SM Energy Co
Form 10-Q
May 01, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2013
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 April 25, 2013, the registrant had 66,275,824 shares of common stock, $0.01 par value, outstanding.

SM ENERGY COMPANY

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PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)
(in thousands, except share amounts)

	March 31, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$87	$5,926
Accounts receivable	255,888	254,805
Refundable income taxes	3,113	3,364
Prepaid expenses and other	28,523	30,017
Derivative asset	23,364	37,873
Deferred income taxes	9,215	8,579
Total current assets	320,190	340,564
Property and equipment (successful efforts method), at cost:		
Land	1,857	1,845
Proved oil and gas properties	5,670,183	5,401,684
Less - accumulated depletion, depreciation, and amortization	(2,564,865)	(2,376,170)
Unproved oil and gas properties	173,215	175,287
Wells in progress	296,854	273,928
Materials inventory, at lower of cost or market	14,110	13,444
Oil and gas properties held for sale net of accumulated depletion, depreciation and amortization of $21,305 in 2013 and $20,676 in 2012	33,340	33,620
Other property and equipment, net of accumulated depreciation of $23,968 in 2013 and $22,442 in 2012	156,416	153,559
Total property and equipment, net	3,781,110	3,677,197
Noncurrent assets:		
Derivative asset	8,571	16,466
Restricted cash	106,800	86,773
Other noncurrent assets	75,653	78,529
Total other noncurrent assets	191,024	181,768
Total Assets	$4,292,324	$4,199,529
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$480,318	$525,627
Derivative liability	22,836	8,999
Other current liabilities	7,000	6,920
Total current liabilities	510,154	541,546
Noncurrent liabilities:		
Revolving credit facility	430,000	340,000
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	400,000

Asset retirement obligation	115,163	112,912
Asset retirement obligation associated with oil and gas properties held for sale	4,396	1,393
Net Profits Plan liability	76,902	78,827
Deferred income taxes	548,339	537,383
Derivative liability	12,669	6,645
Other noncurrent liabilities	57,876	66,357
Total noncurrent liabilities	2,345,345	2,243,517
Commitments and contingencies (note 6)		
Stockholders' equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued: 66,300,003 shares in 2013 and 66,245,816 shares in 2012; outstanding, net of treasury shares: 66,249,422 shares in 2013 and 66,195,235 shares in 2012	663	662
Additional paid-in capital	242,526	233,642
Treasury stock, at cost: 50,581 shares in 2013 and 2012	(1,221)	(1,221)
Retained earnings	1,203,813	1,190,397
Accumulated other comprehensive loss	(8,956)	(9,014)
Total stockholders' equity	1,436,825	1,414,466
Total Liabilities and Stockholders' Equity	$4,292,324	$4,199,529

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 March 31,	
	2013	2012
Operating revenues:		
Oil, gas, and NGL production revenue	$469,575	$362,595
Other operating revenues	14,605	14,828
Total operating revenues	484,180	377,423
Operating expenses:		
Oil, gas, and NGL production expense	125,633	87,132
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	198,709	169,570
Exploration	15,398	18,607
Impairment of properties	21,521	142
General and administrative	32,280	28,142
Change in Net Profits Plan liability	(1,925)	3,939
Unrealized and realized derivative loss	30,572	2,216
Other operating expenses	15,794	11,450
Total operating expenses	437,982	321,198
Income from operations	46,198	56,225
Nonoperating income (expense):		
Interest income	12	70
Interest expense	(19,101)	(14,278)
Income before income taxes	27,109	42,017
Income tax expense	(10,382)	(15,681)
Net income	$16,727	$26,336
Basic weighted-average common shares outstanding	66,211	64,104
Diluted weighted-average common shares outstanding	67,521	67,845
Basic net income per common share	$0.25	$0.41
Diluted net income per common share	$0.25	$0.39
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 March 31,	
	2013	2012
Net income	$16,727	$26,336
Other comprehensive income (loss), net of tax:		
Reclassification to earnings	61	(1,034)
Pension liability adjustment	(3)	—
Total other comprehensive income (loss), net of tax	58	(1,034)
Total comprehensive income	$16,785	$25,302

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 Three Months Ended March 31,	
	2013	2012
Cash flows from operating activities:		
Net income	$16,727	$26,336
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	198,709	169,570
Exploratory dry hole expense	159	606
Impairment of properties	21,521	142
Stock-based compensation expense	8,113	4,350
Change in Net Profits Plan liability	(1,925)	3,939
Unrealized derivative loss	42,364	7,652
Amortization of debt discount and deferred financing costs	1,077	3,665
Deferred income taxes	10,280	15,288
Other	1,032	(2,580)
Changes in current assets and liabilities:		
Accounts receivable	(22,164)	(13,967)
Refundable income taxes	251	3,006
Prepaid expenses and other	354	(3,003)
Accounts payable and accrued expenses	5,794	(26,951)
Net cash provided by operating activities	282,292	188,053
Cash flows from investing activities:		
Net proceeds from sale of oil and gas properties	4,307	1,679
Capital expenditures	(381,185)	(335,015)
Other	(2,025)	1,550
Net cash used in investing activities	(378,903)	(331,786)
Cash flows from financing activities:		
Proceeds from credit facility	223,500	26,000
Repayment of credit facility	(133,500)	(2,000)
Proceeds from sale of common stock	772	1,038
Other	—	(213)
Net cash provided by financing activities	90,772	24,825
Net change in cash and cash equivalents	(5,839)	(118,908)
Cash and cash equivalents at beginning of period	5,926	119,194
Cash and cash equivalents at end of period	$87	$286

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 Three Months Ended March 31,	
	2013	2012
	(in thousands)	
Cash paid for interest, net of capitalized interest	$(24,721)	$(11,729)
Net cash refunded for income taxes	$165	$3,397

Dividends of approximately $3.3 million were declared by the Company’s Board of Directors, but not paid, as of March 31, 2013. Dividends of approximately $3.2 million were declared by the Company’s Board of Directors, but not paid, as of March 31, 2012.

As of March 31, 2013, and 2012, $202.8 million and $199.6 million, respectively, of accrued capital expenditures were included in accounts payable and accrued expenses in the Company’s condensed consolidated balance sheets. These oil and gas property additions are reflected in cash used in investing activities in the periods during which 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 and condensate, natural gas, and natural gas liquids (also respectively referred to as "oil," "gas," and "NGLs" throughout this report) in onshore North America, with a current focus on oil and liquids-rich resource plays.

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

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements of SM Energy have been prepared in accordance with accounting principles generally accepted in the United States ("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, 2012, ("2012 Form 10-K"). In the opinion of management, all adjustments, consisting of normal recurring accruals 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 unaudited condensed consolidated financial statements, the Company evaluated events subsequent to the balance sheet date of March 31, 2013, 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 2012 Form 10-K, and are supplemented throughout the notes to the unaudited condensed consolidated financial statements in this report. It is suggested that these unaudited condensed consolidated financial statements be read in conjunction with the consolidated financial statements and notes included in the 2012 Form 10-K.

Recently Issued and Adopted Accounting Standards

On January 1, 2013, the Company adopted new authoritative accounting guidance issued by the Financial Accounting Standards Board ("FASB"), which applied to the offsetting of certain assets and liabilities on the balance sheet and clarified the application of previously issued guidance to derivative instruments, repurchase agreements, and securities lending transactions, requiring disclosure of gross and net amounts for those items. The only item applicable to the Company is derivative instruments. The Company currently records its derivative instruments on a gross basis by contract; therefore, the adoption of this statement did not have a material impact on the Company's financial statements or disclosures.

On March 31, 2013, the Company adopted the presentation requirements of new authoritative accounting guidance issued by the FASB in February 2013. The purpose of the guidance was to improve the reporting of reclassifications out of accumulated other comprehensive income (loss) ("AOCIL"), which required entities to report the effect of significant reclassifications out of AOCIL into current year income on the respective line items in net income. The presentation of those amounts may be on the face of the financial statements or in the notes thereto. This amendment was effective prospectively for periods beginning after December 15, 2012. As of March 31, 2013, the Company does not have any significant reclassifications out of AOCIL into current year income. The Company will continue to monitor items that are subject to the new guidance and elect the presentation for significant items reclassified out of AOCIL, for the disclosure period any such item becomes material.

In February 2013, the FASB issued new authoritative accounting guidance related to the recognition and measurement of obligations arising from joint and several liability arrangements. This authoritative accounting guidance is effective for interim and annual periods beginning after December 15, 2013. The Company is currently evaluating the provisions of this authoritative accounting guidance and assessing its impact, but does not currently believe it will have a material effect on the Company’s financial statements or disclosures.

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There are no new significant accounting standards applicable to the Company that have been issued but not yet adopted by the Company as of March 31, 2013.

Note 3 - Earnings per Share

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

Diluted net income per common share 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 stock options, unvested restricted stock units ("RSUs"), and contingent performance share units ("PSUs"). The treasury stock method is used to measure the dilutive impact of unvested RSUs, contingent PSUs, and in-the-money stock options.

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.

Although all of the Company's 3.50% Senior Convertible Notes due 2027 ("3.50% Senior Convertible Notes") were redeemed or settled prior to June 30, 2012, potentially dilutive securities for this calculation for the three months ended March 31, 2012, included shares into which the 3.50% Senior Convertible Notes were convertible. 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 elected 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. The 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-month period ended March 31, 2012, making them dilutive for that period.

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

	For the Three Months Ended March 31,	
	2013	2012
	(in thousands, except per share amounts)	
Net income	$16,727	$26,336
Basic weighted-average common shares outstanding	66,211	64,104
Add: dilutive effect of stock options, unvested RSUs, and contingent PSUs	1,310	2,210
Add: dilutive effect of 3.50% Senior Convertible Notes	—	1,531
Diluted weighted-average common shares outstanding	67,521	67,845
Basic net income per common share	$0.25	$0.41
Diluted net income per common share	$0.25	$0.39

Note 4 - Income Taxes

Income tax expense for the three months ended March 31, 2013, and 2012, differs from the amounts that would be provided by applying the statutory United States 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 allowance adjustments, and other permanent differences. The quarterly rate can also be impacted by the proportional effects of forecasted net income as of each period end.

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The provision for income taxes consists of the following:

	For the Three Months Ended March 31,	
	2013	2012
	(in thousands)	
Current portion of income tax expense:		
Federal	$—	$—
State	102	393
Deferred portion of income tax expense	10,280	15,288
Total income tax expense	$10,382	$15,681
Effective tax rate	38.3 %	37.3 %

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 various state tax jurisdictions. Cumulative effects of state rate changes are reflected in the period legislation is enacted. The 2013 increase in the effective rate from 2012 primarily reflects changes in the mix of the highest marginal state tax rates, the effects of valuation allowance adjustments, the state tax rate effect on year-to-date net income from divestitures, drilling activities, and changes in the effects of other permanent differences.

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 United States federal or state income tax examinations by these tax authorities for years before 2007. Federal tax law allowing for the calculation of a R&D credit was enacted in 2013 but the Company has not yet commissioned a study to calculate the credit for the 2012 or 2013 tax years, so the table above excludes any impact of a credit which would be allowed under the new law. The Internal Revenue Service ("IRS") initiated an audit in the first quarter of 2012 related to R&D tax credits claimed by the Company for the 2007 and 2010 tax years. This audit was still ongoing at March 31, 2013. On April 23, 2013, the IRS issued a Notice of Proposed Adjustment disallowing all R&D tax credits claimed for open tax years during the audit period. The Company intends to contest the report's conclusions and maintains it is entitled to the claimed credits.

Note 5 - Long-term Debt

Revolving Credit Facility

Subsequent to March 31, 2013, the Company and its lenders entered into a Fifth Amended and Restated Credit Agreement. This amended revolving credit facility replaced the Company's previous revolving credit facility. The credit facility has a maximum loan amount of $2.5 billion, current aggregate lender commitments of $1.3 billion, and a maturity date of April 12, 2018. The borrowing base under the credit facility as of the filing date of this report is $1.9 billion and is subject to regular semi-annual redeterminations. The borrowing base redetermination process under the credit facility considers the value of the Company's oil and gas properties and other assets, as determined by the bank group. The next scheduled re-determination date is October 1, 2013. Borrowings under the facility are secured by substantially all of the Company's proved oil and gas properties. As of the date of this filing, the Company has incurred approximately $3.3 million in additional deferred financing costs in association with the amendment and extension of this credit facility.

The Company must comply with certain financial and non-financial covenants under the terms of its credit facility agreement, including the limitation of the Company's dividends to no more than $50.0 million per year. The Company was in compliance with all financial covenants under the credit facility as of the filing date of this report. There were no changes to the borrowing base utilization grid provided under the Company's Fourth Amended and Restated Credit

Agreement. Please refer to the borrowing base utilization grid in Note 5 - Long-term Debt in the Company's 2012 Form 10-K.

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The following table presents the outstanding balance, total amount of letters of credit, and available borrowing capacity under the Company’s credit facility as of April 25, 2013, March 31, 2013, and December 31, 2012:

	As of April 25, 2013	As of March 31, 2013	As of December 31, 2012
	(in millions)		
Credit facility balance	$470.0	$430.0	$340.0
Letters of credit (1)	$0.8	$0.8	$0.8
Available borrowing capacity	$829.2	$569.2	$659.2

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

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 2012 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.

On January 27, 2011, Chieftain Royalty Company (“Chieftain”) filed a Class Action Petition against the Company in the District Court of Beaver County, Oklahoma, claiming damages related to royalty valuation on all of the Company’s Oklahoma wells. These claims include breach of contract, breach of fiduciary duty, fraud, unjust enrichment, tortious breach of contract, conspiracy, and conversion, based generally on asserted improper deduction of post-production costs. The Company removed this lawsuit to the United States District Court for the Western District of Oklahoma on February 22, 2011. The Company has responded to the petition and denied the allegations. The court has not yet ruled on Chieftain’s motion to certify the putative class, and has stayed all proceedings until the United States Court of Appeals for the Tenth Circuit issues its ruling on class certification in two similar royalty class action lawsuits. The opinion from the Tenth Circuit is expected during 2013.

This case involves complex legal issues and uncertainties; a potentially large class of plaintiffs, and a large number of related producing properties, lease agreements and wells; and an alleged class period commencing in 1988 and spanning the entire producing life of the wells. Because the proceedings are in the early stages, with substantive discovery yet to be conducted, the Company is unable to estimate what impact, if any, the action will have on its financial condition, results of operations or cash flows. The Company is still evaluating the claims, but believes that it has properly paid royalties under Oklahoma law and has and will continue to vigorously defend this case.

Note 7 - Compensation Plans

Cash Bonus Plan

During the first quarter of 2013 and 2012, the Company paid $16.0 million and $24.0 million, respectively, for cash bonuses earned during the 2012 and 2011 performance years, respectively. The general and administrative expense and exploration expense line items in the accompanying condensed consolidated statements of operations (“accompanying statements of operations”) include $5.6 million and $4.7 million of accrued cash bonus plan expense for the three-month periods ended March 31, 2013, and 2012, respectively, related to the respective performance year.

Restricted Stock Units Under the Equity Incentive Compensation Plan

The Company grants RSUs as part of its 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.

Expense associated with RSUs is recognized as general and administrative expense and exploration expense over the vesting period of the award.

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Total expense recorded for RSUs for the three-month periods ended March 31, 2013, and 2012, was $3.0 million and $1.2 million, respectively. As of March 31, 2013, there was $11.0 million of total unrecognized compensation expense related to unvested RSU awards, which is being amortized through 2015. There have been no material changes to the outstanding and non-vested RSUs during the three month period ended March 31, 2013.

Performance Stock Units Under the Equity Incentive Compensation Plan

The Company grants PSUs as part of its equity compensation program. PSUs are structurally the same as the previously granted performance share awards. 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. Expense associated with PSUs is 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 March 31, 2013, and 2012, was $4.7 million and $2.9 million, respectively. As of March 31, 2013, there was $14.7 million of total unrecognized compensation expense related to unvested PSUs to be amortized through 2015. There have been no material changes to the outstanding and non-vested PSUs during the three-month period ended March 31, 2013.

Stock Option Grants Under the Equity Incentive Compensation Plan

A summary of activity associated with the Company's Stock Option Plan for the three months ended March 31, 2013, is presented in the following table:

	Shares		Weighted-Average Exercise Price	Aggregate Intrinsic Value (in thousands)
Outstanding, at beginning of year	267,846		$14.95	$9,983
Exercised	(54,187	)	$14.24	$2,393
Forfeited	—		$—	
Outstanding, at end of quarter	213,659		$15.11	$9,424
Vested and exercisable, at end of quarter	213,659		$15.11	$9,424

As of March 31, 2013, there was no unrecognized compensation expense related to stock option awards.
Net Profits Interest Bonus Plan

Cash payments made or accrued under the Company's 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 March 31,	
	2013	2012
	(in thousands)	
General and administrative expense	$3,786	$4,412
Exploration expense	374	525
Total	$4,160	$4,937

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

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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” and together with the Qualified Pension Plan, the “Pension Plans”).

Components of Net Periodic Benefit Cost for the Pension Plans

The following table presents the components of the net periodic benefit cost for the Pension Plans:

	For the Three Months Ended March 31,	
	2013	2012
	(in thousands)	
Service cost	$1,232	$950
Interest cost	345	296
Expected return on plan assets that reduces periodic pension costs	(286)	(220)
Amortization of prior service costs	4	—
Amortization of net actuarial loss	197	101
Net periodic benefit cost	$1,492	$1,127

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 $373,000 to the Pension Plans for the 2013 plan year.

Note 9 - 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 March 31, 2013, and through the filing date of this report, the Company has commodity derivative contracts outstanding through the fourth quarter of 2015 for a total of 13.0 million Bbls of oil production, 119.0 million MMBtu of gas production, and 1.5 million Bbls of NGL production.

The Company’s commodity derivatives are measured at fair value and are included in the accompanying condensed consolidated balance sheets (“accompanying balance sheets”) as derivative assets and liabilities. The fair value of the commodity derivative contracts was a net liability of $3.6 million and a net asset of $38.7 million at March 31, 2013, and December 31, 2012, 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 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 periods ended March 31, 2013, and 2012.

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As a result of discontinuing hedge accounting on January 1, 2011, 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 March 31, 2013, AOCIL included $1.1 million of net unrealized losses, net of income tax, on commodity derivative contracts that had been previously designated as cash flow hedges, all of which will be reclassified into earnings from AOCIL during the next twelve months. Please refer to Note 10 - Fair Value Measurements for more information regarding the Company's derivative instruments, including its valuation techniques.

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

	As of March 31, 2013			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$23,364	Current liabilities	$22,836
Commodity contracts	Noncurrent assets	8,571	Noncurrent liabilities	12,669
Derivatives not designated as hedging instruments		$31,935		$35,505

	As of December 31, 2012			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$37,873	Current liabilities	$8,999
Commodity contracts	Noncurrent assets	16,466	Noncurrent liabilities	6,645
Derivatives not designated as hedging instruments		$54,339		$15,644

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

	For the Three Months Ended March 31,	
	2013	2012
	(in thousands)	
Cash settlement (gain) loss:		
Oil contracts	$277	$8,299
Gas contracts	(9,824)	(15,212)
NGL contracts	(2,245)	1,477
Total cash settlement (gain)	$(11,792)	$(5,436)
Unrealized (gain) loss on change in fair value:		
Oil contracts	$3,789	$29,491
Gas contracts	40,069	(17,634)
NGL contracts	(1,494)	(4,205)

Total net unrealized loss on change in fair value	$42,364	$7,652
Total unrealized and realized derivative loss	$30,572	$2,216

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

	Derivatives	Location in Statements of Operations	For the Three Months Ended March 31,	
			2013	2012
			(in thousands)	
Amount reclassified from AOCIL	Commodity contracts	Other operating revenues	$61	$(1,034)

The Company realized a net hedge gain of $99,000 and $1.7 million from its commodity derivative contracts for the three months ended March 31, 2013, and 2012, 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 other operating revenues in the accompanying statements of operations.

Credit Related Contingent Features

As of March 31, 2013, 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.

Note 10 - 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 fair value 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 their classification within the fair value hierarchy as of March 31, 2013:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives (1)	$—	$31,935	$—
Oil and gas properties held for sale (2)	$—	$—	$15,095
Liabilities:			
Derivatives (1)	$—	$35,505	$—
Net Profits Plan (1)	$—	$—	$76,902

(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 their classification within the fair value hierarchy as of December 31, 2012:

	Level 1 (in thousands)	Level 2	Level 3
Assets:			
Derivatives (1)	$—	$54,339	$—
Proved oil and gas properties (2)	$—	$—	$209,959
Unproved oil and gas properties (2)	$—	$—	$42,765
Oil and gas properties held for sale (2)	$—	$—	$16,527
Liabilities:			
Derivatives (1)	$—	$15,644	$—
Net Profits Plan (1)	$—	$—	$78,827

(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 above fair value 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 above fair value 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 9 - 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 oil, gas, and NGL commodity markets.

If the commodity prices used in the calculation changed by five percent, the liability recorded at March 31, 2013, would differ by approximately $7 million. A one percent increase or decrease in the discount rate would result in a change of approximately $3 million. Actual cash payments to be made to participants in future periods are dependent on realized actual production, realized commodity prices, and costs associated with the properties in each individual pool of the Net Profits Plan. Consequently, actual cash payments are inherently different from the amounts estimated.

No published market quotes exist on which to base the Company's estimate of fair value of its 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 Company's Net Profits Plan liability measured at fair value using Level 3 inputs:

	As of March 31, 2013	
	(in thousands)	
Beginning balance	$78,827	
Net increase in liability [1]	2,236	
Net settlements [1] [2]	(4,161	)
Transfers in (out) of Level 3	—	
Ending balance	$76,902	

(1)

Net changes in the Company's 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.

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Long-term Debt

The following table reflects the fair value of the 6.625% Senior Notes due 2019 (the “2019 Notes”), the 6.50% Senior Notes due 2021 (the “2021 Notes”), and the 6.50% Senior Notes due 2023 (the “2023 Notes” or collectively referred to as the “Senior Notes”) measured at fair value using Level 1 inputs based on quoted secondary market trading prices. The Senior Notes were not presented at fair value on the accompanying balance sheets as of March 31, 2013, or December 31, 2012, as they are recorded at historical value.

	As of March 31, 2013	As of December 31, 2012
	(in thousands)	
2019 Notes	$374,850	$371,875
2021 Notes	$382,375	$371,070
2023 Notes	$442,000	$424,200

The carrying value of the Company’s revolving credit facility approximates its fair value, as interest rates are variable, based on prevailing market rates.

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 as of March 31, 2013, and December 31, 2012. 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, after which a flat terminal price is used for each commodity stream. The prices for NGLs are forecasted using Oil Price Information System Mont Belvieu (“OPIS”) pricing, adjusted for basis differentials, for as long as the market is actively trading, after which a flat terminal price is used. Future operating costs are also adjusted as deemed appropriate for these estimates. Proved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If an estimated selling price is not available, the Company utilizes the income valuation technique discussed above.

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. Unproved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If an estimated selling price is not available, the Company utilizes a market approach which estimates acreage value based on the price received for similar acreage in recent transactions by the Company or other market participants in the principal market.

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 recorded at fair value in the accompanying balance sheets at March 31, 2013, or December 31, 2012.

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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 exposure to oil-focused plays in the Permian Basin and the Granite Wash play. We have built a portfolio of onshore properties in the contiguous United States primarily through early entry 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. Furthermore, by entering these plays early, we believe we can capture larger resource potential at a lower cost. At year-end 2012, our reserves shifted from being majority gas to majority liquids. As a result, we are now reporting volumes on a barrels of oil equivalent ("BOE") basis rather than on a natural gas equivalent ("MCFE") basis. Prior year volumes have been conformed to current year presentation.

Our principal business strategy is to focus on the early capture of resource plays in order to create and then enhance value for our stockholders 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 to mitigate our risks by selectively divesting of certain assets when we deem appropriate. We continually examine our portfolio for opportunities to improve the quality of our asset base in order to optimize our returns and preserve our financial strength.

In the first quarter of 2013, we had the following financial and operational results:

- Average daily production for the three months ended March 31, 2013, was 34.8 MBbls of oil, 358.2 MMcf of gas, and 20.5 MBbls of NGLs, for a record average equivalent daily production rate of 115.0 MBOE, compared with 92.8 MBOE for the same period in 2012. Please see additional discussion below under the caption Production Results.

- Net income for the three months ended March 31, 2013, was $16.7 million, or $0.25 per diluted share, compared to net income for the three months ended March 31, 2012, of $26.3 million or $0.39 per diluted share. Please refer to the Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2013, and 2012 for additional discussion regarding the components of net income.

- Costs incurred for oil and gas producing activities for the three months ended March 31, 2013, were $341.9 million, compared with $368.0 million for the same period in 2012. 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 March 31, 2013, was $328.8 million, compared with $259.0 million for the same period in 2012. Please refer to the caption Non-GAAP Financial Measures below for additional discussion, including our definition of EBITDAX and reconciliations of our GAAP net income and net cash provided by operating activities 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 various industry posted prices, most commonly NYMEX West Texas Intermediate ("WTI"). We are paid the average of the daily settlement price for the respective posted prices for the period in which the product is produced, adjusted for quality, transportation, API gravity, and location differentials. Substantially all of our oil production in our South Texas & Gulf Coast

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region is condensate. When we refer to realized oil, gas, and NGL prices below, the disclosed price represents the average price for the respective period unless otherwise indicated.

The following table summarizes commodity price data for the first quarter of 2013, as well as the fourth and first quarters of 2012:

	For the Three Months Ended		
	March 31, 2013	December 31, 2012	March 31, 2012
Crude Oil (per Bbl):			
Average NYMEX price	$94.30	$88.17	$102.99
Realized price	$91.67	$84.65	$90.67
Natural Gas:			
Average NYMEX price (per MMBtu)	$3.48	$3.40	$2.44
Realized price (per Mcf)	$3.57	$3.54	$2.90
Natural Gas Liquids (per Bbl):			
Average OPIS price	$40.61	$41.58	$54.15
Realized price	$36.65	$35.60	$44.67

Note: Average OPIS prices per barrel of NGL are based on a product mix of 37% Ethane, 32% Propane, 6% Isobutane, 11% Normal Butane, and 14% Natural Gasoline for all periods presented. This product mix represents the industry standard composite barrel and does not necessarily represent our product mix for NGL production. Our actual product mix is reflected in actual prices received for NGLs produced.

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 NGL products correlate to the price of oil and accordingly are likely to directionally follow that market. Gas prices have been under downward pressure for a long period of time due to market oversupply resulting from high levels of drilling activity and tepid economic growth, although gas prices have increased moderately in the last half of 2012 and early 2013. The 12-month strip prices for NYMEX WTI oil, NYMEX Henry Hub gas, and OPIS NGLs (same product mix as discussed under the table above) as of March 31, 2013, were $96.26 per Bbl of oil, $4.20 per MMBtu of gas, and $40.78 per Bbl of NGLs, respectively. Comparable prices as of April 25, 2013, were $92.72 per Bbl of oil, $4.32 per MMBtu of gas, and $39.59 per Bbl of NGLs, respectively.

While 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. Consistent with all prior periods reported, our realized prices shown in the table above do not include the impact of cash settlements from derivative contracts.

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 amount 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 9 - 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 quarter of 2013, as well as the fourth and first quarters of 2012:

	For the Three Months Ended		
	March 31, 2013	December 31, 2012	March 31, 2012
Crude Oil (per Bbl):			
Realized price	$91.67	$84.65	$90.67
Add (less) the effects of derivative cash settlements	(0.37)	0.11	(4.32)
Adjusted price, including the effects of derivative cash settlements	$91.30	$84.76	$86.35
Natural Gas (per Mcf):			
Realized price	$3.57	$3.54	$2.90
Add the effects of derivative cash settlements	0.33	0.29	0.70
Adjusted price, including the effects of derivative cash settlements	$3.90	$3.83	$3.60
Natural Gas Liquids (per Bbl):			
Realized price	$36.65	$35.60	$44.67
Add (less) the effects of derivative cash settlements	1.15	1.72	(1.69)
Adjusted price, including the effects of derivative cash settlements	$37.80	$37.32	$42.98

The Dodd-Frank Wall Street Reform and Consumer Protection Act (“Dodd-Frank Act”) included provisions requiring over-the-counter derivative transactions to be cleared through clearinghouses and traded on exchanges. On July 10, 2012, the Commodity Futures Trading Commission (“CFTC”) and the Securities and Exchange Commission (“SEC”) adopted final joint rules under Title VII of the Dodd-Frank Act, which define certain terms that determine what types of transactions will be subject to regulation 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. Under CFTC rules we believe our derivative activity will qualify for the non-financial, commercial end-user exception, which exempts derivatives intended to hedge or mitigate commercial risk entered into by entities predominantly engaged in non-financial activity from the mandatory swap clearing requirement. However, we are not certain whether the provisions of the final rules and regulations will exempt us 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.

First Quarter 2013 Highlights and Outlook for the Remainder of 2013

Operational Activities. Our capital program for 2013 is currently budgeted at $1.5 billion, of which $1.2 billion is allocated to drilling and completion activities. We expect that approximately 90% of our drilling and completion budget will be spent on our Eagle Ford, Bakken/Three Forks, and Permian programs.

We operated an average of 15 drilling rigs during the first quarter of 2013. The primary focus of our operated drilling activity 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 five drilling rigs throughout the first quarter of 2013 and expect to operate between four and five rigs for the remainder of the year. Our program will continue to focus largely on multi-well pad drilling on the northern portions of our acreage position, which have higher condensate and NGL yields. We believe we have secured most of 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 continued growth of our operated program.

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In our non-operated Eagle Ford program, the operator had nine drilling rigs running during the first quarter of 2013. We expect the majority of our non-operated Eagle Ford drilling and completion program to be funded by Mitsui E&P Texas, LP ("Mitsui") throughout 2013 and into 2014 under the terms of our previously announced Acquisition and Development Agreement with Mitsui.
Therefore, we expect to deploy minimal drilling and completion capital in this program during the term of the Mitsui carry. Costs that are not associated with drilling or completion activities, such as infrastructure construction, are not carried by Mitsui, and we will be responsible for our proportionate share of these costs.
During the first quarter of 2013, we operated four 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 our exploration program. We began the second quarter of 2013 with four operated rigs in our Bakken/Three Forks program. During the second quarter, we plan to swap two traditional rigs for one walking rig that is more efficient for pad drilling. After the rig change, we expect to run three rigs for the rest of the year. Our program for the remainder of 2013 will focus on infill drilling in our three focus prospects, Gooseneck, Raven, and Bear Den, and improving efficiencies through pad drilling
We operated three drilling rigs during the first quarter of 2013 in our Permian region. Two of the rigs were focused on testing the Mississippian limestone formation in the northeast Midland Basin and the third rig was focused on the Bone Spring formation in New Mexico. We plan to continue to run a three drilling rig program for the remainder of 2013 focusing on such formations.
We started 2013 operating three drilling rigs in our Granite Wash program in western Oklahoma and the Texas Panhandle and dropped to two drilling rigs during the first quarter. We plan to release one of the two rigs we currently operate, exiting the year with one rig. We expect that our program for the remainder of 2013 will focus on the Hogshooter formation. Essentially all of our acreage in this program is held by production.

We have an ongoing exploration effort that is engaged in acquiring leasehold and testing concepts in new plays. We recently announced a successful exploration well test in East Texas targeting the Woodbine interval and will be conducting further tests later this year.

Please refer to Overview of Liquidity and Capital Resources for additional discussion regarding how we intend to fund our 2013 capital program.
Production Results. The table below provides a regional breakdown of our first quarter 2013 production:

	South Texas & Gulf Coast	Mid-Continent	Permian	Rocky Mountain	Total [1]
First quarter 2013 production:					
Oil (MMBbl)	1.2	0.2	0.3	1.4	3.1
Gas (Bcf)	19.4	10.9	0.8	1.2	32.2
NGLs (MMBbl)	1.8	0.1	—	—	1.8
Equivalent (MMBOE)	6.2	2.0	0.5	1.6	10.3
Avg. daily equivalents (MBOE/d)	68.6	22.7	5.3	18.3	115.0
Relative percentage	60 %	20 %	4 %	16 %	100 %

[1] Totals may not add due to rounding.

We had record production in the first quarter of 2013, which was primarily driven by the continued development of our operated and non-operated Eagle Ford shale programs in our South Texas & Gulf Coast region. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2013, and 2012 for additional discussion on production.

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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 March 31, 2013
	(in millions)
Development costs	$289.4
Exploration costs	44.4
Acquisitions:	
Proved properties	—
Unproved properties	8.1
Total, including asset retirement obligations	$341.9

The majority of costs incurred for oil and gas producing activities during the first quarter of 2013 were in our Eagle Ford shale, Bakken/Three Forks, and Permian programs. Please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we expect to fund our capital program.

Subsequent Events. Subsequent to March 31, 2013, we and our lenders entered into a Fifth Amended and Restated Credit Agreement, which increased our aggregate lender commitments to $1.3 billion from $1.0 billion and extended the maturity of our revolving credit facility to April 12, 2018. Also, our borrowing base was increased to $1.9 billion from $1.55 billion as the result of our lenders' regularly scheduled redetermination process. Please refer to Note 5 - Long-term Debt in Part I, Item 1 of this report for additional discussion.

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Financial Results of Operations and Additional Comparative Data

The table below provides information regarding selected production and financial information for the quarter ended March 31, 2013, and the immediately preceding three quarters. Additional details of per BOE costs are presented later in this section.

	For the Three Months Ended			
	March 31, 2013	December 31, 2012	September 30, 2012	June 30, 2012
	(in millions, except for production data)			
Production (MMBOE)	10.3	10.1	9.5	8.4
Oil, gas, and NGL production revenue	$469.6	$424.7	$373.9	$312.6
Lease operating expense	$54.7	$48.0	$46.5	$46.1
Transportation costs	$47.4	$43.0	$37.0	$30.3
Production taxes	$23.5	$20.2	$18.9	$14.7
DD&A	$198.7	$204.3	$192.4	$161.6
Exploration	$15.4	$24.2	$25.4	$22.0
General and administrative	$32.3	$28.4	$32.2	$31.1
Net income (loss)	$16.7	$(67.1)	$(38.3)	$24.9

Selected Performance Metrics:

	For the Three Months Ended			
	March 31, 2013	December 31, 2012	September 30, 2012	June 30, 2012
Average net daily production equivalent (MBOE per day)	115.0	109.9	103.3	92.6
Lease operating expense (per BOE)	$5.28	$4.74	$4.89	$5.48
Transportation costs (per BOE)	$4.58	$4.25	$3.90	$3.59
Production taxes as a percent of oil, gas, and NGL production revenue	5.0%	4.8%	5.1%	4.7%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	$19.20	$20.20	$20.25	$19.17
General and administrative (per BOE)	$3.12	$2.81	$3.39	$3.69

Note: Amounts may not recalculate due to rounding.

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

	For the Three Months Ended March 31, 2013	2012	Amount Change Between Periods	Percent Change Between Periods
Net production volumes [(1)]				
Oil (MMBbl)	3.1	2.5	0.6	25 %
Gas (Bcf)	32.2	28.7	3.6	13 %
NGLs (MMBbl)	1.8	1.2	0.7	58 %
Equivalent (MMBOE)	10.3	8.4	1.9	22 %
Average net daily production [(1)]				
Oil (MBbl per day)	34.8	27.6	7.2	26 %
Gas (MMcf per day)	358.2	314.9	43.3	14 %
NGLs (MBbl per day)	20.5	12.8	7.7	60 %
Equivalent (MBOE per day)	115.0	92.8	22.1	24 %
Oil, gas, & NGL production revenue (in millions)				
Oil production revenue	$287.1	$227.4	$59.7	26 %
Gas production revenue	115.0	83.2	31.8	38 %
NGL production revenue	67.5	52.0	15.5	30 %
Total	$469.6	$362.6	$107.0	30 %
Oil, gas, & NGL production expense (in millions)				
Lease operating expense	$54.7	$39.4	$15.3	39 %
Transportation costs	47.4	28.6	18.8	66 %
Production taxes	23.5	19.1	4.4	23 %
Total	$125.6	$87.1	$38.5	44 %
Realized price				
Oil (per Bbl)	$91.67	$90.67	$1.00	1 %
Gas (per Mcf)	$3.57	$2.90	$0.67	23 %
NGLs (per Bbl)	$36.65	$44.67	$(8.02)	(18)%
Per BOE	$45.38	$42.92	$2.46	6 %
Per BOE Data [(1)]				
Production costs:				
Lease operating expenses	$5.28	$4.66	$0.62	13 %
Transportation costs	$4.58	$3.38	$1.20	36 %
Production taxes	$2.28	$2.26	$0.02	1 %
General and administrative	$3.12	$3.33	$(0.21)	(6)%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$19.20	$20.07	$(0.87)	(4)%
Derivative cash settlement [(2)]	$1.13	$0.84	$0.29	35 %
Earnings per share information				
Basic net income per common share	$0.25	$0.41	$(0.16)	(39)%
Diluted net income per common share	$0.25	$0.39	$(0.14)	(36)%
Basic weighted-average common shares outstanding (in thousands)	66,211	64,104	2,107	3 %
Diluted weighted-average common shares outstanding (in thousands)	67,521	67,845	(324)	— %

[(1)] Amounts and percentage changes may not recalculate due to rounding.
[(2)] Derivative cash settlements are included within the other operating revenues and unrealized and realized derivative loss line items in the accompanying statements of operations.

We present per BOE 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 months ended March 31, 2013, increased 24 percent compared with the same period in 2012, driven primarily by the development of our Eagle Ford shale 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 BOE basis for the three months ended March 31, 2013, increased six percent compared to the same period in 2012, due primarily to improved gas prices.

Lease operating expenses ("LOE") on a per BOE basis for the three months ended March 31, 2013, increased 13 percent compared to the same period in 2012 due to an overall increase in costs, with the largest increase in our South Texas & Gulf Coast region as a result of high water disposal costs. Based upon the current level of industry activity, we believe that LOE on a per BOE basis will remain relatively stable throughout 2013.

Production taxes on a per BOE basis remained relatively the same for the three months ended March 31, 2013, compared to the same period in 2012. We generally expect production tax expense to trend with oil, gas, and NGL revenues.

Transportation costs on a per BOE basis for the three months ended March 31, 2013, increased 36 percent compared to the same period in 2012. This is a result of increased production in our Eagle Ford shale program, where our transportation arrangements have higher per unit transportation costs compared with our other regions. We anticipate transportation costs will continue to increase on a per BOE basis as our Eagle Ford shale program becomes a larger portion of our total production.

General and administrative expense on a per BOE basis for the three months ended March 31, 2013, decreased six percent compared to the same period in 2012, 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 correlate with net cash flows and therefore are subject to variability.

Depletion, depreciation, and amortization ("DD&A") expense on a per BOE basis for the three months ended March 31, 2013, decreased four percent compared to the same period in 2012. 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 classified as held for sale can also impact our DD&A rate since these properties are no longer depleted. Our DD&A rate has improved in part due to the utilization of our carry with Mitsui. As we continue to utilize our carry, we expect our DD&A rate to continue to improve as we add reserves without incurring capital costs.

Please refer to Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2013, and 2012 for additional discussion on oil, gas, and NGL production expense, DD&A, and general and administrative expense.
Please refer to Note 3 - 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.

Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2013, and 2012

Oil, gas, and NGL production revenue. The following table presents the regional changes in our production and oil, gas, and NGL revenues and costs between the three months ended March 31, 2013, and 2012:

	Average Net Daily Production Added (Lost) (MBOE/d)	Oil, Gas, & NGL Revenue Added (Lost) (in millions)	Production Costs Increase (Decrease) (in millions)

South Texas & Gulf Coast	25.0	$92.0	$32.7
Mid-Continent	(4.8)	3.9	(0.8)
Permian	0.5	(1.4)	3.1
Rocky Mountain	1.4	12.5	3.5
Total	22.1	$107.0	$38.5

The largest regional production increase between the two periods occurred in the South Texas & Gulf Coast region as a result of drilling activity in our Eagle Ford shale program. Production in our Eagle Ford shale program continues to increase and we expect it to continue to do so for the next several years. Unfavorable price differentials in our Permian region caused a decline in oil, gas, and NGL production revenue between the three months ended March 31, 2013, and 2012, despite an increase in production volumes.

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The following table summarizes the realized prices we received for the three months ended March 31, 2013, and 2012, before the effects of derivative cash settlements:

	For the Three Months Ended March 31,	
	2013	2012
Realized oil price ($/Bbl)	$91.67	$90.67
Realized gas price ($/Mcf)	$3.57	$2.90
Realized NGL price ($/Bbl)	$36.65	$44.67
Realized equivalent price ($/BOE)	$45.38	$42.92

A 22 percent increase in production on an equivalent basis combined with a six percent increase in the realized price per BOE resulted in a 30 percent increase in revenue between the two periods. Based on current levels of activity, we expect production volumes to increase annually for the next several years. We also expect our realized prices to trend with commodity prices.

Other operating revenues and expenses. These line items are comprised primarily of marketed gas system revenue and expense. Marketed gas system revenue increased $1.9 million to $14.3 million for the three months ended March 31, 2013, compared with $12.4 million for the same period of 2012, as a result of increased gas prices. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $3.4 million to $14.3 million for the three months ended March 31, 2013, compared with $10.9 million for the same period of 2012. The decrease in our net margin is due to an increase in gathering fees we paid to third parties, which went into effect in the second half of 2012. 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 increased 44 percent to $125.6 million for the three months ended March 31, 2013, compared with $87.1 million for the same period of 2012, as a result of a 22 percent increase in net production volumes on an equivalent basis, as well as an overall increase in costs driven largely by high water disposal costs and transportation costs in our South Texas & Gulf Coast region. Please refer to the caption A three-month overview of selected production and financial information, including trends above for discussion of production costs on a per BOE basis.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A expense increased 17 percent to $198.7 million for the three-month period ended March 31, 2013, compared with $169.6 million for the same period in 2012 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 overview of selected production and financial information, including trends above for discussion of DD&A on a per BOE basis.

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

	For the Three Months Ended March 31,	
	2013	2012
	(in millions)	
Geological and geophysical expenses	$1.5	$3.9
Exploratory dry hole expense	0.2	0.6
Overhead and other expenses	13.7	14.1
Total	$15.4	$18.6

Exploration expense for the three months ended March 31, 2013, decreased 17 percent compared to the same period in 2012 due largely to a decrease in geological and geophysical expenses as a result of costs incurred in the first quarter of 2012 related to a seismic study. 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. We currently expect to

expand our exploration program, which creates an increased potential for exploratory dry holes.
Impairment of properties. We recorded a $21.5 million impairment of proved and unproved properties expense for the three months ended March 31, 2013, related primarily to non-Eagle Ford, dry gas assets in our South Texas & Gulf Coast region as a result of us commencing a plugging and abandonment program. We recorded immaterial impairment expense for the three months ended March 31, 2012. We expect impairments of properties to be more likely to occur in periods of low commodity prices, which negatively impact operating cash flows available for exploration and development, as well as anticipated economic performance.

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General and administrative. General and administrative expense increased 15 percent to $32.3 million for the three months ended March 31, 2013, compared with $28.1 million for the same period of 2012. The increase is due to an increase in employee headcount, which increased overall compensation and benefits expense. Please refer to the caption A three-month overview of selected production and financial information, including trends above for discussion of general and administrative expense on a per BOE basis.
Change in Net Profits Plan liability. This non-cash expense generally relates to the change in the estimated value of the associated noncurrent liability between reporting periods. For the three months ended March 31, 2013, we recorded a non-cash benefit of $1.9 million compared to an expense of $3.9 million for the same period in 2012. The change in our liability is subject to estimation and may change 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 and ongoing operations will also impact our liability. Please refer to Note 10 - Fair Value Measurements in Part I, Item 1 of this report for additional discussion. We broadly expect the change in our Net Profits Plan liability to trend with changes in commodity prices.

Unrealized and realized derivative loss. We recognized an unrealized and realized derivative loss of $30.6 million for the three-month period ended March 31, 2013, compared to a loss of $2.2 million for the same period in 2012. Increasing commodity prices in both periods resulted in unfavorable derivative positions, with the increase in gas strip prices in early 2013 being the largest driver of the loss recorded for the three months ended March 31, 2013. Please refer to Note 9 - Derivative Financial Instruments in Part I, Item 1 of this report for additional discussion.

Income tax expense. We recorded income tax expense of $10.4 million for the three-month period ended March 31, 2013, compared to expense of $15.7 million for the same period in 2012, resulting in effective tax rates of 38.3 percent and 37.3 percent, respectively. The decrease in income tax expense reflects the decrease in net income before income tax between comparable periods. The 2013 increase in the effective rate from 2012 primarily reflects changes in the mix of the highest marginal state tax rates, the effects of valuation allowance adjustments, the state tax rate effect on year-to-date net income from divestitures and drilling activities and changes in the effects of other permanent differences.

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 continue to manage the duration and level of our drilling and completion service commitments in order to provide us with some flexibility to reduce activity and capital expenditures in periods of prolonged commodity price decline.

Sources of Cash

We currently expect our 2013 capital program to be partially funded by cash flows from operations, with an anticipated shortfall to be funded by borrowings under our credit facility. Although we anticipate cash flow from operations and borrowing capacity under our credit facility will be sufficient to fund our expected 2013 capital program, we may also elect to access the capital markets, depending on prevailing market conditions. The divestiture of certain oil and gas properties is also a potential source of funding, and we will continue to evaluate our portfolio to identify potential divestiture candidates.

Our primary sources of liquidity are the cash flows provided by our operating activities, borrowings under our credit facility, proceeds received from 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. Historically, decreases in commodity prices have limited our industry’s access to capital markets. The borrowing base under our credit facility could be reduced as a result of lower commodity prices, divestitures of proved properties, or newly issued debt. See Credit Facility below for a discussion of the amendment to our credit facility subsequent to March 31, 2013.

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. Of the original $680.0 million carry amount, approximately $347.3 million had been spent as of March 31, 2013. The remaining carry is expected to be used throughout 2013 and into 2014. Please refer to Note 12 - Acquisition and Development Agreement and Carry and Earning Agreement in our 2012 Form 10-K, under Part II, Item 8 for additional discussion.

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

Credit Facility

Subsequent to March 31, 2013, we and our lenders entered into a Fifth Amended and Restated Credit Agreement. This amended revolving credit facility replaced our previous facility. The credit facility has a maximum loan amount of $2.5 billion, current aggregate lender commitments of $1.3 billion, and a maturity date of April 12, 2018. The borrowing base under the credit facility as of the filing date of this report is $1.9 billion and is subject to regular semi-annual redeterminations. 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 utilizing our credit facility. No individual bank participating in our credit facility represents more than 10 percent of the lending commitments under the credit facility. Please refer to Note 5 - Long-term Debt in Part I, Item 1 of this report for additional discussion as well as the presentation of the outstanding balance, total amount of letters of credit, and available borrowing capacity under our credit facility as of March 31, 2013, and April 25, 2013.

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 and an adjusted current ratio, as defined by our credit agreement, of no less than 1.0. As of March 31, 2013, our debt to EBITDAX ratio and adjusted current ratio were 1.4 and 1.8, respectively. As of the filing date of this report, we are in compliance with all financial and non-financial covenants under our credit facility.

Our daily weighted-average credit facility debt balance was approximately $394.8 million and $600,000 for the three months ended March 31, 2013, and 2012, respectively. This increase is due to capital spending, as well as the timing of our application of proceeds from our 2021 Notes during the first quarter of 2012. Borrowings under our credit facility are secured by mortgages on the majority of our oil and gas properties.

Weighted-Average Interest Rates

Our weighted-average interest rates in the current year include accrued interest payments, cash fees paid on the unused portion of the credit facility’s aggregate commitment amount, letter of credit fees, and amortization of deferred financing costs. Additionally, our prior year weighted-average interest rate includes amortization of the debt discount related to our 3.50% Senior Convertible Notes. Our weighted-average borrowing rate is calculated using only our accrued interest and fee payments.

The following table presents our weighted-average interest rates and our weighted-average borrowing rates for the three-month periods ended March 31, 2013, and 2012:

	For the Three Months Ended March 31,			
	2013		2012	
Weighted-average interest rate	5.8	%	7.6	%
Weighted-average borrowing rate	5.4	%	5.7	%

The decrease in our weighted-average interest rate from 2012 is a result of our 2023 Notes being outstanding for the first quarter of 2013 at a rate lower than the average interest rate for the quarter ended March 31, 2012, as well as a higher average balance on our revolving credit facility during the current quarter, which reduces the fee paid on the unused portion of our commitment. Our weighted-average borrowing rate remained relatively constant between the two periods.

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Uses of Cash

We use cash for the acquisition, exploration, and development of oil and gas properties and for the payment of operating and general and administrative costs, 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 three months of 2013, we spent $381.2 million for exploration and development capital activities and leasehold acquisitions. These amounts differ from the cost incurred amounts, which are accrual-based and include asset retirement obligation, G&G, and exploration overhead amounts.

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 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.

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.

As of the filing date of this report, we could repurchase up to 3,072,184 shares of our common stock under our stock repurchase program, subject to the approval of our Board of Directors. Shares may be repurchased from time to time in open market, or privately negotiated transactions, subject to market conditions and other factors, including; certain provisions of our credit facility, the indentures governing our Senior Notes, compliance with securities laws, and the terms and provisions of our stock repurchase program. Our Board of Directors reviews this program as part of the allocation of our capital. We currently do not plan to repurchase any shares in 2013.

The following table presents changes in cash flows between the three-month periods ended March 31, 2013, and 2012. 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 Three Months Ended March 31, 2013	2012	Amount Change Between Periods	Percent Change Between Periods
	(in millions)			
Net cash provided by operating activities	$282.3	$188.1	$94.2	50 %
Net cash (used in) investing activities	$(378.9)	$(331.8)	$(47.1)	14 %
Net cash provided by financing activities	$90.8	$24.8	$66.0	266 %

Analysis of Cash Flow Changes Between the Three Months Ended March 31, 2013, and 2012

Operating activities. Cash received from oil, gas, and NGL production revenues, including derivative cash settlements, increased $88.3 million, or 24 percent, to $460.5 million for the first three months of 2013, compared to the same period in 2012. This increase was due to an increase in production volumes and an increase in our adjusted realized price, including derivative cash settlements. Cash paid for lease operating expenses increased $9.9 million to $54.3 million for the first three months of 2013, compared to the same period in 2012, due to increased service costs, as well as high water disposal costs in our South Texas & Gulf Coast region. Cash paid for interest, net of capitalized interest, during the first three months of 2013 increased $13.0 million compared to the same period in 2012 due to interest paid on our 2023 Notes in the first quarter of 2013, offset partially by interest no longer paid on the 3.50% Senior Convertible Notes that were redeemed in April 2012.

Investing activities. Capital expenditures in 2013 increased $46.2 million, or 14 percent, compared with the same period in 2012. This increase was due to increased drilling activity, driven primarily by successful development and delineation activities in our Eagle Ford shale, Bakken/Three Forks, and Permian programs.

Financing activities. We had net borrowings under our credit facility of $90.0 million during the three months ended March 31, 2013, compared with net borrowings of $24.0 million made during the same period in 2012. In the first quarter 2012, we borrowed less under our credit facility due to cash on hand from the proceeds of our 2021 Notes issued in late 2011.

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Interest Rate Risk and Commodity Price Risk

We are exposed to market risk due to the floating interest rate on our revolving credit facility. Our credit agreement allows us to fix the interest rate for all or a portion of the principal balance of our revolving credit facility for a period up to six months. To the extent that the interest rate is fixed, interest rate changes affect the credit facility's fair market value but do not impact results of operations or cash flows. Conversely, for the portion of the credit facility that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows. Changes in interest rates do not impact the amount of interest we pay on our fixed-rate Senior Notes, but can impact fair market values. As of March 31, 2013, we had $430.0 million of floating-rate debt outstanding, and our fixed-rate debt outstanding totaled $1.1 billion. The carrying amount of our floating-rate debt at March 31, 2013, approximates its fair value. Please refer to Note 10 - Fair Value Measurements in Part I, Item 1 of this report for additional discussion on the fair value of our Senior Notes.

The prices we receive for our oil, gas, and NGL production heavily impact our revenue, overall profitability, access to capital and future rate of growth. Oil, gas, and NGLs are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil, gas, and NGLs have been volatile, and these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control.

We enter into commodity derivative contracts in order to reduce the impact of fluctuations in commodity prices. Please refer to Note 9 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information about our oil, gas, and NGL derivative contracts, and additional information below under the caption Summary of Oil, Gas, and NGL Derivative Contracts in Place.

There has been no material change to the interest rate risk analysis or oil and gas price sensitivity analysis previously disclosed. Please refer to the corresponding section under Part II, Item 7 of our 2012 Form 10-K.

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

Our oil, gas, and NGL derivative contracts include costless swap and costless collar arrangements. All contracts are entered into for other-than-trading purposes. Please refer to Note 9 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding accounting for our derivative transactions.

As of March 31, 2013, and through the filing date of this report, we had derivative positions in place covering a portion of anticipated production through the fourth quarter of 2015, totaling 13.0 million Bbls of oil, 119.0 million MMBtu of gas, and 1.5 million Bbls of NGLs.

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

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The following tables describe the approximate volumes, average contract prices, and fair values of contracts we had in place as of March 31, 2013:

Oil Contracts

Oil Swaps

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price	Fair Value at March 31, 2013 (Liability)	
	(Bbls)	(per Bbl)	(in millions)	
Second quarter 2013	1,093,000	$93.72	$(4.1	)
Third quarter 2013	758,000	$95.11	(1.5	)
Fourth quarter 2013	657,000	$93.98	(1.1	)
2014	1,599,000	$91.98	(2.2	)
2015	356,000	$88.40	(0.5	)
All oil swaps	4,463,000		$(9.4	)

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at March 31, 2013 Asset (Liability)	
	(Bbls)	(per Bbl)	(per Bbl)	(in millions)	
Second quarter 2013	620,000	$76.65	$109.08	$(0.1	)
Third quarter 2013	765,000	$74.89	$107.98	(0.5	)
Fourth quarter 2013	727,000	$81.02	$116.09	0.7	
2014	3,022,000	$84.07	$105.46	4.7	
2015	3,366,000	$85.00	$94.25	1.2	
All oil collars	8,500,000			$6.0	

Gas Contracts

Gas Swaps

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at March 31, 2013 (Liability)	
	(MMBtu)	(per MMBtu)	(in millions)	
Second quarter 2013	14,927,000	$ 3.93	$(0.5	)
Third quarter 2013	12,956,000	$ 3.96	(1.5	)
Fourth quarter 2013	11,553,000	$ 4.08	(0.6	)
2014	36,517,000	$ 4.05	(3.6	)
2015	17,470,000	$ 4.02	(2.8	)
All gas swaps*	93,423,000		$(9.0	)

*Gas swaps are comprised of IF El Paso Permian (2%), IF HSC (68%), IF NGPL TXOK (3%), IF NNG Ventura (1%), IF PEPL (12%), IF Reliant N/S (11%), and IF TETCO STX (3%).

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Gas Collars

Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at March 31, 2013 Asset (Liability)
	(MMBtu)	(per MMBtu)	(per MMBtu)	(in millions)
Second quarter 2013	1,910,000	$4.39	$5.32	$0.9
Third quarter 2013	1,770,000	$4.39	$5.31	0.8
Fourth quarter 2013	1,640,000	$4.39	$5.31	0.7
2014	5,734,000	$4.38	$5.36	2.9
2015	14,480,000	$3.96	$4.30	(1.7)
All gas collars*	25,534,000			$3.6

*Gas collars are comprised of IF El Paso Permian (2%), IF HSC (48%), IF NGPL TXOK (7%), IF NNG Ventura (4%), IF PEPL (6%), IF Reliant N/S (18%), and IF TETCO STX (15%).

NGL Contracts

NGL Swaps

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at March 31, 2013 Asset
	(Bbls)	(per Bbl)	(in millions)
Second quarter 2013	552,000	$ 53.13	$1.9
Third quarter 2013	375,000	$ 60.17	1.3
Fourth quarter 2013	342,000	$ 59.77	1.1
2014	208,000	$ 75.87	0.9
All NGL swaps*	1,477,000		$5.2

*NGL swaps are comprised of OPIS Mont. Belvieu Ethane Purity (20%), OPIS Mont. Belvieu LDH Propane (13%), OPIS Mont. Belvieu NON-LDH Isobutane (18%), OPIS Mont. Belvieu NON-LDH Normal Butane (22%), and OPIS Mont. Belvieu NON-LDH Natural Gasoline (27%).

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, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes.

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.

Critical Accounting Policies and Estimates

Please refer to the corresponding section in Part II, Item 7 of our 2012 Form 10-K and to the footnote disclosures included in Part I, Item 1 of this report for a discussion of our accounting policies and estimates.

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 (loss) 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 that 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 (loss), income (loss) from operations, net cash provided by (used in) operating activities, profitability, or liquidity measures prepared under GAAP. Because EBITDAX excludes some, but not all items that affect net income (loss) 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 and from EBITDAX to net cash provided by operating activities for the periods presented:

	For the Three Months Ended March 31,	
	2013	2012
	(in thousands)	
Net income (GAAP)	$16,727	$26,336
Interest expense	19,101	14,278
Interest income	(12)	(70)
Income tax expense	10,382	15,681
Depreciation, depletion, amortization, and asset retirement obligation liability accretion	198,709	169,570
Exploration	13,224 [(1)]	18,607
Impairment of properties	21,521	142
Stock-based compensation expense	8,113	4,350
Unrealized derivative loss	42,364	7,652
Change in Net Profits Plan liability	(1,925)	3,939
(Gain) loss on divestiture activity	574 [(2)]	(1,462)
EBITDAX (Non-GAAP)	$328,778	$259,023
Interest expense	$(19,101)	$(14,278)
Interest income	12	70
Income tax expense	(10,382)	(15,681)
Exploration	(13,224)	(18,607)
Exploratory dry hole expense	159	606
Amortization of debt discount and deferred financing costs	1,077	3,665
Deferred income taxes	10,280	15,288
Other	458 [(3)]	(1,118)
Changes in current assets and liabilities	(15,765)	(40,915)
Net cash provided by operating activities (GAAP)	$282,292	$188,053

[(1)] Stock-based compensation expense is a component of exploration expense and general and administrative expense on the accompanying statements of operations. Therefore, the exploration line items shown in the reconciliation above will vary from the amount shown on the accompanying statements of operations because of the component of stock-based compensation expense recorded to exploration.

(2) (Gain) loss on divestiture activity is included within the other operating revenues line item of the accompanying statements of operations.

(3) Does not include the impact of any (gain) loss on divestiture activity, which is included in other on the accompanying statements of cash flows.

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Cautionary Information about Forward-Looking Statements

This report contains “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this report 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 report, 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. Some of these risks are described in the Risk Factors section of our 2012 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;

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- our limited control over activities on non-operated properties;
- 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;
- our ability to deliver necessary quantities of natural gas to contractual counterparties;
- 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 the amount we are able 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;
- the possibility that covenants in our debt agreements may limit our discretion in the operation of our business, prohibit us from engaging in beneficial transactions or lead to the accelerated payment of our debt;
- operating and environmental risks and hazards that could result in substantial losses;
- the impact of seasonal weather conditions and lease stipulations on our ability to conduct drilling activities;
- our ability to acquire adequate supplies of water and dispose of or recycle water we use at a reasonable cost in accordance with environmental rules;
- 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;
- 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 legislation and 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 Interest Rate Risk and Commodity Price 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 2012 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 first quarter of 2013 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

There have been no material changes to the legal proceedings as previously disclosed in our 2012 Form 10-K, under Part I, Item 3. 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 2012 Form 10-K.

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ITEM 6. EXHIBITS

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

Exhibit	Description
3.1	Amended and Restated By-Laws of SM Energy Company amended effective as of January 1, 2013 (filed as Exhibit 3.1 to the registrant's Current Report on Form 8-K filed on January 7, 2013, and incorporated herein by reference)
10.1	Fifth Amended and Restated Credit Agreement dated April 12, 2013, among SM Energy Company, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant's Current Report of Form 8-K filed on April 15, 2013, 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
99.1*	Audit Committee Pre-Approval of Non-Audit Services
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.

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SIGNATURES

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

	SM ENERGY COMPANY
May 1, 2013	By: /s/ ANTHONY J. BEST Anthony J. Best Chief Executive Officer (Principal Executive Officer)
May 1, 2013	By: /s/ A. WADE PURSELL A. Wade Pursell Executive Vice President and Chief Financial Officer (Principal Financial Officer)
May 1, 2013	By: /s/ MARK T. SOLOMON Mark T. Solomon Vice President - Controller and Assistant Secretary (Principal Accounting Officer)