SM Energy Co
Form 10-Q
November 02, 2011
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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 September 30, 2011
Commission File Number 001-31539
SM ENERGY COMPANY
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	41-0518430 (I.R.S. Employer Identification No.)
1775 Sherman Street, Suite 1200, Denver, Colorado (Address of principal executive offices)	80203 (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 October 25, 2011, the registrant had 64,000,662 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)

	September 30, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$29,923	$5,077
Accounts receivable	183,943	163,190
Refundable income taxes	—	8,482
Prepaid expenses and other	30,937	45,522
Derivative asset	54,698	43,491
Deferred income taxes	5,203	8,883
Total current assets	304,704	274,645
Property and equipment (successful efforts method), at cost:		
Land	1,543	1,491
Proved oil and gas properties	4,070,916	3,389,158
Less - accumulated depletion, depreciation, and amortization	(1,635,470)	(1,326,932)
Unproved oil and gas properties	107,651	94,290
Wells in progress	329,363	145,327
Materials inventory, at lower of cost or market	14,959	22,542
Oil and gas properties held for sale (note 3)	105,918	86,811
Other property and equipment, net of accumulated depreciation of $18,312 in 2011 and $15,480 in 2010	47,655	21,365
Total property and equipment, net	3,042,535	2,434,052
Other noncurrent assets:		
Derivative asset	39,891	18,841
Other noncurrent assets	69,150	16,783
Total other noncurrent assets	109,041	35,624
Total Assets	$3,456,280	$2,744,321
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$400,420	$417,654
Derivative liability	21,106	82,044
Deposit associated with oil and gas properties held for sale	2,000	2,355
Total current liabilities	423,526	502,053
Noncurrent liabilities:		
Long-term credit facility	—	48,000
3.50% Senior Convertible Notes, net of unamortized discount of $4,861 in 2011 and $11,827 in 2010	282,639	275,673
6.625% Senior Notes	350,000	—
Asset retirement obligation	73,693	69,052

Asset retirement obligation associated with oil and gas properties held for sale (note 3)	220	2,119
Net Profits Plan liability	108,489	135,850
Deferred income taxes	609,393	443,135
Derivative liability	3,184	32,557
Other noncurrent liabilities	17,383	17,356
Total noncurrent liabilities	1,445,001	1,023,742
Commitments and contingencies (note 7)		
Stockholders' equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued: 64,079,885 shares in 2011 and 63,412,800 shares in 2010; outstanding, net of treasury shares: 63,998,818 shares in 2011 and 63,310,165 shares in 2010	641	634
Additional paid-in capital	223,120	191,674
Treasury stock, at cost: 81,067 shares in 2011 and 102,635 shares in 2010	(1,544)	(423)
Retained earnings	1,371,869	1,042,123
Accumulated other comprehensive loss	(6,333)	(15,482)
Total stockholders' equity	1,587,753	1,218,526
Total Liabilities and Stockholders' Equity	$3,456,280	$2,744,321

The accompanying notes are an integral part of these condensed 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 September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
Operating revenues and other income:				
Oil, gas, and NGL production revenue	$325,231	$197,354	$935,478	$586,128
Realized hedge (loss) gain (note 10)	(6,843)	8,847	(14,548)	20,771
Gain on divestiture activity (note 3)	190,728	4,184	245,662	132,183
Marketed gas system and other operating revenue	21,458	16,499	57,184	59,634
Total operating revenues and other income	530,574	226,884	1,223,776	798,716
Operating expenses:				
Oil, gas, and NGL production expense	77,753	44,606	196,907	138,114
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	123,067	83,800	343,805	241,335
Exploration	11,272	14,437	33,587	42,833
Impairment of proved properties	48,525	—	48,525	—
Abandonment and impairment of unproved properties	—	1,719	4,316	4,998
General and administrative	29,787	26,219	82,958	75,103
Change in Net Profits Plan liability (note 8)	(24,930)	4,086	(24,719)	(29,785)
Unrealized and realized derivative (gain) loss (note 10)	(128,425)	5,727	(83,872)	(4,095)
Marketed gas system and other expense	20,737	15,238	57,746	54,621
Total operating expenses	157,786	195,832	659,253	523,124
Income from operations	372,788	31,052	564,523	275,592
Nonoperating income (expense):				
Interest income	27	85	382	268
Interest expense	(9,372)	(6,339)	(33,636)	(19,469)
Income before income taxes	363,443	24,798	531,269	256,391
Income tax expense	(133,346)	(9,346)	(195,142)	(96,693)
Net income	$230,097	$15,452	$336,127	$159,698
Basic weighted-average common shares outstanding	63,904	63,031	63,665	62,914
Diluted weighted-average common shares outstanding	67,386	64,794	67,390	64,599
Basic net income per common share (note 6)	$3.60	$0.25	$5.28	$2.54
Diluted net income per common share (note 6)	$3.41	$0.24	$4.99	$2.47

The accompanying notes are an integral part of these condensed 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		Additional Paid-in Capital	Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
	Shares	Amount		Shares	Amount			
Balances, January 1, 2011	63,412,800	$634	$191,674	(102,635)	$(423)	$1,042,123	$ (15,482)	$ 1,218,526
Comprehensive income, net of tax:								
Net income						336,127		336,127
Reclassification to earnings							9,149	9,149
Total comprehensive income								345,276
Cash dividends, $ 0.10 per share						(6,381)		(6,381)
Issuance of common stock under Employee Stock Purchase Plan	22,373	1	1,120					1,121
Issuance of common stock upon vesting of RSUs and settlement of PSUs, net of shares used for tax withholdings, including income tax benefit of RSUs and PSUs	278,595	3	(9,969)					(9,966)
Sale of common stock, including income tax benefit of stock option exercises	366,117	3	19,624					19,627
Stock-based compensation expense			20,671	21,568	(1,121)			19,550
	64,079,885	$641	$223,120	(81,067)	$(1,544)	$1,371,869	$ (6,333)	$ 1,587,753

Balances, September 30, 2011								
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	—	—	—	—	—	159,698	—	159,698
Change in derivative instrument fair value	—	—	—	—	—	—	50,136	50,136
Reclassification to earnings	—	—	—	—	—	—	1,903	1,903
Minimum pension liability adjustment	—	—	—	—	—	—	4	4
Total comprehensive income								211,741
Cash dividends, $ 0.10 per share	—	—	—	—	—	(6,297)	—	(6,297)
Issuance of common stock under Employee Stock Purchase Plan	27,456	—	799	—	—	—	—	799
Issuance of common stock upon vesting of RSUs, net of shares used for tax withholdings, including income tax cost of RSUs	57,687	1	(909)	—	—	—	—	(908)
Sale of common stock, including income tax benefit of stock option exercises	163,348	1	3,692	—	—	—	—	3,693
Stock-based compensation expense	—	—	19,105	24,258	748	—	—	19,853
Balances, September 30, 2010	63,147,613	$631	$183,203	(102,635)	$(456)	$1,004,984	$ 14,089	$ 1,202,451

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

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SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)
(in thousands)

	For the Nine Months Ended September 30,	
	2011	2010
Cash flows from operating activities:		
Net income	$336,127	$159,698
Adjustments to reconcile net income to net cash provided by operating activities:		
Gain on divestiture activity	(245,662)	(132,183)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	343,805	241,335
Exploratory dry hole expense	49	289
Impairment of proved properties	48,525	—
Abandonment and impairment of unproved properties	4,316	4,998
Stock-based compensation expense	19,550	19,853
Change in Net Profits Plan liability	(24,719)	(29,785)
Unrealized derivative gain	(108,020)	(4,095)
Amortization of debt discount and deferred financing costs	14,698	10,022
Deferred income taxes	164,251	85,695
Plugging and abandonment	(2,935)	(7,106)
Other	(5,952)	(3,085)
Changes in current assets and liabilities:		
Accounts receivable	(20,787)	(4,937)
Refundable income taxes	8,482	31,402
Prepaid expenses and other	14,732	512
Accounts payable and accrued expenses	(41,558)	47,123
Excess income tax benefit from the exercise of stock awards	(15,155)	(1,376)
Net cash provided by operating activities	489,747	418,360
Cash flows from investing activities:		
Net proceeds from sale of oil and gas properties	325,053	259,501
Capital expenditures	(1,081,617)	(488,684)
Acquisition of oil and gas properties	—	(685)
Other	(340)	(6,492)
Net cash used in investing activities	(756,904)	(236,360)
Cash flows from financing activities:		
Proceeds from credit facility	115,500	315,059
Repayment of credit facility	(163,500)	(501,059)
Debt issuance costs related to credit facility	(8,719)	—
Net proceeds from 6.625% Senior Notes	341,122	—
Proceeds from sale of common stock	5,593	3,116
Dividends paid	(3,181)	(3,144)
Excess income tax benefit from the exercise of stock awards	15,155	1,376
Other	(9,967)	(908)
Net cash provided by (used in) financing activities	292,003	(185,560)

Net change in cash and cash equivalents	24,846	(3,560)
Cash and cash equivalents at beginning of period	5,077	10,649
Cash and cash equivalents at end of period	$29,923	$7,089

The accompanying notes are an integral part of these condensed 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 non-cash investing and financing activities:

	For the Nine Months Ended September 30,	
	2011	2010
	(in thousands)	
Cash paid for interest	$(24,095)	$(9,091)
Net cash refunded for income taxes	$2,346	$24,949

Dividends of approximately $3.2 million have been declared by the Company's Board of Directors, but not paid, as of September 30, 2011. Dividends of approximately $3.2 million were declared by the Company's Board of Directors, but not paid, as of September 30, 2010.

As of September 30, 2011, and 2010, $271.5 million, and $133.3 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 condensed 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 onshore North America, with a focus on oil and liquids-rich resource plays.

Note 2 - Basis of Presentation, Significant Accounting Policies, and Recently Issued Accounting Standards

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 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 September 30, 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

In May 2011, the Financial Accounting Standards Board ("FASB") issued new fair value measurement authoritative guidance clarifying the application of fair value measurement and disclosure requirements and changes particular principles or requirements for measuring fair value. This guidance is effective for interim and annual periods beginning after December 15, 2011. The Company is currently evaluating the provisions of this guidance and assessing the impact, if any, it may have on the Company's fair value disclosures.

In June 2011, the FASB issued new authoritative guidance that states an entity that reports items of other comprehensive income has the option to present the components of net income and comprehensive income in either one continuous financial statement, or two consecutive financial statements. This guidance is effective for interim and annual periods beginning after December 15, 2011. The Company is currently evaluating the provisions of this guidance and assessing the impact it will have on the Company's comprehensive income disclosures.

Note 3 - Divestitures and Assets Held for Sale

Eagle Ford Shale Divestiture

On August 2, 2011, the Company divested of certain operated Eagle Ford shale assets located in its South Texas & Gulf Coast region. This divestiture was comprised of the Company's entire operated acreage in LaSalle County, Texas, as well as an immaterial adjacent block of its operated acreage in Dimmit County, Texas. Total cash received, before marketing costs, was approximately $226.9 million. The final sales price is subject to post-closing adjustments and is expected to be finalized in the fourth quarter of 2011. The estimated gain on this divestiture is approximately $191.4 million. The Company determined the sale did not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

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Mid-Continent Divestiture

In June 2011, the Company divested of certain non-strategic Constitution Field assets located in its Mid-Continent region. Total cash received, before marketing costs and Net Profits Interest Bonus Plan ("Net Profits Plan") payments, was approximately $35.7 million. The final sales price is subject to post-closing adjustments and is expected to be finalized during the fourth quarter of 2011. The estimated gain on this divestiture is approximately $28.4 million. The Company determined the sale did not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

Rocky Mountain Divestiture

In January 2011, the Company divested of certain non-strategic assets located in its Rocky Mountain region. Total cash received, before marketing costs and Net Profits Plan payments, was approximately $45.5 million. The final gain related to the divestiture was approximately $27.2 million. The Company determined the sale 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 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 which fair value is determined to be less than the carrying value of the assets.

As of September 30, 2011, the accompanying condensed consolidated balance sheets ("accompanying balance sheets") included $105.9 million in book value of assets held for sale, net of accumulated depletion, depreciation and amortization and a corresponding asset retirement obligation liability is also separately presented. The above assets held for sale and asset retirement obligation liability amounts include certain assets located in Pennsylvania and the Company's gathering assets as described in Note 12 - Acquisition and Development Agreement. The Company determined these planned asset sales do not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

In July 2011, the Company entered into an agreement to divest Marcellus shale assets located in Pennsylvania that were classified as held for sale at September 30, 2011, for $80.0 million subject to closing and post-closing adjustments. The agreement has an effective date of April 1, 2011. The agreement provided the purchaser with the option of extending the agreed upon closing date from October 15, 2011, to December 14, 2011, in exchange for an additional deposit. The purchaser has exercised this option and made the additional deposit. The closing of this transaction is subject to the satisfaction of certain closing conditions, including the resolution of any title defects exceeding specified levels. There can be no assurance that this transaction will be completed in the anticipated time frame, or at all.

Note 4 - Income Taxes

Income tax expense for the nine months ended September 30, 2011, and 2010, differs from the amounts that would be provided by applying the statutory U.S. federal income tax rate to income before income taxes as a result of the estimated effect of the domestic production activities deduction, percentage depletion, research and development credits, the effect of state income taxes, and other permanent differences.

The provision for income taxes consists of the following:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Current portion of income tax expense:				
Federal	$20,699	$2,194	$29,855	$10,410
State	637	277	1,036	588
Deferred portion of income tax expense	112,010	6,875	164,251	85,695
Total income tax expense	$133,346	$9,346	$195,142	$96,693
Effective tax rate	36.7 %	37.7 %	36.7 %	37.7 %

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On a year-to-date basis, 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. Cumulative effects of state rate changes are reflected in the period legislation is enacted. Changes in the effective tax rate between periods also occur due to estimates for the domestic production activities deduction, percentage depletion, research and development credits, uncertain tax positions, valuation allowances, 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. The quarterly rate can also be impacted by the proportion of income earned in reported periods.

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. In the third quarter of 2011, the Company completed a research and development credit study and filed an amended 2007 federal return to claim a credit for that year. In the first quarter of 2011, the Company received a $5.5 million refund from its 2006 tax year as a result of a net operating loss carryback claim from the 2008 tax year. In the fourth quarter of 2010, the Internal Revenue Service initiated an audit of the Company for the 2009 tax year. The audit was concluded in the second quarter of 2011 with a $110,000 decrease to the Company's total 2005 refund claim of $25.0 million. A quick refund claim of $22.9 million from 2005 was received in the third quarter of 2010.

Note 5 - Long-Term Debt

Revolving Credit Facility

The Company executed a Fourth Amended and Restated Credit Agreement on May 27, 2011. This amended revolving credit facility replaced the Company's previous facility. The Company incurred $8.7 million of deferred financing costs in association with the amended credit facility. Borrowings under the facility are secured by substantially all of the Company's proved oil and gas properties. The credit facility has a maximum loan amount of $2.5 billion, with current aggregate lender commitments of $1.0 billion, and a maturity date of May 27, 2016. On September 29, 2011, the lending group redetermined the Company's borrowing base under the credit facility at an amount of $1.4 billion, up from $1.3 billion. The borrowing base is subject to regular semi-annual redeterminations by the Company's lenders. The borrowing base redetermination process considers the value of the Company's oil and gas properties.

The Company must comply with certain financial and non-financial covenants under the terms of its credit facility agreement, including the limitation of the Company's dividends to no more than $50.0 million per year. The Company was in compliance with all financial and non-financial covenants under the credit facility as of September 30, 2011, and through the filing of this report. Interest and commitment fees are accrued based on the borrowing base utilization grid below. Eurodollar loans accrue interest at the London Interbank Offered Rate plus the applicable margin from the utilization table below, and Alternate Base Rate ("ABR") and swingline loans accrue interest at Prime plus the applicable margin from the utilization table below. Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the accompanying condensed consolidated statements of operations ("accompanying statements of operations").

Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	<25%	≥25% <50%	≥50% <75%	≥75% <90%	≥90%
Eurodollar Loans	1.500 %	1.750 %	2.000 %	2.250 %	2.500 %
ABR Loans or Swingline Loans	0.500 %	0.750 %	1.000 %	1.250 %	1.500 %
Commitment Fee Rate	0.375 %	0.375 %	0.500 %	0.500 %	0.500 %

The Company had no outstanding borrowings under its credit facility as of September 30, 2011. The Company had $48.0 million of outstanding borrowings under its previous credit facility at December 31, 2010. The Company had $999.4 million of available borrowing capacity under its current credit facility as of September 30, 2011, and had $629.5 million of available borrowing capacity under its previous facility at December 31, 2010, when the aggregate commitment amount was $678.0 million. The Company had two letters of credit outstanding for a total of $608,000 at September 30, 2011, and had one letter of credit outstanding in the amount of $483,000 at December 31, 2010. Outstanding letters of credit reduce the amount available under the commitment amount on a dollar-for-dollar basis.

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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 $341.1 million after deducting fees of approximately $8.9 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 all borrowings under the Company's previous credit facility, and the remaining proceeds were used to fund 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. The Company may also redeem the 6.625% Senior Notes, in whole or in part, at any time prior to February 15, 2015, at a redemption price equal to 100% of the principal amount, plus a specified make whole premium and accrued and unpaid interest.

The Company may also redeem all or, from time to time, a portion of the 6.625% Senior Notes on or after February 15, 2015, at the prices set forth below, during the twelve-month period beginning on February 15 of the applicable year, 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 subject to certain covenants under the indenture governing the 6.625% Senior Notes that limit incurring additional indebtedness, issuing preferred stock, and making restricted payments in excess of specified amounts. The payment of dividends on the Company's common stock must comply with the restricted payment covenant; provided, however, the first $6.5 million of dividends paid each year are not restricted by this covenant. To pay any additional dividends, the Company must comply with this covenant. The Company was in compliance with all covenants under its 6.625% Senior Notes as of September 30, 2011, and through the filing 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 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.

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 they are 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 3.50% Senior Convertible 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. If holders elect to convert all or a portion of the 3.50% Senior Convertible Notes during a calendar quarter in which they are eligible to do so, they will receive cash, 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. As of December 31, 2010, the 3.50% Senior Convertible Notes were not convertible. The closing price of the Company's common stock exceeded the conversion trigger price of $70.75 per share for the quarter ended March 31, 2011; however,

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none of the holders opted to convert their 3.50% Senior Convertible Notes during the second quarter of 2011. The closing price of the Company's common stock did not exceed the conversion trigger price for the quarters ended June 30, 2011, and September 30, 2011; therefore, the 3.50% Senior Convertible Notes were not eligible to be converted during the third quarter of 2011 and will not be eligible to be converted during the fourth quarter of 2011.

Note 6 - Earnings per Share

Basic net income per common share of stock is calculated by dividing net income 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 per common share of stock is calculated by dividing adjusted net income 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 contingent Performance Stock Units, and shares into which the 3.50% Senior Convertible Notes are convertible.

Performance Stock Units are structurally the same as the previously granted PSAs (collectively known as "Performance Stock Units" or "PSUs"). PSUs represent the right to receive, upon settlement of the PSUs after 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 PSUs granted on the award date. The number of potentially dilutive shares related to PSUs 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 PSUs, please refer to Note 8 - Compensation Plans under the heading Performance Stock Units Under the Equity Incentive Compensation Plan.

The Company’s 3.50% Senior Convertible Notes have a net-share settlement right giving the Company 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. Shares of the Company’s common stock traded at a quarterly average closing price exceeding the $54.42 conversion price for the three and nine-month periods ended September 30, 2011, making them dilutive for those respective periods. The 3.50% Senior Convertible Notes were not dilutive for the three and nine-month periods ended September 30, 2010.

The treasury stock method is used to measure the dilutive impact of unvested RSUs, contingent PSUs, and in-the-money stock options.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands, except per share amounts)			
Net income	$230,097	$15,452	$336,127	$159,698

Basic weighted-average common shares outstanding	63,904	63,031	63,665	62,914
Add: dilutive effect of stock options, unvested RSUs, and contingent PSUs	2,062	1,763	2,589	1,685
Add: dilutive effect of 3.50% Senior Convertible Notes	1,420	—	1,136	—
Diluted weighted-average common shares outstanding	67,386	64,794	67,390	64,599
Basic net income per common share	$3.60	$0.25	$5.28	$2.54
Diluted net income per common share	$3.41	$0.24	$4.99	$2.47

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Note 7 - Commitments and Contingencies

During the second quarter of 2011, the Company entered into two natural gas gathering and services agreements whereby it is subject to certain natural gas gathering through-put commitments for up to ten years pursuant to each contract. The Company may be required to make periodic deficiency payments for any shortfalls in delivering the minimum applicable annual or semi-annual volume commitments. In the event that no gas is delivered in accordance with the agreements, the aggregate deficiency payments will total approximately $726.2 million as of September 30, 2011. If a shortfall in the minimum volume commitment arises, the Company can arrange for third party gas to be delivered into the applicable gathering system and applied to the Company's minimum commitment.

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. As of September 30, 2011, the remaining commitment was $112.5 million. However, the Company's liability in the event of early termination of this contract without cause is not to exceed $24.0 million. In the event of early termination of this contract with cause there is no termination fee.

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 probable and the amount can be reasonably estimated. The Company currently has no such accruals. In the opinion of management, any 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 where the plaintiffs claim an aggregate overriding royalty interest of 7.46875 percent in production from approximately 22,000 of the Company's net acres in the Eagle Ford shale play in South Texas. The plaintiffs seek to quiet title to their claimed overriding royalty interest and seek the recovery of unpaid overriding royalty interest proceeds allegedly due. The Texas District Court 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 claim. The court entered judgment against all defendants awarding the plaintiffs damages of approximately $5.1 million. 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 effect on the financial position of the Company. Based on the Company's current view of the facts and circumstances of the case, no accrual has been made for any loss.

The Company initiated an arbitration proceeding on May 11, 2011, against Anadarko E&P Company, LP ("Anadarko"), alleging that Anadarko breached a Joint Exploration Agreement ("JEA") originally executed between Anadarko and TXCO Energy Corp. ("TXCO") in March 2008, and relating to oil and gas properties located in Maverick, Dimmitt, Webb and LaSalle Counties, Texas. The Company has been a party to the JEA since May 15, 2008. The Company asserts that Anadarko is required under the JEA to tender to the Company its proportionate share of the leasehold interests that Anadarko acquired in TXCO's bankruptcy proceeding in February 2010. The arbitration hearing related to this dispute was held in September 2011; however, the arbitration panel has not announced its determination. If the Company prevails in this matter, Anadarko could be obligated to sell to the Company an undivided interest of up to 8.333% (or up to approximately 27,000 net acres) of the total leasehold governed by the JEA in return for the Company's payment of a proportionate share of the price Anadarko paid TXCO in the bankruptcy proceeding (adjusted for revenues and expenses attributable to the purchased interest since January 1, 2010), or in the alternative, pay the Company damages in an amount to be determined by the arbitration panel.
In a separate, unrelated matter, the Company initiated an arbitration proceeding against Springfield Pipeline, LLC ("Springfield"), a wholly owned affiliate of Anadarko Petroleum Corporation, and another party in October 2011,

alleging that Springfield and the other party had unreasonably withheld or delayed consents, which are closing conditions of the Company's Acquisition and Development Agreement with Mitsui E&P Texas LP, and which are required (but are not to be unreasonably withheld or delayed) under an Agreement for the Construction, Ownership and Operation of Midstream Assets in Maverick, Dimmit, Webb and La Salle Counties, Texas, executed by the Company and Springfield and under certain other related gathering agreements. The Company has dismissed its claims in the arbitration proceeding against the other party in return for its consent. The Company has requested an expedited arbitration hearing under the commercial rules of the American Arbitration Association and is endeavoring to conclude this arbitration proceeding against Springfield during the fourth quarter of 2011.

Note 8 - Compensation Plans

Cash Bonus Plan

During the first quarters 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

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the 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 September 30, 2011, and 2010, respectively, and $11.3 million and $9.2 million for the nine-month periods ended September 30, 2011, and 2010, respectively.

Performance Stock Units Under the Equity Incentive Compensation Plan

PSUs are the primary form of long-term equity incentive compensation for the Company. The PSU multiplier is based on the Company’s performance after completion of a three-year performance period. The performance criteria for PSUs is 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. In addition, there are separate employment service vesting provisions. PSUs are recognized as general and administrative and exploration expense over the vesting period of the award.

Total stock-based compensation expense related to PSUs for the three-month periods ended September 30, 2011, and 2010, was $5.9 million and $5.6 million, respectively, and $14.3 million and $13.0 million for the nine-month periods ended September 30, 2011, and 2010, respectively. As of September 30, 2011, there was $31.9 million of total unrecognized compensation expense related to unvested PSUs that is being amortized through 2014.

A summary of the status and activity concerning PSUs for the nine-month period ended September 30, 2011, is presented in the following table:

	PSUs	Weighted-Average Grant-Date Fair Value
Non-vested, at January 1, 2011	1,110,666	$39.48
Granted	266,282	$91.45
Vested [1]	(359,671)	$35.53
Forfeited	(125,849)	$32.89
Non-vested, at September 30, 2011	891,428	$58.77

(1) The number of awards vested assumes 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.

During the third quarter of 2011, the Company granted a total of 266,282 PSUs as part of its regular annual long-term equity compensation process with a fair value of $24.3 million. These PSUs will vest 1/7th on July 1, 2012, 2/7ths on July 1, 2013, and 4/7ths on July 1, 2014. During the third quarter of 2011, the Company settled 305,423 PSUs that related to awards granted in 2008 through the issuance of shares of the Company's common stock in accordance with the terms of the PSU awards. As a result, the Company issued a net of 206,468 shares of common stock associated with these grants. The remaining 98,955 shares were withheld to satisfy income and payroll tax withholding obligations that arose upon delivery of the shares underlying those PSUs.

Restricted Stock Units Under the Equity Incentive Compensation Plan

The Company grants RSUs for a portion of its annual long-term equity compensation. An RSU represents a right to receive one share of the Company’s common stock to be delivered upon settlement of the RSU when it vests. Total RSU compensation expense for the three-month periods ended September 30, 2011, and 2010, was $1.6 million and $2.1 million, respectively, and $3.6 million and $5.7 million for the nine-month periods ended September 30, 2011, and 2010, respectively. As of September 30, 2011, there was $9.2 million of total unrecognized compensation expense related to unvested RSU awards that is being amortized through 2014.

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A summary of the status and activity concerning RSUs for the nine-month period ended September 30, 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	98,952	$72.69
Vested	(105,554)	$30.63
Forfeited	(17,270)	$36.06
Non-vested, at September 30, 2011	309,487	$44.34

During the third quarter of 2011, the Company granted a total of 90,665 RSUs as part of its regular annual long-term equity compensation process with a fair value of $6.7 million. These RSUs will vest 1/7th on July 1, 2012, 2/7ths on July 1, 2013, and 4/7ths on July 1, 2014. During the first nine months of 2011, the Company settled 105,554 RSUs that related to awards granted in 2008, 2009 and 2010 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 72,127 shares of common stock associated with these grants. The remaining 33,427 shares were withheld to satisfy income and payroll tax withholding obligations that arose upon delivery of the shares underlying those RSUs.

Stock Option Grants Under Prior Stock Option Plans

The following table summarizes stock option activity for the nine months ended September 30, 2011:

	Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value
Outstanding, January 1, 2011	920,765	$13.11	$42,192,057
Exercised	(366,117)	$12.22	
Forfeited	—	$—	
Outstanding, September 30, 2011	554,648	$13.69	$26,043,950
Vested and exercisable, September 30, 2011	554,648	$13.69	$26,043,950

As of September 30, 2011, there was no unrecognized compensation expense related to stock option awards.

Director Shares

During the nine months ended September 30, 2011, and 2010, the Company issued 21,568 and 24,258 shares, respectively, of the Company's common stock held as treasury shares to the Company's non-employee directors. The shares were issued pursuant to the Company's Equity Incentive Compensation Plan. There was no compensation expense recorded for the three months ended September 30, 2011. The Company recorded $33,000 of related compensation expense for the three months ended September 30, 2010, and $1.0 million and $748,000 of related compensation expense for the nine months ended September 30, 2011, and 2010, respectively.

Employee Stock Purchase Plan

Under the Company's Employee Stock Purchase Plan (the "ESPP"), eligible employees may purchase shares of the Company's common stock through payroll deductions of up to 15 percent of eligible compensation without accruing in excess of $25,000 in fair market value from such purchases for each calendar year. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on the first or last day of the purchase period. The ESPP is intended to qualify under Section 423 of the Internal Revenue Code. The Company has set aside 2,000,000 shares of its common stock to be available for issuance under the ESPP, of which 1,392,954 shares were available for issuance as of September 30, 2011. There were 22,373 and 27,456 shares issued under the ESPP during the first nine months of 2011 and 2010, respectively, with a six month minimum holding period. Shares issued under the ESPP on or after July 1, 2011, have no minimum holding period. The fair value of ESPP grants is measured at the date of grant using the Black-Scholes option-pricing model.

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Net Profits Plan

Under the Company’s Net Profits Plan, all of the Company's 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 a 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. As a result, the 2007 Net Profits Plan pool was the last pool established by the Company.

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 September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
General and administrative expense	$4,229	$3,918	$14,820	$16,233
Exploration expense	507	638	1,569	1,896
Total	$4,736	$4,556	$16,389	$18,129

Additionally, the Company accrued or made cash payments under the Net Profits Plan of $686,000, relating to divestiture proceeds for the three months ended September 30, 2010, and $6.3 million and $20.8 million for the nine months ended September 30, 2011, and 2010, respectively. There were no cash payments made or accrued for relating to divestiture proceeds for the three months ended September 30, 2011. 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 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. If the Company allocated the change in liability to these specific functional line items, based on the current allocation of actual distributions made by the Company, such expenses or benefits would predominately be allocated to general and administrative expense. The amount that would be allocated to exploration expense is minimal in comparison. Over time, less of the amount distributed relates to prospective exploration efforts as more of the amount distributed is to employees that have terminated employment and do not provide ongoing exploration support to the Company.

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”).

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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 September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Service cost	$950	$848	$2,850	$2,544
Interest cost	296	280	888	840
Expected return on plan assets	(220)	(159)	(660)	(477)
Amortization of net actuarial loss	102	91	304	273
Net periodic benefit cost	$1,128	$1,060	$3,382	$3,180

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.

Contributions

The Company is currently required to contribute $6.3 million to its Qualified Pension Plan for the 2011 plan year. The Company has contributed $4.3 million as of September 30, 2011.

Note 10 - Derivative Financial Instruments

To mitigate a portion of the exposure to potentially adverse market changes in oil, natural 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 September 30, 2011, and through the filing date of this report, the Company has commodity derivative contracts in place through the second quarter of 2014 for a total of approximately 9 MMBbls of anticipated crude oil production, 63 million MMBtu of anticipated natural gas production, and 2 MMBbls 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 that take 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 pertinent 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 the commodity derivative contracts was a net asset of $70.3 million and a net liability of $52.3 million at September 30, 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, for which unrealized changes in fair value were recorded to accumulated other comprehensive income (loss) ("AOCIL"), 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 AOCIL.

At December 31, 2010, accumulated other comprehensive loss (“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 are reclassified into earnings as the original derivative transactions settle. During the nine months ended September 30, 2011, $14.5 million ($9.1 million, net of income tax) of derivative losses relating to de-designated commodity hedges were reclassified from

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AOCL into earnings. As of September 30, 2011, AOCL included $4.1 million ($2.7 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 $2.4 million, net of income tax, related to de-designated commodity derivative contracts during the next twelve months.

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

	As of September 30, 2011			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity Contracts	Current Assets	$54,698	Current Liabilities	$21,106
Commodity Contracts	Noncurrent Assets	39,891	Noncurrent liabilities	3,184
Derivatives not designated as hedging instruments		$94,589		$24,290

	As of December 31, 2010			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	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 gains and losses on derivative cash settlements and changes in fair value of derivative contracts as presented in the accompanying statements of operations.

	For the Three Months Ended September 30, 2011	For the Nine Months Ended September 30, 2011
	(in thousands)	
Cash settlement (gain) loss:		
Oil contracts	$1,058	$18,421
Natural gas contracts	(1,434)	(3,751)
NGL contracts	4,131	9,478
Total cash settlement loss	$3,755	$24,148
Unrealized (gain) loss on changes in fair value:		
Oil contracts	$(106,780)	$(90,629)
Natural gas contracts	(19,083)	(21,504)
NGL contracts	(6,317)	4,113
Total net unrealized (gain) on change in fair value	$(132,180)	$(108,020)
Total unrealized and realized derivative (gain)	$(128,425)	$(83,872)

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

	Derivatives	Location on Consolidated Statement of Operations	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
			2011	2010	2011	2010
			(in thousands)		(in thousands)	
Amount of loss reclassified from AOCIL to realized hedge (loss) gain	Commodity Contracts	Realized hedge (loss) gain	$4,271	$2,685	$9,149	$1,903

The realized net hedge loss for the three and nine-month periods ended September 30, 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 and nine-month periods ended September 30, 2010, is comprised of realized cash settlements on all commodity derivative contracts. Realized hedge gains or losses from the settlement of commodity 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 $6.8 million and a net hedge gain of $8.8 million from its commodity derivative contracts for the three months ended September 30, 2011, and 2010, respectively, and a net loss of $14.5 million and a net gain of $20.8 million from its commodity derivative contracts for the nine months ended September 30, 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 AOCIL at September 30, 2011. The following table details the effect of derivative instruments on AOCIL and the balance sheets (net of income tax):

	Derivatives	Location on Consolidated Balance Sheets	For the Nine Months Ended September 30, 2010	For the Year Ended December 31, 2010
			(in thousands)	
Amount of gain on derivatives recognized in AOCIL during the period (effective portion)	Commodity Contracts	AOCIL	$50,136	$16,811

The Company has no derivatives designated as cash flow hedges at September 30, 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 and nine-month periods ended September 30, 2010.

Derivatives Qualifying as Cash Flow Hedges	Location on Consolidated Statements of Operations	Loss (Gain) Recognized in Earnings (Ineffective Portion) For the Three Months Ended September 30, 2010	For the Nine Months Ended September 30, 2010
		(in thousands)	
Commodity Contracts	Unrealized and realized derivative (gain) loss	$5,727	$(4,095)

Credit Related Contingent Features

As of September 30, 2011, and through the filing of this report, all of the Company's derivative counterparties were members of the Company's credit facility syndicate. The Company's credit facility is secured by liens on substantially all of the Company's proved oil and gas properties; therefore such counterparties do not currently require the Company to post cash collateral in instances where the Company is in a liability position under its derivative instruments. No collateral was posted as of September 30, 2011, or through the filing of this report.

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Convertible Note Derivative Instruments

The contingent interest provision of the 3.50% Senior Convertible Notes is an embedded derivative instrument. As of September 30, 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

The following is a listing of the Company’s financial assets and liabilities that are measured at fair value and where they are classified within the hierarchy as of September 30, 2011:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives [(a)]	$—	$94,589	$—
Proved oil and gas properties [(b)]	$—	$—	$19,113
Liabilities:			
Derivatives [(a)]	$—	$24,290	$—
Net Profits Plan [(a)]	$—	$—	$108,489

(a) This represents a financial asset or liability that is measured at fair value on a recurring basis.
(b) This represents a nonfinancial asset that is measured at fair value on a nonrecurring basis.

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	Level 3
	(in thousands)		
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 December 31, 2010.

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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 cash collateral 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 the Company's credit facility bank syndicate.

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, principal market, or 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 September 30, 2011, would differ by approximately $9.1 million. A one percent increase in the discount rate would decrease the liability by approximately $4.8 million whereas a one percent decrease in the discount rate would increase the liability by approximately $5.3 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

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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.

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 September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Beginning balance	$133,419	$136,420	$135,850	$170,291
Net (decrease) increase in liability [(a)]	(20,194)	9,328	(2,001)	9,110
Net settlements [(a)(b)(c)]	(4,736)	(5,242)	(25,360)	(38,895)
Transfers in (out) of Level 3	—	—	—	—
Ending balance	$108,489	$140,506	$108,489	$140,506

(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. The Company accrued or made cash payments under the Net Profits Plan relating to divestiture proceeds of $686,000 for the three months ended September 30, 2010, and $6.3 million and $20.8 million for the nine months ended September 30, 2011, and 2010, respectively. There were no cash payments made or accrued relating to divestiture proceeds for the three months ended September 30, 2011.

(c) During the first quarter of 2011, the Company made the decision to cash out several Net Profits Plan pools associated with the acquisition of Nance Petroleum Corporation in 1999, through a $2.6 million direct payment. As a result, the Company reduced its Net Profits Plan liability by that amount. There is no impact on the accompanying statements of operations for the three-month or nine-month periods ended September 30, 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 these notes was approximately $357.2 million and $351.0 million as of September 30, 2011, and December 31, 2010, respectively. The fair value of the embedded contingent interest derivative on the 3.50% Senior Convertible Notes was immaterial as of September 30, 2011, and December 31, 2010.

6.625% Senior Notes

Based on the secondary market trading price of the 6.625% Senior Notes, the estimated fair value of these notes was approximately $351.8 million as of September 30, 2011.

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 exceed the sum of the undiscounted cash flows. 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 nine months ended September 30, 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.

As a result of the impairment discussed in Note 13 - Impairment of Proved Properties, the proved oil and gas properties measured at fair value within the accompanying balance sheets were $19.1 million at September 30, 2011. There were no proved oil and gas properties measured at fair value within the accompanying balance sheets at December 31, 2010.

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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 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 September 30, 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 September 30, 2011, or December 31, 2010.

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

Note 12 - Acquisition and Development Agreement

In June 2011, the Company entered into an Acquisition and Development Agreement (the "Acquisition and Development Agreement") with Mitsui E&P Texas LP ("Mitsui"), an indirect subsidiary of Mitsui & Co., Ltd. Pursuant to the Acquisition and Development Agreement, the Company agreed to transfer to Mitsui a 12.5 percent working interest in certain non-operated oil and gas assets representing approximately 39,000 net acres in Dimmit, LaSalle, Maverick and Webb Counties, Texas. The agreement also provides for the conveyance of one-half of the Company's ownership in related gathering assets for the reimbursement by Mitsui of 50 percent of costs incurred on those assets and paid by the Company through the closing date. If consummated, the effective date of the transfer would be March 1, 2011. As consideration for the oil and gas interests transferred, Mitsui has agreed to pay, or carry, 90 percent of certain drilling and completion costs attributable to the Company's remaining interest in these assets following the closing of the transaction, until Mitsui has expended an aggregate $680.0 million on behalf of the Company. The Company estimates it will take three to four years to fully utilize the carry, based on the operator's announced current drilling plans. Mitsui would also reimburse the Company for capital expenditures and other costs, net of revenues, that the Company paid and attributable to the transferred interest during the period between March 1, 2011 and the closing date. The Company would apply these reimbursed costs to the remaining ten percent of the Company's drilling and completion costs for the affected acreage. The transaction was initially expected to close in the third quarter of 2011, subject to the satisfaction of closing conditions. Subsequent to September 30, 2011, the Company and Mitsui mutually agreed to extend the outside date for closing to December 23, 2011 to allow the parties to continue efforts to satisfy outstanding closing conditions, including obtaining required consents. There can be no assurance that this transaction will be completed in the anticipated time frame, or at all.

Note 13 - Impairment of Proved Properties

The Company recorded $48.5 million of proved property impairments on the Company's legacy James Lime assets for the three months ended September 30, 2011, due primarily to low natural gas prices. There were no impairments of proved properties in the third quarter of 2010.

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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 built a portfolio of onshore properties in the contiguous United States primarily through early entrance into existing and emerging resource plays. This portfolio is comprised of properties with established production and reserves, prospective drilling opportunities, and unconventional resource prospects. We believe our strategy allows for stable and predictable production and reserves growth. Furthermore, by entering these plays early, we believe that we can capture larger resource potential at lower costs.

Our business strategy is to increase net asset value through attractive oil and gas investment activities, while maintaining a conservative capital structure and optimizing our capital expenditures. We focus our efforts on the exploration for and development of onshore, lower-risk resource plays in North America. We believe our inventory of resource plays is well suited for lower risk reserve and production growth due to the more predictable geologic profile of these types of assets. Furthermore, several of our assets produce significant volumes of oil and NGLs that limit our exposure to the current low 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, natural gas, and NGL reserves;
- focusing on resource plays with lower geologic risk 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 third quarter of 2011, we had the following financial and operational results:

- Our average daily production for the three months ended September 30, 2011, was 21.5 MBbls of oil, 281.2 MMcf of gas, and 8.6 MBbls of NGLs, for a record average equivalent production rate of 462.1 MMCFE per day, compared with 298.4 MMCFE per day for the same period in 2010. Please see additional discussion below under the caption Production Results.
- We recorded net income for the three months ended September 30, 2011, of $230.1 million or $3.41 per diluted share compared to net income for the three months ended September 30, 2010, of $15.5 million or $0.24 per diluted share.
-

Costs incurred for oil and gas producing activities for the three months ended September 30, 2011, were $440.3 million, compared with $226.4 million for the same period in 2010. Please see additional discussion below under the caption Costs Incurred.

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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. Prior to 2011, we reported our natural gas production as a single stream of rich gas measured at the well head. As a result, we historically reported realized prices for our natural gas production for periods through December 31, 2010, that were higher than industry benchmarks due to the price uplift associated with incremental value contained in the higher BTU content of our produced gas stream. 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. Projected rapid production growth from our rich gas assets with plant product sales contracts necessitated a change in our reporting of production volumes. 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 high energy content contained in the gas stream. Our NGL production is generally sold using contracts that pay us a 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.

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

	For the Three Months Ended		
	September 30, 2011	June 30, 2011	September 30, 2010
Crude Oil (per Bbl):			
Average NYMEX price	$89.51	$102.28	$76.09
Realized price	$82.63	$97.51	$68.56
Natural Gas (per Mcf):			
Average NYMEX price	$4.12	$4.36	$4.28
Realized price	$4.52	$4.63	$4.93
Natural Gas Liquids (per Bbl):			
Average OPIS price	$61.85	$61.62	$—
Realized price	$56.10	$54.02	$—

Note: Prior year NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of NGL volumes in prior periods. Please refer to additional discussion above. Average OPIS prices per barrel of NGL, historical or strip, are based on a product mix of 35% Ethane, 7% Isobutane, 11% Normal Butane, 15% Natural Gasoline and 32% Propane for all periods presented.

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 continue to face downward pressure as a result of 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 September 30, 2011, were $80.26 per Bbl, $4.11 per MMBTU, and $55.18 per Bbl, respectively. Comparable prices as of October 25, 2011, were $91.86 per Bbl, $3.98 per MMBTU, and $ 56.43 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.

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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 use of derivatives. 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 future operations and partially reduced 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 Derivative Contracts in Place, below.

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. The changes in the fair value of these contracts result in gains and losses, which are recognized immediately in earnings. For the three and nine months ended September 30, 2011, realized cash settlements from our commodity risk management program resulted in losses of $10.6 million and $38.7 million, respectively. For the three and nine months ended September 30, 2011, fluctuations in the fair value of our commodity risk management program portfolio of derivative contracts resulted in unrealized gains of $132.2 million and $108.0 million, respectively.

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 third quarters of 2011 and 2010 and the second quarter of 2011:

	For the Three Months Ended		
	September 30, 2011	June 30, 2011	September 30, 2010
Crude Oil (per Bbl):			
Realized price	$82.63	$97.51	$68.56
Less the effects of derivative cash settlements	(7.61)	(13.11)	(4.28)
Adjusted price, including the effects of derivative cash settlements	$75.02	$84.40	$64.28
Natural Gas (per Mcf):			
Realized price	$4.52	$4.63	$4.93
Plus the effects of derivative cash settlements	0.37	0.38	0.88
Adjusted price, including the effects of derivative cash settlements	$4.89	$5.01	$5.81
Natural Gas Liquids (per Bbl):			
Realized price	$56.10	$54.02	$—
Less the effects of derivative cash settlements	(6.39)	(6.53)	—
Adjusted price, including the effects of derivative cash settlements	$49.71	$47.49	$—

Note: Prior year 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.

In July 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"), the SEC, and other regulators to establish rules and regulations to implement the new legislation. The CFTC has proposed new rules governing margin requirements for uncleared swaps entered into by non-bank swap entities, and U.S. banking regulators have proposed new rules regarding margin requirements for uncleared swaps entered into by bank swap entities. The ultimate effect of the proposed new rules and any additional regulations on our business is currently uncertain. Of particular concern to us is whether the provisions of the final rules and regulations will allow us to qualify as a non-financial, commercial end user exempt from the requirements to post margin in connection with commodity price risk management activities. Final rules and regulations on major provisions of the legislation, such as new margin requirements, are to be established through regulatory rulemaking. Although we cannot predict the ultimate outcome of these rulemakings, new rules and 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.

Third Quarter 2011 Highlights

Operational Activities. We operated an average of 12 drilling rigs company-wide during the third quarter of 2011. The focus of our operated drilling activity this year has been on oil and NGL-rich gas programs and selected natural gas projects of potential strategic importance to us. We have also participated in higher levels of outside-operated activity in oil and NGL-rich gas plays.

We had four drilling rigs running in our operated Eagle Ford shale program in South Texas at the end of the third quarter of 2011. We focused our drilling in areas with higher BTU gas content and condensate yields. We continue to test different ways to complete and space these wells to optimize future development potential. These tests include the near simultaneous fracturing of multiple wells, as well as increased density drilling to test wells spaced as close as 625 feet apart. Testing of these concepts are at various stages of maturity and we are evaluating results. In September 2011, the third party owned and operated Eagle Ford Gathering, LLC pipeline was placed into service, which increased our total wet gas takeaway capacity in the play. During the third quarter, we closed our previously announced divestiture of approximately 15,000 net operated acres in LaSalle and Dimmit Counties, Texas. This transaction closed on August 2, 2011, at which time we received approximately $226.9 million in cash proceeds, subject to post-closing adjustments. As part of this transaction, we also assigned a small portion of our committed takeaway capacity to service these assets. After the closing of this transaction we now have approximately 150,000 net operated acres in the Eagle Ford shale. During the third quarter of 2011, we announced a second transaction involving our outside-operated Eagle Ford assets. This agreement calls for the transfer of a 12.5 percent working interest in our non-operated acreage in exchange for the carry of 90 percent of our drilling and completion costs in the same acreage for an amount not to exceed $680.0 million. This agreement also provides for the divestiture of one-half of our interest in the gathering assets that service these non-operated assets in exchange for reimbursement of 50 percent of our costs on those assets. The outside closing date for this transaction has been extended to December 23, 2011, and is subject to the satisfaction of closing conditions, including the receipt of certain consents. There can be no assurance that this transaction will be completed in the anticipated time frame, or at all. If this transaction closes, we will have approximately 46,000 non-operated net acres in the Eagle Ford play and a total of 196,000 net acres in the Eagle Ford shale play. The operator of our outside-operated Eagle Ford acreage maintained a steady level of activity throughout the third quarter of 2011. During the third quarter, the operator ran ten drilling rigs and we believe the operator will operate 10 to12 drilling rigs in the fourth quarter of 2011.

We operated three drilling rigs in the Williston Basin throughout the third quarter of 2011, all of which focused on Bakken and Three Forks drilling in our Raven and Gooseneck prospects in McKenzie and Divide Counties, North Dakota. Our drilling results in these prospects have continued to meet or exceed our expectations throughout the first nine months of 2011. During the third quarter, we were able to recommence drilling and completion work as well as restart previously shut-in production related to assets affected by weather and flooding during the first half of the year. Elsewhere in the Rocky Mountain region, we continued to test the Niobrara formation in both southeastern and central Wyoming with one drilling rig. We drilled three additional test wells in the first nine months of 2011 for a total of five test wells in southeastern Wyoming, south of Silo Field, where we have approximately 26,500 net acres. In addition, during the quarter, we have initiated the drilling of our first horizontal test well targeting the Niobrara formation in the Powder River Basin where we have approximately 64,700 net acres.

In our Mid-Continent region, we operated two rigs in our Granite Wash program in the Texas Panhandle and western Oklahoma during the third quarter of 2011 to test and delineate our acreage in the play. We have approximately 34,000 net acres in the Granite Wash, which are held by production.

In our ArkLaTex region, we operated one rig in our Haynesville shale program during the third quarter of 2011, with a focus on getting the acreage to held by production status. By getting the acreage held by production, we will hold both

Haynesville and Bossier interests in the acreage with the expectation we would benefit from any future improvement in natural gas prices. We anticipate that we can drill the remaining six wells required to hold this acreage by production by the third quarter of 2012.

Our Permian region operated a one rig program during the third quarter of 2011, splitting its focus between the testing of Wolfberry down spacing and drilling Mississippian targets as part of our exploration effort.

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Production Results. The table below provides a regional breakdown of our production during the third quarter of 2011:

	Mid-Continent	ArkLaTex	South Texas & Gulf Coast	Permian	Rocky Mountain	Total [1]
Third Quarter 2011 Production:						
Oil (MBbl)	85.7	12.9	668.7	324.7	889.4	1,981.4
Gas (MMcf)	6,977.4	7,279.2	9,716.9	882.4	1,018.2	25,874.1
NGLs (MBbl)	37.4	22.2	721.4	3.4	8.1	792.4
Equivalent (MMCFE)	7,715.7	7,489.6	18,057.5	2,851.1	6,403.4	42,517.3
Avg. Daily Equivalents (MMCFE/d)	83.9	81.4	196.3	31.0	69.6	462.1
Relative percentage	18 %	18 %	42 %	7 %	15 %	100 %

[1] Totals may not add due to rounding.

For the third quarter of 2011, our production was led by our South Texas & Gulf Coast region due to the ongoing drilling activities in our Eagle Ford shale program. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2011, and 2010 for additional discussion on production.

Costs Incurred. The following table sets forth the costs incurred for our oil and gas activities for the third quarter of 2011:

	For the Three Months Ended September 30, 2011 (in thousands)
Development costs	$ 347,052
Facility costs	34,288
Exploration costs	31,908
Acquisitions of unproved properties	27,004
Total, including asset retirement obligations	$ 440,252

Our capital and exploration activities reflect higher cash flows provided by operating activities, divestiture proceeds, and proceeds from the issuance of our 6.625% Senior Notes.

Eagle Ford Shale Divestiture. In August 2011, we completed the divestiture of certain operated Eagle Ford shale assets located in our South Texas & Gulf Coast region. This position comprised our entire operated acreage in LaSalle County, Texas, as well as an immaterial adjacent block of our operated acreage in Dimmit County, Texas. Total cash received, before marketing costs, was approximately $226.9 million, subject to post-closing adjustments. The estimated gain on this divestiture is approximately $191.4 million.

Marcellus Divestiture. During the third quarter of 2011, we entered into an agreement to divest of our Marcellus shale assets, including associated infrastructure, located in north central Pennsylvania for $80.0 million, subject to closing and post-closing adjustments. These assets were classified as assets held for sale at September 30, 2011. The agreement has an effective date of April 1, 2011. The agreement provided the purchaser with the option of extending the agreed upon closing date from October 15, 2011, to December 14, 2011, in exchange for an additional deposit. The purchaser has exercised this option and made the additional deposit. The closing of this transaction is subject to the satisfaction of certain closing conditions, including the resolution of title defects exceeding specified levels. There can be no assurance that this transaction will be completed in the anticipated time frame, or at all.

Equity Compensation. During the third quarter of 2011, we granted 266,282 PSUs and 90,665 RSUs pursuant to our long term incentive program. Please refer to Note 8 - Compensation Plans within Part I, Item 1 of this report for additional discussion.

Credit Facility. The borrowing base for our credit facility was increased to $1.4 billion from $1.3 billion during the third quarter of 2011. The current commitment amount remains at $1.0 billion. Please refer to Overview of Liquidity and Capital Resources below for additional discussion.

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First Nine Months 2011 Highlights

Production Results. The table below provides a regional breakdown of our first nine months of 2011 production:

	Mid-Continent	ArkLaTex	South Texas & Gulf Coast	Permian	Rocky Mountain	Total [1]
First Nine Months of 2011 Production:						
Oil (MBbl)	246.2	46.2	1,783.6	1,000.7	2,542.0	5,618.8
Gas (MMcf)	22,026.5	20,605.5	23,120.5	2,720.5	3,041.9	71,514.8
NGLs (MBbl)	57.5	61.3	2,045.9	8.9	22.6	2,196.3
Equivalent (MMCFE)	23,848.8	21,250.5	46,097.9	8,778.4	18,429.3	118,404.8
Avg. Daily Equivalents (MMCFE/d)	87.4	77.8	168.9	32.2	67.5	433.7
Relative percentage	20 %	18 %	39 %	7 %	16 %	100 %

(1) Totals may not add due to rounding.

For the first nine months of 2011, our production was led by our South Texas & Gulf Coast region due to the ongoing drilling activities in our Eagle Ford shale program. Please refer to Comparison of Financial Results and Trends Between the Nine Months Ended September 30, 2011, and 2010 for additional discussion on production.

Costs Incurred. The following table sets forth the costs incurred for our oil and gas activities for the first nine months of 2011:

	For the Nine Months Ended September 30, 2011 (in thousands)
Development costs	$ 815,684
Facility costs	86,893
Exploration costs	133,472
Acquisitions of unproved properties	47,081
Total, including asset retirement obligations	$ 1,083,130

Our capital and exploration activities reflect higher cash flows provided by operating activities, divestiture proceeds, and proceeds from the issuance of our 6.625% Senior Notes.

Rocky Mountain Divestiture. In January 2011, we received cash, before marketing costs and Net Profits Plan payments, of $45.5 million from the completed sale of certain non-strategic assets located in our Rocky Mountain region. The final gain on this divestiture was approximately $27.2 million.

6.625% Senior Notes. In the first quarter of 2011, we issued $350.0 million in aggregate principal amount of 6.625% Senior Notes. These notes were issued at par value and have a maturity date of February 15, 2019. Net proceeds from the issued notes were approximately $341.1 million. We used a portion of the proceeds to repay the outstanding balance under our previous credit facility. Remaining proceeds were used to fund our ongoing capital expenditure program and for general corporate purposes.

Credit Facility. We completed a $2.5 billion Fourth Amended and Restated Credit Agreement on May 27, 2011. The initial borrowing base for the facility was set at $1.3 billion and was increased to $1.4 billion during the third quarter of 2011. The initial commitment amount was $1.0 billion. Please refer to Overview of Liquidity and Capital Resources below for additional discussion.

Mid-Continent Divestiture. In June 2011, we completed the divestiture of certain non-strategic Constitution Field assets located in our Mid-Continent region. Total cash received, before marketing costs and Net Profits Plan payments, was approximately $35.7 million. The final sales price is subject to post-closing adjustments and is expected to be finalized during the fourth quarter of 2011. The estimated gain on this divestiture is approximately $28.4 million.

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Acquisition and Development Agreement. The Acquisition and Development Agreement between us and Mitsui E&P Texas LP calls for the transfer of a 12.5 percent working interest in certain non-operated oil and gas assets representing approximately 39,000 net acres in Dimmit, LaSalle, Maverick and Webb Counties, Texas. If consummated, the agreement also provides for the conveyance of one-half of the Company's ownership in related gathering assets for reimbursement by Mitsui of 50 percent of costs incurred on those assets and paid by the Company through the closing date. The effective date of the transfer would be March 1, 2011. As consideration for the interests, Mitsui has agreed to pay, or carry, 90 percent of certain drilling and completion costs attributable to our remaining interests in these assets following the closing of the transaction, until Mitsui has expended an aggregate $680.0 million on our behalf. We estimate it will take three to four years to fully utilize the carry, based on our forecast of the operator's drilling plans. Mitsui would also reimburse us for capital expenditures and other costs, net of revenues, that we paid and attributable to the transferred interests during the period between March 1, 2011 and the closing date. We would apply these reimbursed costs to the remaining ten percent of our drilling and completion costs for the affected acreage. The transaction was expected to close in the third quarter of 2011, subject to the satisfaction of closing conditions. Subsequent to September 30, 2011, we and Mitsui mutually agreed to extend the outside date for closing to December 23, 2011 to allow the parties to continue efforts to satisfy outstanding closing conditions, including obtaining required consents. There can be no assurance that this transaction will be completed in the anticipated time frame, or at all.

Outlook for the Remainder of 2011 and 2012

We began 2011 operating two rigs on our Eagle Ford shale acreage with plans to increase our operated drilling rig count to five or six by year end. We believe we have secured the drilling rigs and completion services necessary to execute our development program in the Eagle Ford shale into the future. We believe our water rights in the Rio Grande River will meet our planned drilling and completion needs, and we are currently completing our wells with water from the Rio Grande River. Currently we are running four operated rigs on our Eagle Ford shale acreage. By the end of the first quarter of 2012, we expect to take delivery of two more walking rigs that will focus on pad drilling, which we expect these rigs to enhance operational efficiencies in our program with reduced time from spud to production and reduced well costs. Along with our pad drilling tests, we have started down spacing pilots to test approximately 625 foot spacing from the current 1,250 foot spacing. During the third quarter of 2011, additional wet gas takeaway capacity from the Eagle Ford Gathering, LLC pipeline system became available and we began transporting gas on that system in the third quarter. With regard to oil and condensate take-away capacity, we have commissioned an in-field pipeline to transport oil and condensate at two take away points at the edge of our leasehold. This line will allow for more efficient trucking of our oil and condensate. The operator of our outside-operated Eagle Ford shale properties ran an average of ten drilling rigs in the third quarter of 2011. We anticipate they will operate ten to twelve rigs on these assets in the fourth quarter of 2011 and through the end of 2012.

We expect to operate three drilling rigs for the remainder of 2011 in our Bakken/Three Forks program in the Williston Basin of North Dakota. We have approximately 205,500 net acres in the Williston Basin, of which approximately 85,000 acres are in areas we are currently developing. Our drilling has focused on our Raven and Gooseneck prospects in McKenzie and Divide Counties, North Dakota, respectively. Our plans are to continue with a three to four rig program throughout 2012. As normal operating conditions have returned following flooding in the region, we have been able to complete a significant number of wells and restore efforts to meet our original drilling and completion plan. Elsewhere in the Rocky Mountain region, we have drilled and completed all five planned exploration wells in the DJ Basin of southeastern Wyoming. We have since dropped that rig and picked up a new rig for the Powder River Basin in Wyoming, where it will be used to drill several exploratory wells targeting the Niobrara formation in that area.

In our ArkLaTex region, we plan to continue to drill wells in our operated Haynesville shale program, where we anticipate a one rig program through the third quarter of 2012. This program will focus on drilling the remaining six wells required to have all of our acreage held by production. Once we have all of our operated Haynesville acreage held by production, we plan to cease our drilling operations in this area until higher natural gas prices justify resuming activity.

We plan to run two operated drilling rigs targeting the Granite Wash formation in our Mid-Continent region for the remainder of the year. As our acreage in this play is held by production, we can adjust our activity levels quickly as circumstances warrant.

In our Permian Basin region, we plan to focus on drilling Mississippian wells and testing several exploration concepts.

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

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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 September 30, 2011, and the immediately preceding three quarters. Additional details of per MCFE costs are presented later in this section.

	For the Three Months Ended			
	September 30, 2011	June 30, 2011	March 31, 2011	December 31, 2010
	($ in millions, except for production data)			
Production (BCFE)	42.5	39.8	36.1	31.6
Oil, gas, and NGL production revenue	$325.2	$333.9	$276.3	$250.1
Realized hedge (loss) gain	$(6.8)	$(6.3)	$(1.4)	$2.8
Gain on divestiture activity	$190.7	$30.0	$24.9	$23.1
Lease operating expense	$40.0	$33.2	$33.1	$33.5
Transportation costs	$23.9	$16.9	$15.0	$7.1
Production taxes	$13.8	$3.3	$17.8	$16.4
DD&A	$123.1	$115.4	$105.4	$94.7
Exploration	$11.3	$9.6	$12.7	$21.1
General and administrative	$29.8	$27.3	$25.9	$31.6
Change in Net Profits Plan liability	$(24.9)	$(14.0)	$14.2	$(4.6)
Unrealized and realized derivative (gain) loss	$(128.4)	$(43.9)	$88.4	$13.0
Net income (loss)	$230.1	$124.5	$(18.5)	$37.0

Note: Prior to 2011, 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 and nine-month overview of selected production and financial information, including trends:

	For the Three Months Ended September 30, 2011	For the Three Months Ended September 30, 2010	Amount Change Between Periods	Percent Change Between Periods	For the Nine Months Ended September 30, 2011	For the Nine Months Ended September 30, 2010	Amount Change Between Periods	Percent Change Between Periods
Net production volumes								
Oil (MMBbl)	2.0	1.6	0.4	25 %	5.6	4.5	1.1	24 %
Natural gas (Bcf)	25.9	17.9	8.0	44 %	71.5	51.2	20.3	40 %
NGLs (MMBbl)	0.8	—	0.8	N/A	2.2	—	2.2	N/A
Equivalent (BCFE)	42.5	27.5	15.0	55 %	118.4	78.3	40.1	51 %
Average daily production								
Oil (MBbl per day)	21.5	17.3	4.2	25 %	20.6	16.6	4.0	24 %
Natural gas (MMcf per day)	281.2	194.8	86.4	44 %	262.0	187.4	74.6	40 %
NGLs (MBbl per day)	8.6	—	8.6	N/A	8.0	—	8.0	N/A
Equivalent (MMCFE per day)	462.1	298.4	163.7	55 %	433.7	286.9	146.8	51 %
Oil, gas, & NGL production revenue (in thousands)								
Oil production revenue	$163,735	$108,943	$54,792	50 %	$497,480	$320,038	$177,442	55 %
Gas production revenue	117,041	88,411	28,630	32 %	322,234	266,090	56,144	21 %
NGL production revenue	44,455	—	44,455	N/A	115,764	—	115,764	N/A
Total	$325,231	$197,354	$127,877	65 %	$935,478	$586,128	$349,350	60 %
Oil, gas, & NGL production expense (in thousands)								
Lease operating expense	$40,012	$29,046	$10,966	38 %	$106,302	$88,031	$18,271	21 %
Transportation costs	23,911	4,877	19,034	390 %	55,759	14,069	41,690	296 %
Production taxes	13,830	10,683	3,147	29 %	34,846	36,014	(1,168)	(3)%
Total	$77,753	$44,606	$33,147	74 %	$196,907	$138,114	$58,793	43 %
Realized sales price (before derivative settlements)								
Oil (per Bbl)	$82.63	$68.56	$14.07	21 %	$88.54	$70.70	$17.84	25 %
Natural gas (per Mcf)	$4.52	$4.93	$(0.41)	(8)%	$4.51	$5.20	$(0.69)	(13)%
NGLs (per Bbl)	$56.10	$—	$56.10	N/A	$52.71	$—	$52.71	N/A
Per MCFE Data:								
Realized price	$7.65	$7.19	$0.46	6 %	$7.90	$7.48	$0.42	6 %
Lease operating expenses	(0.94)	(1.06)	0.12	(11)%	(0.90)	(1.12)	0.22	(20)%
Transportation costs	(0.56)	(0.18)	(0.38)	211 %	(0.47)	(0.18)	(0.29)	161 %
Production taxes	(0.33)	(0.39)	0.06	(15)%	(0.29)	(0.46)	0.17	(37)%
	(0.70)	(0.96)	0.26	(27)%	(0.70)	(0.96)	0.26	(27)%

General and administrative								
Operating profit, before the effects of derivative cash settlements	$5.12	$4.60	$0.52	11 %	$5.54	$4.76	$0.78	16 %
Derivative cash settlement	(0.25)	0.32	(0.57)	(178)%	(0.33)	0.27	(0.60)	(222)%
Operating profit, including the effects of derivative cash settlements	$4.87	$4.92	$(0.05)	(1)%	$5.21	$5.03	$0.18	4 %

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	For the Three Months Ended September 30, 2011	2010	Amount Change Between Periods	Percent Change Between Periods	For the Nine Months Ended September 30, 2011	2010	Amount Change Between Periods	Percent Change Between Periods
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$(2.89)	$(3.05)	$0.16	(5)%	$(2.90)	$(3.08)	$0.18	(6)%
Earnings per share information								
Basic net income per common share	$3.60	$0.25	$3.35	1,340 %	$5.28	$2.54	$2.74	108 %
Diluted net income per common share	$3.41	$0.24	$3.17	1,321 %	$4.99	$2.47	$2.52	102 %
Basic weighted-average shares outstanding	63,904	63,031	873	1 %	63,665	62,914	751	1 %
Diluted weighted-average shares outstanding	67,386	64,794	2,592	4 %	67,390	64,599	2,791	4 %

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

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 nine months of 2011 increased 51 percent compared with the same period in 2010, driven primarily by the development of our Eagle Ford shale 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 on a per MCFE basis increased six percent for both the three months and nine months ended September 30, 2011, compared to the same periods in 2010. The majority of the increase is due to a higher realized price received for oil. 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 on a per MCFE basis for the three and nine months ended September 30, 2011, decreased 11 percent and 20 percent, respectively, compared to the same periods in 2010. The divestiture of non-strategic properties within our Rocky Mountain and Mid-Continent regions in 2011 and Permian region in late 2010 with meaningfully higher per unit 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.

Production taxes on a per MCFE basis for the three and nine months ended September 30, 2011, decreased 15 percent and 37 percent, respectively, compared to the same periods in 2010. We received notification in the second quarter that wells within our Eagle Ford and Haynesville shale plays qualified for the severance tax incentive programs in Texas. As a result a sizable incentive tax rebate was recorded during the second quarter, causing a significant decrease for the nine months ended September 30, 2011. Production taxes for the three months ended September 30, 2011, decreased due to lower anticipated severance tax accruals as a result of the reduced tax rates. We expect that substantially all future operated wells to be drilled in these areas will qualify for enacted reduced tax rates. We generally expect production taxes to trend with oil, gas, and NGL revenues.

Transportation costs on a per MCFE basis for the three and nine months ended September 30, 2011, increased 211 percent and 161 percent, respectively, compared to the same periods in 2010. This is a result of increased production in our Eagle Ford shale program, where new transportation arrangements that we have entered into are resulting in higher per unit transportation costs, due to the lack of infrastructure in the emerging play. We anticipate transportation costs will increase over the remainder of the year on a per MCFE basis, as the Eagle Ford shale becomes a larger portion of our production mix.

Our general and administrative expense on a per MCFE basis for both the three and nine months ended September 30, 2011, decreased 27 percent compared to the same periods in 2010. Production increased at a faster rate than our 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 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 and nine months ended September 30, 2011, decreased one percent and increased four percent, respectively, compared to the same periods in 2010.

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Our depletion, depreciation, and amortization, including asset retirement obligation accretion expense, for the three and nine months ended September 30, 2011, decreased five percent and six percent per MCFE, respectively, compared to the same periods in 2010. The property balances between the periods presented stayed relatively constant while the reserve base increased causing the per unit 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.

Our basic and diluted earnings per share, for the three and nine months ended September 30, 2011, increased substantially compared to the same periods in 2010. The majority of this increase is due to our net income balance used to derive earnings per share, which includes a gain of approximately $191.4 million related to our divestiture of our operated acreage in LaSalle County, Texas. See Note 3 - Divestitures and Assets Held for Sale, in Part I, Item 1 of this report. Divestitures by nature are considered non-recurring by the Company and are not indicative of future activity.

Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2011, and 2010 and Comparison of Financial Results and Trends Between the Nine Months Ended September 30, 2011, and 2010 for additional discussion on oil, gas, and NGL production expense, DD&A, and general and administrative expense.

Both basic and diluted earnings per share are presented in the table above. We use the treasury stock method to account for the potential diluted earnings per share impact of unvested RSUs, contingent PSUs, in-the-money stock options, and our 3.50% Senior Convertible Notes. In-the-money stock options, unvested RSUs, and contingent PSUs were dilutive for the three and nine months ended September 30, 2011, and 2010. Basic common shares outstanding used in our September 30, 2011, and 2010 earnings per share calculations reflect increases in outstanding shares related to stock option exercises and vested RSUs. Our September 30, 2011, calculation also includes fully vested and released PSUs. We issued 366,117 and 163,348 shares of common stock during the nine-month periods ended September 30, 2011, and 2010, respectively, as a result of stock option exercises. The number of RSUs that vested and settled during the first nine months of 2011 and 2010 were 72,127 and 57,687, respectively. During the nine months ended September 30, 2011, 206,468 PSUs fully vested and settled as part of the first settlement of this type of award. For the three months and nine months ended September 30, 2011, our average stock price exceeded the conversion price of $54.42 making our 3.50% Senior Convertible Notes dilutive for our 2011 quarter-to-date and year-to-date diluted weighted-average common shares outstanding calculation. The 3.50% Senior Convertible Notes were not dilutive for the three-month and nine-month periods ended September 30, 2010. Currently, our stock price continues to trade above the $54.42 conversion price, therefore we expect our 3.50% Senior Convertible Notes to have a dilutive impact on our fourth quarter earnings per share calculation. Please refer to Note 6 - Earnings per Share in Part I, Item 1 of this report for additional discussion.

Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2011, and 2010

Oil, gas, and NGL production revenue. Average daily reported production increased 55 percent to 462.1 MMCFE for the quarter ended September 30, 2011, compared with 298.4 MMCFE for the quarter ended September 30, 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)	Oil, Gas, & NGL Revenue Added (Decreased)	Production Costs Increase (Decrease)

	(MMCFE/d)	(in millions)	(in millions)
Mid-Continent	(8.7)	$1.6	$—
ArkLaTex	46.3	18.1	2.7
South Texas & Gulf Coast	131.4	88.5	26.9
Permian	(8.2)	(1.2)	(1.1)
Rocky Mountain	2.9	20.9	4.6
Total	163.7	$127.9	$33.1

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 will continue to increase for the foreseeable future. We also saw an increase in our ArkLaTex region, as a result of strong production performance from wells drilled in our Haynesville shale program in late 2010 and early 2011.

A six percent increase in the realized equivalent price per MCFE, combined with a 55 percent increase in production volumes, resulted in a substantial increase in revenue between the two periods. We expect our realized prices to trend with commodity prices.

Realized hedge (loss) gain. We recorded a net realized hedge loss of $6.8 million for the three-month period ended September 30, 2011, compared with a $8.8 million net 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 at the time of settlement and the price at the time the derivative transaction was entered into.

Gain on divestiture activity. We recorded a $190.7 million net gain on divestiture activity for the quarter ended September 30, 2011, relating mainly to the divestiture of certain Eagle Ford shale oil and gas assets in our South Texas & Gulf Coast region. We recorded a $4.2 million net gain on divestiture activity for the comparable period of 2010, related to a divestiture of non-core oil and gas properties located in our Rocky Mountain region. 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.

Marketed gas system revenue and expense. Marketed gas system revenue increased $6.0 million to $21.8 million for the quarter ended September 30, 2011, compared with $15.8 million for the same period of 2010. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $4.4 million to $19.1 million for the quarter ended September 30, 2011, compared with $14.7 million for the same 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 third quarter of 2011 increased 74 percent, to $77.8 million compared with $44.6 million for the same period of 2010. Total oil and gas production costs per MCFE increased $0.20, or 12 percent, to $1.83 for the third quarter of 2011, compared with $1.63 for the same period in 2010. The per MCFE increase is comprised of the following:

- A $0.38 increase in overall transportation costs on a per MCFE basis is primarily a result of increased production in our Eagle Ford shale. Please refer to our transportation cost discussion under the caption A three-month and nine-month overview of selected production and financial information, including trends for additional information.

- A $0.18 decrease in recurring LOE on a per MCFE basis reflects the 2010 and early 2011 sales of non-core properties with higher per unit LOE costs.

- A $0.06 per MCFE decrease in production taxes is due to severance tax incentives within our South Texas & Gulf Coast and ArkLaTex regions. Please refer to our production tax discussion under the caption A three-month and nine-month overview of selected production and financial information, including trends for additional information.

- A $0.06 overall increase in workover LOE on a per MCFE basis relates primarily to increased workover activity in our Permian Region.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A increased $39.3 million, or 47 percent, to $123.1 million for the three-month period ended September 30, 2011, compared with $83.8 million for the same period in 2010. Please refer to our depletion, depreciation, amortization, and asset retirement obligation liability accretion comparison discussion under the caption A three-month and nine-month overview of selected production and financial information, including trends for additional information.

Exploration. The components of exploration expense are summarized as follows:

	For the Three Months Ended September 30,	
	2011	2010
	(in millions)	
Geological and geophysical expenses	$0.2	$4.9
Exploratory dry hole expense	—	—
Overhead and other expenses	11.1	9.5
Total	$11.3	$14.4

The majority of the change in exploration expense between the three-month periods ended September 30, 2011, and 2010 is due to decreased geological and geophysical expense as our current plays become more established. As a result, the amount spent on seismic activity is less. We continue to test our current resource plays and expect to maintain a modest exploratory program for new assets in future periods. Any exploratory well incapable of producing oil, gas, or NGLs in commercial quantities will be deemed an exploratory dry hole, which will impact the amount of exploration expense we record. There were no exploratory wells deemed dry during the third quarters of 2011 or 2010.

General and administrative. General and administrative expense increased $3.6 million, or 14 percent, to $29.8 million for the three months ended September 30, 2011, compared with $26.2 million for the same period of 2010. On a per unit basis, G&A expense decreased $0.26 to $0.70 per MCFE for the third quarter of 2011 compared to $0.96 per MCFE for the same period in 2010.

The majority of the increase in general and administrative expense is due to a $2.5 million increase in base compensation and $400,000 increase in pension expense for the three months ended September 30, 2011, compared with the same period in 2010. The increase in base compensation and pension expense is due to an increase in employee headcount between the two periods. We ramped up our hiring efforts for operational personnel during the second half of 2010 and expect our efforts will continue into 2012.

Change in Net Profits Plan liability. For the quarter ended September 30, 2011, this non-cash item was a benefit of $24.9 million compared to an expense of $4.1 million for the same period in 2010. The expense or benefit is directly related to the change in the estimated value of the associated liability over the reporting period. Commodity prices decreased from the second quarter of 2011 to the third quarter of 2011, resulting in a non-cash benefit. Adjustments to the liability are subject to estimation and may change dramatically from period to period based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, tax rates, and production costs.

Unrealized and realized derivative (gain) loss. We recognized an unrealized and realized derivative gain of $128.4 million for the third quarter of 2011 compared to a loss of $5.7 million for the same period in 2010. The 2011 amount includes gains on unrealized changes in fair value on commodity derivative contracts of $132.2 million and realized cash settlement losses on derivatives for which unrealized changes in fair value were not previously recorded in other comprehensive loss of $3.8 million. The 2010 balance is comprised solely of the ineffective portion of derivatives designated as cash flow hedges. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional discussion.

Impairment of proved properties. We recognized an impairment loss of approximately $48.5 million for the third quarter of 2011. The impaired properties are legacy assets targeting the James Lime formation in the Company's ArkLaTex region. This impairment was related to continued depressed gas prices in the region. There were no impairments of proved properties in the third quarter of 2010.

Income tax expense. We recorded expense of $133.3 million for the third quarter of 2011 compared to expense of $9.3 million for the third quarter of 2010 resulting in effective tax rates of 36.7 percent and 37.7 percent, respectively. The change in income tax expense is primarily the result of the differences in components of net income discussed above and the effect of recording a credit benefit in the third quarter of 2011 from completing a three year research and development tax credit study. The 2011 decrease in the effective tax rate from 2010 primarily reflects the changes in the mix of the highest marginal state tax rates, the state tax rate effect on year-to-date net income from divestiture and drilling activity in 2010, the effect related to recording research and development tax credits, and changes in the effects of other permanent differences. The current portion of our income tax expense is higher compared with the same period of 2010 as a result of the differing impacts from 2011 and 2010 non-core asset divestitures and differing impacts of each annual drilling program.

Comparison of Financial Results and Trends Between the Nine Months Ended September 30, 2011, and 2010

Oil, gas, and NGL production revenue. Average daily reported production increased 51 percent to 433.7 MMCFE for the nine months ended September 30, 2011, compared with 286.9 MMCFE for the same period in 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 periods:

	Average Net Daily Production Added (Decreased) (MMCFE/d)	Oil, Gas, & NGL Revenue Added (Decreased) (in millions)	Production Costs Increase (Decrease) (in millions)
Mid-Continent	(5.7)	$(0.1)	$(0.2)
ArkLaTex	42.1	44.8	3.7
South Texas & Gulf Coast	118.8	250.3	50.4
Permian	(7.9)	(3.8)	0.1
Rocky Mountain	(0.5)	58.2	4.8
Total	146.8	$349.4	$58.8

Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2011, and 2010 for additional discussion regarding the above results.

A six percent increase in realized equivalent price per MCFE, combined with a 51 percent increase in production volumes, resulted in a substantial increase in revenue.

Realized hedge (loss) gain. We recorded a net realized hedge loss of $14.5 million for the nine-month period ended September 30, 2011, compared with a $20.8 million gain for the same period in 2010. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2011, and 2010 for additional discussion.

Gain on divestiture activity. We had a $245.7 million net gain on divestiture activity for the nine months ended September 30, 2011, relating mainly to the divestiture of non-strategic oil and gas properties located in our Mid-Continent, Rocky Mountain, and South Texas & Gulf Coast regions. We recorded a $132.2 million net gain on divestiture activity for the comparable period of 2010, due primarily to the divestiture of non-strategic oil and gas properties located in our Rocky Mountain region.

Marketed gas system revenue and expense. Marketed gas system revenue increased $2.3 million, or four percent, to $56.3 million for the nine months ended September 30, 2011, compared with $54.0 million for the comparable period of 2010. Marketed gas system expense decreased $1.0 million, or two percent, to $51.6 million for the nine months ended September 30, 2011, compared with $52.6 million for the comparable period of 2010.

Oil, gas, and NGL production expense. Total production costs for the first nine months of 2011 increased 43 percent to $196.9 million compared with $138.1 million for the same period of 2010. Total oil and gas production costs per MCFE decreased $0.10 to $1.66 for the first nine months of 2011, compared with $1.76 for the same period in 2010. The per MCFE decrease is comprised of the following:

- a $0.29 increase in overall transportation costs per MCFE;

• a $0.25 decrease in recurring LOE per MCFE;

• a $0.17 decrease in production taxes per MCFE; and

• a $0.03 increase in workover LOE per MCFE.

Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2011, and 2010 for additional discussion related to production expense.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A increased $102.5 million, or 42 percent, to $343.8 million for the nine-month period ended September 30, 2011, compared with $241.3 million for the same period in 2010. Please refer to our depletion, depreciation, amortization, and asset retirement obligation liability accretion comparison discussion under the caption A three-month and nine-month overview of selected production and financial information, including trends for additional information.

Exploration. The components of exploration expense are summarized as follows:

	For the Nine Months Ended September 30,	
	2011	2010
	(in millions)	
Geological and geophysical expenses	$2.3	$13.7
Exploratory dry hole expense	—	0.3
Overhead and other expenses	31.3	28.8
Total	$33.6	$42.8

Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2011, and 2010, in the above section for additional discussion.

General and administrative. General and administrative expense increased $7.9 million, or ten percent, to $83.0 million for the nine months ended September 30, 2011, compared with $75.1 million for the same period of 2010. On a per unit basis, G&A expense decreased $0.26 to $0.70 per MCFE for the first nine months of 2011 compared to $0.96 per MCFE for the same nine-month period in 2010.

General and administrative expense increased due to a $5.3 million increase in base compensation, accruals for cash bonus, and equity compensation expense along with a $3.9 million increase in corporate office expenses for the nine months ended September 30, 2011, compared with the same period in 2010. The increase in base compensation and corporate office expenses are due to an increase in employee headcount between the two periods. We ramped up our hiring efforts for operational personnel during the second half of 2010. G&A expense decreased $1.4 million for the nine months ended September 30, 2011, primarily due to a decrease in Net Profits Plan payments as a result of the Permian divestiture that was completed in late 2010.

Change in Net Profits Plan liability. This non-cash charge is directly related to the change in the estimated value of the associated liability between the reporting periods. For the nine months ended September 30, 2011, this non-cash item was a benefit of $24.7 million compared to a benefit of $29.8 million for the same period in 2010. The change between the two periods is due to decreases in commodity prices, which we broadly expect the change in this liability to trend with. Adjustments to the liability are subject to estimation and may change dramatically from period to period based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, tax rates, and production costs.

Unrealized and realized derivative (gain) loss. We recognized an unrealized and realized derivative gain of $83.9 million for the first nine months of 2011 compared to a gain of $4.1 million for the same period in 2010. The 2011 amount includes gains on unrealized changes in fair value on commodity derivative contracts of $108.0 million and realized cash settlement losses on derivatives for which unrealized changes in fair value were not previously recorded in other comprehensive loss of $24.1 million. The 2010 balance is comprised solely of the ineffective portion of derivatives designated as cash flow hedges. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report.

Impairment of proved properties. We recognized an impairment loss of $48.5 million for the first nine months of 2011. The impaired properties are legacy assets in the Company's ArkLaTex region. This impairment was related to continued depressed gas prices in the region. There were no impairments of proved properties in the third quarter of 2010.

Income tax expense. Income tax expense totaled $195.1 million for the nine-month period ended September 30, 2011, compared to an income tax expense of $96.7 million for the same period in 2010, resulting in effective tax rates of 36.7 percent and 37.7 percent, respectively. The change in income tax expense is the result of the differences in components of net income and recording research and development tax credits. The 2011 decrease in effective tax rate from 2010 is primarily the result of recording a credit benefit from completing a three year research and development tax credit study, a change in North Dakota's corporate tax rate during 2011, and to a lesser extent the impact of other permanent differences including the domestic production activities deduction partially offset by an increase related to the mix of the highest marginal state tax rates resulting from divestiture and drilling activity in 2010. The current portion of our tax expense is greater in 2011 compared to 2010 due to differing impact between years of our drilling program, operating income from our oil and gas properties and non-core asset divestitures.

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Overview of Liquidity and Capital Resources

We believe that we have sufficient liquidity and capital resources to execute our business plans for the foreseeable future.

Sources of Cash

For the remainder of 2011, we anticipate that cash flow from operations, expected divestiture proceeds, and/or joint venture activity will fund the majority of our capital program. Our credit facility, which was undrawn as of quarter end, will be used to fund any remaining balance of our capital program. Although we anticipate that our cash flow and borrowing capacity under our credit facility will be more than sufficient to fund our current capital program, accessing the capital markets or using other financing alternatives is an option if deemed the best solution for our demands. We will continue to evaluate our property base to identify and divest properties we consider non-core to our strategic goals.

Our primary sources of liquidity are cash flows provided by operating activities, use of our credit facility, divestitures of properties, and other financing alternatives, including accessing the debt and equity markets. From time to time, we may be able to enter into carrying cost funding and sharing arrangements with third parties for particular exploration and/or development programs. All of our sources of liquidity can be impacted by the general condition of the broad economy and by significant fluctuations in oil, gas, and NGL prices, operating costs, and volumes produced, all of which affect us and our industry. We have no control over the market prices for oil, gas, or NGLs, although we are able to influence the amount of our net realized revenues related to our oil, gas, and NGL sales through the use of derivative contracts as part of our commodity price risk management program. The borrowing base on our credit facility could be reduced due to lower commodity prices or any divestiture by us of a significant amount of producing properties. Historically, decreases in commodity prices have limited our industry's access to the capital markets. In the first quarter of 2011, we issued $350.0 million in aggregate principal amount of 6.625% Senior Notes at par. During the second quarter of 2011, we amended and restated our credit facility with a $2.5 billion maximum loan amount, $1.0 billion in current lender commitments, and a borrowing base of $1.3 billion, which was increased to $1.4 billion in the third quarter of 2011. We also entered into an Acquisition and Development Agreement that would fund, or carry, 90 percent of our costs for the drilling and completion of certain wells in our outside operated Eagle Ford position until $680.0 million has been expended on our behalf. The closing of this transaction is now anticipated to occur in the fourth quarter of 2011, and remains subject to the satisfaction of closing conditions, including the receipt of certain consents. There can be no assurance that this transaction will be completed in the anticipated time frame, or at all.

Current Credit Facility

In May 2011, we completed our Fourth Amended and Restated Credit Agreement with a $2.5 billion senior secured revolving credit facility with a scheduled maturity date of May 27, 2016. This credit facility replaced our prior $1.0 billion senior secured revolving credit facility. The initial borrowing base for the new credit facility was $1.3 billion, which was increased to $1.4 billion in the third quarter of 2011. Our lenders have agreed to a current aggregate commitment amount of $1.0 billion. The borrowing base is redetermined semi-annually by our lenders. We believe that the current commitment amount is sufficient to meet our current liquidity and operating needs. To date, we have experienced no issues drawing upon our credit facility. No individual bank participating in the credit facility represents more than ten percent of the lending commitments under the credit facility.

We had no borrowings outstanding under our credit facility as of September 30, 2011. We had two letters of credit outstanding under our credit facility for a total amount of $608,000 as of September 30, 2011. Letters of credit reduce the amount available under the credit facility on a dollar-for-dollar basis. We had $999.4 million of available borrowing capacity under this facility as of September 30, 2011. Our daily weighted-average credit facility debt balance was zero for the three months ended September 30, 2011. Our daily weighted-average credit facility debt balance was $5.4 million for the nine months ended September 30, 2011, and $6.8 million and $43.9 million for the three months and nine months ended September 30, 2010, respectively.

Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report, for further discussion on our credit facility.

Weighted-Average Interest Rates

Our weighted-average interest rates in the current and prior year include cash interest payments, cash fees paid on the unused portion of the credit facility's aggregate commitment amount, letters of credit fees, amortization of the 3.50% Senior Convertible Notes debt discount, and amortization of deferred financing costs. Our weighted-average interest rates for the three months ended September 30, 2011, and 2010 were 7.9 percent and 9.2 percent, respectively, and 9.0 percent and 8.4 percent for the nine months ended September 30, 2011, and 2010, respectively. The decrease in the weighted-average interest rates for the three months ended September 30, 2011, is a result of commitment fees increasing at a slower rate than the weighted-average debt balance during that period. The increase in our weighted-average interest rate for the nine months ended September 30, 2011, is the result of commitment fees increasing at a faster rate than the average outstanding debt balance.

We are subject to customary covenants under our credit facility, including limitations on dividend payments and requirements to maintain certain financial ratios, which include debt to earnings before interest, taxes, depreciation, depletion, amortization, and exploration expense of less than 4.0 to 1.0 and a current ratio, as defined by our credit agreement, of not less than 1.0. As of September 30, 2011, our debt to EBITDAX ratio and current ratio as defined by our credit agreement, were 0.79 and 3.10 respectively. As of the filing of this report, we are in compliance with all financial and non-financial covenants under our credit facility.

Uses of Cash

We use cash for the acquisition, exploration, and development of oil and gas properties, and for the payment of debt obligations, trade payables, overhead, income taxes, and stockholder dividends. Expenditures for the exploration and development of oil and gas properties are the primary use of our capital resources. In the first nine months of 2011, we spent $1.1 billion for exploration and development capital expenditures. These amounts differ from our costs incurred amounts based on the timing of cash payments associated with these activities as compared to the accrual based activity upon which costs incurred amounts are presented. These cash outflows were funded using cash inflows from operations, proceeds from the sale of assets, and proceeds from our 6.625% Senior Notes.

The amount and allocation of future capital expenditures will depend upon a number of factors including the number and size of available economic acquisitions and drilling opportunities, our cash flows from operating, investing, and financing activities, and our ability to assimilate acquisitions and execute our drilling programs. In addition, the impact of oil, natural gas, and NGL prices on investment opportunities, the availability of capital and borrowing facilities, and the success of our development and exploratory activities may lead to changes in funding requirements for future development. We regularly review our capital expenditure budget to assess changes in current and projected cash flows, acquisition opportunities, debt requirements, and other factors.

As of the filing of this report, we have Board authorization to repurchase up to 3,072,184 shares of our common stock under our stock repurchase program. Shares may be repurchased from time to time in open market transactions or privately negotiated transactions subject to market conditions and other factors, including certain provisions of our credit facility and the indenture governing our 6.625% Senior Notes, compliance with securities laws, and the terms and provisions of our stock repurchase program. There have been no share repurchases to date in 2011, and we do not plan to repurchase shares for the remainder of 2011.

We have no debt maturities until April 1, 2012, when all or a portion of our outstanding 3.50% Senior Convertible Notes can be put to us. If the notes are put to us on that date, we have the option of paying the purchase price in cash, shares of our common stock, or any combination thereof. On or after April 6, 2012, we have the option of redeeming all or a portion of the outstanding notes for cash. The notes are convertible into shares of our common stock under certain circumstances, including if they are called for redemption, and we may elect to settle conversion obligations in cash, shares of our common stock, or a combination thereof. The closing price of our common stock exceeded 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 for the quarter ended March 31, 2011; however, none of the holders opted to convert their 3.50% Senior Convertible Notes during the second quarter of 2011. The closing price of our common stock did not exceed the conversion trigger price for the quarters ended June 30, 2011, and September 30, 2011; therefore, the 3.50% Senior Convertible Notes were not, and are not eligible to be converted during the third and fourth quarters of 2011.

Current proposals to fund the federal government budget include eliminating or reducing current tax deductions for intangible drilling costs, the domestic production activities deduction, and percentage depletion. Legislation modifying or eliminating these deductions would have the immediate effect of reducing operating cash flows thereby reducing funding available for our exploration and development capital programs and those of our peers in the industry. These funding reductions could have a significant adverse effect on drilling and production in the United States for a number of years.

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The following table presents changes in cash flows between the nine-month periods ended September 30, 2011, and 2010. The analysis following the table should be read in conjunction with our condensed consolidated statements of cash flows in Part I, Item 1 of this report.

	For the Nine Months Ended September 30,			
	2011	2010	Change	Percent Change
	(in thousands)			
Net cash provided by operating activities	$489,747	$418,360	$71,387	17 %
Net cash (used in) investing activities	$(756,904)	$(236,360)	$(520,544)	220 %
Net cash provided by (used in) financing activities	$292,003	$(185,560)	$477,563	(257)%

Analysis of Cash Flow Changes Between the Nine Months Ended September 30, 2011, and 2010

Operating activities. Cash received from oil and gas production revenue, including the effects of derivative cash settlements, increased $269.4 million to $872.3 million for the first nine months of 2011, compared with $602.9 million for the same period in 2010. Cash paid for lease operating expenses increased $22.1 million to $111.0 million for the first nine months of 2011, compared with $88.9 million for the same period in 2010.

Investing activities. Cash outflows for capital expenditures increased by $592.9 million for the nine months ended September 30, 2011, compared with the same period in 2010. This increase in capital and exploration activities reflects higher cash flows available to us for investment provided by operating activities, divestiture proceeds, and proceeds from the issuance of our 6.625% Senior Notes. Net proceeds from the sale of oil and gas properties increased $65.6 million between the two periods due to an increase in the size of the divestiture packages.

Financing activities. We received net proceeds of $341.1 million from the issuance of our 6.625% Senior Notes. We incurred $8.7 million of debt issuance costs related to our amended credit facility in 2011. Net repayments on our credit facility decreased by $138.0 million for the nine months ended September 30, 2011, compared with the same period in 2010. As of September 30, 2011, we had no outstanding borrowings under the credit facility.

Commodity Price Risk and Interest Rate Risk

We are exposed to market risk, including the effects of changes in oil, gas, and NGL commodity prices and changes in interest rates as discussed below under the caption Summary of Interest Rate Risk. Changes in interest rates can affect the amount of interest we earn on our cash and cash equivalents and the amount of interest we pay on borrowings under our revolving credit facility. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate 3.50% Senior Convertible Notes or our 6.625% Senior Notes, but do affect their fair market value.

There has been no material change to the natural gas and crude oil price sensitivity analysis previously disclosed. Refer to the corresponding section under Part II, Item 7 of our 2010 Form 10-K.

Summary of Oil, Gas, and NGL Derivative Contracts in Place

Our oil, gas, and NGL derivative contracts include costless swaps and costless collar arrangements. All contracts are entered into for other-than-trading purposes. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding accounting for our derivative transactions.

As of September 30, 2011, and as of the filing of this report, we have derivative positions in place covering a portion of anticipated production through the second quarter of 2014 totaling approximately 9 MMBbls of oil, 63 million MMBtu of natural gas, and 2 MMBbls of NGLs.

In a typical commodity swap agreement, if the agreed upon published third-party index price is lower than the swap fixed price, we receive the difference between the index price and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, we pay the difference. For collar agreements, we receive the difference between an agreed upon index and the floor price if the index price is below the floor price. We pay the difference between the agreed upon ceiling price and the index price if the index price is above the ceiling price. No amounts are paid or received if the index price is between the floor and ceiling prices.

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The following tables describe the volumes, average contract prices, and fair values of contracts we have in place as of September 30, 2011.

Oil Contracts

Oil Swaps

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price	Fair Value at September 30, 2011 Asset (Liability)
	(Bbls)	(per Bbl)	(in thousands)
Fourth quarter 2011	377,500	$76.79	$(952)
2012	2,204,000	$84.89	8,634
2013	616,200	$88.22	2,925
2014	660,600	$91.72	4,382
All oil swaps	3,858,300		$14,989

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at September 30, 2011 Asset (Liability)
	(Bbls)	(per Bbl)	(per Bbl)	(in thousands)
Fourth quarter 2011	514,850	$61.86	$81.73	$(4,087)
2012	1,434,600	$76.49	$109.79	9,094
2013	2,146,500	$75.84	$109.81	10,020
2014	560,200	$80.00	$116.05	3,981
All oil collars	4,656,150			$19,008

Natural Gas Contracts

Natural Gas Swaps

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at September 30, 2011 Asset
	(MMBtu)	(per MMBtu)	(in thousands)
Fourth quarter 2011	4,730,000	$ 5.88	$10,312
2012	27,600,000	$ 5.01	25,396
2013	13,810,000	$ 5.05	5,650
2014	2,910,000	$ 5.42	1,021
All natural gas swaps*	49,050,000		$42,379

*Natural gas swaps are comprised of IF ANR OK (1%), IF CIG (3%), IF El Paso Permian (2%), IF HSC (9%), IF NGPL MidCont. (2%), IF NGPL TXOK (5%), IF NNG Ventura (2%), IF PEPL (18%), IF Reliant N/S (33%), IF TETCO STX (24%), and NYMEX Henry Hub (1%).

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Natural Gas Collars

Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at September 30, 2011 Asset (Liability)
	(MMBtu)	(per MMBtu)	(per MMBtu)	(in thousands)
Fourth quarter 2011	1,660,000	$5.25	$6.49	$2,618
2012	—	$—	$—	—
2013	6,650,000	$4.39	$5.34	571
2014	5,734,000	$4.38	$5.36	(568)
All gas collars*	14,044,000			$2,621

*Natural gas collars are comprised of IF CIG (3%), IF HSC (16%), IF NGPL TXCO (16%), IF Reliant N/S (26%), IF TETCO STX (31%), IF PEPL (8%), and NYMEX Henry Hub (<1%).

Natural Gas Liquid Contracts

NGL Swaps

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at September 30, 2011 (Liability)
	(approx. Bbls)	(per Bbl)	(in thousands)
Fourth quarter 2011	398,000	$ 44.74	$(4,590)
2012	1,217,000	$ 46.73	(3,590)
2013	84,000	$ 44.95	(518)
All NGL swaps*	1,699,000		$(8,698)

*NGL swaps are comprised of OPIS Mont. Belvieu LDH Propane (30%), OPIS Mont. Belvieu Purity Ethane (42%), OPIS Mont. Belvieu NON-LDH Isobutane (6%), OPIS Mont. Belvieu NON-LDH Natural Gasoline (11%), and OPIS Mont. Belvieu NON-LDH Normal Butane (11%).

Refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding our oil, gas, and NGL derivative contracts.

Summary of Interest Rate Risk

Market risk is estimated as the potential change in fair value resulting from an immediate hypothetical one percentage point parallel shift in the yield curve. For fixed-rate debt, interest changes affect the fair market value but do not impact results of operations or cash flows. Conversely, interest rate changes for floating-rate debt generally do not affect the fair market value but do impact future results of operations and cash flows, assuming other factors are held constant. The carrying amount of our floating-rate debt typically approximates its fair value. As of September 30, 2011, we had no floating-rate debt outstanding, and our fixed-rate debt outstanding, net of debt discount, was $632.6 million.

Contractual Obligations

Please see Note 7 - Commitments and Contingencies under Part I, Item 1 of this report for information pertaining to our contractual obligations.

Off-Balance Sheet Arrangements

As part of our ongoing business, we have not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance entities or special purpose entities ("SPE"), which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. As of September 30, 2011, we have not been involved in any unconsolidated SPE transactions.

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We evaluate our transactions to determine if any variable interest entities exist. If we determine that we are the primary beneficiary of a variable interest entity, that entity is consolidated into our consolidated financial statements.

Critical Accounting Policies and Estimates

We refer you to the corresponding section in Part II, Item 7 of our 2010 Form 10-K and to the footnote disclosures included in Part I, Item 1 of this report.

New Accounting Pronouncements

Please refer to Note 2 - Basis of Presentation, Significant Accounting Policies, and Recently Issued Accounting Standards under Part I, Item 1 of this report for new accounting matters.

Environmental

The Company’s compliance with applicable environmental laws and regulations has to date not resulted in significant capital expenditures or material adverse effects on our liquidity or results of operations. We believe we are in substantial compliance with environmental laws and regulations and do not currently anticipate that material future expenditures will be required under the existing regulatory framework. However, environmental laws and regulations are subject to frequent changes and we are unable to predict the impact that compliance with future laws or regulations, such as those currently being considered as discussed below, may have on future capital expenditures, liquidity, and results of operations.

Hydraulic fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas and NGLs, from tight formations. For additional information about hydraulic fracturing and related environmental matters, see “Risk Factors - Risks Related to Our Business - Proposed federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays” in our 2010 Form 10-K and Part II, Item 1A of this report.

Climate Change. In December 2009, the U.S. Environmental Protection Agency (the “EPA”) determined that emissions of carbon dioxide, methane and other ‘‘greenhouse gases’’ present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth’s atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the Clean Air Act (“CAA”). The EPA recently adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including petroleum refineries, on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain onshore oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011. In addition, on July 28, 2011 the EPA proposed new rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and many states have already taken measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

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In terms of opportunities, the regulation of greenhouse gas emissions and the introduction of alternative incentives, such as enhanced oil recovery, carbon sequestration and low carbon fuel standards, could benefit us in a variety of ways. For example, although climate change legislation could reduce the overall demand for the oil and natural gas that we produce, the relative demand for natural gas may increase since the burning of natural gas produces lower levels of emissions than other readily available fossil fuels such as oil and coal. In addition, if renewable resources, such as wind or solar power become more prevalent, natural gas-fired electric plants may provide an alternative backup to maintain consistent electricity supply. Also, if states adopt low-carbon fuel standards, natural gas may become a more attractive transportation fuel. For the nine-month periods ended September 30, 2011, and 2010, approximately 72 percent and 65 percent, respectively, of our production was natural gas and NGLs on an MCFE basis. Market-based incentives for the capture and storage of carbon dioxide in underground reservoirs, particularly in oil and natural gas reservoirs, could also benefit us through the potential to obtain greenhouse gas emission allowances or offsets from or government incentives for the sequestration of carbon dioxide.

Cautionary Information about Forward-Looking Statements

This Quarterly Report on Form 10-Q contains “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this Form 10-Q that address activities, events, or developments with respect to our financial condition, results of operations, or economic performance that we expect, believe, or anticipate will or may occur in the future, or that address plans and objectives of management for future operations, are forward-looking statements. The words “anticipate,” “assume,” “believe,” “budget,” “estimate,” “expect,” “forecast,” “intend,” “plan,” “project, similar expressions are intended to identify forward-looking statements. Forward-looking statements appear in a number of places in this Form 10-Q, and include statements about such matters as:

- the amount and nature of future capital expenditures and the availability of liquidity and capital resources to fund capital expenditures;
- the drilling of wells and other exploration and development activities and plans, as well as possible future acquisitions;
- the possible divestiture or farm-down of, or joint venture relating to, certain properties;
- proved reserve estimates and the estimates of both future net revenues and the present value of future net revenues associated with those proved reserve estimates;
- future oil, natural gas, and NGL production estimates;
- our outlook on future oil, natural gas, and NGL prices, well costs, and service costs;
- cash flows, anticipated liquidity, and the future repayment of debt;
- business strategies and other plans and objectives for future operations, including plans for expansion and growth of operations or to defer capital investment, and our outlook on our future financial condition or results of operations; and
- other similar matters such as those discussed in the “Management’s Discussion and Analysis of Financial Condition and Results of Operations” section of this report.

Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments, and other factors that we believe are appropriate under the circumstances. These statements are subject to a number of known and unknown risks and uncertainties which may cause our actual results and performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. These risks are described in the “Risk Factors” section of our 2010 Annual Report on Form 10-K and in this Form 10-Q and include such factors as:

- the volatility of oil, natural gas, and NGL prices, and the effect it may have on our profitability, financial condition, cash flows, access to capital, and ability to grow;
- the continued weakness in economic conditions and uncertainty in financial markets;

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- our ability to replace reserves in order to sustain production;
- our ability to raise the substantial amount of capital that is required to replace our reserves;
- our ability to compete against competitors that have greater financial, technical, and human resources;
- the imprecise estimations of our actual quantities and present values of proved oil, natural gas, and NGL reserves;
- the uncertainty in evaluating recoverable reserves and other expected benefits or liabilities;
- the possibility that exploration and development drilling may not result in commercially producible reserves;
- the possibility that our planned drilling in existing or emerging resource plays using some of the latest available horizontal drilling and completion techniques is subject to drilling and completion risks and may not meet our expectations for reserves or production;
- the uncertainties associated with our reported anticipated divestiture, joint venture, farm-down, and similar transactions with respect to certain assets, including whether such transactions will be consummated or completed in the form or timing and for the value that we anticipate;
- the uncertainties associated with enhanced recovery methods;
- our commodity price risk management activities may result in financial losses or may limit the prices that we receive for oil, natural gas, and NGL sales;
- the inability of one or more of our customers to meet their obligations;
- price declines or unsuccessful exploration efforts result in write-downs of our asset carrying values;
- the impact that lower oil, natural gas, or NGL prices could have on our ability to borrow under our credit facility;
- the possibility that our amount of debt may limit our ability to obtain financing for acquisitions, make us more vulnerable to adverse economic conditions, and make it more difficult for us to make payments on our debt;
- operating and environmental risks and hazards that could result in substantial losses;
- complex laws and regulations, including environmental regulations, that result in substantial costs and other risks;
- the availability and capacity of gathering, transportation, processing, and/or refining facilities;
- our ability to sell and/or receive market prices for our oil, natural gas, and NGLs;
- new technologies may cause our current exploration and drilling methods to become obsolete;
- the uncertainties regarding the ultimate impact of potentially dilutive securities; and
- litigation, environmental matters, the potential impact of government regulations, and the use of management estimates regarding such matters.

We caution you that forward-looking statements are not guarantees of future performance and that actual results or performance may be materially different from those expressed or implied in the forward-looking statements. The forward-looking statements in this report speak as of the filing date of this report. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by securities laws.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item is provided under the captions Commodity Price Risk and Interest Rate Risk, Summary of Oil, Gas, and NGL Derivative Contracts in Place, and Summary of Interest Rate Risk in Item 2 above and is incorporated herein by reference. Please refer to the sensitivity analysis within our 2010 Annual Report on Form 10-K in Part II, Item 7.

ITEM 4. CONTROLS AND PROCEDURES

We maintain a system of disclosure controls and procedures that is designed to ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC’s rules and forms, and to ensure that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

We carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this Quarterly Report on Form 10-Q. Based upon that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures are effective for the purposes discussed above as of the end of the period covered by this Quarterly Report on Form 10-Q. There was no change in our internal control over financial reporting that occurred during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the effectiveness of our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We initiated an arbitration proceeding on May 11, 2011, against Anadarko E&P Company, LP (“Anadarko”), alleging that Anadarko breached a Joint Exploration Agreement (“JEA”) originally executed between Anadarko and TXCO Energy Corp. (“TXCO”) in March 2008, and relating to oil and gas properties located in Maverick, Dimmitt, Webb and LaSalle Counties, Texas. We have been a party to the JEA since May 15, 2008. We assert that Anadarko is required under the JEA to tender to us our proportionate share of the leasehold interests that Anadarko acquired in TXCO's bankruptcy proceeding in February 2010. The arbitration hearing related to this dispute was held in September 2011; however, the arbitration panel has not announced its determination. If we prevail in this matter, Anadarko could be obligated to sell to us an undivided interest of up to 8.333% (or up to approximately 27,000 net acres) of the total leasehold governed by the JEA in return for our payment of a proportionate share of the price Anadarko paid TXCO in the bankruptcy proceeding (adjusted for revenues and expenses attributable to the purchased interest since January 1, 2010), or in the alternative, pay us damages in an amount to be determined by the arbitration panel.
In a separate, unrelated matter, we initiated an arbitration proceeding against Springfield Pipeline, LLC (“Springfield”), a wholly owned affiliate of Anadarko Petroleum Corporation, and another party in October 2011, alleging that Springfield and the other party had unreasonably withheld or delayed consents, which are closing conditions of our Acquisition and Development Agreement with Mitsui E&P Texas LP, and which are required (but are not to be unreasonably withheld or delayed) under an Agreement for the Construction, Ownership and Operation of Midstream Assets in Maverick, Dimmit, Webb and La Salle Counties, Texas, executed by us and Springfield and under certain other related gathering agreements. We have dismissed our claims in the arbitration proceeding against the other party in return for its consent. We have requested an expedited arbitration hearing under the commercial rules of the American Arbitration Association and are endeavoring to conclude this arbitration proceeding against Springfield during the fourth quarter of 2011.

With the exception of the above disclosures, there have been no material changes from the legal proceedings as previously disclosed in our 2010 Form 10-K in response to Item 3 of Part I of such Form 10-K. See Note 7 - Commitments and Contingencies, in Part I, Item 1 of this report, which is incorporated by reference herein.

ITEM 1A. RISK FACTORS

The following risk factors update should be considered in addition to the risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2010.

Proposed federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

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Hydraulic-fracturing is an essential and common practice in the oil and gas industry used to stimulate production of oil, natural gas, and associated liquids from dense subsurface rock formations. We routinely apply hydraulic-fracturing techniques to many of our oil and natural gas properties, including our unconventional resource plays in the Granite Wash of Texas and Oklahoma, the Eagle Ford shale of south Texas, and the Bakken/Three Forks resource play in North Dakota. Hydraulic-fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore. The process is typically regulated by state oil and natural gas commissions; however, the EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities involving diesel under the Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In addition, legislation has been introduced before Congress, called the Fracturing Responsibility and Awareness of Chemicals Act, to provide for federal regulation of hydraulic-fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process.

Certain states in which we operate, including Pennsylvania, Texas and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, waste disposal and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas (RCT) and the public of certain information regarding the components used in the hydraulic-fracturing process. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling and/or completion of wells.

There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic-fracturing practices. The White House Council on Environmental Quality is coordinating a review of hydraulic-fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic-fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands.

Additionally, certain members of the Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the U.S. Securities and Exchange Commission to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These ongoing or proposed studies, depending on their course and results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory processes.

Further, on July 28, 2011, the EPA issued proposed rules that would subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The EPA proposed rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards include the reduced emission completion (REC) techniques developed in EPA's Natural Gas STAR program along with the pit flaring of gas not sent to the gathering line. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed regulations under NESHAPS include maximum achievable control technology (MACT) standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. We are currently evaluating the effect these proposed rules could have on our business. Final action on the proposed rules is expected no later than February 28, 2012.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil, natural gas, and associated liquids including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of additional federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows.

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On October 20, 2011, EPA announced a schedule for development of standards for disposal of wastewater produced from shale gas operations to publicly owned treatment works (POTWs). The regulations will be developed under EPA's Effluent Guidelines Program under the authority of the Clean Water Act. EPA anticipates issuing the proposed rules in 2014.

Certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and production may be eliminated as a result of future legislation.

On September 12, 2011, President Obama sent to Congress a legislative package that included proposed legislation that, if enacted into law, would eliminate certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, among other proposals:

•the repeal of the percentage depletion allowance for oil and natural gas properties;

•the elimination of current deductions for intangible drilling and development costs;

•the elimination of the deduction for certain domestic production activities; and

•an extension of the amortization period for certain geological and geophysical expenditures.

These proposals also were included in President Obama's Proposed Fiscal Year 2012 Budget. It is unclear whether these or similar changes will be enacted. The passage of this legislation or any similar changes in federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development. Any such changes could have an adverse effect on our financial position, results of operations and cash flows.

Our ability to produce crude oil and natural gas economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations and/or completions or are unable to dispose of or recycle the water we use at a reasonable cost and in accordance with applicable environmental rules.

The hydraulic fracturing process on which we depend to produce commercial quantities of crude oil, natural gas and associated liquids from many reservoirs requires the use and disposal of significant quantities of water.

Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of wastes, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas.

Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.

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ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

(c) The following table provides information about purchases by the Company or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the fiscal quarter ended September 30, 2011, of shares of the Company's common stock, which is the sole class of equity securities registered by the Company pursuant to Section 12 of the Exchange Act:

PURCHASES OF EQUITY SECURITIES BY ISSUER
AND AFFILIATED PURCHASERS

Period	(a) Total Number of Shares Purchased [1]	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Program	(d) Maximum Number of Shares that May Yet Be Purchased Under the Program [2]
07/01/11 - 07/31/11	5,125	$73.82	—	3,072,184
08/01/11 - 08/31/11	118,379	$75.56	—	3,072,184
09/01/11 - 09/30/11	—	$—	—	3,072,184
Total:	123,504	$75.49	—	3,072,184

(1) Consists of a total of 123,504 shares withheld (under the terms of grants under the Equity Incentive Compensation Plan) to offset tax withholding obligations that occur upon the delivery of outstanding shares underlying RSUs and PSUs.

(2) In July 2006, the Company's Board of Directors approved an increase in the number of shares that may be repurchased under the original August 1998 authorization to an aggregate of 6,000,000. Accordingly, as of this filing, the Company has authorization to repurchase 3,072,184 shares of common stock on a prospective basis. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of the Company's credit facility and other agreements, provisions of SM Energy's 6.625% Senior Notes and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow, and borrowings under the Company's credit facility. The stock repurchase program may be suspended or discontinued at any time.

The payment of dividends and stock repurchases are subject to covenants in our credit facility, including the requirement that we maintain certain levels of stockholders' equity and the limitation that does not allow our annual dividend payments to exceed $50.0 million. The payment of dividends is also subject to covenants under our 6.625% Senior Notes, including covenants limiting the payment of dividends on our common stock to $6.5 million in the aggregate in any given calendar year during the eight year term of the notes.

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ITEM 6. EXHIBITS

The following exhibits are filed or furnished with or incorporated by reference into this report:

Exhibit	Description
2.1*	First Amendment to Acquisition and Development Agreement dated October 13, 2011 between SM Energy Company and Mitsui E&P Texas LP
10.1*†	Form of Performance Stock Unit Award Agreement as of September 6, 2011
10.2*†	Form of Restricted Stock Unit Award Agreement as of September 6, 2011
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes - Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes - Oxley Act of 2002
32.1**	Certification pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002
101.INS****	XBRL Instance Document
101.SCH****	XBRL Schema Document
101.CAL****	XBRL Calculation Linkbase Document
101.LAB****	XBRL Label Linkbase Document
101.PRE****	XBRL Presentation Linkbase Document
101.DEF****	XBRL Taxonomy Extension Definition Linkbase Document

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*	Filed with this report.
**	Furnished with this report.
****	Furnished, not filed. Users of this data submitted electronically herewith are advised pursuant to Rule 406T of Regulation S-T that this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.
†	Exhibit constitutes a management contract or compensatory plan or agreement.

SIGNATURES

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

	SM ENERGY COMPANY
November 2, 2011	By: /s/ ANTHONY J. BEST Anthony J. Best President and Chief Executive Officer
November 2, 2011	By: /s/ A. WADE PURSELL A. Wade Pursell Executive Vice President and Chief Financial Officer
November 2, 2011	By: /s/ MARK T. SOLOMON Mark T. Solomon Vice President and Controller