is also subject to certain covenants under its 6.625% Senior Notes that limit the payment of dividends on its common stock to $6.5 million in any given calendar year during the eight year term of the notes. The Company is in compliance with all covenants under its 6.625% Senior Notes as of March 31, 2011, and through the filing date of this report.

Additionally, on February 7, 2011, the Company entered into a registration rights agreement that provides holders of the 6.625% Senior Notes certain registration rights for the 6.625% Senior Notes under the Securities Act of 1933, as amended (the Securities Act). Pursuant to the registration rights agreement, the Company will file an exchange offer registration statement with the Securities and Exchange Commission (the SEC) with respect to an offer to exchange the 6.625% Senior Notes for substantially identical notes that are registered under the Securities Act. Under certain circumstances, in lieu of a registered exchange offer, the Company has agreed to file a shelf registration statement relating to the resale of the 6.625% Senior Notes. If the exchange offer is not completed on or before February 7, 2012, or the shelf registration statement, if required, is not declared effective within the time periods specified in the registration rights agreement, then the Company has agreed to pay additional interest with respect to the 6.625% Senior Notes in an amount not to exceed one percent of the principal amount of the 6.625% Senior Notes until the exchange offer is completed or the shelf registration statement is declared effective. The estimated fair value of the 6.625% Senior Notes was approximately $357 million as of March 31, 2011.

Note 6 Earnings per Share

Basic net income or loss per common share of stock is calculated by dividing net income or loss available to common stockholders by the basic weighted-average common shares outstanding for the respective period. The Company s earnings per share calculations reflect the impact of any repurchases of shares of common stock made by the Company.

Diluted net income or loss per common share of stock is calculated by dividing adjusted net income or loss by the number of diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of unvested restricted stock units (RSUs), in-the-money outstanding options to purchase the Company s common stock, contingent Performance Share Awards (PSAs), and shares into which the 3.50% Senior Convertible Notes are convertible.

The Company s 3.50% Senior Convertible Notes have a net-share settlement right whereby the Company has the option to irrevocably elect, by notice to the trustee under the indenture for the notes, to settle the Company s obligation to deliver shares of the Company s common stock, in the event that holders of the notes elect to convert all or a portion of their notes, by delivering cash in an amount equal to each $1,000 principal amount of notes surrendered for conversion and, if applicable, at the Company s option, shares of common stock or cash, or any combination of common stock and cash, for the amount of conversion value in excess of the principal amount. For accounting purposes, the treasury stock method is used to measure the potentially dilutive impact of shares associated with this conversion feature. During the first quarter of

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2011, shares of the Company s common stock traded at an average quarterly closing price that exceeded the $54.42 conversion price. This would have resulted in the 3.50% Senior Convertible Notes having a dilutive impact on the Company s first quarter 2011 diluted earnings per share calculation. However, the Company recorded a loss from continuing operations for the three months ended March 31, 2011, and as a result all potentially dilutive shares became anti-dilutive. The 3.50% Senior Convertible Notes were not dilutive for the three months ended March 31, 2010, or for any reporting period prior to March 31, 2011, in which they have been outstanding.

The PSAs represent the right to receive, upon settlement of the PSAs after the completion of the three-year performance period, a number of shares of the Company s common stock that may range from zero to two times the number of PSAs granted on the award date. The number of potentially dilutive shares related to PSAs is based on the number of shares, if any, which would be issuable at the end of the respective reporting period, assuming that date was the end of the contingency period. For additional discussion on PSAs, please refer to Note 8 Compensation Plans under the heading *Performance Share Awards Under the Equity Incentive Compensation Plan*.

For accounting purposes, the treasury stock method is used to measure potentially dilutive securities. When there is a loss from continuing operations, all potentially dilutive shares become anti-dilutive. There were no dilutive securities for the three months ended March 31, 2011, as the Company recorded a loss from continuing operations for this period. Unvested RSUs, contingent PSAs, and in-the-money options had a dilutive impact for the three-month period ended March 31, 2010.

The following table sets forth the calculation of basic and diluted earnings per share:

	For the Three Months Ended March 31, 2011	2010
	(in thousands, except per share amounts)	
Net income (loss)	$ (18,503)	$ 126,178
Basic weighted-average common shares outstanding	63,447	62,792
Add: dilutive effect of stock options, unvested RSUs, and contingent PSAs		1,585
Add: dilutive effect of 3.50% senior convertible notes		
Diluted weighted-average common shares outstanding	63,447	64,377
Basic net income (loss) per common share	$ (0.29)	$ 2.01
Diluted net income (loss) per common share	$ (0.29)	$ 1.96

Note 7 Commitments and Contingencies

During the first quarter of 2011, the Company entered into a hydraulic fracturing services contract. The total commitment is $180.0 million over a two year term commencing January 1, 2011; provided however, the Company s liability upon early termination of this contract does not exceed $24.0 million.

Subsequent to March 31, 2011, the Company entered into a natural gas gathering and services agreement whereby it is subject to certain natural gas gathering through-put commitments during the ten year contract term, commencing July 1, 2013. The Company may be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments. In the event that no gas is delivered pursuant to the agreement, the aggregate deficiency payments will total approximately $513.4 million over the ten year term of the contract. If a shortfall in the minimum volume commitment arises, the Company can arrange for third party gas to be delivered into the gathering system and applied to its minimum commitment.

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The Company is subject to litigation and claims that have arisen in the ordinary course of its business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated; however, the Company currently has no such accruals. In the opinion of management, adverse results in any such pending litigation and claims will not have a material effect on the results of operations, the financial position, or cash flows of the Company.

The Company is currently a defendant in litigation regarding an overriding royalty interest in less than one percent of the Company s net acreage in the Eagle Ford shale play in South Texas. The Texas District Court has issued an order granting plaintiffs motion for summary judgment, but the Company believes that the summary judgment order is incorrect under the governing agreements and applicable law, and the Company intends to appeal and continue to contest the litigation. If the plaintiffs were to ultimately prevail, the overriding royalty interest would reduce the Company s net revenue interest in the affected acreage. The Company does not currently believe that an unfavorable ultimate outcome is probable, nor that if the plaintiffs prevail there would be a material adverse effect on the financial position of the Company. Under the Company s current view of facts and circumstances of the case, no accrual has been made for any loss.

Note 8 Compensation Plans

Cash Bonus Plan

During the first three months of 2011 and 2010, the Company paid $21.6 million and $7.7 million for cash bonuses earned in the 2010 and 2009 performance years, respectively. Within the general and administrative expense and exploration expense line items in the accompanying condensed consolidated statements of operations (accompanying statements of operations) was $3.8 million and $3.1 million of accrued cash bonus plan expense related to the specific performance year for the three-month periods ended March 31, 2011, and 2010, respectively.

Performance Share Awards Under the Equity Incentive Compensation Plan

PSAs are the primary form of long-term equity incentive compensation for the Company. The PSA factor is based on the Company s performance after completion of a three-year performance period. The performance criteria for the PSAs are based on a combination of the Company s annualized total shareholder return (TSR) for the performance period and the relative measure of the Company s TSR compared with the annualized TSR of an index comprised of certain peer companies for the performance period. PSAs are recognized as general and administrative and exploration expense over the vesting period of the award.

Total stock-based compensation expense related to PSAs for the three-month periods ended March 31, 2011, and 2010, was $4.3 million and $3.6 million, respectively. As of March 31, 2011, there was $18.0 million of total unrecognized compensation expense related to unvested PSAs that is being amortized through 2013.

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A summary of the status and activity of PSAs for the three-month period ended March 31, 2011, is presented in the following table:

	PSAs		Weighted-Average Grant-Date Fair Value
Non-vested, at January 1, 2011	1,110,666	$	39.48
Granted		$	
Vested (1)	(6,844)	$	37.30
Forfeited	(16,319)	$	37.71
Non-vested and outstanding, at March 31, 2011	1,087,503	$	39.52

(1) The number of awards vested assume a multiplier of one. The final number of shares vested may vary depending on the ending three-year multiplier, which ranges from zero to two.

Restricted Stock Unit Incentive Program Under the Equity Incentive Compensation Plan

Total RSU compensation expense for the three-month periods ended March 31, 2011, and 2010, was $1.1 million, and $1.8 million, respectively. As of March 31, 2011, there was $5.1 million of total unrecognized compensation expense related to unvested RSU awards that is being amortized through 2013.

During the first three months of 2011, the Company settled 27,714 RSUs that relate to awards granted in 2008 through the issuance of shares of the Company s common stock in accordance with the terms of the RSU awards. As a result, the Company issued a net of 18,836 shares of common stock associated with these grants. The remaining 8,878 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon delivery of the shares underlying those RSUs.

A summary of the status and activity of RSUs for the three-month period ended March 31, 2011, is presented in the following table:

	RSUs		Weighted-Average Grant-Date Fair Value
Non-vested, at January 1, 2011	333,359	$	31.16
Granted	6,778	$	58.93
Vested	(27,714)	$	37.84
Forfeited	(4,338)	$	29.10
Non-vested and outstanding, at March 31, 2011	308,085	$	31.20

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Stock Option Grants Under Prior Stock Option Plans

The following table summarizes stock option activity for the three months ended March 31, 2011:

	Options		Weighted-Average Exercise Price		Aggregate Intrinsic Value
Outstanding, beginning of period	920,765	$	13.11	$	42,192,057
Exercised	(288,540)	$	12.20		
Forfeited		$			
Outstanding, end of period	632,225	$	13.52	$	38,357,544
Vested, end of period	632,225	$	13.52	$	38,357,544
Exercisable, end of period	632,225	$	13.52	$	38,357,544

As of March 31, 2011, there was no unrecognized compensation expense related to stock option awards.

Net Profits Plan

Under the Company s Net Profits Plan, all oil and gas wells that were completed or acquired during a year were designated within a specific pool. Key employees recommended by senior management and designated as participants by the Compensation Committee of the Company s Board of Directors (Board) and employed by the Company on the last day of that year became entitled to payments under the Net Profits Plan after the Company had received net cash flows returning 100 percent of all costs associated with that pool. Thereafter, ten percent of future net cash flows generated by the pool are allocated among the participants and distributed at least annually. The portion of net cash flows from the pool to be allocated among the participants increases to 20 percent after the Company has recovered 200 percent of the total costs for the pool, including payments made under the Net Profits Plan at the ten percent level. In December 2007 the Board discontinued the creation of new pools under the Net Profits Plan. Consequently, the 2007 Net Profits Plan pool was the last pool established by the Company. All pools are currently fully vested.

Cash payments made or accrued under the Net Profits Plan that have been recorded as either general and administrative expense or exploration expense are detailed in the table below:

	For the Three Months Ended March 31,			
	2011		2010	
	(in thousands)			
General and administrative expense	$	5,330	$	6,934
Exploration expense		477		591
Total	$	5,807	$	7,525

Additionally, the Company accrued cash payments under the Net Profits Plan of $4.3 million and $18.2 million for the three-month periods ended March 31, 2011, and 2010, respectively, as a result of divestiture proceeds. The cash payments are accounted for as a reduction of the gain on divestiture activity in the accompanying statements of operations.

The Company records changes in the present value of estimated future payments under the Net Profits Plan as a separate line item in the accompanying statements of operations. The change in the estimated

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liability is recorded as a non-cash expense or benefit in the current period. The amount recorded as an expense or benefit associated with the change in the estimated liability is not allocated to general and administrative expense or exploration expense because it is associated with the future net cash flows from oil and gas properties in the respective pools rather than results being realized through current period production. The table below presents the estimated allocation of the change in the liability if the Company did allocate the adjustment to these specific functional line items based on the current allocation of actual distributions made by the Company. As time progresses, less of the distributions relate to prospective exploration efforts as more of the distributions are made to employees that have terminated employment and do not provide ongoing exploration support to the Company.

	For the Three Months Ended March 31, 2011		2010	
	(in thousands)			
General and administrative expense (benefit)	$	13,028	$	(25,132)
Exploration expense (benefit)		1,167		(2,140)
Total	$	14,195	$	(27,272)

During the first quarter of 2011, the Company made the decision to cash out several Net Profits Plan pools associated with the Panterra Petroleum partnership acquired in 1999 through a $2.6 million direct payment, and as a result, the Company reduced its Net Profits Plan liability. This cash out is expected to be paid in the second quarter of 2011 and is included in accounts payable and accrued expenses at March 31, 2011. There is no impact on the accompanying statements of operations for the three months ended March 31, 2011, related to these settlements.

Note 9 Pension Benefits

Pension Plans

The Company has a non-contributory pension plan covering substantially all employees who meet age and service requirements (the Qualified Pension Plan). The Company also has a supplemental non-contributory pension plan covering certain management employees (the Nonqualified Pension Plan).

Components of Net Periodic Benefit Cost for Both Plans

The following table presents the components of the net periodic benefit cost for both the Qualified Pension Plan and the Nonqualified Pension Plan:

	For the Three Months Ended March 31, 2011	2010
	(in thousands)	

Service cost	$	848	$	848
Interest cost		280		280
Expected return on plan assets that reduces periodic pension costs		(159)		(159)
Amortization of net actuarial loss		91		91
Net periodic benefit cost	$	1,060	$	1,060

Prior service costs are amortized on a straight-line basis over the average remaining service period of active participants. Gains and losses in excess of ten percent of the greater of the benefit obligation or the market-related value of assets are amortized over the average remaining service period of active participants.

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Contributions

The Company is required to contribute $6.3 million to its Qualified Pension Plan for the 2011 plan year. The Company has made a $2.9 million contribution as of March 31, 2011.

Note 10 Derivative Financial Instruments

To mitigate a portion of the exposure to potentially adverse market changes in oil, gas, and NGL prices and the associated impact on cash flows, the Company has entered into various derivative commodity contracts. The Company s derivative contracts in place include swap and collar arrangements for oil, natural gas, and NGLs. As of March 31, 2011, and through the filing date of this report, the Company has commodity derivative contracts in place through the fourth quarter of 2013 for a total of approximately 8 million Bbls of anticipated crude oil production, 44 million MMBtu of anticipated natural gas production, and 2 million Bbls of anticipated NGL production.

The Company s oil, natural gas, and NGL derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities. The Company derives internal valuation estimates taking into consideration the counterparties credit ratings, the Company s credit rating, and the time value of money. These valuations are then compared to the respective counterparties mark-to-market statements. The considered factors result in an estimated exit-price that management believes provides a reasonable and consistent methodology for valuing derivative instruments. The derivative instruments utilized by the Company are not considered by management to be complex, structured, or illiquid. The oil, natural gas, and NGL derivative markets are highly active. The fair value of oil, natural gas, and NGL commodity derivative contracts was a net liability of $132.9 million and $52.3 million at March 31, 2011, and December 31, 2010, respectively.

Discontinuance of Cash Flow Hedge Accounting

Prior to January 1, 2011, the Company designated its commodity derivative contracts as cash flow hedges, whose unrealized changes in fair value were recorded to accumulated other comprehensive loss (AOCL), to the extent the hedges were effective. As of January 1, 2011, the Company elected to de-designate all of its commodity derivative contracts that had been previously designated as cash flow hedges at December 31, 2010. As a result, subsequent to December 31, 2010, the Company recognizes all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in AOCL.

At December 31, 2010, AOCL included $18.6 million ($11.8 million, net of income tax) of unrealized losses, representing the change in fair value of the Company s open commodity derivative contracts designated as cash flow hedges as of that balance sheet date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on January 1, 2011, such fair values at December 31, 2010 were frozen in AOCL as of the de-designation date and reclassified into earnings as the original derivative transactions settle. During the three months ended March 31, 2011, $1.4 million ($927,000, net of income tax) of derivative losses relating to de-designated commodity hedges were reclassified from AOCL into earnings. As of March 31, 2011, AOCL included $17.2 million ($10.9 million, net of income tax) of unrealized losses on commodity derivative contracts that had been previously designated as cash flow hedges. The Company expects to reclassify into earnings from AOCL after-tax net losses of $11.7 million related to de-designated commodity derivative contracts during the next twelve months.

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The following table details the fair value of derivatives recorded in the accompanying balance sheets, by category:

	As of March 31, 2011					
	Derivative Assets			Derivative Liabilities		
	Balance Sheet	Fair Value		Balance Sheet	Fair Value	
	(in thousands)					
Commodity Contracts	Current Assets	$	33,571	Current Liabilities	$	(114,228)
Commodity Contracts	Noncurrent Assets		12,325	Noncurrent Liabilities		(64,574)
Derivatives not designated as hedging instruments		$	45,896		$	(178,802)

	As of December 31, 2010					
	Derivative Assets			Derivative Liabilities		
	Balance Sheet	Fair Value		Balance Sheet	Fair Value	
	(in thousands)					
Commodity Contracts	Current Assets	$	43,491	Current Liabilities	$	(82,044)
Commodity Contracts	Noncurrent Assets		18,841	Noncurrent liabilities		(32,557)
Derivatives designated as hedging instruments		$	62,332		$	(114,601)

The following table summarizes the unrealized and realized gain and loss from derivative cash settlements and changes in fair value of derivative contracts as presented in the accompanying statements of operations.

	For the Three Months Ended March 31, 2011 (in thousands)	
Cash settlement (gain) and loss:		
Oil contracts	$	6,730
Gas contracts		(1,727)
NGL contracts		1,414
Total cash settlement loss		6,417
Unrealized loss on changes in fair value:		
Oil contracts		67,367
Gas contracts		4,260
NGL contracts		10,385
Total net unrealized loss on change in fair value		82,012
Total unrealized and realized derivative loss	$	88,429

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The following table details the effect of derivative instruments on other comprehensive income (loss) and the accompanying statements of operations (net of income tax):

	Derivatives	Location on Consolidated Statements of Operations	For the Three Months Ended March 31, 2011	2010
			(in thousands)	
Amount of (gain) loss reclassified from AOCL to realized hedge gain (loss)	Commodity Contracts	Realized hedge gain (loss)	$ 927	$ (1,945)

The realized net hedge loss for the three-month period ended March 31, 2011, is comprised of realized cash settlements on commodity derivative contracts that were previously designated as cash flow hedges, whereas the realized net hedge gain for the three-month period ended March 31, 2010, is comprised of realized cash settlements on all commodity derivative contracts. Realized hedge gains or losses from the settlement of oil, natural gas, and NGL derivatives previously designated as cash flow hedges are reported in the total operating revenues and other income section of the accompanying statements of operations. The Company realized a net hedge loss of $1.4 million and a net hedge gain of $2.6 million from its oil, natural gas, and NGL derivative contracts for the three-month periods ended March 31, 2011, and 2010, respectively.

As noted above, effective January 1, 2011, the Company elected to de-designate all of its commodity derivative contracts that had been previously designated as cash flow hedges at December 31, 2010, and as such no new gains or losses are deferred in AOCL at March 31, 2011. The following table details the effect of derivative instruments on other comprehensive income (loss) and the accompanying balance sheets (net of income tax):

	Derivatives	Location on Consolidated Balance Sheets	For the Three Months Ended March 31, 2010 (in thousands)
Amount of (gain) loss on derivatives recognized in OCI during the period (effective portion)	Commodity Contracts	AOCL	$ (33,702)

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The Company has no derivatives designated as cash flow hedges at March 31, 2011. The following table details the ineffective portion of derivative instruments classified as cash flow hedges on the accompanying statements of operations for the three month period ended March 31, 2010.

Derivatives Qualifying as Cash Flow Hedges	**Location on Consolidated Statements of Operations**	**Gain Recognized in Earnings (Ineffective Portion) For the Three Months Ended March 31, 2010 (in thousands)**	
Commodity contracts	Unrealized and realized derivative (gain) loss	$	(7,735)

Credit Related Contingent Features

As of March 31, 2011, through the filing date of this report, all of the Company s derivative counterparties were members of the Company s credit facility bank syndicate. The Company s credit facility is secured by liens on substantially all of the Company s oil and gas assets; therefore such counterparties do not currently require the Company to post collateral in instances where the Company is in a liability position under its derivative instruments. No collateral was posted as of March 31, 2011, nor through the filing date of this report.

Convertible Note Derivative Instruments

The contingent interest provision of the 3.50% Senior Convertible Notes is an embedded derivative instrument. As of March 31, 2011, and December 31, 2010, the fair value of this derivative was determined to be immaterial.

Note 11 Fair Value Measurements

The Company follows fair value measurement authoritative guidance for all assets and liabilities measured at fair value. That guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Market or observable inputs are the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The hierarchy for grouping these assets and liabilities is based on the significance level of the following inputs:

- Level 1 quoted prices in active markets for identical assets or liabilities

- Level 2 quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable

- Level 3 significant inputs to the valuation model are unobservable

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The following is a listing of the Company s financial assets and liabilities that are measured at fair value on a recurring basis and where they are classified within the hierarchy as of March 31, 2011:

	Level 1		Level 2 (in thousands)		Level 3
Assets:					
Derivatives	$	$	45,896	$	
Liabilities:					
Derivatives	$	$	178,802	$	
Net Profits Plan	$	$		$	147,403

The following is a listing of the Company s financial assets and liabilities that are measured at fair value on a recurring basis and where they are classified within the hierarchy as of December 31, 2010:

	Level 1		Level 2 (in thousands)		Level 3
Assets:					
Derivatives	$	$	62,332	$	
Liabilities:					
Derivatives	$	$	114,601	$	
Net Profits Plan	$	$		$	135,850

Both financial and non-financial assets and liabilities are categorized within the hierarchy based on the lowest level of input that is significant to the fair value measurement. The following is a description of the valuation methodologies used by the Company as well as the general classification of such instruments pursuant to the hierarchy. There were no nonfinancial assets or liabilities measured at fair value on a nonrecurring basis at March 31, 2011, or December 31, 2010.

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil, natural gas, and NGL commodity derivatives. Fair values are based upon interpolated data. The Company derives internal valuation estimates taking into consideration the counterparties credit ratings, the Company s credit rating, and the time value of money. These valuations are then compared to the respective counterparties mark-to-market statements. The considered factors result in an estimated exit-price that management believes provides a reasonable and consistent methodology for valuing derivative instruments.

Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. However, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. The Company monitors the credit ratings of its counterparties and may ask counterparties to post collateral if their ratings deteriorate. In some instances the Company will attempt to novate the trade to a more stable counterparty.

Valuation adjustments are necessary to reflect the effect of the Company s credit quality on the fair value of any liability position with a counterparty. This adjustment takes into account any credit enhancements, such as collateral margin that the Company may have posted with a counterparty, as well as any letters of credit between the parties. The methodology to determine this adjustment is consistent with how the Company evaluates counterparty credit risk, taking into account the Company s credit rating, current credit facility margins, and any change in such margins since the last measurement date. All of the Company s derivative counterparties are members of SM Energy s credit facility bank syndicate.

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The methods described above may result in a fair value estimate that may not be indicative of net realizable value or may not be reflective of future fair values and cash flows. While the Company believes that the valuation methods utilized are appropriate and consistent with accounting authoritative guidance and with other marketplace participants, the Company recognizes that third parties may use different methodologies or assumptions to determine the fair value of certain financial instruments that could result in a different estimate of fair value at the reporting date.

Net Profits Plan

The Net Profits Plan is a standalone liability for which there is no available market price nor principal market, nor does it have market participants. The inputs available for this instrument are unobservable and are therefore classified as Level 3 inputs. The Company employs the income approach, which converts expected future cash flow amounts to a single present value amount. This technique uses the estimate of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk to calculate the fair value. There is a direct correlation between realized oil and gas commodity prices driving net cash flows and the Net Profits Plan liability. Generally, higher commodity prices result in a larger Net Profits Plan liability and vice versa.

The Company records the estimated fair value of the long-term liability for estimated future payments under the Net Profits Plan based on the discounted value of estimated future payments associated with each individual pool. The calculation of this liability is a significant management estimate. For those pools currently in payout, a discount rate of 12 percent is used to calculate this liability. A discount rate of 15 percent is used to calculate the liability for pools that have not reached payout. These rates are intended to represent the best estimate of the present value of expected future payments under the Net Profits Plan.

The Company s estimate of its liability is highly dependent on commodity prices, cost assumptions, and the discount rates used in the calculations. The Company continually evaluates the assumptions used in this calculation in order to consider the current market environment for oil and gas prices, costs, discount rates, and overall market conditions. The Net Profits Plan liability is determined using price assumptions of five one-year strip prices with the fifth year s pricing then carried out indefinitely. The average price is adjusted for realized price differentials and to include the effects of the forecasted production covered by derivatives contracts in the relevant periods. The non-cash expense associated with this significant management estimate is highly volatile from period to period due to fluctuations that occur in the crude oil, natural gas, and NGL commodity markets.

If the commodity prices used in the calculation changed by five percent, the liability recorded at March 31, 2011, would differ by approximately $11 million. A one percentage point change in the discount rate would change the liability by approximately $7 million. Actual cash payments to be made to participants in future periods are dependent on realized actual production, realized commodity prices, and costs associated with the properties in each individual pool of the Net Profits Plan. Consequently, actual cash payments are inherently different from the amounts estimated.

No published market quotes exist on which to base the Company s estimate of fair value of the Net Profits Plan liability. As such, the recorded fair value is based entirely on management estimates that are described within this footnote. While some inputs to the Company s calculation of fair value on the Net Profits Plan s future payments are from published sources, others, such as the discount rate and the expected future cash flows, are derived from the Company s own calculations and estimates.

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The following table reflects the activity for the Net Profits Plan liability measured at fair value using Level 3 inputs:

	For the Three Months Ended March 31, 2011	2010
	(in thousands)	
Beginning balance	$ 135,850	$ 170,291
Net increase (decrease) in liability (a)	24,285	(1,536)
Settlements (a)(b)(c)	(12,732)	(25,736)
Transfers in (out) of Level 3		
Ending balance	$ 147,403	$ 143,019

(a) Net changes in the Net Profits Plan liability are shown in the Change in Net Profits Plan liability line item of the accompanying statements of operations.

(b) Settlements represent cash payments made or accrued under the Net Profits Plan. Settlements for the three months ended March 31, 2011, and 2010 include $4.3 million and $18.2 million, respectively, of cash payments related to divestitures.

(c) During the first quarter of 2011, the Company made the decision to cash out several Net Profits Plan pools associated with the Panterra Petroleum partnership acquired in 1999, through a $2.6 million direct payment, and as a result, the Company reduced its Net Profits Plan liability. This cash out payment is expected to be paid in the second quarter of 2011 and is included in accounts payable and accrued expenses at March 31, 2011. There is no impact on the accompanying consolidated statements of operations for the three months ended March 31, 2011, related to these settlements.

3.50% Senior Convertible Notes

Based on the secondary market trading price of the 3.50% Senior Convertible Notes, the estimated fair value of the notes was approximately $410 million and $351 million as of March 31, 2011, and December 31, 2010, respectively. The fair value of the embedded contingent *interest derivative on the 3.50%* Senior Convertible Notes was zero as of March 31, 2011, and December 31, 2010.

Please refer to Note 5 Long-Term Debt for the estimated fair value of the 6.625% Senior Notes.

Proved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. The Company uses Level 3 inputs and the income valuation technique, which converts future amounts to a single present value amount, to measure the fair value of proved properties through an application of discount rates and price forecasts selected by the Company s management. The calculation of the discount rate is a significant management estimate based on the best information available and estimated to be 12 percent for the three months ended March 31, 2011. Management believes that the discount rate is representative of current market conditions and reflects the following factors: estimate of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The price forecast is based on New York Mercantile Exchange (NYMEX) strip pricing, adjusted for basis differentials, for the first five years. Future operating costs are also adjusted as deemed appropriate for these estimates.

There were no proved oil and gas properties measured at fair value within the accompanying balance sheets at March 31, 2011, or December 31, 2010.

Materials Inventory

Materials inventory is valued at the lower of cost or market. The Company uses Level 2 inputs to measure the fair value of materials inventory, which is primarily comprised of tubular goods. The Company uses third party market quotes and compares the quotes to the book value of the materials inventory. If the book value exceeds the quoted market price, the Company reduces the book value to the

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market price. The considered factors result in an estimated exit price that management believes provides a reasonable and consistent methodology for valuing materials inventory.

There were no materials inventory measured at fair value within the accompanying balance sheets at March 31, 2011, or December 31, 2010.

Asset Retirement Obligations

The income valuation technique is utilized by the Company to determine the fair value of the asset retirement obligation liability at the point of inception by applying a credit-adjusted risk-free rate to the undiscounted expected abandonment cash flows. The credit-adjusted risk-free rate takes into account the Company s credit risk, the time value of money, and the current economic state. Given the unobservable nature of the inputs, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. There were no asset retirement obligations measured at fair value within the accompanying balance sheets at March 31, 2011, or December 31, 2010.

Refer to Note 10 Derivative Financial Instruments for more information regarding the Company s derivative instruments.

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

This discussion and analysis contains forward-looking statements. Refer to Cautionary Information about Forward-Looking Statements at the end of this item for an explanation of these types of statements.

Overview of the Company, Highlights, and Outlook

General Overview

We are an independent energy company engaged in the acquisition, exploration, exploitation, development and production of crude oil, natural gas, and NGLs in onshore North America. Our assets include leading positions in the Eagle Ford shale and Bakken/Three Forks resource plays, as well as meaningful positions in the Granite Wash, Haynesville shale, and Woodford shale resource plays. We have developed our portfolio of properties with reserves, development drilling opportunities, and unconventional resource prospects onshore in North America, typically through early entrance into existing and emerging resource plays. We believe this approach allows for stable and predictable production and reserves growth. Furthermore, by entering these plays early, we believe that we can reduce costs and capture larger resource potential.

Our business strategy is to increase net asset value through attractive oil and gas investment activity, while maintaining a conservative capital structure and optimizing capital expenditures. We focus our efforts on the exploration for and development of onshore, lower-risk resource plays in onshore North America. We believe our inventory is well suited for growing reserves and production due to its predictable geology and lower-risk profile. Furthermore, our assets produce significant volumes of oil and NGLs that limit our exposure to the current lower natural gas price environment. Our strategy is based on the following:

- leveraging our core competencies in replicating resource play success in the drilling, completion, and development of oil and natural gas reserves;
- focusing on resource plays with low-risk geology and high liquids content;
- exploiting our legacy assets and optimizing our asset base;
- selectively acquiring leasehold positions in new and emerging resource plays; and

- maintaining a strong balance sheet while funding the growth of our business.

In the first quarter of 2011 we had the following financial and operational results:

- Our average daily production for the three months ended March 31, 2011, was 19.8 MBbls of oil, 241.5 MMcf of gas, and 6.8 MBbl of NGLs, for a record average equivalent production rate of 401.4 MMCFE per day, compared with 285.8 MMCFE per day for the comparable period in 2010. Please see additional discussion below under the caption *Production Results*.

- Costs incurred for oil and gas producing activities for the three months ended March 31, 2011, were $290.7 million, compared with $146.7 million for the same period in 2010. Please see additional discussion below under the caption *Cost Incurred*.

- We recorded a net loss for the quarter ended March 31, 2011, of $18.5 million or ($0.29) per diluted share, driven by an $82.0 million non-cash unrealized derivative loss, compared to first quarter 2010 results of net income of $126.2 million or $1.96 per diluted share.

Oil, Gas, and NGL Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for oil, natural gas, and NGL production, which can fluctuate dramatically. Please refer to *Comparison of Financial Results and Trends between the three months ended March 31, 2011, and 2010* for the realized price tables for the respective periods. Historically, we have reported our natural gas production as a single stream of rich gas measured at the well head. As a result, we have historically reported realized prices for our natural gas production that were higher than industry benchmarks due to the economic uplift associated with incremental value contained in the higher BTU content of our gas production stream. Beginning in the first quarter of 2011, we have changed our reporting for natural gas volumes to show natural gas and NGL production volumes consistent with title transfer for each product. Projected rapid production growth from our rich gas assets associated with plant product sales contracts necessitated a change in our production volume reporting. Prior period production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of the NGL volumes produced in prior periods. We sell the majority of our natural gas under contracts that use first-of-the-month index pricing, which means that gas produced in a given month is sold at the first-of-the-month price regardless of the spot price on the day the gas is produced. For assets where high BTU gas is sold at the wellhead, we also receive additional value for the higher energy content contained in the gas stream. Our NGL production is generally sold using contracts that pay us the monthly average of the posted Oil Price Information Service Mont Belvieu daily settlement prices, adjusting for processing, transportation, and location differentials. Our crude oil and condensate are sold using contracts that pay us either the average of the NYMEX WTI daily settlement price or the average of alternative posted prices for the periods in which the product is produced, adjusted for quality, transportation, and location differentials.

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The following table is a summary of commodity price data for the first quarters of 2011 and 2010 and the fourth quarter of 2010:

	For the Three Months Ended		
	March 31, 2011	December 31, 2010	March 31, 2010
Crude Oil (per Bbl):			
Average NYMEX price	$ 94.46	$ 85.16	$ 78.84
Realized price	$ 85.79	$ 77.46	$ 72.73
Natural Gas (per Mcf):			
Average NYMEX price	$ 4.18	$ 3.80	$ 5.09
Realized price	$ 4.35	$ 5.23	$ 6.15
Natural Gas Liquids (per Bbl):			
Average OPIS price	$ 56.28	$	$
Realized price	$ 46.65	$	$

Note: Prior period NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of the volumes in prior periods. Please refer to additional discussion above.

We expect future prices for oil, gas, and NGLs to be volatile. In addition to supply and demand fundamentals, the relative strength of the U.S. dollar will likely continue to impact crude oil prices. Historically, NGL prices have trended and correlated with the price for crude oil. The supply of NGLs is expected to grow in the near term as a result of a number of industry participants targeting projects that produce these products, which could increase supplies and negatively impact future pricing. Natural gas prices are facing downward pressure as a result of excess supply resulting from high levels of drilling activity across the country. The 12-month strip prices for NYMEX WTI crude oil, NYMEX Henry Hub natural gas, and OPIS NGLs as of March 31, 2011, were $107.86 per Bbl, $4.75 per MMBTU, and $57.19 per Bbl, respectively. Comparable prices as of April 26, 2011, were $112.73 per Bbl, $4.75 per MMBTU, and $61.54 per Bbl, respectively.

While changes in quoted NYMEX oil and natural gas and OPIS NGL prices are generally used as a basis for comparison within our industry, the price we receive is affected by quality, energy content, location, and transportation differentials for these products. Our realized prices shown in the table above do not include the impact of cash settlements from derivative contracts, which is consistent with all prior periods reported. Effective January 1, 2011, we elected to discontinue hedge accounting for all commodity derivative contracts on a prospective basis. Please refer to our discussion under *Derivative Activities* below, which includes our calculation of the adjusted price, including the effects of derivative cash settlements.

First Quarter 2011 Highlights

Operational activities. We had eleven operated drilling rigs running company-wide at the end of the first quarter 2011. The focus of our operated drilling activity this year has been, and will be, on oil and NGL-rich gas programs and selected natural gas projects of potential strategic importance to us. Our operating partners have also increased their levels of activity in oil and NGL-rich gas plays.

In our operated Eagle Ford shale program in South Texas, we had three drilling rigs running by the end of the first quarter 2011 on our acreage. We focused on drilling in areas with higher BTU gas content and higher condensate yields. We continue to test different ways to complete these wells with the objective of optimizing future development potential. We have been encouraged by the results in our operated portion of the play and have been working to increase the pace of development of our acreage. We have entered into several significant contracts with downstream service providers to gather, process, market, and transport natural gas and NGLs from our South Texas assets. While we have made significant strides toward matching our infrastructure needs with our expected production increase for the coming years, increased activity across the Eagle Ford shale play as a whole will likely cause the industry, including us, to experience periods of limited takeaway capacity as the infrastructure required to serve this play develops and expands. Subsequent to March 31, 2011, we entered into an additional arrangement to increase the takeaway capacity of our natural gas and NGLs starting in 2013. Please refer to Note 7 Commitments and Contingencies in Part I, Item 1 of this report for additional discussion concerning these agreements. We believe we have secured the majority of drilling and completion services we will require to execute our development program for our operated acreage for the next few years. On outside-operated Eagle Ford acreage, the operator continued to increase activity throughout the first quarter. At quarter end, nine partner operated drilling rigs were running in this program. This outside-operated acreage has had limited infrastructure to support the development program, and accordingly we continue to participate in infrastructure construction projects with our partner. Despite the heightened activity by the operator and its announced joint venture in our non-operated acreage, it is our belief the activity will level off at 10 rigs by the end of the second quarter, because of current infrastructure limitations. We have initiated a marketing effort that includes a portion of both our operated and non-operated Eagle Ford acreage, which could result in a partial sale or farm-down. We expect bids for the package during the second quarter of 2011.

We operated two drilling rigs in the Williston Basin throughout the first quarter of 2011, both of which were focused on Bakken and Three Forks drilling in our Raven and Gooseneck prospects in North Dakota. Our drilling results in these prospects continued to meet or exceed our expectations throughout the first quarter of 2011. Elsewhere in the Rocky Mountain region, we continued to test the Niobrara formation in southeastern Wyoming. We drilled two test wells in 2010 and intend to drill four additional test wells in 2011. We recently began drilling two of the planned 2011 wells in this program. Interest in the Niobrara formation remains high despite mixed reports coming out of the play. While some of our early results have been encouraging, it is our belief that this will be a challenging play that requires significant technical expertise.

In our Mid-Continent region, we operated an average of two drilling rigs in our Granite Wash program in western Oklahoma, during the first quarter of 2011 to test and delineate our acreage in the play. Our acreage position is held by production, and we believe the potential from this emerging program could be significant.

Our Permian region operated a one rig program throughout the first quarter of 2011, focusing on Wolfberry tight oil targets.

In our operated Haynesville shale program in our ArkLaTex region, we have now completed our previously reported carry and earning agreement. We are working to execute a similar but separate transaction. Our goal with such a transaction is to drill a sufficient number of wells to hold our acreage in this play by production while minimizing our capital expenditures in this area when natural gas prices are depressed. Recent drilling results in our East Texas Haynesville drilling program have exceeded our expectations.

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Production results. The table below details the regional breakdown of our first quarter 2011 production:

	Mid-Continent	ArkLaTex	South Texas & Gulf Coast	Permian	Rocky Mountain	Total (1)
First Quarter 2011 Production:						
Oil (MBbl)	50.9	15.5	509.2	355.4	853.5	1,784.5
Gas (MMcf)	7,366.3	5,581.3	6,734.7	914.0	1,138.3	21,734.6
NGLs (MBbl)	2.9	20.3	583.1	1.3	6.7	614.2
Equivalent (MMCFE)	7,689.1	5,796.0	13,288.4	3,053.9	6,299.7	36,127.1
Avg. Daily Equivalents (MMCFE/d)	85.4	64.4	147.6	33.9	70.0	401.4
Relative percentage	21%	16%	37%	9%	17%	100%

(1) Totals may not add due to rounding.

For the first quarter of 2011, our production was led by our South Texas & Gulf Coast region due to our continuing drilling activities in our Eagle Ford shale program. Please refer to *Comparison of Financial Results and Trends between the three months ended March 31, 2011, and 2010,* for additional discussion on production.

Cost Incurred. Costs incurred for oil and gas producing activities for the three months ended March 31, 2011, were $290.7 million, compared with $146.7 million for the same period in 2010. Costs incurred for development and exploration activities during the first three months of 2011 increased $148.0 million or 112 percent compared to the same period in 2010. This increase in capital and exploration activities reflects higher cash flows available for investment provided by operating activities, divestiture proceeds, and proceeds from the issuance of our 6.625% Senior Notes.

6.625% Senior Notes. In the first quarter of 2011, we issued $350.0 million in aggregate principal amount of 6.625% Senior Notes. The notes were issued at par value and have a maturity date of February 15, 2019. Net proceeds from the issued senior notes were approximately $341.4 million. We used a portion of the proceeds from our 6.625% Senior Notes offering to repay our outstanding balance under our credit facility. Remaining proceeds will be used to fund our ongoing capital expenditure program and for general corporate purposes.

Marketing of properties. In the first quarter of 2011, we initiated a marketing effort that could result in a partial joint venture of our Eagle Ford shale position.

Rocky Mountain Divestiture. In January 2011, we completed the divestiture of certain non-strategic assets located in our Rocky Mountain region that were classified as assets held for sale at December 31, 2010. Total cash received before marketing costs and Net Profits Plan payments was $44.4 million. The final sale price is subject to post-closing adjustments and is expected to be finalized during the second quarter of 2011. The estimated gain on this divestiture is approximately $26.1 million and may be impacted by the post-closing adjustments mentioned above.

Derivative Activities. We use financial derivative instruments as part of our financial risk management program. We have a Board-approved financial risk management policy governing our derivative practices. The level of our production covered by derivatives is driven by the amount of debt on our balance sheet and the level of capital commitments and long-term obligations we have in place. With the derivative contracts we have in place, we believe we have established a base cash flow stream for our

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future operations and reduced a portion of our exposure to volatility in commodity prices. Our use of collars for a portion of the derivatives allows us to participate in upward movements in oil, gas, and NGL prices while also setting a price floor for a portion of our production. Please see Note 10 Derivative Financial Instruments of Part I, Item 1 of this report for additional information regarding our oil, gas, and NGL derivatives, and see the caption, *Summary of Oil, Gas, and NGL Derivatives in Place,* later in this section.

As of January 1, 2011, we elected to de-designate all commodity derivative contracts that had previously been designated as cash flow hedges as of December 31, 2010, and to discontinue hedge accounting prospectively. Accordingly, beginning January 1, 2011, all of our derivative contracts are stated at fair value each quarter with changes in fair value resulting in gains and losses, which are recognized immediately in earnings. For the three months ended March 31, 2011, our adjusted oil price was negatively impacted by $19.1 million of realized oil derivative cash settlements, our adjusted natural gas price was positively impacted by $14.9 million of realized natural gas derivative cash settlements, and our adjusted NGL price was negatively impacted by $3.5 million of realized NGL derivative cash settlements.

The following table is a reconciliation from our realized prices to our adjusted price for the commodities indicated, including the effects of derivative cash settlements for the first quarters of 2011 and 2010 and the fourth quarter of 2010:

	For the Three Months Ended		
	March 31, 2011	**December 31, 2010**	**March 31, 2010**
Crude Oil (per Bbl):			
Realized price	$ 85.79	$ 77.46	$ 72.73
Less the effects of derivative cash settlements	(10.72)	(7.16)	(5.77)
Adjusted price, including the effects of derivative cash settlements	$ 75.07	$ 70.30	$ 66.96
Natural Gas (per Mcf):			
Realized price	$ 4.35	$ 5.23	$ 6.15
Plus the effects of derivative cash settlements	0.69	0.77	0.69
Adjusted price, including the effects of derivative cash settlements	$ 5.04	$ 6.00	$ 6.84
NGLs (per Bbl):			
Realized price	$ 46.65	$	$
Less the effects of derivative cash settlements	(5.76)		
Adjusted price, including the effects of derivative cash settlements	$ 40.89	$	$

Note: Prior period NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of the volumes in prior periods. Please refer to additional discussion above under the caption *Oil, Gas, and NGL Prices*.

On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act was enacted into law. This financial reform legislation includes provisions that require over-the-counter derivative transactions to be executed through an exchange or centrally cleared. The Dodd-Frank Act requires the Commodities Futures Trading Commission (the CFTC) and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. On October 1, 2010, the

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CFTC introduced its first series of proposed rules. On April 12, 2011, the CFTC proposed new rules governing margin requirements for uncleared swaps entered into by non-bank swap entities, and U.S. banking regulators proposed rules regarding margin requirements for uncleared swaps entered into by bank swap entities. The effect of the proposed rules and any additional regulations on our business is currently uncertain. Of particular concern to us, the Dodd-Frank Act does not explicitly exempt non-financial, commercial end users (such as exploration and production companies) from the requirements to post margin in connection with commodity price risk management activities. While several senators have indicated it was not the intent of the Dodd-Frank Act to require margin from non-financial, commercial end users, the exemption is not explicit in the Dodd-Frank Act. Final rules on major provisions in the legislation, such as new margin requirements, will be established through rulemakings and will not take effect until 12 months after the date of enactment. Although we cannot predict the ultimate outcome of these rulemakings, new regulations in this area may result in increased costs and cash collateral requirements for the types of derivative instruments we use to manage our financial risks related to volatility in oil, gas, and NGL commodity prices.

Outlook for the Remainder of 2011

We entered the year with a capital expenditure budget of approximately $1.0 billion, of which approximately $830.0 million is expected to be spent on drilling activity. Approximately 80 percent of our drilling capital budget will be deployed in our Eagle Ford shale and Bakken/Three Forks programs.

We began 2011 operating two rigs on our Eagle Ford acreage with plans to increase our operated rig count to six drilling rigs by year end. We have secured the drilling rigs we believe will be necessary to execute our development program for the next few years. We have also been working with well completion service providers to ensure we have access to the completion services we will require. We have obtained commitments that secure a portion of our required services and we continue to work with service providers to support our anticipated level of activity. During 2010 and 2011, we entered into separate arrangements that increase our gas takeaway capacity in 2011 and beyond in this play. Our current contracted available gas transportation capacity is approximately 100 MMcf per day and we expect to have takeaway capacity of 150 MMcf per day shortly after mid-2011, with an anticipated increase to 230 MMcf per day by year end 2011. Currently we have contracts for firm transportation for gas takeaway capacity that ramp up to 470 MMcf per day by the second half of 2014. Due to the high condensate yields associated with large portions of the broader Eagle Ford play, transportation of crude oil and condensate has periodically been an issue for industry participants, including us, in recent months. We are exploring a number of different near- and long-term arrangements to improve our ability to transport our production.

In our non-operated Eagle Ford shale program, the operator is currently operating nine drilling rigs and our expectation is that it will increase to ten rigs by the end of the second quarter of 2011. At the end of the first quarter, the operator in these assets announced a transaction to sell down a portion of its assets in this area. We have initiated a marketing effort to sell down or joint venture a portion of our total Eagle Ford shale position. Although the details of the transaction are yet to be determined, we plan to farm down or joint venture approximately 20 to 30 percent of our total net acreage position (approximately 72,000 acres). Bids are expected in the second quarter of 2011.

We plan to deploy approximately $170 million of our capital budget in our Bakken/Three Forks formations in the Williston Basin in 2011. We currently operate two drilling rigs in this program and plan to add a third rig by mid-year. The majority of our drilling has been in Divide and McKenzie counties in North Dakota. We expect our drilling program for the remainder of the year to focus on these same areas. We may consider increasing activity in this program beyond three rigs if additional capital becomes available for investment during the year and if other circumstances, such as rig availability and expected service costs, warrant such action.

We also have activity planned in our Granite Wash, Permian Basin, and Haynesville shale programs in 2011. Approximately $60 million of our capital budget in 2011 is budgeted for our Granite

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Wash program, where we anticipate operating one to two rigs throughout the year. Granite Wash drilling will be focused on testing and delineating our assets in the play. We plan to spend approximately $40 million of our capital budget in our Permian region in 2011. Approximately 50 percent of our activity in this region will be focused on our vertical Wolfberry tight oil program, where we have been testing down spacing to twenty acres.

In our Haynesville shale program in our ArkLaTex region, our 2011 capital budget is approximately $35 million primarily for non-operated activity. As of the end of the first quarter 2011, we have completed our previously reported carry and earning agreement covering a portion of our operated Haynesville shale acreage in East Texas. We are currently working to secure an agreement, which would facilitate drilling a sufficient number of wells to hold our acreage by production. We are currently evaluating plans to continue our operated drilling activity in the East Texas Haynesville shale program on our own due to a recent string of strong producing wells in late 2010 and early 2011. Finally, we are continuing to explore options to divest or sell down our Marcellus shale assets located in north-central Pennsylvania. We have minimal capital expenditures planned for this program in 2011.

Please refer to Overview of Liquidity and Capital Resources for additional discussion regarding how we anticipate funding our 2011 capital program.

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Financial Results of Operations and Additional Comparative Data

The table below provides information regarding selected production and financial information for the quarter ended March 31, 2011, and the immediately preceding three quarters. Additional details of per MCFE costs are presented later in this section.

	For the Three Months Ended			
	March 31, 2011	December 31, 2010	September 30, 2010	June 30, 2010
	($ in millions, except production sales data)			
Production (BCFE)	36.1	31.6	27.5	25.2
Oil, gas, and NGL production revenue	$ 276.3	$ 250.1	$ 197.4	$ 175.9
Realized hedge gain (loss)	$ (1.4)	$ 2.8	$ 8.8	$ 9.3
Gain on divestiture activity	$ 24.9	$ 23.1	$ 4.2	$ 7.0
Lease operating expense	$ 33.1	$ 33.5	$ 29.0	$ 29.0
Transportation costs	$ 15.0	$ 7.1	$ 4.9	$ 5.1
Production taxes	$ 17.8	$ 16.4	$ 10.7	$ 11.1
DD&A	$ 105.4	$ 94.7	$ 83.8	$ 79.8
Exploration	$ 12.7	$ 21.1	$ 14.4	$ 14.5
General and administrative	$ 25.9	$ 31.6	$ 26.2	$ 25.4
Change in Net Profits Plan liability	$ 14.2	$ (4.6)	$ 4.1	$ (6.6)
Unrealized and realized derivative (gain) loss	$ 88.4	$ 13.0	$ 5.7	$ (2.1)
Net income (loss)	$ (18.5)	$ 37.0	$ 15.5	$ 18.1
Percentage change from previous quarter:				
Production (BCFE)	14%	15%	9%	(2)%
Oil, gas, and NGL production revenue	10%	27%	12%	(17)%
Realized hedge gain (loss)	(150)%	(68)%	(5)%	258%
Gain on divestiture activity	8%	450%	(40)%	(94)%
Lease operating expense	(1)%	16%	%	(3)%
Transportation costs	111%	45%	(4)%	24%
Production taxes	9%	53%	(4)%	(22)%
DD&A	11%	13%	5%	3%
Exploration	(40)%	47%	(1)%	4%
General and administrative	(18)%	21%	3%	8%
Change in Net Profits Plan liability	(409)%	(212)%	(162)%	(76)%
Unrealized and realized derivative (gain) loss	580%	128%	(371)%	(73)%
Net income (loss)	(150)%	139%	(14)%	(86)%

Note: Historically, we have reported our natural gas production as a single stream of rich gas measured at the well head. Beginning in the first quarter of 2011, we changed our reporting for natural gas volumes to show natural gas and NGL production volumes consistent with title transfer for each product. Please refer to additional discussion above under the caption *Oil, Gas, and NGL Prices*.

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A three-month overview of selected production and financial information, including trends:

	For the Three Months Ended March 31, 2011	For the Three Months Ended March 31, 2010	Amount Change Between Periods	Percent Change Between Periods
Net production volumes				
Oil (MBbl)	1,785	1,526	259	17%
Gas (MMcf)	21,735	16,567	5,168	31%
NGLs (MBbl)	614		614	N/A
MMCFE (6:1)	36,127	25,720	10,407	40%
Average daily production				
Oil (Bbl per day)	19,828	16,950	2,878	17%
Gas (Mcf per day)	241,495	184,073	57,422	31%
NGLs (Bbl per day)	6,824		6,824	N/A
MCFE per day (6:1)	401,412	285,773	115,639	40%
Oil, gas, and NGL production revenue (in thousands)				
Oil production revenue	$ 153,091	$ 110,946	$ 42,145	38%
Gas production revenue	94,568	101,941	(7,373)	(7)%
NGL production revenue	28,654		28,654	N/A
Total	$ 276,313	$ 212,887	$ 63,426	30%
Oil, gas, & NGL production expense (in thousands)				
Lease operating expense	$ 33,071	$ 30,030	$ 3,041	10%
Transportation costs	14,984	4,094	10,890	266%
Production taxes	17,757	14,216	3,541	25%
Total	$ 65,812	$ 48,340	$ 17,472	36%
Realized sales price				
Oil (per Bbl)	$ 85.79	$ 72.73	$ 13.06	18%
Gas (per Mcf)	$ 4.35	$ 6.15	$ (1.80)	(29)%
NGLs (per Bbl)	$ 46.65	$	$ 46.65	N/A
Per MCFE Data:				
Realized price	$ 7.65	$ 8.28	$ (0.63)	(8)%
Lease operating expenses	(0.92)	(1.17)	0.25	(21)%
Transportation costs	(0.41)	(0.16)	(0.25)	156%
Production taxes	(0.49)	(0.55)	0.06	(11)%
General and administrative	(0.72)	(0.91)	0.19	(21)%
Operating profit, before the effects of derivative cash settlements	$ 5.11	$ 5.49	$ (0.38)	(7)%
Derivative cash settlements	(0.22)	0.10	(0.32)	(320)%
Operating profit, including the effects of derivative cash settlements	$ 4.89	$ 5.59	$ (0.70)	(13)%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$ 2.92	$ 3.02	$ (0.10)	(3)%
Earnings per share information				
Basic net income (loss) per common share	$ (0.29)	$ 2.01	$ (2.30)	(114)%
Diluted net income (loss) per common share	$ (0.29)	$ 1.96	$ (2.25)	(115)%
Basic weighted-average shares outstanding	63,447	62,792	655	1%
Diluted weighted-average shares outstanding	63,447	64,377	(930)	(1)%

Note: Prior period NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of the volumes in prior periods. Please refer to additional discussion above under the caption *Oil, Gas, and NGL Prices*.

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We present per MCFE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends that we believe require analysis. Average daily reported production for the first three months of 2011 increased 40 percent to 401.4 MMCFE compared with 285.8 MMCFE for the same period in 2010, driven by the development of our Eagle Ford program.

Changes in production volumes, oil, gas, and NGL production revenues, and costs reflect the cyclical and highly volatile nature of our industry. Our realized price for the three months ended March 31, 2011, was $7.65 per MCFE compared with $8.28 per MCFE for the respective period of 2010. Our realized price received for natural gas was lower for the quarter ended March 31, 2011, compared with the same quarter in 2010. Please refer to discussion above under *Oil, Gas, and NGL Prices* for information regarding how we have changed our reporting for natural gas volumes to show post processing production volumes of natural gas and NGLs for assets where our sales contracts permit us to do so.

Our LOE for the three months ended March 31, 2011, decreased $0.25 per MCFE to $0.92 per MCFE compared to the respective period in 2010. The divestiture of non-strategic properties with meaningfully higher operating costs is a driver of the decline in LOE from 2010. In addition, our LOE declined on a per MCFE basis due to higher production volumes. We believe the current high level of industry activity has the potential to increase lease operating costs in 2011. Production taxes for the three months ended March 31, 2011, decreased $0.06 per MCFE to $0.49 per MCFE compared to the comparable period in 2010. We received severance tax rebates on properties located in our Mid-Continent region, which decreased our production tax per MCFE for the first quarter of 2011. We generally expect production taxes to trend with oil, gas, and NGL revenues.

Transportation costs for the three months ended March 31, 2011, increased $0.25 per MCFE to $0.41 per MCFE from the corresponding period in 2010. Transportation costs increased on a per MCFE basis caused by the increase in production from our Eagle Ford shale program, which tends to have higher transportation costs. We anticipate transportation costs will increase over the remainder of the year on a per MCFE basis, as we continue to develop the Eagle Ford shale program.

Our general and administrative expense for the three months ended March 31, 2011, was $0.72 per MCFE, compared with $0.91 per MCFE for the comparable period of 2010. The decrease per MCFE is due to production increasing at a faster rate than general and administrative expense. A portion of our general and administrative expense is linked to our profitability and cash flow, which are driven in large part by the realized commodity prices we receive for our production. The Net Profits Plan and a portion of our current short-term incentive compensation are tied to net revenues and therefore are subject to variability. Our operating profit, including the effects of derivative cash settlements for the three months ended March 31, 2011, was $4.89 per MCFE compared with $5.59 per MCFE for the comparable period of 2010, which was a decrease of $0.70, or 13 percent.

Our depletion, depreciation, and amortization, including asset retirement obligation accretion expense, for the three months ended March 31, 2011, was $2.92 per MCFE compared with $3.02 per MCFE for the comparable period of 2010. The property balances between the two periods stayed relatively constant while the reserve base increased causing the DD&A rate to decrease. Our DD&A rate can fluctuate as a result of impairments, divestitures, and changes in the mix of our production and the underlying proved reserve volumes. Additionally, the accounting treatment for assets that are classified as assets held for sale can also impact our DD&A rate since properties held for sale are no longer depleted.

Please refer to *Comparison of Financial Results and Trends between the three months ended March 31, 2011, and 2010* for additional discussion on oil, gas, and NGL production expense, DD&A, and general and administrative expense.

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We use the treasury stock method to account for our 3.50% Senior Convertible Notes. This quarter was the first time that our average stock price exceeded the conversion price making our 3.50% Senior Convertible Notes potentially dilutive. However we recorded a net loss for the quarter, therefore all potentially dilutive securities were anti-dilutive. Subsequent to the first quarter of 2011, we have continued to trade above the $54.42 conversion price, and as such we expect that the 3.50% Senior Notes will have a dilutive impact on our future dilutive earnings per share calculations if we record net income for the second quarter of 2011. Our in-the-money stock options, unvested RSUs, and contingent PSAs were dilutive for the three-month period ended March 31, 2010. Both basic and diluted earnings per share are presented in the table above. A detailed explanation is presented in Note 6 Earnings per Share in Part I, Item 1 of this report. Basic and diluted weighted-average common shares outstanding used in our March 31, 2011, and 2010, earnings per share calculations reflect increases in outstanding shares related to stock option exercises and vested RSUs. We issued 288,540 and 18,214 shares of common stock during the three-month periods ended March 31, 2011, and 2010, respectively, as a result of stock option exercises. The number of RSUs that vested and settled during the first three months of 2011 and 2010 were 27,714 and 48,725, respectively.

Comparison of Financial Results and Trends between the three months ended March 31, 2011, and 2010

Oil, gas, and NGL production revenue. Average daily reported production increased 40 percent to 401.4 MMCFE for the quarter ended March 31, 2011, compared with 285.8 MMCFE for the quarter ended March 31, 2010. Please refer to the discussion above under *Oil, Gas, and NGL Prices* regarding how we have changed our reporting for natural gas and NGL volumes. The following table presents the regional changes in our production, oil, gas, and NGL revenues, and costs between the two quarters:

	Average Net Daily Production Added (Decreased) (MMCFE/d)	Oil, Gas, & NGL Revenue Added (Decreased) (in millions)	Production Costs Increase (Decrease) (in millions)
Mid-Continent	(11.5)	$ (14.3)	$ (0.4)
ArkLaTex	28.6	5.5	0.8
South Texas & Gulf Coast	109.1	66.4	18.2
Permian	(6.3)	(2.0)	1.3
Rocky Mountain	(4.3)	7.8	(2.4)
Total	115.6	$ 63.4	$ 17.5

The largest increase in production occurred in the South Texas & Gulf Coast region as a result of drilling activity in our Eagle Ford shale program. Activity in our Eagle Ford shale program continues to increase and we anticipate production from this region to continue to ramp up over the next several years. We also saw an increase in our ArkLaTex region, as a result of strong production performance from wells drilled in the Haynesville Shale in late 2010 and early 2011.

The following table summarizes the average realized prices we received in the first quarter of 2011 and 2010 before the effects of cash derivative settlements.

	For the Three Months Ended March 31, 2011	2010
Realized oil price ($/Bbl)	$ 85.79	$ 72.73

Realized gas price ($/Mcf)	$	4.35	$	6.15
Realized NGL price ($/Bbl)	$	46.65	$	
Realized equivalent price ($/MCFE)	$	7.65	$	8.28

Note: Prior period NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of the volumes in prior periods. Please refer to additional discussion above under the caption *Oil, Gas, and NGL Prices*.

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An eight percent decrease in realized prices per MCFE, combined with a 40 percent increase in production volumes, resulted in an overall increase in revenue. We expect our realized prices to trend with commodity prices.

Realized hedge gain (loss). We recorded a net realized hedge loss of $1.4 million for the three-month period ended March 31, 2011, compared with a $2.6 million gain for the same period in 2010. The realized net loss in 2011 is comprised of realized cash settlements on commodity derivative contracts that were previously recorded in AOCL, whereas the realized net gain in 2010 is comprised of realized cash settlements on all commodity derivative contracts. Our realized oil, gas, and NGL hedge gains and losses are a function of commodity prices and the price at which production was hedged.

Gain (loss) on divestiture activity. We had a $24.9 million net gain on divestiture activity for the quarter ended March 31, 2011, related to a divestiture of non-strategic oil and gas properties located in our Rocky Mountain region. We recorded a $121.0 million net gain on divestiture activity for the comparable period of 2010, due primarily to the divestiture of non-strategic oil properties located in Wyoming and North Dakota. We are currently marketing other oil and gas properties, and we will continue to evaluate properties for divestiture in the normal course of our business. Please refer to *Marketing of properties* under *First Quarter 2011 Highlights* for additional discussion.

Marketed gas system revenue and expense. Marketed gas system revenue decreased $6.2 million to $15.6 million for the quarter ended March 31, 2011, compared with $21.8 million for the comparable period of 2010. Concurrent with the decrease in marketed gas system revenue, marketed gas system expense decreased $6.0 to $16.0 million for the quarter ended March 31, 2011, compared with $22.0 million for the comparable period of 2010. The net margin stayed relatively consistent with historical performance. We expect that marketed gas system revenue and expense will continue to coincide with increases and decreases in production and our realized price for natural gas.

Oil, gas, and NGL production expense. Total production costs for the first quarter of 2011 increased $17.5 million, or 36 percent, to $65.8 million compared with $48.3 million for the same period of 2010. Total oil and gas production costs per MCFE decreased $0.06 to $1.82 for the first quarter of 2011, compared with $1.88 for the same period in 2010. The per MCFE decrease is comprised of the following:

- A $0.30 decrease in recurring LOE on a per MCFE basis reflects the 2010 and early 2011 sale of non-core properties with higher per unit LOE costs. We expect the various resources required to service our industry will become more sought after and harder to secure as a result of an increase in activity. We expect to see upward pressure on LOE throughout the remainder of the year.

- A $0.06 per MCFE decrease in production taxes due to severance tax rebates. Please refer to Financial Results of Operations and Additional Comparative Data for additional discussion.

- A $0.25 increase in overall transportation costs on a per MCFE basis as a result of increased production in our Eagle Ford shale. Please refer to Financial Results of Operations and Additional Comparative Data for additional discussion.

- A $0.05 overall increase in workover LOE on a per MCFE basis relating primarily to an increase in workover activity in our South Texas & Gulf Coast region.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A increased $27.6 million, or 35 percent, to $105.4 million for the three-month period ended March 31, 2011, compared with $77.8 million for the same period in 2010. Please refer to Financial Results of Operations and Additional Comparative Data for additional discussion.

Abandonment and impairment of unproved properties. We recorded abandonment and impairment of unproved properties expense of $3.1 million for the three months ended March 31, 2011, associated with

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lease expirations in our ArkLaTex region. We recorded $904,000 of abandonment and impairment of unproved properties expense for the comparable period in 2010. We generally expect abandonments and impairments of unproved properties to be more likely to occur in periods of low commodity prices, since fewer dollars will be available for exploratory and development efforts.

Exploration. The components of exploration expense are as follows:

Summary of Exploration Expense	For the Three Months Ended March 31, 2011	2010
	(in millions)	
Geological and geophysical expenses	$ 2.1	$ 3.6
Exploratory dry hole expense		