SM Energy Co
Form 10-Q
August 03, 2012

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 June 30, 2012
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 þ 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 þ No o

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

Large accelerated filer þ	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

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

As of July 27, 2012, the registrant had 65,151,506 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)

	June 30, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$184	$119,194
Accounts receivable	209,633	210,368
Refundable income taxes	2,603	5,581
Prepaid expenses and other	46,812	68,026
Derivative asset	69,207	55,813
Deferred income taxes	5,798	4,222
Total current assets	334,237	463,204
Property and equipment (successful efforts method), at cost:		
Land	1,845	1,548
Proved oil and gas properties	4,869,603	4,378,987
Less - accumulated depletion, depreciation, and amortization	(2,034,929)	(1,766,445)
Unproved oil and gas properties	122,005	120,966
Wells in progress	274,690	273,428
Materials inventory, at lower of cost or market	12,966	16,537
Oil and gas properties held for sale (note 3)	60,711	246
Other property and equipment, net of accumulated depreciation of $20,799 in 2012 and $23,985 in 2011	120,058	71,369
Total property and equipment, net	3,426,949	3,096,636
Other noncurrent assets:		
Derivative asset	44,270	31,062
Restricted cash	109,486	124,703
Other noncurrent assets	84,629	83,375
Total other noncurrent assets	238,385	239,140
Total Assets	$3,999,571	$3,798,980
LIABILITIES AND STOCKHOLDERS’ EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$460,611	$456,999
Derivative liability	9,150	42,806
Other current liabilities	6,000	6,000
Total current liabilities	475,761	505,805
Noncurrent liabilities:		
Long-term credit facility	61,000	—
3.50% Senior Convertible Notes, net of unamortized discount of $2,431 in 2011	—	285,069
6.625% Senior Notes Due 2019	350,000	350,000
6.50% Senior Notes Due 2021	350,000	350,000
6.50% Senior Notes Due 2023	400,000	—

Asset retirement obligation	89,027	87,167
Asset retirement obligation associated with oil and gas properties held for sale (note 3)	1,732	1,277
Net Profits Plan liability (note 11)	89,591	107,731
Deferred income taxes	596,725	568,263
Derivative liability	956	12,875
Other noncurrent liabilities	57,083	67,853
Total noncurrent liabilities	1,996,114	1,830,235
Commitments and contingencies (note 6)		
Stockholders’ equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued: 65,155,340 shares in 2012 and 64,145,482 shares in 2011; outstanding, net of treasury shares: 65,100,773 shares in 2012 and 64,064,415 shares in 2011	652	641
Additional paid-in capital	234,562	216,966
Treasury stock, at cost: 54,567 shares in 2012 and 81,067 shares in 2011	(1,263)	(1,544)
Retained earnings	1,299,175	1,251,157
Accumulated other comprehensive loss	(5,430)	(4,280)
Total stockholders' equity	1,527,696	1,462,940
Total Liabilities and Stockholders’ Equity	$3,999,571	$3,798,980

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 June 30,		For the Six Months Ended June 30,	
	2012	2011	2012	2011
Operating revenues and other income:				
Oil, gas, and NGL production revenue	$312,608	$333,934	$675,203	$610,247
Realized hedge gain (loss) (note 10)	185	(6,330)	1,837	(7,705)
Gain (loss) on divestiture activity	(24,176)	30,019	(22,714)	54,934
Marketed gas system and other operating revenue	15,803	20,250	27,517	35,726
Total operating revenues and other income	304,420	377,873	681,843	693,202
Operating expenses:				
Oil, gas, and NGL production expense	91,134	53,342	178,266	119,154
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	161,608	115,382	331,178	220,738
Exploration	22,007	9,603	40,614	22,315
Impairment of proved properties	38,523	—	38,523	—
Abandonment and impairment of unproved properties	10,707	1,237	10,849	4,316
General and administrative	31,130	27,310	59,272	53,171
Change in Net Profits Plan liability	(22,079)	(13,984)	(18,140)	211
Unrealized and realized derivative (gain) loss (note 10)	(98,112)	(43,876)	(95,896)	44,553
Marketed gas system and other operating expense	17,111	17,152	28,561	37,009
Total operating expenses	252,029	166,166	573,227	501,467
Income from operations	52,391	211,707	108,616	191,735
Nonoperating income (expense):				
Interest income	5	227	75	355
Interest expense	(12,712)	(14,550)	(26,990)	(24,264)
Income before income taxes	39,684	197,384	81,701	167,826
Income tax expense	(14,795)	(72,851)	(30,476)	(61,796)
Net income	$24,889	$124,533	$51,225	$106,030
Basic weighted-average common shares outstanding	64,585	63,638	64,345	63,543
Diluted weighted-average common shares outstanding	67,556	66,909	67,806	66,695
Basic net income per common share (note 9)	$0.39	$1.96	$0.80	$1.67
Diluted net income per common share (note 9)	$0.37	$1.86	$0.76	$1.59
Dividends per common share	$—	$—	$0.05	$0.05

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 COMPREHENSIVE INCOME (UNAUDITED)
(in thousands)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2012	2011	2012	2011
Net income	$24,889	$124,533	$51,225	$106,030
Other comprehensive income (loss), net of tax:				
Reclassification to earnings	(116)	3,951	(1,150)	4,878
Total other comprehensive income (loss), net of tax	(116)	3,951	(1,150)	4,878
Total comprehensive income	$24,773	$128,484	$50,075	$110,908

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 Six Months Ended June 30, 2012	2011
Cash flows from operating activities:		
Net income	$51,225	$106,030
Adjustments to reconcile net income to net cash provided by operating activities:		
(Gain) loss on divestiture activity	22,714	(54,934)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	331,178	220,738
Exploratory dry hole expense	8,198	49
Impairment of proved properties	38,523	—
Abandonment and impairment of unproved properties	10,849	4,316
Stock-based compensation expense	12,372	11,837
Change in Net Profits Plan liability	(18,140)	211
Unrealized derivative (gain) loss	(74,014)	24,160
Amortization of debt discount and deferred financing costs	4,616	11,294
Deferred income taxes	30,215	52,241
Plugging and abandonment	(1,516)	(1,430)
Other	(867)	(5,888)
Changes in current assets and liabilities:		
Accounts receivable	735	(10,370)
Refundable income taxes	2,978	5,348
Prepaid expenses and other	(4,759)	15,692
Accounts payable and accrued expenses	(4,019)	(2,530)
Excess income tax benefit from the exercise of stock awards	—	(6,791)
Net cash provided by operating activities	410,288	369,973
Cash flows from investing activities:		
Net proceeds from sale of oil and gas properties	15,410	97,952
Capital expenditures	(705,366)	(662,372)
Acquisition of oil and gas properties	(5,312)	—
Other	111	(2,355)
Net cash used in investing activities	(695,157)	(566,775)
Cash flows from financing activities:		
Proceeds from credit facility	802,500	102,000
Repayment of credit facility	(741,500)	(150,000)
Debt issuance costs related to credit facility	—	(8,525)
Net proceeds from 6.625% Senior Notes Due 2019	—	341,435
Net proceeds from 6.50% Senior Notes Due 2023	392,336	—
Repayment of 3.50% Convertible Notes	(287,500)	—
Proceeds from sale of common stock	2,888	4,929
Dividends paid	(3,208)	(3,181)
Excess income tax benefit from the exercise of stock awards	—	6,791
Other	343	(644)
Net cash provided by financing activities	165,859	292,805

Net change in cash and cash equivalents	(119,010)	96,003
Cash and cash equivalents at beginning of period	119,194	5,077
Cash and cash equivalents at end of period	$184	$101,080

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 Six Months Ended June 30,	
	2012	2011
	(in thousands)	
Cash paid for interest	$(30,137)	$(6,378)
Net cash refunded for income taxes	$2,815	$2,543

As of June 30, 2012, and 2011, $226.0 million, and $237.9 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, development, and production of crude oil, natural gas, and natural gas liquids (also referred to as "oil", "gas", and "NGLs" throughout the document) in onshore North America, with a current focus on oil and NGL-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 ("GAAP") 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 GAAP 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, 2011 (the "2011 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 events subsequent to the balance sheet date of June 30, 2012, 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 2011 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 2011 Form 10-K.

Recently Issued and Recently Adopted Accounting Standards

On January 1, 2012, the Company adopted new fair value measurement authoritative accounting guidance issued by the Financial Accounting Standards Board (the "FASB"), that clarifies the application of fair value measurement and disclosure requirements and changing particular principles and requirements for measuring fair value. For each class of assets and liabilities not measured at fair value in the Company's financial statements but for which fair value is disclosed, this guidance requires the Company to disclose the nature, characteristics, and risks of the asset or liability and the level of the fair value hierarchy within which the fair value measurement is categorized. Please refer to Note 11 - Fair Value Measurements in which the changes to the Company's financial statements resulting from the new authoritative guidance are presented.

On January 1, 2012, the Company adopted new authoritative accounting guidance issued by the FASB stating an entity that reports items of other comprehensive income has the option to present the components of comprehensive income in either one continuous financial statement, or two consecutive financial statements, including reclassification adjustments. Subsequent to the issuance of this authoritative guidance, the FASB issued additional authoritative accounting guidance that effectively deferred the requirement to present the reclassification adjustments on the face of the financial statements, as well as the requirement to present the individual components of other comprehensive income for interim periods. The adoption of this statement did not have a material impact on the Company. The Company has elected to present a separate statement of comprehensive income, including the individual components, titled Condensed Consolidated Statements of Comprehensive Income, as part of Item 1 to this report.

There are no new significant accounting standards applicable to SM Energy that have been issued but not yet adopted as of June 30, 2012.

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Note 3 - Assets Held for Sale

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

As of June 30, 2012, the accompanying condensed consolidated balance sheets ("accompanying balance sheets") present $60.7 million of assets held for sale, net of accumulated depletion, depreciation, and amortization expense. A corresponding asset retirement obligation liability of $1.7 million is separately presented. These assets held for sale include certain assets located in the Company's Rocky Mountain region, as well as the Company's Marcellus shale assets in Pennsylvania. The Company determined that these planned asset sales do not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

During the second quarter of 2012, the Company reclassified a portion of the assets previously held for sale as of March 31, 2012, to assets held and used, as these assets were no longer being actively marketed. The assets were measured at the lower of the carrying value of the assets before being classified as held for sale, adjusted for any depletion, depreciation, and amortization expense ("DD&A") that would have been recognized had the assets been continuously held and used, or the fair value of the assets at the date they no longer met the criteria as held for sale. As a result of this measurement, the Company recognized $1.7 million of DD&A expense and a $28.3 million loss on unsuccessful sale of properties, which is included in gain (loss) on divestiture activity in the accompanying condensed consolidated statements of operations ("accompanying statements of operations").

Note 4 - Income Taxes

Income tax expense for the six months ended June 30, 2012, and 2011 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 percentage depletion, the effect of state income taxes, uncertain tax positions, valuation allowances, and other permanent differences. The quarterly rate can also be impacted by the proportion of income earned in the reported periods.

The provision for income taxes consists of the following:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands)			
Current portion of income tax benefit (expense):				
Federal	$—	$(2,212)	$—	$(9,156)
State	132	(224)	(261)	(399)
Deferred portion of income tax expense	(14,927)	(70,415)	(30,215)	(52,241)
Total income tax expense	$(14,795)	$(72,851)	$(30,476)	$(61,796)
Effective tax rate	37.3%	36.9%	37.3%	36.8%

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.

The Company and its subsidiaries file federal income tax returns and various state income tax returns. With certain 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 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. The Internal Revenue Service initiated an audit in the first quarter of 2012 for the 2007 and 2010 tax years.

In the third quarter of 2011, the Company completed a multi-year research and development credit study and recorded a cumulative discrete tax benefit. As of the filing date of this report, federal tax law allowing for the calculation of these credits from the Company’s increasing research activities has not been extended past December 31, 2011. For these reasons, comparable periods of 2012 and 2011 presented in this report reflect no benefit for the credit.

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Note 5 - Long-Term Debt

The Company satisfied its obligations to exchange its outstanding $350.0 million 6.50% Senior Notes due 2021 (the "2021 Notes") and its outstanding $350.0 million 6.625% Senior Notes due 2019 (the "2019 Notes") for notes registered under the Securities Act of 1933, as amended (the "Securities Act"), on March 7, 2012, and on January 12, 2012, respectively. There are no subsidiary guarantors of these notes.

3.50% Senior Convertible Notes Due 2027

On April 2, 2012, the Company called for redemption all of its outstanding 3.50% Senior Convertible Notes due 2027 (the "3.50% Senior Convertible Notes"). The call for redemption resulted in note holders of $281.3 million aggregate principal amount electing to convert their notes. The Company settled the principal amount of all converted 3.50% Senior Convertible Notes in cash and the excess conversion value by issuing 864,106 shares of its common stock. The Company redeemed the remaining $6.2 million of aggregate principal amount of notes that were not converted on the redemption date at par plus accrued interest in cash. The Company used funds borrowed under its credit facility to pay the cash portion of the 3.50% Senior Convertible Notes settlement.

6.50% Senior Notes Due 2023

On June 29, 2012, the Company issued $400.0 million in aggregate principal amount of 6.50% Senior Notes due 2023 (the "2023 Notes"). The 2023 Notes were issued at par and mature on January 1, 2023. The Company received net proceeds of $392.3 million after deducting fees of $7.7 million, which will be amortized as deferred financing costs over the life of the 2023 Notes. The net proceeds were used to reduce the Company's outstanding credit facility balance.

Prior to July 1, 2015, the Company may redeem, on one or more occasions, up to 35 percent of the aggregate principal amount of the 2023 Notes with the net cash proceeds of certain equity offerings at a redemption price of 106.5% of the principal amount thereof, plus accrued and unpaid interest. The Company may also redeem the 2023 Notes, in whole or in part, at any time prior to July 1, 2017, at a redemption price equal to 100 percent of the principal amount of the 2023 Notes to be redeemed, plus a specified make-whole premium and accrued and unpaid interest to the applicable redemption date.

On or after July 1, 2017, the Company may also redeem all or, from time to time, a portion of the 2023 Notes at the redemption prices set forth below, during the twelve-month period beginning on July 1 of each applicable year, expressed as a percentage of the principal amount redeemed, plus accrued and unpaid interest:

2017	103.250	%
2018	102.167	%
2019	101.083	%
2020 and thereafter	100.000	%

The 2023 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 2023 Notes. The Company is subject to certain covenants under the indenture governing the 2023 Notes that limit the Company's ability to incur additional indebtedness, issue preferred stock, and make restricted payments, including dividends. However, the first $6.5 million of dividends paid each year are not restricted by this covenant. The Company was in compliance with all financial covenants under its 2023 Notes as of June 30, 2012.

Additionally, on June 29, 2012, the Company entered into a registration rights agreement that provides holders of the 2023 Notes certain registration rights under the Securities Act. Pursuant to the registration rights agreement, the Company will file an exchange offer registration statement with the Securities and Exchange Commission ("SEC") with respect to its offer to exchange the 2023 Notes for substantially identical notes that are registered under the Securities

Act. Under certain circumstances, the Company has agreed to file a shelf registration statement relating to the resale of the 2023 Notes in lieu of a registered exchange offer. If the exchange offer is not completed on or before June 29, 2013, or the shelf registration statement, if required, is not declared effective within the time periods specified in the registration rights agreement, the Company has agreed to pay additional interest with respect to the 2023 Notes in an amount not to exceed one percent of the principal amount of the 2023 Notes until the exchange offer is completed or the shelf registration statement is declared effective.

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Note 6 - Commitments and Contingencies
Commitments

There have been no material changes from the commitments disclosed in the notes to the Company's consolidated financial statements included in the 2011 Form 10-K.
Contingencies
The Company is subject to litigation and claims arising in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of such pending litigation and claims will not have a material effect on the results of operations, the financial position, or the cash flows of the Company.
The Company was 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 sought to quiet title to their claimed overriding royalty interest and to recover unpaid overriding royalty interest proceeds allegedly due. The Company believes that the claimed overriding royalty interest has been terminated under the governing agreements and the applicable law, and has contested the plaintiffs' claims. Both parties filed motions for summary judgment, and on February 8, 2011, the District Court issued an order granting plaintiffs' motion for summary judgment and denying the Company's motion for summary judgment. On September 30, 2011, the District Court entered final judgment for the plaintiffs and awarded damages of approximately $5.1 million, which included prejudgment interest. The District Court also awarded attorneys fees and costs to the plaintiffs. The Company appealed the District Court's judgment and obtained a stay pending appeal that prevented the plaintiffs from executing on the judgment.

On May 23, 2012, the Fourth Court of Appeals for the State of Texas delivered its opinion in this case, which reversed the summary judgment granted to the plaintiffs by the District Court and rendered judgment that the plaintiffs take nothing. Accordingly, based on the judgment of the Fourth Court of Appeals, the plaintiffs are not entitled to their claimed aggregate 7.46875 percent overriding royalty interest, nor are they entitled to the claimed damages related to the overriding royalty interest, attorneys fees or costs. The plaintiffs have the right to petition the Supreme Court of Texas for a review of the judgment of the Fourth Court of Appeals. In the event the plaintiffs' file such petition and review is granted by the Supreme Court of Texas, the Company will continue to contest this litigation.

Note 7 - Compensation Plans

Cash Bonus Plan

During the first six months of 2012 and 2011, the Company paid $24.0 million and $21.6 million for cash bonuses earned in the 2011 and 2010 performance years, respectively. The general and administrative expense and exploration expense line items in the accompanying statements of operations include $4.6 million and $3.7 million of accrued cash bonus plan expense attributable to the three-month periods ended June 30, 2012, and 2011, respectively, and $9.3 million and $7.5 million for the six-month periods ended June 30, 2012, and 2011, respectively, related to the respective performance year.

Restricted Stock Units Under the Equity Incentive Compensation Plan

The Company grants Restricted Stock Units ("RSUs") as part of its long-term equity compensation program. Each RSU represents a right to one share of the Company's common stock to be delivered upon settlement of the award at the end of the specified vesting period. RSUs are recognized as general and administrative expense and exploration expense over the vesting period of the award.

Total expense recorded for RSUs for the three-month periods ended June 30, 2012, and 2011, was $1.4 million and $985,000, respectively, and $2.6 million and $2.0 million for the six-month periods ended June 30, 2012, and 2011, respectively. As of June 30, 2012, there was $4.9 million of total unrecognized compensation expense related to unvested RSU awards, which is being amortized through 2014. There have been no material changes to outstanding and non-vested RSUs during the six months ended June 30, 2012.

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Subsequent to June 30, 2012, the Company granted 365,787 RSUs as part of its regular annual long-term equity compensation program. These RSUs will vest 1/3rd on each of the next three anniversary dates of the grant. Also subsequent to June 30, 2012, the Company settled 160,484 RSUs that related to awards granted in previous years by issuing a net 111,123 shares of the Company's common stock in accordance with the terms of the RSU awards. The remaining 49,361 shares were withheld to satisfy income and payroll tax withholding obligations that arose upon delivery of the shares underlying those RSUs.

Performance Stock Units Under the Equity Incentive Compensation Plan

The Company also grants Performance Share Units as part of its long-term equity compensation program. Performance Stock Units are structurally the same as the previously granted Performance Share Awards (collectively known as "Performance Share Units" or "PSUs"). The number of shares of the Company's common stock issued to settle PSUs ranges from zero to two times the number of PSUs awarded and is determined based on the Company's performance over a three-year measurement period. The performance criteria for the PSUs are based on a combination of the Company's annualized total shareholder return ("TSR") for the measurement period and the relative measure of the Company's TSR compared with the annualized TSRs of a group of peer companies for the measurement period. PSUs are recognized as general and administrative expense and exploration expense over the vesting period of the award.

Total expense recorded for PSUs for the three-month periods ended June 30, 2012, and 2011, was $5.2 million and $4.1 million, respectively, and $8.1 million and $8.4 million for the six-month periods ended June 30, 2012, and 2011, respectively. As of June 30, 2012, there was $16.5 million of total unrecognized compensation expense related to unvested PSUs to be amortized through 2014. There have been no material changes to outstanding and non-vested PSUs during the six months ended June 30, 2012.

Subsequent to June 30, 2012, the Company granted 314,853 PSUs as part of its regular annual long-term equity compensation program. These PSUs will vest 1/3rd on each of the next three anniversary dates of the grant. Also subsequent to June 30, 2012, the Company settled 609,714 PSUs that were granted in 2009 and earned a two times multiplier by issuing a net 812,562 shares of the Company's common stock in accordance with the terms of the PSU awards. There were 406,866 shares withheld to satisfy income and payroll tax withholding obligations that arose upon delivery of the shares underlying those PSUs.

Stock Option Grants Under the Equity Incentive Compensation Plan

A summary of activity associated with the Company's Stock Option Plan for the six months ended June 30, 2012, is presented in the following table:

	Shares	Weighted-Average Exercise Price	Aggregate Intrinsic Value (in thousands)
Outstanding, at beginning of year	508,214	$13.86	$30,109
Exercised	(108,299)	$12.36	$6,667
Forfeited	—	$—	
Outstanding, at end of quarter	399,915	$14.26	$13,937
Vested and exercisable, at end of quarter	399,915	$14.26	$13,937

As of June 30, 2012, there was no unrecognized compensation expense related to stock option awards.

Director Shares

During the six months ended June 30, 2012, and 2011, the Company issued 26,500 and 21,568 shares, respectively, of the Company's common stock from treasury to the Company's non-employee directors, under the Company's Equity Incentive Compensation Plan. The Company recorded $1.1 million and $1.0 million of compensation expense related to these awards for both the three and six months ended June 30, 2012, and 2011, respectively. The Company appointed a new non-employee director on July 16, 2012, and granted him 3,986 shares of the Company’s common stock from treasury, as a pro-rata share of the Company’s annual director compensation. All shares of common stock issued to the Company’s non-employee directors are earned over a one-year service period.

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Employee Stock Purchase Plan

Under the Company's Employee Stock Purchase Plan ("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 value from 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, and shares issued under the ESPP have no restriction period. The ESPP is intended to qualify under Section 423 of the Internal Revenue Code. The Company had 1.3 million shares available for issuance under the ESPP as of June 30, 2012. There were 37,124 and 22,373 shares issued under the ESPP during the second quarters of 2012 and 2011, respectively. The fair value of ESPP grants is measured at the date of grant using the Black-Scholes option-pricing model.

Net Profits Interest Bonus Plan

Cash payments made or accrued under the Net Profits Interest Bonus Plan ("Net Profits Plan") that have been recorded as either general and administrative expense or exploration expense are presented in the table below:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands)			
General and administrative expense	$3,682	$5,261	$8,094	$10,591
Exploration expense	493	585	1,018	1,062
Total	$4,175	$5,846	$9,112	$11,653

Additionally, the Company accrued or made cash payments under the Net Profits Plan of $1.4 million and $2.0 million for the three-month periods ended June 30, 2012, and 2011, respectively, and $1.7 million and $6.3 million for the six-month periods ended June 30, 2012, and 2011, respectively, as a result of divestiture proceeds. These cash payments are accounted for as a reduction in the gain (loss) 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 paid to employees that have terminated employment and do not provide ongoing exploration support to the Company.

Note 8 - 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 Pension 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 June 30,		For the Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands)			
Service cost	$1,515	$1,052	$2,465	$1,900
Interest cost	393	312	689	592
Expected return on plan assets that reduces periodic pension costs	(352)	(281)	(572)	(440)
Amortization of prior service costs	9	—	9	—
Amortization of net actuarial loss	293	111	394	202
Net periodic benefit cost	$1,858	$1,194	$2,985	$2,254

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 10 percent of the greater of the benefit obligation and the market-related value of assets are amortized over the average remaining service period of active participants.

Contributions

The Company is required to contribute a total of $5.4 million to its Qualified Pension Plan for the 2012 plan year. The Company has contributed $4.6 million of such amount as of June 30, 2012.

Note 9 - Earnings per Share

Basic net income per common share is calculated by dividing net income available to common shareholders 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 is calculated by dividing adjusted net income by the diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of in-the-money outstanding options, unvested RSUs, contingent PSUs, and shares into which the 3.50% Senior Convertible Notes were convertible.

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, that would be issuable at the end of the respective reporting period, assuming that date was the end of the contingency period applicable to such PSUs. For additional discussion on PSUs, please refer to Note 7 - Compensation Plans under the heading Performance Stock Units Under the Equity Incentive Compensation Plan.

The Company called for redemption the 3.50% Senior Convertible Notes on April 2, 2012, and the majority of the then outstanding holders of the 3.50% Senior Convertible Notes elected to convert their notes. The Company issued 864,106 common shares upon conversion and these shares were included in the calculation of basic weighted-average common shares outstanding for the three and six months ended June 30, 2012. Please refer to Note 5 - Long-Term Debt for additional discussion. Prior to calling the notes for redemption, the Company’s 3.50% Senior Convertible Notes had 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, 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. Prior to the settlement of the Company's 3.50% Senior Convertible Notes, potentially dilutive shares associated with this conversion feature were accounted for using the treasury stock method when shares of the Company's common stock traded at an average closing price that exceeded the $54.42 conversion price. Shares of the Company's common stock traded at an average closing price exceeding the conversion price for the three and six month periods ended June 30, 2012, and 2011, making them dilutive for those periods. The diluted net income per share calculations for the three-month and six-month periods ended June 30, 2012, were adjusted on a weighted basis for the conversion of the 3.50% Senior Convertible Notes.

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The treasury stock method is used to measure the dilutive impact of unvested RSUs, contingent PSUs, in-the-money stock options, and 3.50% Senior Convertible Notes.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands, except per share amounts)			
Net income	$24,889	$124,533	$51,225	$106,030
Basic weighted-average common shares outstanding	64,585	63,638	64,345	63,543
Add: dilutive effect of stock options, unvested RSUs, and contingent PSUs	2,149	2,182	2,182	2,161
Add: dilutive effect of 3.50% Senior Convertible Notes	822	1,089	1,279	991
Diluted weighted-average common shares outstanding	67,556	66,909	67,806	66,695
Basic net income per common share	$0.39	$1.96	$0.80	$1.67
Diluted net income per common share	$0.37	$1.86	$0.76	$1.59

Note 10 - Derivative Financial Instruments

The Company has entered into various commodity derivative contracts to mitigate a portion of its exposure to potentially adverse market changes in commodity prices and the associated impact on cash flows. The Company’s derivative contracts include swap and collar arrangements for oil, gas, and NGLs. As of June 30, 2012, the Company had commodity derivative contracts through the first quarter of 2015 for a total of 9.1 million Bbls of anticipated oil production, 80.0 million MMBtu of anticipated gas production, and 1.8 million Bbls of anticipated NGL production. Subsequent to June 30, 2012, the Company executed swaps on 2.5 million Bbls of oil from September 2012 through June 2015.

The Company’s commodity derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities. The fair value of the commodity derivative contracts was a net asset of $103.4 million and $31.2 million at June 30, 2012, and December 31, 2011, 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. The Company had no derivatives designated as cash flow hedges for the three-month and six-month periods ended June 30, 2012, and 2011, and as such, no ineffectiveness was recognized in earnings for the respective periods.

As a result of discontinuing hedge accounting on January 1, 2011, such fair values at December 31, 2010, were frozen in AOCIL as of the de-designation date and are reclassified into earnings as the original derivative transactions settle. As of June 30, 2012, AOCIL included immaterial net unrealized gains, net of income tax, on commodity derivative contracts that had been previously designated as cash flow hedges. The Company expects to reclassify into earnings from AOCIL after-tax net gains of $451,000 related to de-designated commodity derivative contracts during the next twelve months. Please refer to Note 11 - Fair Value Measurements for more information regarding the

Company’s derivative instruments, including its valuation techniques.

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

	As of June 30, 2012			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity Contracts	Current Assets	$69,207	Current Liabilities	$9,150
Commodity Contracts	Noncurrent Assets	44,270	Noncurrent Liabilities	956
Derivatives not designated as hedging instruments		$113,477		$10,106

	As of December 31, 2011			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity Contracts	Current Assets	$55,813	Current Liabilities	$42,806
Commodity Contracts	Noncurrent Assets	31,062	Noncurrent Liabilities	12,875
Derivatives not designated as hedging instruments		$86,875		$55,681

The following table summarizes the components of unrealized and realized derivative (gain) loss presented in the accompanying statements of operations:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands)			
Cash settlement (gain) loss:				
Oil contracts	$2,371	$10,633	$10,670	$17,363
Gas contracts	(16,252)	(590)	(31,464)	(2,317)
NGL contracts	(2,565)	3,933	(1,088)	5,347
Total cash settlement (gain) loss	$(16,446)	$13,976	$(21,882)	$20,393
Unrealized (gain) loss on change in fair value:				
Oil contracts	$(92,774)	$(51,216)	$(63,283)	$16,151
Gas contracts	29,867	(6,681)	12,233	(2,421)
NGL contracts	(18,759)	45	(22,964)	10,430
Total net unrealized (gain) loss on change in fair value	$(81,666)	$(57,852)	$(74,014)	$24,160
Total unrealized and realized derivative (gain) loss	$(98,112)	$(43,876)	$(95,896)	$44,553

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

Location in

	Derivatives	Consolidated Statements of Operations	For the Three Months Ended June 30, 2012	2011	For the Six Months Ended June 30, 2012	2011
			(in thousands)			
Amount reclassified from AOCIL	Commodity Contracts	Realized hedge gain (loss)	$(116)	$3,951	$(1,150)	$4,878

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The Company realized a net hedge gain of $185,000 and a net hedge loss of $6.3 million for the three months ended June 30, 2012, and 2011, respectively, and a net hedge gain of $1.8 million and a net hedge loss of $7.7 million from its commodity derivative contracts for the six months ended June 30, 2012, and 2011, respectively, shown net of income tax in the table above. Realized hedge gains and losses are comprised of settlements on commodity derivative contracts that were previously designated as cash flow hedges and are reported in the total operating revenues and other income section of the accompanying statements of operations.

Credit Related Contingent Features

As of June 30, 2012, and through the filing date of this report, all of the Company's derivative counterparties were members of the Company's credit facility syndicate. The Company's obligations under its credit facility and derivative contracts are secured by liens on substantially all of the Company's proved oil and gas properties.

Convertible Note Derivative Instruments

The contingent interest provision of the 3.50% Senior Convertible Notes was an embedded derivative instrument. The fair value of this derivative was determined to be immaterial as of December 31, 2011. The 3.50% Senior Convertible Notes were settled during the second quarter of 2012. Please refer to Note 5 - Long-Term Debt for additional discussion.

Note 11 - Fair Value Measurements

The Company follows fair value measurement authoritative accounting guidance for all assets and liabilities measured at fair value. That authoritative accounting 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 or 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 assets and liabilities that are measured at fair value and where they are classified within the hierarchy as of June 30, 2012:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives (1)	$—	$113,477	$—
Proved oil and gas properties (2)	$—	$—	$79,543
Unproved oil and gas properties (2)	$—	$—	$15,650
Liabilities:			
Derivatives (1)	$—	$10,106	$—
Net Profits Plan (1)	$—	$—	$89,591

(1) This represents a financial asset or liability that is measured at fair value on a recurring basis.
(2) This represents a non-financial asset or liability that is measured at fair value on a nonrecurring basis.

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The following is a listing of the Company's assets and liabilities that are measured at fair value and where they were classified within the hierarchy as of December 31, 2011:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives (1)	$—	$86,875	$—
Proved oil and gas properties (2)	$—	$—	$139,992
Unproved oil and gas properties (2)	$—	$—	$15,809
Liabilities:			
Derivatives (1)	$—	$55,681	$—
Net Profits Plan (1)	$—	$—	$107,731

(1) This represents a financial asset or liability that is measured at fair value on a recurring basis.
(2) This represents a non-financial asset or liability that is measured at fair value on a nonrecurring basis.

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.

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil, 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. The derivative instruments utilized by the Company are not considered by management to be complex, structured, or illiquid. The oil, gas, and NGL commodity derivative markets are highly active.

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

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

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

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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, gas, and NGL 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 lower commodity prices result in a smaller Net Profits Plan liability.

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, discount rates, and the overall market conditions, which are continually evaluated to consider the current market environment. 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, gas, and NGL commodity markets.

If the commodity prices used in the calculation changed by five percent, the liability recorded at June 30, 2012, would differ by approximately $8 million. A one percent increase or decrease in the discount rate would result in a change of approximately $4 million. Actual cash payments to be made to participants in future periods are dependent on realized actual production, realized commodity prices, and costs associated with the properties in each individual pool of the Net Profits Plan. Consequently, actual cash payments are inherently different from the amounts estimated.

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

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 June 30,		For the Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands)			
Beginning balance	$111,670	$147,403	$107,731	$135,850
Net increase (decrease) in liability [1]	(16,473)	(6,092)	(7,311)	18,193
Net settlements [1][2][3]	(5,606)	(7,892)	(10,829)	(20,624)
Transfers in (out) of Level 3	—	—	—	—
Ending balance	$89,591	$133,419	$89,591	$133,419

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(1) 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.

(2) 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 $1.4 million and $2.0 million for the three months ended June 30, 2012, and 2011, respectively, and $1.7 million and $6.3 million for the six months ended June 30, 2012, and 2011, respectively.

(3) During the first quarter of 2011, the Company elected to settle several Net Profits Plan pools associated with the acquisition of Nance Petroleum Corporation in 1999, through an aggregate $2.6 million cash payment. As a result, the Company reduced its Net Profits Plan liability by that amount. There was no impact on the accompanying statements of operations for the three-month or six-month periods ended June 30, 2011, related to these settlements.

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Long-term Debt

The 2019 Notes and 2021 Notes are valued using Level 1 inputs based on quoted secondary market trading prices. The estimated fair value of the 2019 Notes and the 2021 Notes as of June 30, 2012, was approximately $360 million and $356 million, respectively, and as of December 31, 2011, was approximately $359 million and $360 million, respectively.

The 2023 Notes are valued using Level 2 inputs based on bond valuation prices obtained from a third party source. The price is generated by qualitative algorithms that use direct market observations, such as recent sales, bid and ask prices from brokers, dealers, buy side firms, and other market inputs. The estimated fair value of these notes was approximately $403 million as of June 30, 2012. In accordance with the registration rights agreement discussed in Note 5 - Long-Term Debt, the Company is required to register the 2023 Notes within one year of issuance. Upon registration and subsequent trading, the notes will be valued using Level 1 inputs.

The estimated fair value of the 3.50% Senior Convertible Notes was approximately $394 million as of December 31, 2011. The estimated fair value of the embedded contingent interest derivative was immaterial as of December 31, 2011. The 3.50% Senior Convertible Notes were valued using Level 1 inputs, based on quoted secondary market trading prices. The 3.50% Senior Convertible Notes were settled during the second quarter of 2012. Please refer to Note 5 - Long-Term Debt for additional discussion.

Proved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. The Company uses Level 3 inputs and the income valuation technique, which converts future amounts to a single present value amount, to measure the fair value of proved properties through an application of discount rates and price forecasts selected by the Company’s management. The calculation of the discount rate is based on the best information available and was estimated to be 12 percent for the quarter ended June 30, 2012, and the year ended December 31, 2011. Management believes that the discount rate is representative of current market conditions and takes into account estimates of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The prices for oil and gas are forecasted based on New York Mercantile Exchange (“NYMEX”) strip pricing, adjusted for basis differentials, for the first five years. The prices for NGLs are forecasted using the Oil Price Information System Mont Belvieu (“OPIS”) pricing, adjusted for basis differentials, for the first five years. At the end of the first five years, a flat terminal price is used for each commodity stream. Future operating costs are also adjusted as deemed appropriate for these estimates.

As a result of asset write-downs, discussed in Note 13 - Impairment of Proved and Unproved Properties and Note 3 - Assets Held for Sale, the proved oil and gas properties measured at fair value within the accompanying balance sheets were $79.5 million at June 30, 2012, and $140.0 million at December 31, 2011.

Unproved Oil and Gas Properties

Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. The Company uses a market approach, which takes into account the following significant assumptions: future development plans, risk weighted potential resource recovery, and estimated reserve values to measure the fair value of unproved properties.
As a result of asset write-downs, discussed in Note 13 - Impairment of Proved and Unproved Properties, unproved oil and gas properties measured at fair value within the accompanying balance sheets were $15.7 million at June 30, 2012, and $15.8 million at December 31, 2011.

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 inventories measured at fair value in the accompanying balance sheets at June 30, 2012, or December 31, 2011.

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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, which takes into account the Company's credit risk, the time value of money, and the current economic state, to the undiscounted expected abandonment cash flows. 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 in the accompanying balance sheets at June 30, 2012, or December 31, 2011.

Note 12 - Acquisition and Development Agreement

In June 2011, the Company entered into an Acquisition and Development Agreement with Mitsui E&P Texas LP ("Mitsui"), an indirect subsidiary of Mitsui & Co., Ltd. (the "Acquisition and Development Agreement"). 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. As consideration for the oil and gas interests transferred, Mitsui 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. Based on the Company's forecast of the operator's drilling plans, it will take three to four years to fully utilize the carry. The Acquisition and Development Agreement also provided for reimbursement of capital expenditures and other costs, net of revenues, paid by the Company that were attributable to the transferred interest during the period between the effective date and the closing date, which the parties agreed would be applied over the carry period to cover the Company's remaining ten percent of drilling and completion costs for the affected acreage.

As of June 30, 2012, the Company held $109.5 million of contractually restricted cash payments from Mitsui, which will be used solely for development operations and accordingly are classified as non-current assets in the accompanying balance sheets. The Company has recorded a corresponding liability equal to the restricted cash balance. The portion of the liability related to development operations expected to occur within the next year is recorded in accounts payable and accrued expenses within the accompanying balance sheets. The portion of the liability related to development operations expected to occur more than one year in the future is recorded in other noncurrent liabilities within the accompanying balance sheets as of June 30, 2012. There was no net impact on the accompanying condensed consolidated statement of cash flows as restricted cash was offset against the corresponding liability in investing activities. Of the $680.0 million carry amount, $128.3 million had been spent as of June 30, 2012.

Note 13 - Impairment of Proved and Unproved Properties

Proved Properties

During the first half of 2012, the Company recorded proved property impairments of $38.5 million related to its Haynesville shale assets, due to a decline in natural gas prices. There were no proved property impairments recorded during the first half of 2011.

Unproved Properties

During the first half of 2012, the Company recorded abandonment and impairment of unproved properties expense of $10.8 million, the majority of which related to acreage we no longer intend to develop within the Rocky Mountain region. During the first half of 2011, the Company recorded abandonment and impairment of unproved properties expense of $4.3 million associated with lease expirations in the Mid-Continent region.

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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, development, and production of oil, 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, the Haynesville, and Woodford shale resource plays, and the Permian Basin. 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 provides for stable and predictable production and reserve growth.

Our principal business strategy is focused on the early capture of resource plays in order to create and then enhance value for our shareholders, while maintaining a strong balance sheet. We strive to leverage industry-leading exploration and leasehold acquisition teams to quickly acquire and test new resource play concepts at a reasonable cost. Once we have identified potential value through these efforts, our goal is to develop such potential through top-tier operational and project execution, and as appropriate, mitigate our risks by selectively divesting portions of certain assets. We continually examine our portfolio for opportunities to improve the quality of our asset base in order to maximize our returns and preserve our financial strength.

In the second quarter of 2012, we had the following financial and operational results:

- Average daily production for the three months ended June 30, 2012, was 25.9 MBbls of oil, 309.2 MMcf of gas, and 15.2 MBbls of NGLs, for an average equivalent production rate of 555.7 MMCFE per day, compared with 436.9 MMCFE per day for the same period in 2011. Please see additional discussion below under the caption Production Results.

- Net income for the three months ended June 30, 2012, was $24.9 million, or $0.37 per diluted share, compared to net income for the three months ended June 30, 2011, of $124.5 million or $1.86 per diluted share. Please refer to Note 9 - Earnings per Share in Part I, Item 1 of this report for additional discussion of the impact the conversion of our 3.50% Senior Convertible Notes had on our earnings per share calculation and to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2012, and 2011 for additional discussion regarding the components of net income.

- Costs incurred for oil and gas producing activities for the three months ended June 30, 2012, were $407.7 million, compared with $352.2 million for the same period in 2011. Please see additional discussion below under the caption Costs Incurred in Oil and Gas Producing Activities.

- EBITDAX, a non-GAAP financial measure, for the three months ended June 30, 2012, was $213.7 million, compared with $242.4 million for the same period in 2011. Please refer to the caption Non-GAAP Financial Measures below for additional discussion, including a reconciliation from GAAP net income to EBITDAX.

Oil, Gas, and NGL Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for our oil, gas, and NGL production, which can fluctuate dramatically. We sell the majority of our gas under contracts using first-of-the-month index pricing, which means 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 paying us a monthly average of the posted OPIS daily settlement prices, adjusted for processing, transportation, and location differentials. Our oil and condensate are sold using contracts paying us either the average of the NYMEX West Texas Intermediate (“WTI”) daily settlement price or the average of alternative posted prices for the periods in which the product is produced, adjusted for quality, transportation, and location differentials.

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The following table summarizes commodity price data for the first and second quarters of 2012, as well as the second quarter of 2011:

	For the Three Months Ended		
	June 30, 2012	March 31, 2012	June 30, 2011
Crude Oil (per Bbl):			
Average NYMEX price	$93.30	$102.99	$102.28
Realized price	$82.52	$90.67	$97.51
Natural Gas:			
Average NYMEX price (per MMBtu)	$2.28	$2.44	$4.36
Realized price (per Mcf)	$2.34	$2.90	$4.63
Natural Gas Liquids (per Bbl):			
Average OPIS price	$43.71	$54.15	$61.62
Realized price	$37.79	$44.67	$54.02

Note: Average OPIS prices per barrel of NGL, historical or strip, are based on a product mix of 37% Ethane, 6% Isobutane, 11% Normal Butane, 14% 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, as a global commodity, the price of oil will likely continue to be impacted by real or perceived geopolitical risks in oil producing regions of the world, particularly the Middle East. The relative strength of the U.S. dollar compared to other currencies could affect the price of oil. The supply of NGLs in the U.S. is expected to grow in the near term as a result of the number of industry participants targeting projects that produce these products. The pace of NGL production is growing faster than the capacity to process or consume NGLs, which will likely negatively impact pricing in the near term. The prices of several of the specific NGL products correlate to the price of oil and accordingly are likely to directionally follow that market. Gas prices have been under downward pressure due to current market oversupply resulting from high levels of drilling activity, high levels of gas in storage, an unusually mild winter in the United States, and tepid economic growth. The 12-month strip prices for NYMEX WTI oil, NYMEX Henry Hub gas, and OPIS NGLs (same product mix as discussed above) as of June 30, 2012, were $87.14 per Bbl of oil, $3.29 per MMBtu of gas, and $37.26 per Bbl of NGLs, respectively. Comparable prices as of July 27, 2012, were $91.63 per Bbl of oil, $3.41 per MMBtu of gas, and $40.02 per Bbl of NGLs, respectively.
While changes in quoted NYMEX oil and gas and OPIS NGL prices are generally used as a basis for comparison within our industry, the prices we receive are 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.

Derivative Activity
We use financial derivative instruments as part of our financial risk management program. We have a 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 our current derivative contracts, we believe we have established a base cash flow stream for our future operations and have partially reduced our exposure to volatility in commodity prices. Our use of costless collars for a portion of our derivatives allows us to participate in some of the upward movements in oil, gas, and NGL prices while also setting a price floor for a portion of our production. Please refer to Note 10 - Derivative Financial Instruments of Part I, Item 1 of this report for additional information regarding our oil, gas, and NGL derivatives, and the caption, Summary of Oil, Gas, and NGL Derivative Contracts in Place, below.

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The following table presents a reconciliation from our realized price to our adjusted price for the commodities indicated, including the effects of derivative cash settlements for the first and second quarters of 2012, as well as the second quarter of 2011:

	For the Three Months Ended		
	June 30, 2012	March 31, 2012	June 30, 2011
Crude Oil (per Bbl):			
Realized price	$82.52	$90.67	$97.51
Less the effects of derivative cash settlements	(2.00)	(4.32)	(13.11)
Adjusted price, including the effects of derivative cash settlements	$80.52	$86.35	$84.40
Natural Gas (per Mcf):			
Realized price	$2.34	$2.90	$4.63
Add the effects of derivative cash settlements	0.68	0.70	0.38
Adjusted price, including the effects of derivative cash settlements	$3.02	$3.60	$5.01
Natural Gas Liquids (per Bbl):			
Realized price	$37.79	$44.67	$54.02
Add (less) the effects of derivative cash settlements	1.65	(1.69)	(6.53)
Adjusted price, including the effects of derivative cash settlements	$39.44	$42.98	$47.49

The Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act") included provisions requiring over-the-counter derivative transactions to be executed through an exchange or centrally cleared. On July 10, 2012, the Commodities Futures Trading Commission ("CFTC") and the SEC adopted final joint rules under Title VII of the Dodd-Frank Act, which define certain terms and determine what types of transactions will be subject to heightened scrutiny under the Dodd-Frank Act swap rules. The issuance of these final rules also triggers compliance dates for a number of other final Dodd-Frank Act rules, including new rules proposed by the CFTC governing margin requirements for uncleared swaps entered into by non-bank swap entities, and new rules proposed by U.S. banking regulators regarding margin requirements for uncleared swaps entered into by bank swap entities. The ultimate effect on our business of these new rules and any additional regulations 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

Second Quarter 2012 Highlights

Operational Activities. We operated an average of 16 drilling rigs during the second quarter of 2012. The primary focus of our operated drilling activity this year has been on oil and NGL-rich gas projects. We also participated in non-operated drilling activity primarily in oil and NGL-rich plays.

In our Eagle Ford shale program in South Texas, we operated six drilling rigs throughout the second quarter of 2012. We focused our drilling in areas with higher BTU gas content and condensate yields. We believe we have sufficiently secured the requisite services, such as gas pipeline takeaway capacity and drilling and completion services, to support our current development plans. We will continue to explore additional arrangements to facilitate the future growth of our operated program. During the quarter, we began to experience challenges with our third-party operated mid-stream gathering system due to delays in the installation of tank batteries and a lack of sufficient compression, which constrained our production volumes in this program. In our non-operated Eagle Ford program, the operator had nine drilling rigs running during the second quarter of 2012. We expect the majority of our non-operated Eagle Ford drilling program to be funded over the next three to four years by our previously announced Acquisition and Development Agreement with Mitsui.

During the second quarter, we operated three drilling rigs in our Bakken/Three Forks program in the North Dakota portion of the Williston Basin focusing on our Gooseneck, Raven, and Bear Den prospects. In the southern portion of our Rocky Mountain region, we operated one rig testing various formations in the Powder River Basin of Wyoming as part of a continued delineation effort.

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Effective January 1, 2012, we combined our ArkLaTex region into our Mid-Continent region, based in Tulsa, Oklahoma, for operational and reporting purposes. During the second quarter of 2012, we operated three drilling rigs in our Granite Wash program in western Oklahoma and the Texas Panhandle, focusing primarily on the Marmaton washes due to their higher oil and NGL contributions. Essentially all of our acreage position in this play is held by production. We completed our operated Haynesville shale program earlier in the year after reaching held by production status on substantially all of our acreage.

We operated three drilling rigs in our Permian region in the second quarter of 2012. One rig was focused on testing the Mississippian limestone formation in the northeast Midland Basin, where we have approximately 65,000 net acres. The second rig was focused on the Bone Spring formation in New Mexico. The third rig operated in the northern Permian Basin and focused on testing various shale targets.

Production Results. The table below provides a regional breakdown of our second quarter 2012 production:

	South Texas & Gulf Coast	Mid-Continent	Permian	Rocky Mountain	Total [(1)]
Second quarter 2012 production:					
Oil (MMBbl)	0.7	0.1	0.3	1.3	2.4
Gas (Bcf)	12.8	13.4	0.8	1.1	28.1
NGLs (MMBbl)	1.3	0.1	—	—	1.4
Equivalent (BCFE)	24.4	14.6	2.7	8.9	50.6
Avg. daily equivalents (MMCFE/d)	268.4	160.7	29.1	97.5	555.7
Relative percentage	48 %	29 %	5 %	18 %	100 %

(1) Totals may not add due to rounding.

For the second quarter of 2012, our production was led by our South Texas & Gulf Coast region driven by our focus on the development of our Eagle Ford shale operated and non-operated programs. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2012, and 2011 for additional discussion on production.

Costs Incurred in Oil and Gas Producing Activities. Costs incurred in oil and gas property acquisition, exploration and development activities, whether capitalized or expensed, are summarized as follows:

	For the Three Months Ended June 30, 2012 (in millions)
Development costs	$311.9
Facility costs	12.0
Exploration costs	60.5
Acquisitions:	
Proved properties	5.3
Leasing activity	18.0
Total, including asset retirement obligations	$407.7

The majority of costs incurred for oil and gas producing activities during 2012 were spent on the development of our Eagle Ford shale and Bakken/Three Forks programs. Please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we fund our capital program.

3.50% Senior Convertible Notes. In April 2012, we called for redemption of our outstanding 3.50% Senior Convertible Notes. We settled the principal amount of all converted 3.50% Senior Convertible Notes in cash with the excess value settled in shares of common stock. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional information.

2023 Notes. On June 29, 2012, we issued $400.0 million in aggregate principal amount of 2023 Notes. The notes were issued at par and mature on January 1, 2023. We received net proceeds of $392.3 million from this issuance, which we used to pay down outstanding borrowings under our credit facility. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional information.

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Marketing of Properties. During the second quarter of 2012, we began to remarket our Marcellus shale assets located in Pennsylvania and to market certain assets located in our Rocky Mountain region. Please refer to Note 3 - Assets Held for Sale in Part I, Item 1 of this report, as well as Legal Proceedings in Part II, Item 1 of this report for additional information.

Impairment of Properties. In the second quarter of 2012, we recorded proved property impairments of $38.5 million related to our Haynesville shale assets due to low natural gas prices.

Unsuccessful Sale of Properties. During the second quarter of 2012, we reclassified assets located in our Rocky Mountain region previously classified as held for sale as of March 31, 2012, to assets held and used, as these assets were no longer being actively marketed, which resulted in a $28.3 million loss. Please refer to Note 3 - Assets Held for Sale in Part I, Item 1 of this report for additional discussion.

Equity Compensation. Subsequent to June 30, 2012, we granted 365,787 RSUs and 314,853 PSUs pursuant to our long-term equity incentive program. Also subsequent to June 30, 2012, we issued 923,685 shares of our common stock to settle PSU and RSU awards granted in previous years. Please refer to Note 7 - Compensation Plans in Part I, Item 1 of this report for additional discussion.

First Six Months 2012 Highlights

Production Results. The table below provides a regional breakdown of our first half of 2012 production:

	South Texas & Gulf Coast	Mid-Continent	Permian	Rocky Mountain	Total [1]
First six months of 2012 production:					
Oil (MMBbl)	1.4	0.2	0.6	2.6	4.9
Gas (Bcf)	25.7	27.3	1.5	2.3	56.8
NGLs (MMBbl)	2.3	0.2	—	—	2.5
Equivalent (BCFE)	48.3	29.6	5.3	18.1	101.3
Avg. daily equivalents (MMCFE/d)	265.3	162.7	28.9	99.5	556.4
Relative percentage	48 %	29 %	5 %	18 %	100 %

[1] Totals may not add due to rounding.

For the first half of 2012, our production was led by our South Texas & Gulf Coast region due to our focus on the development of our Eagle Ford shale operated and non-operated programs. Please refer to Comparison of Financial Results and Trends Between the Six Months Ended June 30, 2012, and 2011 for additional discussion on production.

Costs Incurred in Oil and Gas Producing Activities. Costs incurred in oil and gas property acquisition, exploration and development activities, whether capitalized or expensed, are summarized as follows:

	For the Six Months Ended June 30, 2012 (in millions)
Development costs	$598.5
Facility costs	23.2
Exploration costs	106.5
Acquisitions	
Proved properties	5.3
Leasing activity	42.2
Total, including asset retirement obligations	$775.7

Outlook for the Remainder of 2012

Our capital program for 2012 is expected to be approximately $1.5 billion, of which $1.1 billion to $1.2 billion will be focused on drilling and completion activities. Approximately 85 percent of our drilling budget has been allocated to our operated properties, and over 95 percent of our allocated drilling and completion capital for 2012 is expected to be directed to oil and NGL-rich projects.

In 2012, we now plan to invest between $520 million and $570 million of drilling and completion capital in our operated Eagle Ford shale program, which represents a decrease of approximately $130 million from our previous guidance of $650 million to $700 million of drilling and completion capital allocated for the program. The decrease in expected capital investment is primarily driven by the deferral of a number of completions as a result of midstream gathering constraints we began experiencing in the second quarter of 2012. We are currently operating six drilling rigs in this program, three of which are pod drilling while the remainder will drill wells throughout our acreage position to satisfy leasehold obligations. We expect to drop one operated rig later in the year. Aside from the drilling necessary to satisfy leasehold obligations throughout our position, we expect to focus our drilling on the northern portion of our acreage position which has higher condensate and NGL yields. For the remainder of 2012, we plan to continue testing our well design and acreage spacing assumptions in order to determine the ultimate development spacing and to optimize the well performance and capital efficiency of our operated acreage.

In our non-operated Eagle Ford shale program, the operator is currently operating nine drilling rigs and one spudder rig. Based on the operator’s stated plans, our expectation is that the number of rigs will remain relatively constant throughout the year. Mitsui is obligated to carry the majority of the drilling and completion costs of our non-operated drilling activity through 2012 and, as such, we expect to deploy minimal capital related to drilling in this program. Costs that are not associated with drilling or completion activities, such as infrastructure construction, are not carried by Mitsui, and accordingly we will be responsible for our proportionate share of these costs. During the second quarter, the operator increased the amount of expected capital to be expended on infrastructure expansion, which is a cost not carried by Mitsui.

We plan to invest between $160 million and $185 million of our capital budget in our operated Bakken/Three Forks program in the North Dakota portion of the Williston Basin in 2012. We added a fourth drilling rig in this program at the end of the second quarter. Our plan with these rigs is to drill sufficient acreage to hold our Raven and Gooseneck prospects through production and to begin infill drilling in our Bear Den prospect, which is held by production.

In our Granite Wash program, we are currently running three drilling rigs focused on the liquids-rich Marmaton washes. As most of this acreage position is held by production, we expect to drop one of the three rigs that we operate in the program during the second half of 2012 as part of a reallocation of capital throughout our development program. We have allocated approximately $50 million to $60 million to this program, a decrease of approximately $10 million from our previous guidance of $60 million to $70 million.

We have allocated $95 million to $105 million on our operated Permian program, which is focused on three projects in our Permian region, each of which is in a different stage of maturity in our delineation and development process. Beginning in the third quarter, we added a fourth rig in our Permian region, which is focused on the Mississippian limestone in the northeastern Midland Basin.

We plan to invest the remainder of our allocated drilling and completion capital for 2012 on our outside operated and other operated programs. The outside operated capital primarily consists of our non-operated Bakken/Three Forks program as well as our non-operated Granite Wash program. We currently have $150 million to $200 million allocated to this program, which represents an increase from our previous guidance of approximately $50 million from our previous guidance, primarily due to an increase in the amount allocated to our non-operated Bakken/Three Forks program. For 2012, we budgeted $60 million to $80 million on our other operated activities which includes first half activity in our Haynesville shale program as well as activity planned for the year in our Powder River Basin program.

Please refer to Overview of Liquidity and Capital Resources for additional discussion regarding how we intend to fund our 2012 capital program.

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Financial Results of Operations and Additional Comparative Data

The table below provides information regarding selected production and financial information for the quarter ended June 30, 2012, and the immediately preceding three quarters. Additional details of per MCFE costs are presented later in this section.

	For the Three Months Ended			
	June 30, 2012	March 31, 2012	December 31, 2011	September 30, 2011
	(in millions, except for production data)			
Production (BCFE)	50.6	50.7	51.3	42.5
Oil, gas, and NGL production revenue	$312.6	$362.6	$397.0	$325.2
Realized hedge gain (loss)	$0.2	$1.7	$(6.2)	$(6.8)
Gain (loss) on divestiture activity	$(24.2)	$1.5	$(25.0)	$190.7
Lease operating expense	$46.1	$39.4	$43.5	$40.0
Transportation costs	$30.3	$28.6	$30.7	$23.9
Production taxes	$14.7	$19.1	$19.0	$13.8
DD&A	$161.6	$169.6	$167.3	$123.1
Exploration	$22.0	$18.6	$20.0	$11.3
Impairment of proved properties	$38.5	$—	$170.5	$48.5
Abandonment and impairment of unproved properties	$10.7	$0.1	$3.1	$—
General and administrative	$31.1	$28.1	$35.6	$29.8
Change in Net Profits Plan liability	$(22.1)	$3.9	$(0.8)	$(24.9)
Unrealized and realized derivative (gain) loss	$(98.1)	$2.2	$46.8	$(128.4)
Net income (loss)	$24.9	$26.3	$(120.7)	$230.1

Selected Performance Metrics:

	For the Three Months Ended			
	June 30, 2012	March 31, 2012	December 31, 2011	September 30, 2011
Average net daily production equivalent (MMCFE per day)	555.7	557.0	557.9	462.1
Lease operating expense (per MCFE)	$0.91	$0.78	$0.85	$0.94
Transportation costs (per MCFE)	$0.60	$0.56	$0.60	$0.56
Production taxes as a percent of oil, gas, and NGL production revenue	4.7 %	5.3 %	4.8 %	4.3 %
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per MCFE)	$3.20	$3.35	$3.26	$2.89
General and administrative (per MCFE)	$0.62	$0.56	$0.69	$0.70

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

	For the Three Months Ended June 30,		Amount Change Between Periods	Percent Change Between Periods	For the Six Months Ended June 30,		Amount Change Between Periods	Percent Change Between Periods
	2012	2011			2012	2011		
Net production volumes								
Oil (MMBbl)	2.4	1.9	0.5	27 %	4.9	3.6	1.2	34 %
Gas (Bcf)	28.1	23.9	4.2	18 %	56.8	45.6	11.1	24 %
NGLs (MMBbl)	1.4	0.8	0.6	75 %	2.5	1.4	1.1	81 %
Equivalent (BCFE)	50.6	39.8	10.8	27 %	101.3	75.9	25.4	33 %
Average net daily production								
Oil (MBbl per day)	25.9	20.4	5.6	27 %	26.7	20.1	6.6	33 %
Gas (MMcf per day)	309.2	262.7	46.5	18 %	312.0	252.2	59.9	24 %
NGLs (MBbl per day)	15.2	8.7	6.5	75 %	14.0	7.8	6.2	80 %
Equivalent (MMCFE per day)	555.7	436.9	118.8	27 %	556.4	419.3	137.1	33 %
Oil, gas, & NGL production revenue (in millions)								
Oil production revenue	$194.7	$180.6	$14.1	8 %	$422.1	$333.7	$88.4	26 %
Gas production revenue	65.7	110.6	(44.9)	(41)%	148.9	205.2	(56.3)	(27)%
NGL production revenue	52.2	42.7	9.5	22 %	104.2	71.3	32.9	46 %
Total	$312.6	$333.9	$(21.3)	(6)%	$675.2	$610.2	$65.0	11 %
Oil, gas, & NGL production expense (in millions)								
Lease operating expense	$46.1	$33.1	$13.0	39 %	$85.6	$66.4	$19.2	29 %
Transportation costs	30.3	16.9	13.4	79 %	58.9	31.8	27.1	85 %
Production taxes	14.7	3.3	11.4	345 %	33.8	21.0	12.8	61 %
Total	$91.1	$53.3	$37.8	71 %	$178.3	$119.2	$59.1	50 %
Realized price								
Oil (per Bbl)	$82.52	$97.51	$(14.99)	(15)%	$86.72	$91.76	$(5.04)	(5)%
Gas (per Mcf)	$2.34	$4.63	$(2.29)	(49)%	$2.62	$4.50	$(1.88)	(42)%
NGLs (per Bbl)	$37.79	$54.02	$(16.23)	(30)%	$40.94	$50.80	$(9.86)	(19)%
Per MCFE	$6.18	$8.40	$(2.22)	(26)%	$6.67	$8.04	$(1.37)	(17)%
Per MCFE Data								
Production costs:								
Lease operating expenses	$0.91	$0.84	$0.07	8 %	$0.85	$0.87	$(0.02)	(2)%
Transportation costs	$0.60	$0.42	$0.18	43 %	$0.58	$0.42	$0.16	38 %
Production taxes	$0.29	$0.08	$0.21	263 %	$0.33	$0.28	$0.05	18 %
General and administrative	$0.62	$0.69	$(0.07)	(10)%	$0.59	$0.70	$(0.11)	(16)%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$3.20	$2.90	$0.30	10 %	$3.27	$2.91	$0.36	12 %
Derivative cash settlement [(1)]	$0.33	$(0.51)	$0.84	(165)%	$0.23	$(0.37)	$0.60	(162)%
Earnings per share information								
Basic net income per common share	$0.39	$1.96	$(1.57)	(80)%	$0.80	$1.67	$(0.87)	(52)%
Diluted net income per common share	$0.37	$1.86	$(1.49)	(80)%	$0.76	$1.59	$(0.83)	(52)%
Basic weighted-average common shares outstanding	64,585	63,638	947	1 %	64,345	63,543	802	1 %

Diluted weighted-average common shares outstanding	67,556	66,909	647	1	%	67,806	66,695	1,111	2	%

(1) Derivative cash settlements are included within the realized hedge gain (loss) and unrealized and realized derivative (gain) loss line items in the accompanying statements of operations.

We present per MCFE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis. Average daily reported production for the three and six months ended June 30, 2012, increased 27 percent and 33 percent, respectively, compared with the same periods in 2011, driven primarily by the development of our Eagle Ford shale program, as well as a substantial increase in production from our Bakken/Three Forks program.

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Changes in production volumes, revenues, and costs reflect the cyclical and highly volatile nature of our industry. Our realized price on a per MCFE basis for the three and six months ended June 30, 2012, decreased 26 percent and 17 percent, respectively, compared to the same periods in 2011. The decrease in realized price is due to a continuing decline in commodity prices during 2012.

LOE on a per MCFE basis for the three and six months ended June 30, 2012, increased eight percent and decreased two percent, respectively, compared to the same periods in 2011. Overall, LOE in all regions has increased throughout the first half of the year as demand for oil and gas services has increased. This was offset by the divestiture of non-strategic properties with meaningfully higher per unit operating costs within our Mid-Continent region that closed at the end of the second quarter of 2011. In the second quarter of 2012, workover activity in our South Texas & Gulf Coast region caused LOE on a per MCFE basis to increase. We believe the current high level of industry activity, particularly in oil and NGL-rich gas plays, has the potential to cause continued increases in LOE for the rest of 2012.

Production taxes on a per MCFE basis for the three and six months ended June 30, 2012, increased 263 percent and 18 percent, respectively, compared to the same periods in 2011. In the second quarter of 2011, we were notified that we qualified for severance tax incentive rebate programs for wells in certain areas of Texas. A sizable incentive tax rebate was recorded in the second quarter of 2011, significantly decreasing that quarter’s per MCFE rate. We expect our future operated wells drilled in these areas to qualify for incentive tax rebate programs. We generally expect production taxes to trend with oil, gas, and NGL revenues.

Transportation costs on a per MCFE basis for the three and six months ended June 30, 2012, increased 43 percent and 38 percent, respectively, compared to the same periods in 2011. This is a result of increased production in our Eagle Ford shale program, in which transportation arrangements have resulted in higher per unit transportation costs, compared with our other regions, due to the costs of developing infrastructure in this emerging play. We anticipate transportation costs will continue to increase on a per MCFE basis as our Eagle Ford shale program becomes a larger portion of our total production.

General and administrative expense on a per MCFE basis for the three and six months ended June 30, 2012, decreased 10 percent and 16 percent, respectively, compared to the same periods in 2011, as 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.

DD&A expense on a per MCFE basis for the three and six months ended June 30, 2012, increased 10 percent and 12 percent, respectively, compared to the same periods in 2011. Our DD&A rate increased as a result of the transfer of a portion of our non-operated working interest to Mitsui, which reduced our reserve base but had no impact on the carrying value of our assets. As we utilize our carry with Mitsui, we expect there to be less of an impact to our DD&A rate as we add reserves without incurring the carried capital costs. Please refer to Note 12 - Acquisition and Development Agreement in Part I, Item 1 of this report for additional discussion on the Mitsui transaction. 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 held for sale can also impact our DD&A rate since these properties are no longer depleted.

Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2012, and 2011 and Comparison of Financial Results and Trends Between the Six Months Ended June 30, 2012, and 2011 for additional discussion on oil, gas, and NGL production expense, DD&A, and general and administrative expense.

Please refer to Note 9 - Earnings per Share in Part I, Item 1 of this report for additional discussion on the types of shares included in our basic and diluted net income per common share calculations. During the second quarter of 2012, we called for redemption all of our outstanding 3.50% Senior Convertible Notes. The shares issued upon conversion are reflected in our basic weighted-average common shares outstanding calculations for the three and six months ended June 30, 2012. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional discussion on our 3.50% Senior Convertible Notes.

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Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2012, and 2011

Oil, gas, and NGL production revenue. Average daily production increased 27 percent to 555.7 MMCFE for the quarter ended June 30, 2012, compared with 436.9 MMCFE for the quarter ended June 30, 2011. The following table presents the regional changes in our oil, gas, and NGL production, revenues, and costs between the two quarters:

	Average Net Daily Production Added (Lost) (MMCFE/d)	Oil, Gas, & NGL Revenue Added (Lost) (in millions)	Production Costs Increase (Decrease) (in millions)
South Texas & Gulf Coast	106.3	$9.6	$31.1
Mid-Continent	(19.6)	(43.2)	(0.6)
Permian	(2.5)	(9.0)	1.3
Rocky Mountain	34.6	21.3	6.0
Total	118.8	$(21.3)	$37.8

The largest regional production increase 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 expect production from this region to increase for the next several years. We also saw an increase in production in our Rocky Mountain region as a result of strong production performance from wells drilled in our Bakken/Three Forks program in late 2011 and early 2012.

The following table summarizes the realized prices we received for the three months ended June 30, 2012, and 2011 before the effects of derivative cash settlements:

	For the Three Months Ended June 30, 2012	2011
Realized oil price ($/Bbl)	$82.52	$97.51
Realized gas price ($/Mcf)	$2.34	$4.63
Realized NGL price ($/Bbl)	$37.79	$54.02
Realized equivalent price ($/MCFE)	$6.18	$8.40

A 26 percent decrease in realized price per MCFE combined with a 27 percent increase in production on an equivalent basis resulted in a six percent decrease in revenue between the two periods. Realized prices per MCFE for all commodities decreased, with gas prices experiencing the largest decline. This decrease was partially offset by increased production, particularly production for oil and NGLs. Based on current levels of activity, we expect production volumes to increase annually for the next several years. We expect our realized prices to trend with commodity prices.

Realized hedge gain (loss). We recorded a net realized hedge gain of $185,000 for the three-month period ended June 30, 2012, compared with a $6.3 million net realized hedge loss for the same period in 2011. These amounts are comprised of realized cash settlements on commodity derivative contracts that were previously recorded in AOCIL. 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 (loss) on divestiture activity. We recorded a $24.2 million loss on divestiture activity for the quarter ended June 30, 2012, compared with a $30.0 million net gain for the comparable period of 2011. The loss in the second quarter of 2012 is the result of an unsuccessful sale of properties. The gain in second quarter of 2011 related to the divestiture of our Constitution Field assets in our Mid-Continent region. We will continue to evaluate our portfolio to determine whether there are non-strategic properties we could divest. Please refer to Note 3 - Assets Held for Sale in Part I, Item 1 of this report for additional discussion.

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Marketed gas system revenue and expense. Marketed gas system revenue decreased $2.1 million to $16.7 million for the quarter ended June 30, 2012, compared with $18.8 million for the same period of 2011 as a result of declining gas prices. Marketed gas system expense decreased $300,000 to $16.2 million for the quarter ended June 30, 2012, compared with $16.5 million for the same period of 2011. Overall our net margin in the second quarter of 2012 decreased as we entered into a new throughput agreement resulting in higher processing fees, which drove our expense up. We expect that marketed gas system revenue and expense will continue to correlate with increases and decreases in production and our realized gas price.

Oil, gas, and NGL production expense. Total production costs for the second quarter of 2012 increased 71 percent to $91.1 million compared with $53.3 million for the same period of 2011 partially due to a 27 percent increase in net production volumes on an equivalent basis. Please refer to the caption A three-month and six-month overview of selected production and financial information, including trends above for discussion of production costs on a per MCFE basis.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A expense increased $46.2 million, or 40 percent, to $161.6 million for the three-month period ended June 30, 2012, compared with $115.4 million for the same period in 2011 due to an increase in our depreciable asset base as a result of the continued development of our Eagle Ford and Bakken/Three Forks assets and the associated growth in our production. Please refer to the caption A three-month and six-month overview of selected production and financial information, including trends above for discussion of DD&A on a per MCFE basis.

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

	For the Three Months Ended June 30,	
	2012	2011
	(in millions)	
Geological and geophysical expenses	$1.5	$—
Exploratory dry hole expense	7.6	—
Overhead and other expenses	12.9	9.6
Total	$22.0	$9.6

Exploration expense for the three months ended June 30, 2012, increased 129 percent compared to the same period in 2011 due in part to an exploratory well being deemed a dry hole in our Rocky Mountain region in the second quarter of 2012, as well as an increase in our technical employee headcount driving our exploratory overhead expense up. An exploratory project resulting in non-commercial quantities of oil, gas, or NGLs is deemed an exploratory dry hole and impacts the amount of exploration expense we record.

Impairment of proved properties. We recorded a $38.5 million impairment of proved oil and gas properties in the second quarter of 2012 related to our Haynesville shale assets, which was caused by a decrease in natural gas prices. We had no proved property impairments during the second quarter of 2011. Proved property impairments are more likely to occur in periods of low commodity prices.

Abandonment and impairment of unproved properties. We recorded abandonment and impairment of unproved properties expense of $10.7 million for the three months ended June 30, 2012, the majority of which related to acreage we no longer intend to develop within our Rocky Mountain region, compared with expense of $1.2 million for the same period of 2011, associated with lease expirations in our Mid-Continent region. We expect our abandonment and impairment of unproved properties to trend with lease expirations.

General and administrative. General and administrative expense increased $3.8 million to $31.1 million for the three months ended June 30, 2012, compared with $27.3 million for the same period of 2011. The change is due to an increase in employee headcount, which resulted in an increase to base compensation, benefits, accruals for cash bonuses, and general corporate office expenses incurred. Please refer to the caption A three-month and six-month overview of selected production and financial information, including trends above for discussion of general and administrative expense on a per MCFE basis.

Change in Net Profits Plan liability. This non-cash expense generally relates to the change in the estimated value of the associated liability between reporting periods. Please refer to Note 11 - Fair Value Measurements in Part I, Item 1 of this report for a discussion of the impact a direct payment to cash-out several pools had on our change in Net Profits Plan liability in 2011. For the quarter ended June 30, 2012, we recorded a non-cash benefit of $22.1 million compared to a benefit of $14.0 million for the

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same period in 2011. The decrease in strip prices for oil, gas, and NGLs was larger during the period from March 31, 2012, to June 30, 2012, than in the comparable period in 2011, resulting in a larger decrease in the liability and corresponding increase in the benefit recognized on the accompanying statements of operations for the second quarter of 2012. The change in our liability is subject to estimation and may change dramatically from period to period based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, and production costs. Payments made to participants as a result of divestitures will also impact our liability. We broadly expect the change in our Net Profits Plan liability to trend with changes in strip prices for oil, gas, and NGLs.

Unrealized and realized derivative (gain) loss. We recognized an unrealized and realized derivative gain of $98.1 million for the second quarter of 2012 compared to a gain of $43.9 million for the same period in 2011, as declining commodity prices have resulted in more favorable derivative positions in the second quarter of 2012. These amounts include the change in fair value on commodity derivative contracts and realized cash settlement gains or losses on derivatives for which unrealized changes in fair value were not previously recorded in AOCIL. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional discussion.

Income tax expense. We recorded income tax expense of $14.8 million for the second quarter of 2012 compared to an expense of $72.9 million for the second quarter of 2011, resulting in effective tax rates of 37.3 percent and 36.9 percent, respectively. The change in income tax expense is a result of the differences in components of net income, primarily a derivative gain in 2012 compared to a derivative loss in 2011, as well as the effect from the sale of assets. Based on our projections at the end of the second quarter of 2012, we expect that we will not owe federal income taxes for the current year.

Comparison of Financial Results and Trends Between the Six Months Ended June 30, 2012, and 2011

Oil, gas, and NGL production revenue. Average daily production increased 33 percent to 556.4 MMCFE for the six months ended June 30, 2012, compared with 419.3 MMCFE for the same period in 2011. The following table presents the regional changes in our oil, gas, and NGL production, revenues, and costs between the two periods:

	Average Net Daily Production Added (Lost) (MMCFE/d)	Oil, Gas, & NGL Revenue Added (Lost) (in millions)	Production Costs Increase (in millions)
South Texas & Gulf Coast	110.3	$67.9	$43.7
Mid-Continent	(2.5)	(52.7)	0.2
Permian	(3.8)	(13.7)	0.6
Rocky Mountain	33.1	63.5	14.6
Total	137.1	$65.0	$59.1

Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2012, and 2011 in the above section for additional discussion regarding the above results.

The following table summarizes the realized prices we received for the six months ended June 30, 2012, and 2011 before the effects of derivative cash settlements:

	For the Six Months Ended June 30,	
	2012	2011
Realized oil price ($/Bbl)	$86.72	$91.76
Realized gas price ($/Mcf)	$2.62	$4.50
Realized NGL price ($/Bbl)	$40.94	$50.80
Realized equivalent price ($/MCFE)	$6.67	$8.04

Revenue increased 11 percent between the two periods due to a 33 percent increase in production volumes on an equivalent basis, which was partially offset by a 17 percent decrease in the realized price per MCFE.

Realized hedge gain (loss). We recorded a net realized hedge gain of $1.8 million for the six-month period ended June 30, 2012, compared with a $7.7 million net loss for the same period in 2011. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2012, and 2011 in the above section for additional discussion.

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Gain (loss) on divestiture activity. We recorded a $22.7 million loss on divestiture activity for the six months ended June 30, 2012. We recorded a $54.9 million net gain for the comparable period of 2011, which related to the divestiture of non-strategic oil and gas properties in our Mid-Continent and Rocky Mountain regions. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2012, and 2011 in the above section for discussion of 2012 divestiture activity.

Marketed gas system revenue and expense. Marketed gas system revenue decreased $5.4 million to $29.1 million for the six months ended June 30, 2012, compared with $34.5 million for the same period of 2011 as a result of declining gas prices. Concurrent with the decrease in marketed gas system revenue, marketed gas system expense decreased $5.4 million to $27.1 million for the six months ended June 30, 2012, compared with $32.5 million for the same period of 2011. There was no significant change in our net margin.

Oil, gas, and NGL production expense. Total production costs for the first six months of 2012 increased 50 percent to $178.3 million compared with $119.2 million for the same period of 2011, as a result of a 33 percent increase in net production volumes on an equivalent basis and an increase in oil and gas service costs due to increased demand in the industry. Please refer to the caption A three-month and six-month overview of selected production and financial information, including trends above for discussion of production costs on a per MCFE basis.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A expense increased 50 percent to $331.2 million for the six-month period ended June 30, 2012, compared with $220.7 million for the same period in 2011 due to an increase in our depreciable asset base as a result of the continued development of our Eagle Ford and Bakken/Three Forks assets and the associated growth in our production. Please refer to the caption A three-month and six-month overview of selected production and financial information, including trends above for discussion of DD&A on a per MCFE basis.

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

	For the Six Months Ended June 30,	
	2012	2011
	(in millions)	
Geological and geophysical expenses	$5.4	$2.1
Exploratory dry hole expense	8.2	—
Overhead and other expenses	27.0	20.2
Total	$40.6	$22.3

Exploration expense for the six months ended June 30, 2012, increased 82 percent compared to the same period in 2011. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2012, and 2011 in the above section for additional discussion.

Impairment of proved properties. We recorded a $38.5 million impairment of proved oil and gas properties for the six months ended June 30, 2012, related to our Haynesville shale assets. We had no proved property impairments for the comparable period in 2011.

Abandonment and impairment of unproved properties. We recorded abandonment and impairment of unproved properties expense of $10.8 million for the six months ended June 30, 2012, compared with $4.3 million for the same period in 2011. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2012, and 2011 in the above section for additional discussion.

General and administrative. General and administrative expense increased $6.1 million to $59.3 million for the six months ended June 30, 2012, compared with $53.2 million for the same period of 2011 due to an increase in employee headcount. Please refer to the caption A three-month and six-month overview of selected production and financial information, including trends above for discussion of general and administrative expense on a per MCFE basis.

Change in Net Profits Plan liability. For the six months ended June 30, 2012, we recorded a non-cash benefit of $18.1 million compared to an expense of $211,000 for the same period in 2011. The strip prices for oil, gas, and NGLs decreased from December 31, 2011, to June 30, 2012, resulting in a decrease in the liability and corresponding increase in the benefit recognized on the accompanying statements of operations for the six months ending June 30, 2012. There was no significant change in strip prices between December 31, 2010, and June 30, 2011. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2012, and 2011 in the above section for additional discussion.

Unrealized and realized derivative (gain) loss. We recognized an unrealized and realized derivative gain of $95.9 million for the six-month period ended June 30, 2012, compared to a loss of $44.6 million for the same period in 2011. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2012, and 2011 in the above section for additional discussion.

Income tax expense. We recorded income tax expense of $30.5 million for the six-month period ended June 30, 2012, compared to an expense of $61.8 million for the same period in 2011, resulting in effective tax rates of 37.3 percent and 36.8 percent, respectively. The change in income tax expense is a result of the differences in components of net income, primarily due to a derivative gain in 2012 compared to a derivative loss in 2011, as well as the effect from the sale of assets.

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. We manage our liquidity and capital resources by entering into commitments for drilling and completion services for varying durations of time, which provides us some flexibility to reduce activity and capital expenditures in periods of prolonged commodity price decline.

Sources of Cash

We currently expect that cash flow from operations and divestiture proceeds will fund the majority of our 2012 capital program, with borrowings under our credit facility funding the remainder of the program. Although we anticipate that cash flow and borrowing capacity under our credit facility will be sufficient to fund our current capital program, accessing the capital markets is an option if deemed the best solution for our demands. We will continue to evaluate our property base to identify potential divestiture candidates.

Our primary sources of liquidity are the cash flows provided by our operating activities, borrowings under our credit facility, divestitures of properties, and other financing alternatives, including accessing capital markets. From time to time, we may 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 broader economy and by fluctuations in commodity 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 realized revenues from our oil, gas, and NGL sales through the use of derivative contracts as part of our commodity price risk management program. The borrowing base under our credit facility could be reduced as a result of lower commodity prices, divestitures of producing properties, or newly issued debt. Historically, decreases in commodity prices have limited our industry’s access to capital markets.

In the second quarter of 2012, we issued $400.0 million in aggregate principal amount of 2023 Notes. In late 2011, we consummated our Acquisition and Development Agreement with Mitsui pursuant to which Mitsui funds, or carries, 90 percent of certain drilling and completion costs attributable to our remaining interest in our non-operated Eagle Ford shale acreage until $680.0 million has been expended on our behalf. This carry is expected to be realized over the next three to four years, and as of June 30, 2012, the remaining carry amount was $551.7 million. Please refer to Note 12 - Acquisition and Development Agreement in Part I, Item 1 of this report for additional information.
Current proposals to fund the federal government budget include eliminating or reducing current tax deductions for intangible drilling costs, domestic production activities, 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 and our peers’ exploration and development capital programs. These funding reductions could have a significant adverse effect on oil and gas drilling in the United States for a number of years.

Credit Facility

In May 2011, we executed our Fourth Amended and Restated Credit Agreement, providing a $2.5 billion senior secured revolving credit facility with a scheduled maturity date of May 27, 2016. Our borrowing base under the credit facility was redetermined during the second quarter of 2012 at $1.5 billion and was subsequently reduced to $1.4 billion upon the issuance of our 2023 Notes in June 2012. Our borrowing base is subject to regular semi-annual redeterminations by our lenders and the next scheduled re-determination date is October 1, 2012. As of the filing date of this report, our lenders have committed to a current aggregate commitment amount of $1.0 billion under the credit agreement. We believe the current commitment amount is sufficient to meet our anticipated liquidity and operating needs. Through the filing date of this report, we have experienced no issues drawing upon our credit facility. No individual bank participating in the credit facility represents more than 10 percent of the lending commitments under the credit facility.

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The following table presents the outstanding balance, total amount of letters of credit, and available borrowing capacity under our credit facility as of June 30, 2012, and July 27, 2012.

	As of June 30, 2012	As of July 27, 2012
	(in millions)	
Credit facility balance	$61.0	$85.5
Letters of credit [(1)]	$0.8	$0.8
Available borrowing capacity	$938.2	$913.7

[(1)] Letters of credit reduce the amount available under the credit facility on a dollar-for-dollar basis.

Our daily weighted-average credit facility debt balance was approximately $236.4 million for the three months ended June 30, 2012. We had no outstanding borrowings during the second quarter of 2011. Our daily weighted-average credit facility debt balance was $118.5 million, and $8.2 million for the six months ended June 30, 2012, and June 30, 2011, respectively. Borrowings under our credit facility are secured by mortgages on substantially all of our oil and gas properties.

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, letter of credit fees, amortization of the debt discount related to our 3.50% Senior Convertible Notes, and amortization of deferred financing costs. Our weighted-average interest rates for the three months ended June 30, 2012, and 2011 were 5.5 percent and 10.6 percent, respectively, and 6.5 percent and 9.6 percent, respectively, for the six months ended June 30, 2012, and 2011. The decrease in our weighted-average interest rate from 2011 is a result of our 2019 Notes and 2021 Notes being outstanding for the entire six months ended June 30, 2012, at rates below the average interest rate for the same period in 2011. During the first six months of 2011, only our 2019 Notes were outstanding and only for part of the period. Our weighted-average borrowing rates for the three months ended June 30, 2012, and 2011, were 4.9 percent and 5.2 percent, respectively, and 5.3 percent and 5.1 percent, respectively for the six months ended June 30, 2012, and 2011. Our weighted-average borrowing rate for the three months ended June 30, 2012, was lower than the rate for the comparable period in 2011 as we funded the settlement of our 3.50% Senior Convertible Notes with our credit facility, which was partially offset by the coupon paid on our 2021 Notes. Our weighted-average borrowing rate for the six months ended June 30, 2012, was slightly higher than the rate for the comparable period in 2011 as the 2019 Notes and 2021 Notes were outstanding for the entire period and the 2023 Notes were issued at the end of the period. The coupons on these notes are all higher than the average borrowing rate for the six months ended June 30, 2011. Our weighted-average borrowing rate includes cash interest payments, and excludes cash fees paid on the unused portion of the credit facility's aggregate commitment amount, letter of credit fees, amortization of the convertible notes debt discount, and amortization of deferred financing costs.
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 EBITDAX, as defined under the caption Non-GAAP Financial Measures below, of less than 4.0 to 1.0 and an adjusted current ratio, as defined by our credit agreement, of no less than 1.0. As of June 30, 2012, our debt to EBITDAX ratio and adjusted current ratio as defined by our credit agreement, were 1.2 and 2.6, respectively. As of the filing date 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 trade payables, overhead, income taxes, dividends, and debt obligations, including interest. Expenditures for the exploration and development of oil and gas properties are the primary use of our capital resources. In the first six months of 2012, we spent $705.4 million for exploration and development capital activities and leasehold acquisitions. These amounts differ from the cost incurred amounts based on the timing of cash payments associated with these activities as

compared to the accrual-based activity upon which the costs incurred amounts are presented.
The amount and allocation of future capital expenditures will depend upon a number of factors, including the number and size of available acquisition and drilling opportunities, our cash flows from operating, investing, and financing activities, and our ability to assimilate acquisitions and execute our drilling program. In addition, the impact of oil, gas, and NGL prices on investment opportunities, the availability of capital and borrowing facilities, and the timing and results of our operated and non-operated 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 and divestiture activities, debt requirements, and other factors.

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We may from time to time repurchase certain amounts of our outstanding debt securities for cash and/or through exchanges for other securities. Such repurchases or exchanges may be made in open market transactions, privately negotiated transactions, or otherwise. Any such repurchases or exchanges will depend on prevailing market conditions, our liquidity requirements, contractual restrictions, compliance with securities laws, and other factors. The amounts involved in any such transaction may be material.

In the second quarter of 2012, we paid $3.2 million in dividends to our stockholders, which constitutes a dividend of $0.05 per share. Our intention is to continue to make dividend payments for the foreseeable future, subject to our future earnings, our financial condition, credit facility and other covenants, and other factors which could arise. Payment of future dividends remains at the discretion of the Board of Directors. Additionally, during the second quarter of 2012 we paid $287.5 million to settle our 3.50% Senior Convertible Notes.

As of the filing date of this report, we had authorization from our Board of Directors 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 indentures governing our 2019 Notes, 2021 Notes, and 2023 Notes, compliance with securities laws, and the terms and provisions of our stock repurchase program. We currently do not plan to repurchase any outstanding shares in 2012.

The following table presents changes in cash flows between the six-month periods ended June 30, 2012, and 2011. 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 Six Months Ended June 30,		Amount Change Between Periods	Percent Change Between Periods
	2012	2011		
	(in millions)			
Net cash provided by operating activities	$410.3	$370.0	$40.3	11 %
Net cash (used in) investing activities	$(695.2)	$(566.8)	$(128.4)	23 %
Net cash provided by financing activities	$165.9	$292.8	$(126.9)	(43)%

Analysis of Cash Flow Changes Between the Six Months Ended June 30, 2012, and 2011

Operating activities. Cash received from oil, gas, and NGL production revenues, including derivative cash settlements, increased $164.8 million or 29 percent to $727.4 million for the first six months of 2012, compared with $562.6 million for the same period in 2011. Cash paid for lease operating expenses increased $24.8 million to $93.8 million for the first six months of 2012, compared with $69.0 million for the same period in 2011. Cash paid for interest during the first six months of 2012 increased $23.8 million compared to the same period in 2011 due to interest payments on our 2019 Notes and 2021 Notes.

Investing activities. Cash outflows for 2012 capital expenditures increased $43.0 million, or six percent, compared with the same period in 2011. This increase was due to increased drilling activity, which was driven by our successful development activities in our Eagle Ford shale and Bakken/Three Forks programs. Net proceeds from the sale of oil and gas properties decreased $82.5 million between the two periods, as we divested a larger package of properties in the first six months of 2011 compared to the same period in 2012.

Financing activities. During the second quarter of 2012, we paid $287.5 million to settle our 3.50% Senior Convertible Notes. We received $392.3 million of net proceeds from the issuance of our 2023 Notes in the second quarter of 2012, compared with $341.4 million of proceeds from the issuance of our 2019 Notes in the first quarter of 2011. We had net borrowings against our credit facility of $61.0 million during the six months ended June 30, 2012, compared with net repayments of $48.0 million made during the same period of 2011.

Commodity Price Risk and Interest Rate Risk

We are exposed to market risk, which is estimated as the potential change in fair value resulting from an immediate hypothetical one percentage point parallel shift in the yield curve, including the effects of changes in oil, gas, and NGL commodity prices and changes in interest rates. 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 credit facility. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate 2019 Notes, 2021 Notes, or 2023 Notes, but do affect their fair market value. The carrying amount of our floating-rate debt typically approximates its fair value. As of June 30, 2012, we had $61.0 million of floating-rate debt outstanding, and our fixed-rate debt outstanding totaled $1.1 billion.

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There has been no material change to the oil and gas price sensitivity analysis previously disclosed. Please refer to the corresponding section under Part II, Item 7 of our 2011 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 June 30, 2012, we had derivative positions in place covering a portion of anticipated production through the first quarter of 2015, totaling 9.1 million Bbls of oil, 80.0 million MMBtu of gas, and 1.8 million Bbls of NGLs. Subsequent to June 30, 2012, we executed swaps on 2.5 million Bbls of oil from September 2012 through June 2015 at a weighted average swap price of $90.33 per Bbl.

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.

The following tables describe the approximate volumes, average contract prices, and fair values of contracts we had in place as of June 30, 2012:

Oil Contracts

Oil Swaps

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price	Fair Value at June 30, 2012 Asset (Liability)
	(Bbls)	(per Bbl)	(in millions)
Third quarter 2012	489,000	$83.87	$(0.8)
Fourth quarter 2012	463,000	$87.08	0.1
2013	616,000	$88.22	(0.1)
2014	661,000	$91.72	2.4
All oil swaps	2,229,000		$1.6

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at June 30, 2012 Asset
	(Bbls)	(per Bbl)	(per Bbl)	(in millions)
Third quarter 2012	638,000	$80.35	$112.53	$1.3
Fourth quarter 2012	566,000	$80.03	$112.28	2.0
2013	2,866,000	$78.14	$110.11	9.1
2014	2,174,000	$83.71	$107.93	10.9

2015	639,000	$85.00	$101.80	2.8
All oil collars	6,883,000			$26.1

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Gas Contracts

Gas Swaps

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at June 30, 2012 Asset (Liability)
	(MMBtu)	(per MMBtu)	(in millions)
Third quarter 2012	12,265,000	$ 3.74	$12.0
Fourth quarter 2012	10,951,000	$ 4.15	12.3
2013	24,907,000	$ 4.30	20.4
2014	14,954,000	$ 4.23	5.5
2015	4,497,000	$ 4.00	(0.6)
All gas swaps*	67,574,000		$49.6

*Gas swaps are comprised of IF CIG (1%), IF El Paso Permian (1%), IF HSC (45%), IF NGPL TXOK (8%), IF NNG Ventura (1%), IF PEPL (15%), IF Reliant N/S (20%), and IF TETCO STX (9%).

Gas Collars

Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at June 30, 2012 Asset
	(MMBtu)	(per MMBtu)	(per MMBtu)	(in millions)
2013	6,650,000	$4.39	$5.34	$6.6
2014	5,734,000	$4.38	$5.36	4.4
All gas collars*	12,384,000			$11.0

*Gas collars are comprised of IF HSC (18%), IF NGPL TXOK (18%), IF Reliant N/S (29%), and IF TETCO STX (35%).

NGL Contracts

NGL Swaps

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at June 30, 2012 Asset
	(approx. Bbls)	(per Bbl)	(in millions)
Third quarter 2012	484,000	$ 45.99	$6.0
Fourth quarter 2012	431,000	$ 46.01	4.8
2013	881,000	$ 34.05	4.3
All NGL swaps*	1,796,000		$15.1

*NGL swaps are comprised of OPIS Mont. Belvieu Ethane Purity (47%), OPIS Mont. Belvieu LDH Propane (32%), OPIS Mont. Belvieu NON-LDH Isobutane (6%), OPIS Mont. Belvieu NON-LDH Normal Butane (7%), and OPIS Mont. Belvieu NON-LDH Natural Gasoline (8%).

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 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 June 30, 2012, we have not been involved in any unconsolidated SPE transactions.

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

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Critical Accounting Policies and Estimates

Please refer to the corresponding section in Part II, Item 7 of our 2011 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.

Non-GAAP Financial Measures

EBITDAX represents income before interest expense, interest income, income taxes, depreciation, depletion, amortization and accretion, exploration expense, property impairments, non-cash stock compensation expense, unrealized derivative gains and losses, change in the Net Profit Plan liability, and gains and losses on divestitures. EBITDAX excludes certain items that we believe affect the comparability of operating results and can exclude items which are generally one-time or whose timing and/or amount cannot be reasonably estimated. EBITDAX is a non-GAAP measure that is presented because we believe that it provides useful additional information to investors, as a performance measure, for analysis of our ability to internally generate funds for exploration, development, acquisitions, and to service debt. We are also subject to financial covenants under our credit facility based on our debt to EBITDAX ratio. In addition, EBITDAX is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. EBITDAX should not be considered in isolation or as a substitute for net income, income from operations, net cash provided by operating activities, profitability, or liquidity measures prepared under GAAP. Since EBITDAX excludes some, but not all items that affect net income and may vary among companies, the EBITDAX amounts presented may not be comparable to similar metrics of other companies. The following table provides a reconciliation of our net income to EBITDAX for the periods presented:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands)			
Net income	$24,889	$124,533	$51,225	$106,030
Interest expense	12,712	14,550	26,990	24,264
Interest income	(5)	(227)	(75)	(355)
Income tax expense	14,795	72,851	30,476	61,796
Depreciation, depletion, amortization, and asset retirement obligation liability accretion	161,608	115,382	331,178	220,738
Exploration	22,007	9,603	40,614	22,315
Impairment of proved properties	38,523	—	38,523	—
Abandonment and impairment of unproved properties	10,707	1,237	10,849	4,316
Stock-based compensation expense	8,022	6,286	12,372	11,837
Unrealized derivative (gain) loss	(81,666)	(57,852)	(74,014)	24,160
Change in Net Profits Plan liability	(22,079)	(13,984)	(18,140)	211
(Gain) loss on divestiture activity	24,176	(30,019)	22,714	(54,934)
EBITDAX	$213,689	$242,360	$472,712	$420,378

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Cautionary Information about Forward-Looking Statements

This Form 10-Q contains "forward-looking statements" within the meaning of Section 27A of the Securities Act 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," "will," and similar ex 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, gas, and NGL production estimates;
- our outlook on future oil, 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 2011 Form 10-K, and include such factors as:

- the volatility of oil, gas, and NGL prices, and the effect it may have on our profitability, financial condition, cash flows, access to capital, and ability to grow production volumes and/or proved reserves;
- the continued weakness in economic conditions and uncertainty in financial markets;
- 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;
- our ability to attract and retain key personnel;
- the imprecise estimations of our actual quantities and present value of proved oil, gas, and NGL reserves;
- the uncertainty in evaluating recoverable reserves and estimating expected benefits or liabilities;
- the possibility that exploration and development drilling may not result in commercially producible reserves;
- our limited control over activities on non-operated properties;

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- our reliance on the skill and expertise of third-party service providers on our operated properties;
- the possibility that title to properties in which we have an interest may be defective;
- 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 divestitures, joint ventures, farm-downs, farm-outs 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 derivative contracts may result in financial losses or may limit the prices that we receive for oil, gas, and NGL sales;
- the inability of one or more of our vendors, customers, or contractual counterparties to meet their obligations;
- price declines or unsuccessful exploration efforts resulting in write-downs of our asset carrying values;
- the impact that lower oil, 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, gas, and NGLs;
- the possibility that new technologies may cause our current exploration and drilling methods to become obsolete;
- the possibility of security threats, including terrorist attacks and cybersecurity breaches, against, or otherwise impacting, our facilities and systems; 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 and Summary of Oil, Gas, and NGL Derivative Contracts in Place in Item 2 above and is incorporated herein by reference. Please also refer to the sensitivity analysis within our 2011 Form 10-K in Part II, Item 7.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that are designed to reasonably 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 reasonably 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 for timely decisions regarding required disclosure.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) ("Disclosure Controls") will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our Disclosure Controls are effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There have been no changes during the second quarter of 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

From time to time, we may be involved in litigation relating to claims arising out of our operations in the normal course of business. As of the filing date of this report, no legal proceedings are pending against us that we believe individually or collectively could have a materially adverse effect upon our financial condition, results of operations

or cash flows.
We were a defendant in litigation, captioned W.H. Sutton, et al. vs. St. Mary Land & Exploration Co., et al., 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 sought to quiet title to their claimed overriding royalty interest and to recover unpaid overriding royalty interest proceeds allegedly due. We believed that the claimed overriding royalty interest had been terminated under the governing agreements and the applicable law, and contested the plaintiffs’ claims. Both parties filed motions for summary judgment, and on February 8, 2011, the District Court issued an order granting plaintiffs’ motion for summary judgment and denying our motion for summary judgment. On September 30, 2011, the District Court entered final judgment for the plaintiffs and awarded damages of approximately $5.1 million, which included prejudgment interest. The District Court also awarded attorneys fees and costs to the plaintiffs. We appealed the District Court’s judgment and obtained a stay pending appeal that prevented the plaintiffs from executing on the judgment.

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On May 23, 2012, the Fourth Court of Appeals for the State of Texas delivered its opinion in this case, which reversed the summary judgment granted to the plaintiffs by the District Court and rendered judgment that the plaintiffs take nothing. Accordingly, based on the judgment of the Fourth Court of Appeals, the plaintiffs are not entitled to their claimed aggregate 7.46875 percent overriding royalty interest, nor are they entitled to the claimed damages related to the overriding royalty interest, attorneys fees or costs. The plaintiffs have the right to petition the Supreme Court of Texas for a review of the judgment of the Fourth Court of Appeals. In the event the plaintiffs' file such petition and review is granted, we will continue to contest this litigation.

We cannot predict the ultimate outcome of this lawsuit. If the plaintiffs were to ultimately prevail in any further appeal, the overriding royalty interest would have the effect of reducing our net revenue interest in the affected acreage, which would negatively impact our economics in this portion of our acreage, but we do not believe would have a material adverse effect upon our financial condition, results of operations, or cash flows.

We recently filed, in Webb County, Texas, a declaratory judgment action, captioned SM Energy Company vs. W.H. Sutton, et al., seeking a judgment declaring that the lease at issue in W.H. Sutton, et al. vs. St. Mary Land & Exploration Co., et al. had terminated with respect to the remaining 18,000 acres, based upon a failure of continuous development, and that any overriding royalty interest claimed by the defendants' has been extinguished.
We, and our working interest partners, recently filed an action against Endeavour Operating Corporation ("Endeavour") in Harris County, Texas, captioned SM Energy Company, et al. v. Endeavour Operating Corporation, seeking an order requiring Endeavour to honor its obligations to consummate the purchase of assets located in Pennsylvania, or in the alternative, for damages. We are required to take reasonable measures to attempt to mitigate our potential losses, and, subsequent to March 31, 2012, we initiated efforts to remarket such assets. If we are successful in such efforts and complete a sale of these assets for less than the $110 million Endeavour agreed to pay to us and our working interest partners ($80 million of which is attributable to our interest) then we will continue to prosecute this action to recover any such deficiency and any amounts expended in our efforts to remarket the assets, and to obtain any other relief to which we are entitled.

With the exception of the above disclosures, there have been no material changes to the legal proceedings as previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2011 under Item 3, Part I. See Note 6 - Commitments and Contingencies, in Part I, Item 1 of this report, for additional discussion.

ITEM 1A. RISK FACTORS

There have been no material changes to the risk factors as previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2011.

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ITEM 5. OTHER INFORMATION

On January 1, 2012, the Company adopted new authoritative accounting guidance issued by the FASB, which provides guidance on the presentation of comprehensive income in financial statements. Entities are required to present total comprehensive income either in a single, continuous statement of comprehensive income or in two separate, but consecutive, statements. We elected to present net income and other comprehensive income in two separate statements in our interim and annual financial statements. The table below reflects the retrospective application of this guidance to each of the three years ended December 31, 2011, 2010 and 2009. The retrospective application did not have a material impact on our consolidated financial statements other than requiring us to present our statements of comprehensive income (loss) separately from our statements of equity, as these statements were previously presented on a combined basis.

SM Energy Company
Consolidated Statements of Comprehensive Income (Loss)
(in thousands)

	For the Years Ended December 31,		
	2011	2010	2009
Net income (loss)	$215,416	$196,837	$(99,370)
Other comprehensive income (loss), net of tax:			
Change in derivative fair value [1]	—	16,811	(35,977)
Reclassification to earnings [2]	12,997	6,641	(67,344)
Pension liability adjustment [3]	(1,795)	(980)	74
Total other comprehensive income (loss), net of tax	11,202	22,472	(103,247)
Total comprehensive income (loss)	$226,618	$219,309	$(202,617)

[1] Presented net of income tax expense (benefit) of $10,093 and ($21,636) for the years ended December 31, 2010, and 2009, respectively.
[2] Presented net of income tax expense (benefit) of $7,710, $3,967 and ($40,727) for the years ended December 31, 2011, 2010, and 2009, respectively.
[3] Presented net of income tax expense (benefit) of ($984), ($590) and $45 for the years ended December 31, 2011, 2010, and 2009, respectively.

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ITEM 6. EXHIBITS

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

Exhibit	Description
4.1	Indenture related to the 6.50% Senior Notes due 2023, dated June 29, 2012, between SM Energy Company, as Issuer, and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on July 3, 2012, and incorporated herein by reference)
4.2	Registration Rights Agreement, dated June 29, 2012, among SM Energy Company and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and J.P. Morgan Securities LLC, as representatives of several purchasers (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on July 3, 2012, and incorporated herein by reference)
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

*	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.

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

August 2, 2012	By:	/s/ ANTHONY J. BEST Anthony J. Best President and Chief Executive Officer
August 2, 2012	By:	/s/ A. WADE PURSELL A. Wade Pursell Executive Vice President and Chief Financial Officer
August 2, 2012	By:	/s/ MARK T. SOLOMON Mark T. Solomon Vice President and Controller