ST MARY LAND & EXPLORATION CO
Form 10-Q
May 05, 2009

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, 2009

Commission file number 001-31539

ST. MARY LAND & EXPLORATION 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.)
1776 Lincoln Street, Suite 700, 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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes o 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. (Check one):

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

smaller reporting company)	company o

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Exchange Act).

Yeso 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 28, 2009 the registrant had 62,393,373 shares of common stock, $0.01 par value, outstanding.

ST. MARY LAND & EXPLORATION COMPANY

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PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (UNAUDITED)
(In thousands, except share amounts)

ASSETS		March 31, 2009		December 31, 2008 (As adjusted, Note 7)
Current assets:				
Cash and cash equivalents	$	2,211	$	6,131
Short-term investments		1,010		1,002
Accounts receivable, net of allowance for doubtful accounts of $16,991 in 2009 and $16,788 in 2008		113,779		157,690
Refundable income taxes		-		13,161
Prepaid expenses and other		22,930		22,161
Accrued derivative asset		119,111		111,649
Total current assets		259,041		311,794
Property and equipment (successful efforts method), at cost:				
Land		1,350		1,350
Proved oil and gas properties		2,941,940		2,969,722
Less - accumulated depletion, depreciation, and amortization		(1,029,858)		(947,207)
Unproved oil and gas properties, net of impairment allowance of $43,069 in 2009 and $42,945 in 2008		167,905		170,644
Wells in progress		54,657		90,910
Materials inventory, at lower of cost or market		36,759		40,455
Other property and equipment, net of accumulated depreciation of $14,676 in 2009 and $13,848 in 2008		13,442		13,458
		2,186,195		2,339,332
Other noncurrent assets:				
Accrued derivative asset		24,246		21,541
Restricted cash subject to Section 1031 Exchange		10,050		14,398
Other noncurrent assets		9,649		10,182
Total other noncurrent assets		43,945		46,121
Total Assets	$	2,489,181	$	2,697,247

LIABILITIES AND STOCKHOLDERS' EQUITY

Current liabilities:				
Accounts payable and accrued expenses	$	201,282	$	254,811
Accrued derivative liability		1,247		501
Deferred income taxes		42,210		41,289
Total current liabilities		244,739		296,601
Noncurrent liabilities:				
Long-term credit facility		299,000		300,000
Senior convertible notes, net of unamortized discount of $26,695 in 2009, and $28,787 in 2008		260,805		258,713
Asset retirement obligation		109,653		108,993
Net Profits Plan liability		154,075		177,366
Deferred income taxes		305,471		354,328
Accrued derivative liability		18,832		27,419
Other noncurrent liabilities		11,730		11,318
Total noncurrent liabilities		1,159,566		1,238,137
Commitments and contingencies				
Stockholders' equity:				
Common stock, $0.01 par value: authorized - 200,000,000 shares; issued: 62,567,962 shares in 2009 and 62,465,572 shares in 2008; outstanding, net of treasury shares: 62,390,975 shares in 2009 and 62,288,585 shares in 2008		626		625
Additional paid-in capital		141,872		141,283
Treasury stock, at cost: 176,987 shares in 2009 and 2008		(1,773)		(1,892)
Retained earnings		866,457		957,200
Accumulated other comprehensive income		77,694		65,293
Total stockholders' equity		1,084,876		1,162,509
Total Liabilities and Stockholders' Equity	$	2,489,181	$	2,697,247

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)
(In thousands, except per share amounts)

	For the Three Months Ended March 31, 2009	2008 (As adjusted, Note 7)
Operating revenues and other income:		
Oil and gas production revenue	$ 130,417	$ 310,432
Realized oil and gas hedge gain (loss)	55,620	(23,950)
Gain (loss) on sale of proved properties	(599)	56,017
Marketed gas system and other operating revenue	13,782	19,603
Total operating revenues and other income	199,220	362,102
Operating expenses:		
Oil and gas production expense	55,829	59,476
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	91,712	70,354
Exploration	13,598	14,308
Impairment of proved properties	147,049	-
Abandonment and impairment of unproved properties	3,902	1,008
Impairment of materials inventory	8,616	-
General and administrative	16,399	21,128
Change in Net Profits Plan liability	(23,291)	13,626
Marketed gas system expense	13,383	17,745
Unrealized derivative loss	1,846	6,417
Other expense	5,642	700
Total operating expenses	334,685	204,762
Income (loss) from operations	(135,465)	157,340
Nonoperating income (expense):		
Interest income	22	97
Interest expense	(6,096)	(6,593)
Income (loss) before income taxes	(141,539)	150,844
Income tax benefit (expense)	53,916	(55,870)
Net income (loss)	$ (87,623)	$ 94,974
	62,335	62,861

Basic weighted-average common shares outstanding				
Diluted weighted-average common shares outstanding		62,335		64,045
Basic net income (loss) per common share	$	(1.41)	$	1.51
Diluted net income (loss) per common share	$	(1.41)	$	1.48

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
(UNAUDITED)
(In thousands, except share amounts)

	Common Stock		Additional Paid-in	Treasury Stock		Retained	Accumulated Other Comprehensive Income (Loss)	Total Stockholders'
	Shares	Amount	Capital	Shares	Amount	Earnings		Equity
Balances, December 31, 2007 (As adjusted, Note 7)	64,010,832	$ 640	$ 211,913	(1,009,712)	$ (29,049)	$ 876,038	$ (156,968)	$ 902,574
Comprehensive income, net of tax:								
Net income (As adjusted, Note 7)	-	-	-	-	-	87,348	-	87,348
Change in derivative instrument fair value	-	-	-	-	-	-	177,005	177,005
Reclassification to earnings	-	-	-	-	-	-	46,463	46,463
Minimum pension liability adjustment	-	-	-	-	-	-	(1,207)	(1,207)
Total comprehensive income								309,609
Cash dividends, $ 0.10 per share	-	-	-	-	-	(6,186)	-	(6,186)
Treasury stock purchases	-	-	-	(2,135,600)	(77,150)	-	-	(77,150)
Retirement of treasury stock	(2,945,212)	(29)	(103,237)	2,945,212	103,266	-	-	-
Issuance of common stock under Employee Stock Purchase Plan	45,228	-	1,055	-	-	-	-	1,055
Issuance of common stock upon settlement of RSUs following expiration of restriction period,								

net of shares used for tax withholdings	482,602	5	(6,910)	-	-	-	-	(6,905)
Sale of common stock, including income tax benefit of stock option exercises	868,372	9	24,691	-	-	-	-	24,700
Stock-based compensation expense	3,750	-	13,771	23,113	1,041	-	-	14,812
Balances, December 31, 2008 (As adjusted, Note 7)	62,465,572	$ 625	$ 141,283	(176,987)	$ (1,892)	$ 957,200	$ 65,293	$ 1,162,509
Comprehensive income (loss), net of tax:								
Net loss	-	-	-	-	-	(87,623)	-	(87,623)
Change in derivative instrument fair value	-	-	-	-	-	-	(14,148)	(14,148)
Reclassification to earnings	-	-	-	-	-	-	26,550	26,550
Minimum pension liability adjustment	-	-	-	-	-	-	(1)	(1)
Total comprehensive loss								(75,222)
Cash dividends, $ 0.05 per share	-	-	-	-	-	(3,120)	-	(3,120)
Issuance of common stock upon settlement of RSUs following expiration of restriction period, net of shares used for tax withholdings, including income tax cost of RSUs	85,638	1	(3,240)	-	-	-	-	(3,239)
Sale of common stock, including income tax benefit of stock option exercises	15,502	-	172	-	-	-	-	172

Stock-based compensation expense	1,250	-	3,657	-	119	-	-	3,776
Balances, March 31, 2009	62,567,962	$ 626	$ 141,872	(176,987)	$ (1,773)	$ 866,457	$ 77,694	$ 1,084,876

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)
(In thousands)

	For the Three Months Ended March 31,			
		2009		2008 (As adjusted, Note 7)
Cash flows from operating activities:				
Reconciliation of net income (loss) to net cash provided by operating activities:				
Net income (loss)	$	(87,623)	$	94,974
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
(Gain) loss on sale of proved properties		599		(56,017)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion		91,712		70,354
Exploratory dry hole expense		94		690
Impairment of proved properties		147,049		-
Abandonment and impairment of unproved properties		3,902		1,008
Impairment of materials inventory		8,616		-
Stock-based compensation expense*		3,776		3,310
Change in Net Profits Plan liability		(23,291)		13,626
Unrealized derivative loss		1,846		6,417
Loss related to hurricanes		2,093		-
Deferred income taxes		(55,390)		49,489
Amortization of debt discount		2,092		1,846
Other		(829)		3,627
Changes in current assets and liabilities:				
Accounts receivable		43,703		(41,236)
Refundable income taxes		13,161		933
Prepaid expenses and other		(5,414)		(336)
Accounts payable and accrued expenses		(20,921)		(5,142)
Excess income tax benefit from the exercise of stock options		-		(860)
Net cash provided by operating activities		125,175		142,683
Cash flows from investing activities:				
Proceeds from sale of oil and gas properties		1,063		130,400
Capital expenditures		(133,625)		(161,530)
Acquisition of oil and gas properties		(53)		(53,031)
Receipts from restricted cash		4,348		-

Other		-		(10,007)
Net cash used in investing activities		(128,267)		(94,168)
Cash flows from financing activities:				
Proceeds from credit facility		1,190,000		389,000
Repayment of credit facility		(1,191,000)		(397,500)
Excess income tax benefit from the exercise of stock options		-		860
Proceeds from sale of common stock		172		328
Repurchase of common stock		-		(77,202)
Net cash used in financing activities		(828)		(84,514)
Net change in cash and cash equivalents		(3,920)		(35,999)
Cash and cash equivalents at beginning of period		6,131		43,510
Cash and cash equivalents at end of period	$	2,211	$	7,511

* Stock-based compensation expense is a component of exploration expense and general and administrative expense on the consolidated statements of operations. For the three months ended March 31, 2009, and 2008, respectively, approximately $1.6 million and $1.1 million of stock-based compensation expense was included in exploration expense. For both the three months ended March 31, 2009, and 2008, approximately $2.2 million of stock-based compensation expense was included in general and administrative expense.

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED) (Continued)

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

	For the Three Months Ended March 31,	
	2009	2008
	(In thousands)	
Cash paid for interest	$ 1,509	$ 3,616
Cash paid or (refunded) for income taxes	$ (10,907)	$ 2,081

For the period ended March 31, 2008, the Company issued 158,744, restricted stock units
to employees as equity-based compensation, pursuant to the Company's 2006
Equity Incentive Compensation Plan. The total fair value of this issuance was $6.0 million.
There were no restricted stock units issued to employees for the period ended March 31, 2009.

As of March 31, 2009, and 2008, $76.4 million, and $132.8 million, respectively, are included as
additions to oil and gas properties and accounts payable and accrued expenses. These oil and gas property
additions are reflected in cash used in investing activities in the periods that the payables are settled.

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

March 31, 2009

Note 1 – The Company and Business

St. Mary Land & Exploration Company ("St. Mary" or the "Company") is an independent energy company engaged in the exploration, exploitation, development, acquisition, and production of natural gas and crude oil. The Company's operations are conducted entirely in the continental United States and offshore in the Gulf of Mexico.

Note 2 – Basis of Presentation and Significant Accounting Policies

Basis of Presentation

The accompanying unaudited consolidated financial statements of St. Mary have been prepared in accordance with accounting principles generally accepted in the United States for interim financial information and the instructions to Form 10-Q and Regulation S-X. They do not include all information and notes required by generally accepted accounting principles for complete financial statements. However, except as disclosed herein, there has been no material change in the information disclosed in the notes to consolidated financial statements included in St. Mary's Annual Report on Form 10-K for the year ended December 31, 2008. In the opinion of management, all adjustments, consisting of normal recurring accruals that are considered necessary for fair presentation of the interim financial information, have been included. Operating results for the periods presented are not necessarily indicative of expected results for the full year.

On January 1, 2009, the Company adopted Financial Accounting Standards Board ("FASB") Staff Position ("FSP") Accounting Principles Board Opinion ("APB") 14-1, "Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement)" ("FSP APB 14-1"), which required retrospective application. As a result, prior period balances presented have been adjusted to reflect the period-specific effects of applying FSP APB 14-1. Please refer to Note 7 – Long-term Debt for additional information regarding adoption.

Materials Inventory

The Company's materials inventory is primarily comprised of tubular goods. The Company acquires materials inventory for use in future drilling or repair operations. Materials inventory is valued at the lower of cost or market. Materials inventory totaled $36.8 million and $40.5 million at March 31, 2009, and December 31, 2008, respectively. The Company incurred materials inventory write-downs for the three months ended March 31, 2009, totaling $8.6 million as a result of the decrease in the value of tubular goods. There were no materials inventory write-downs for the three months ended March 31, 2008. Materials inventory has been classified as a separate line item in the consolidated balance sheets for all periods presented.

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 Form 10-K for the year ended December 31, 2008, and are supplemented throughout the footnotes of this document. It is suggested that these consolidated financial statements be read in conjunction with the consolidated financial statements and notes included in the Form 10-K for the year ended December 31, 2008.

Note 3 – Recent Accounting Pronouncements

The Company adopted Statement of Financial Accounting Standards ("SFAS") No. 141(R), "Business Combinations" ("SFAS No. 141(R)") on January 1, 2009, which requires the acquiring entity in a business combination to recognize and measure all assets and liabilities assumed in the transaction and any non-controlling interest in the acquiree at fair value as of the acquisition date. SFAS No. 141(R) changes the way the Company accounts for acquisitions of oil and gas properties. Such acquisitions will now be treated as business combinations, which will require transaction costs to be expensed as incurred, may generate gains or losses due to changes between the effective and closing dates of acquisitions, and require possible recognition of goodwill given differences between the purchase price and fair value of assets received. The impact of SFAS No. 141(R) on the Company's consolidated financial statements will largely be dependent on the size and nature of the business combinations completed after adoption. There have not been any significant acquisitions of oil and gas properties since adoption.

The Company adopted SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements – an amendment to ARB No. 51" on January 1, 2009, which established accounting and reporting standards that require noncontrolling interests to be reported as a component of equity along with any changes in the parent's ownership interest. The adoption of this pronouncement did not have a material impact on the Company's consolidated financial statements.

In December 2008 the Securities and Exchange Commission ("SEC") published the final rules and interpretations updating its oil and gas reporting requirements. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the Petroleum Resource Management System, which is a widely accepted standard for the management of petroleum resources developed by several industry organizations. Key revisions include changes to 12-month average pricing rather than year-end pricing used to estimate proved reserves, the ability to include nontraditional resources in reserves, the use of new technology for determining proved reserves, and permitting disclosure of probable and possible reserves. The SEC will require companies to comply with the amended disclosure requirements for registration statements filed after January 1, 2010, and for annual reports for fiscal years ending on or after December 15, 2009. Early adoption is not permitted. The SEC is working with the FASB to facilitate corresponding accounting standard revisions, which may affect the adoption date. The Company is currently assessing the impact that the adoption will have on the Company's disclosures, operating results, and financial position.

In December 2008 FASB issued FSP SFAS No. 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets" ("FSP SFAS 132(R)-1"). FSP SFAS 132(R)-1 amends the disclosure requirements of plan assets for defined benefit pensions and other postretirement plans. The objective of FSP SFAS 132(R)-1 is to provide users of financial statements with an understanding of how investment allocation decisions are made, the major categories of plan assets held by the plans, the inputs and valuation techniques used to measure the fair value of plan assets, significant concentration of risk within a company's plan assets, fair value measurements determined using significant unobservable inputs, and a reconciliation of changes between the beginning and ending balances. FSP SFAS 132(R)-1 will be effective for fiscal years ending after December 15, 2009. The Company will adopt the new disclosure requirements in the Form 10-K for the fiscal year ending December 31, 2009.

In April 2009, the FASB issued FSP SFAS 107-1 and APB No. 28-1, "Interim Disclosures about Fair Value of Financial Instruments." FSP SFAS 107-1 and APB 28-1 amends SFAS No.107, "Disclosures about Fair Value of Financial Instruments," and APB No. 28, "Interim Financial Reporting," (collectively "FSP SFAS 107-1") to require an entity to provide disclosures about fair value of financial instruments in interim financial information. Under FSP SFAS 107-1, the Company will be required to include disclosures about the fair value of its financial instruments whenever it issues financial information for interim reporting periods and annual reporting periods, whether recognized or not recognized in the statement of financial position. FSP SFAS 107-1 will be effective for periods ending after June 15, 2009. The Company will adopt the new disclosure requirements in the Form 10-Q for the quarter ending June 30, 2009.

Please refer to Note 7 – Long-term Debt, Note 8 – Derivative Financial Instruments, and Note 11 – Fair Value Measurements for additional information on recently adopted accounting standards.

Note 4 – Earnings per Share

Basic net income per common share of stock is calculated by dividing net income available to common stockholders by the weighted-average basic common shares outstanding for the respective period. The shares represented by vested restricted stock units ("RSUs") are included in the calculation of the weighted-average basic common shares outstanding. The earnings per share calculations reflect the impact of any repurchases of shares of common stock made by the Company.

Diluted net income per common share of stock is calculated by dividing adjusted net income by the weighted-average diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculations consist of unvested RSUs, in-the-money outstanding options to purchase the Company's common stock, Performance Share Awards ("PSAs"), and shares into which the 3.50% Senior Convertible Notes due 2027 (the "3.50% Senior Convertible Notes") are convertible.

The Company's 3.50% Senior Convertible Notes, which were issued April 4, 2007, have a net-share settlement right whereby each $1,000 principal amount of notes may be surrendered for conversion to cash in an amount equal to the principal amount and, if applicable, shares of common stock for the amount in excess of the principal amount. The treasury stock method is used to measure the potentially dilutive impact of shares associated with that conversion feature. The 3.50% Senior Convertible Notes have not been dilutive for any reporting period that they have been outstanding and therefore do not impact the diluted earnings per share calculation for the three-month periods ended March 31, 2009, and 2008.

The Company's PSAs have a three-year performance period. At the end of each grant's three-year performance period, a multiplier will be applied to all vested PSAs to determine the number of common shares issued. The number of common shares issued is calculated based on the Company's absolute stock price performance and a comparison of the Company's stock price performance to that of its peers. The number of potentially dilutive shares related to the PSAs is based on the number of shares, if any, which would be issuable if the end of the reporting period, was the end of the contingency period. There were no potentially dilutive shares related to the PSAs included in the diluted earnings per share calculation as of March 31, 2009. For additional discussion on PSAs, please see Note 5 – Compensation Plans under heading Performance Share Awards Under the Equity Incentive Compensation Plan.

The treasury stock method is used to measure the dilutive impact of stock options, RSUs, and PSAs. In accordance with SFAS No. 128, "Earnings Per Share", when there is a loss from continuing operations, all potentially dilutive shares will be anti-dilutive. As such, for the three months ended March 31, 2009, there were no dilutive shares. The unvested RSUs and in-the-money options had a dilutive impact for the three-month period ended March 31, 2008, as calculated in the table below.

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

	For the Three Months Ended March 31,	
	2009	2008
	(In thousands, except per share amounts)	
Net income (loss)	$ (87,623)	$ 94,974
Basic weighted-average common stock outstanding	62,335	62,861
Add: dilutive effect of stock options, unvested RSUs, and PSAs	-	1,184
Add: dilutive effect of 3.50% senior convertible notes	-	-
Diluted weighted-average common shares outstanding	62,335	64,045
Basic net income (loss) per common share	$ (1.41)	$ 1.51
Diluted net income (loss) per common share	$ (1.41)	$ 1.48

Note 5 – Compensation Plans

Cash Bonus Plan

In March 2009 the Company paid $6.0 million for cash bonuses earned in the 2008 performance year and in February 2008 paid $3.5 million earned in the 2007 performance year. Included in the general and administrative and exploration expense line items in the accompanying consolidated statements of operations is the cash bonus expense related to the specific performance year of $2.4 million and $1.8 million for the three-month periods ended March 31, 2009, and 2008, respectively.

Performance Share Awards Under the Equity Incentive Compensation Plan

Total stock-based compensation expense related to PSAs for the three-month period ended March 31, 2009, was $1.4 million. There was no stock-based compensation expense related to PSAs for the three-month period ended March 31, 2008.

A summary of the status and activity of PSAs for the three-month period ended March 31, 2009, is presented in the following table.

	PSAs	Weighted-Average Grant-Date Fair Value
Non-vested, at January 1, 2009	464,333	$ 26.48
Granted	-	$ -
Vested	-	$ -
Forfeited	(16,539)	$ 26.48
Non-vested, at March 31, 2009	447,794	$ 26.48

Restricted Stock Incentive Program Under the Equity Incentive Compensation Plan

The total RSU compensation expense for the three-month periods ended March 31, 2009, and 2008, was $2.1 million and $3.1 million, respectively. As of March 31, 2009, there was $10.3 million of total unrecognized compensation expense related to unvested RSU awards. This unrecognized compensation expense will be amortized through 2011.

During the first quarter of 2009, the Company converted 124,076 RSUs, which related to grants awarded in 2008, 2007, and 2006, into common stock based on the terms or amended terms of the RSU awards. The Company and the majority of the grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and the award agreements. As a result, the Company issued 86,888 shares of common stock associated with these grants. The remaining 37,188 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon the delivery of the shares underlying those RSUs.

A summary of the status and activity of non-vested RSUs for the three-month period ended March 31, 2009, is presented in the following table.

	RSUs		Weighted-Average Grant-Date Fair Value
Non-vested, at January 1, 2009	402,297	$	48.24
Granted	-	$	-
Vested	(118,018)	$	34.64
Forfeited	(10,984)	$	53.39
Non-vested, at March 31, 2009	273,295	$	53.75

As of March 31, 2009, a total of 274,328 RSUs were outstanding, of which 1,033 were vested.

Stock Option Grants Under the Equity Incentive Compensation Plan

The following table summarizes the three-month activity for stock options outstanding as of March 31, 2009:

	Options		Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (In years)		Aggregate Intrinsic Value (In thousands)
Outstanding, January 1, 2009	1,509,710	$	12.69			
Exercised	(15,502)	$	11.21			
Forfeited	-	$	-			
Outstanding, March 31, 2009	1,494,208	$	12.71	3.44	$	2,027
Vested, or expect to vest, end of period	1,494,208	$	12.71	3.44	$	2,027
Exercisable, end of period	1,494,208	$	12.71	3.44	$	2,027

As of March 31, 2009, there was no unrecognized compensation cost related to unvested stock option awards.

Net Profits Plan

Cash payments made under the Net Profits Interest Bonus Plan ("Net Profits Plan") have been expensed as compensation costs in the amounts of \$3.6 million and \$21.5 million for the three-months

ended March 31, 2009, and 2008, respectively. Of the $3.6 million expensed in 2009, approximately $406,000 was recorded as exploration expense and $3.2 million was recorded as general and administrative expense. Of the $21.5 million expensed in 2008, approximately $2.2 million was recorded as exploration expense and $19.3 million was recorded as general and administrative expense.

The Company records changes in the present value of estimated future payments under the Net Profits Plan as a separate item in the accompanying consolidated 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. The table below presents the estimated allocation of the change in the liability if the Company did allocate the adjustment to these specific functional line items based on the current allocation of actual distributions being made by the Company. The change in allocation of costs to the functional classification relates to the current composition of employees as compared to those individuals that have terminated employment with the Company. Of the payments made under the Net Profits Plan, 11 percent and 10 percent would have been classified as exploration expense in the accompanying unaudited consolidated statements of operations for the three-month periods ended March 31, 2009, and 2008, respectively. As time progresses, less of the distributions relate to prospective exploration efforts as more of the distributions are made to employees that have terminated employment and thereby do not provide ongoing exploration support.

	For the Three Months Ended March 31,			
		2009		2008
	(In thousands)			
General and administrative expense (benefit)	$	(20,694)	$	12,247
Exploration expense (benefit)		(2,597)		1,379
Total	$	(23,291)	$	13,626

Note 6 – Income Taxes

Income tax expense (benefit) for the three-month periods ended March 31, 2009, and 2008, differs from the amount that would be provided by applying the statutory U.S. federal income tax rate to income before income taxes as a result of the estimated effect of the domestic production activities deduction, percentage depletion, the effect of state income taxes, and other permanent differences.

	For the Three Months Ended March 31,			
		2009		2008
	(In thousands)			
Current portion of income tax expense:				
Federal	$	1,083	$	5,881
State		390		500
Deferred portion of income tax expense (benefit):		(55,389)		49,489
Total income tax expense (benefit)	$	(53,916)	$	55,870
Effective tax rates		38.1%		37.0%

A change in the Company’s tax rates between reported periods will generally reflect differences in its estimated highest marginal state tax rate due to changes in the composition of income between state tax jurisdictions resulting from Company activities. Currently low commodity prices and uncertain future pricing are causing the rate to vary from period to period as estimates for the domestic production activities

deduction, percentage depletion, and the impact of potential permanent state differences have impacted each period differently.

The Company or its subsidiaries file income tax returns in the U.S. federal jurisdiction and in various states. With few exceptions, the Company is no longer subject to U.S. federal or state income tax examinations by tax authorities for years before 2004. The Internal Revenue Service completed its 2005 audit in March 2009 with a refund due to the Company of $278,000. There was no change to the provision for income tax expense as a result of this examination. The Company received $980,000 in the first quarter of 2008 for income tax refunds and accrued interest resulting from a carry-over of minimum tax credits to its 2003 tax year.

Note 7 – Long-term Debt

Revolving Credit Facility

The Company executed a Third Amended and Restated Credit Agreement on April 14, 2009. This amended revolving credit facility replaced the previous facility. Borrowings under the facility are secured by a pledge, in favor of the lenders, of collateral that includes the majority of the Company's oil and gas properties. The credit facility specifies a maximum loan amount of $1.0 billion and has a maturity date of July 31, 2012. The borrowing base under the credit facility, as authorized by the bank group as of the date of this filing, is $900 million and is subject to regular semi-annual redeterminations. The borrowing base redetermination process considers the value of St. Mary's oil and gas properties and other assets, as determined by the bank syndicate. The Company has an aggregate commitment amount of $678 million under the 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 annual dividend rate to no more than $0.25 per share. The Company is in compliance with all financial and non-financial covenants under the credit facility as of March 31, 2009, and through the date of this filing. Interest and commitment fees are accrued based on the borrowing base utilization grid below. Eurodollar loans accrue interest at the London Interbank Offered Rate ("LIBOR") plus the applicable margin from the utilization table, and Alternative Base Rate ("ABR") and swingline loans accrue interest at Prime plus the applicable margin from the utilization table. Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the accompanying consolidated statements of operations.

Borrowing Base Utilization Grid				
Borrowing Base Utilization Percentage	<25%	>25% <50%	>50% <75%	>75%
Eurodollar Loans	2.000%	2.250%	2.500%	2.750%
ABR Loans or Swingline Loans	1.000%	1.250%	1.500%	1.750%
Commitment Fee Rate	0.500%	0.500%	0.500%	0.500%

The Company had $299.0 million and $295.0 million outstanding under its revolving credit agreement as of March 31, 2009, and April 28, 2009, respectively. The Company had $199.7 million and $381.7 million of available borrowing capacity under this facility as of March 31, 2009, and April 28, 2009, respectively. The Company has a single letter of credit outstanding under the credit facility in the amount of $1.3 million as of March 31, 2009, and through the date of this filing. This reduces the amount available under the commitment amount on a dollar-for-dollar basis.

Adoption of FSP APB 14-1

On January 1, 2009, the Company adopted FSP APB 14-1. FSP APB 14-1 requires issuers of convertible debt that may be settled fully or partially in cash upon conversion to account separately for the liability and equity components of the debt in a manner that will reflect the entity's nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. FSP APB 14-1 applies to the

Company's 3.50% Senior Convertible Notes. Upon adopting the provisions of FSP APB 14-1 the Company retrospectively applied its provisions and restated the Company's consolidated financial statements for prior periods.

In applying FSP APB 14-1, $42 million of the carrying value of our 3.50% Senior Convertible Notes was recorded as additional paid-in capital as of the April 4, 2007, issuance date. This amount represents the equity component of the proceeds from the 3.50% Senior Convertible Notes, calculated assuming a 7.0% discount rate, which was the Company's borrowing rate for a similar debt instrument without the conversion feature at the date of the issuance of the 3.50% Senior Convertible Notes. Upon retrospective application, the adoption resulted in a $6.8 million decrease in the Company's retained earnings at December 31, 2008, comprised of non-cash interest expense of $10.8 million, net of capitalized interest of $2.2 million, less deferred taxes of $4.0 million, for the period of April 4, 2007, through December 31, 2008. The following table presents the December 31, 2008, consolidated balance sheets line items affected as adjusted and as originally reported:

	December 31, 2008	
	As Adjusted	As Originally Reported
	(In thousands)	
Proved oil and gas properties	$ 2,969,722	$ 2,967,491
3.50% Senior Convertible Notes	258,713	287,500
Deferred income taxes	354,328	358,334
Additional paid-in capital	141,283	99,440
Retained earnings	957,200	964,019

As of March 31, 2009, and December 31, 2008, the carrying value of the equity component was $42 million. The principal amount of the 3.50% Senior Convertible Notes, the unamortized debt discount, and the net carrying amounts were as follows:

	As of March 31, 2009	As of December 31, 2008 (Adjusted)
	(In thousands)	
3.50% Senior Convertible Notes	$ 287,500	$ 287,500
Unamortized debt discount	(26,695)	(28,787)
Net carrying amount of the 3.50% Senior Convertible Notes	$ 260,805	$ 258,713

The remaining unamortized debt discount will be recognized under the interest method, over the next 36 months.

The consolidated statements of operations were retroactively modified compared to previously reported amounts as follows:

	For the Three Months Ended March 31, 2008	
	As Adjusted	As Originally Reported
	(In thousands except per share amounts)	
Interest expense	$ 6,593	$ 4,971
Income tax expense	55,870	56,470
Net income	94,974	95,996
Basic net income per common share	$ 1.51	$ 1.53
Diluted net income per common share	$ 1.48	$ 1.50

For the three months ended March 31, 2009, and 2008, the Company recognized $2.1 million and $1.6 million, respectively, of additional non-cash interest expense relating to the debt discount within the accompanying consolidated statement of operations. Accumulated amortization related to the debt discount was $15.1 million as of March 31, 2009.

Note 8 – Derivative Financial Instruments

Adoption of SFAS No. 161

On January 1, 2009, the Company adopted SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities - an amendment of FASB Statement No. 133 ("SFAS No. 161"). SFAS No. 161 requires entities to provide greater transparency about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS No. 133") and how derivative instruments and related hedged items affect an entity's financial position, results of operations, and cash flows.

Oil and Natural Gas Commodity Hedges

To mitigate a portion of the potential exposure to adverse market changes in oil and gas prices, the Company has entered into various derivative contracts. The Company's derivative contracts in place include swap and collar arrangements for oil, natural gas, and natural gas liquids ("NGL"). As of March 31, 2009, the Company has hedge contracts in place through 2011 for a total of approximately 7 million Bbls of anticipated crude oil production, 59 million MMBtu of anticipated natural gas production, and 1 million Bbls of anticipated natural gas liquids production.

The Company attempts to qualify its oil and gas derivative instruments as cash flow hedges for accounting purposes under SFAS No. 133 and related pronouncements. The Company formally documents all relationships between the derivative instruments and the hedged production, as well as the Company's risk management objective and strategy for the particular derivative contracts. This process includes linking all derivatives that are designated as cash flow hedges to the specific forecasted sale of oil or gas at its physical location. The Company also formally assesses (both at the derivative's inception and on an ongoing basis) whether the derivatives being utilized have been highly effective in offsetting changes in the cash flows of hedged production and whether those derivatives may be expected to remain highly effective in future periods. If it is determined that a derivative has ceased to be highly effective as a hedge, the Company will discontinue hedge accounting prospectively. If hedge accounting is discontinued and the derivative remains outstanding, the Company will recognize all subsequent changes in its fair value on the Company's consolidated statements of operations for the period in which the change occurs. As of March 31, 2009, all

oil and natural gas derivative instruments qualified as cash flow hedges for accounting purposes. The Company anticipates that all forecasted transactions will occur by the end of their originally specified periods. All contracts are entered into for other than trading purposes.

The Company's oil and gas hedges are measured at fair value and are included in the accompanying consolidated balance sheets as accrued derivative assets and liabilities. The Company derives internal valuation estimates taking into consideration the counterparties' credit worthiness, the Company's credit worthiness, and the time value of money. Those internal evaluations are then compared to the counterparties' mark-to-market statements. The consideration of the factors results in an estimated exit-price for each derivative asset or liability under a market place participant's view. Management believes that this approach provides a reasonable, non-biased, verifiable, 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 and gas derivative markets are highly active. The fair value of oil and natural gas derivative contracts designated and qualifying as cash flow hedges under SFAS No. 133 was a net asset of $123.3 million at March 31, 2009.

The following table details the fair value of derivatives recorded to derivative instruments valuation in the consolidated balance sheets, by category:

	Location on Consolidated Balance Sheets	Fair Value at March 31, 2009
		(In thousands)
Derivative assets designated as cash flow hedges:		
Oil, natural gas, and NGL commodity	Current assets	$ 119,111
Oil, natural gas, and NGL commodity	Other noncurrent assets	24,246
Total derivative assets designated as cash flow hedges under SFAS No. 133		$ 143,357
Derivative liabilities designated as cash flow hedges:		
Oil, natural gas, and NGL commodity	Current liabilities	$ (1,247)
Oil, natural gas, and NGL commodity	Other noncurrent liabilities	(18,832)
Total derivative liabilities designated as cash flow hedges under SFAS No. 133		$ (20,079)

The Company recognized a net gain of $55.6 million and a net loss of $24.0 million from its oil and natural gas derivative contracts for the three months ended March 31, 2009, and 2008, respectively.

After-tax changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributed to the hedged risk, are recorded in other comprehensive income in the accompanying consolidated balance sheets until the hedged item is recognized in earnings upon the sale of the hedged production. As of March 31, 2009, the amount of unrealized gain net of deferred income taxes to be reclassified from accumulated other comprehensive income to realized oil and gas hedge gain (loss) in the Company's accompanying statement of operations in the next twelve months was $71.8 million.

Any change in fair value resulting from ineffectiveness is recognized currently in unrealized derivative loss in the accompanying consolidated statements of operations. Unrealized derivative loss for the three months ended March 31, 2009, and 2008, includes net losses of $1.8 million and $6.4 million, respectively, from ineffectiveness related to oil and natural gas derivative contracts.

Realized gains or losses from the settlement of oil and gas derivative contracts are reported in the operating revenues and other income section of the accompanying consolidated statements of operations.

The company seeks to minimize ineffectiveness by entering into oil derivative contracts indexed to NYMEX WTI and natural gas derivative contracts indexed to regional index prices associated with pipelines in proximity to the Company's areas of production. As the Company's derivative contracts contain the same index as the Company's sales contracts, this results in derivative contracts that are highly correlated with the underlying hedged item.

The following table details the effect of derivative instruments on other comprehensive income, the consolidated balance sheets, and the consolidated statements of operations for the three months ended March 31, 2009.

Derivatives Qualifying as Cash Flow Hedges	Amount of Gain Recognized in OCI on Derivatives (Effective Portion)	Location of Gain Reclassified from AOCI to Income (Effective Portion)	Amount of Gain Reclassified from AOCI to Income (Effective Portion)
	(In thousands)		(In thousands)
Commodity hedges	$ 80,461	Realized oil and gas hedge gain (loss)	$ 26,550

Derivatives Qualifying as Cash Flow Hedges	Location of Loss Reclassified from AOCI to Income (Ineffective Portion)	Amount of Loss Reclassified from AOCI to Income (Ineffective Portion)
		(In thousands)
Commodity hedges	Unrealized derivative loss	$ 1,846

Credit Related Contingent Features

As of March 31, 2009, only one of the Company's hedge counterparties was not a member of the Company's credit facility bank syndicate. Member banks are secured by the Company's oil and gas assets, and so do not require the Company to post collateral in hedge liability instances. When the Company is in a liability position with the non-member bank, posting collateral may be required if the Company's liability balance exceeds the limit set forth in the agreement with the non-member bank. The Company is subject to financial ratio tests, and the liability balance above which the Company is required to post collateral varies from one dollar to an unlimited amount. No collateral was posted as of March 31, 2009, as the Company was in a net asset position with the non-member bank. On April 14, 2009, another of the Company's hedge counterparties became a non-member of the Company's credit facility bank syndicate. Under the agreement with this counterparty, the liability balance above which the Company is required to post collateral is $5 million. No collateral was posted as of April 28, 2009, as the Company was in a net asset position with both of the non-member banks.

Convertible Note Derivative Instruments

The contingent interest provision of the 3.50% Senior Convertible Notes is a derivative instrument. As of March 31, 2009, and December 31, 2008, the value of this derivative was determined to be immaterial.

Note 9 – Pension Benefits

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

Components of Net Periodic Benefit Cost

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

	For the Three Months Ended March 31,	
	2009	2008
	(In thousands)	
Service cost	$ 625	$ 460
Interest cost	234	222
Expected return on plan assets	(108)	(168)
Amortization of net actuarial loss	93	40
Net Periodic benefit cost	$ 844	$ 554

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

Contributions

Under the Pension Protection Act of 2006 St. Mary is required to contribute at least $380,000 to the Pension Plans in 2009.

Note 10 – Asset Retirement Obligations

The Company recognizes an estimated liability for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and a corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is completed or acquired. The increase in carrying value is included in proved oil and gas properties in the accompanying consolidated balance sheets. The Company depletes the amount added to proved oil and gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and gas properties. Cash paid to settle asset retirement obligations is included in the operating section of the Company's accompanying consolidated statements of cash flows.

The Company's estimated asset retirement obligation liability is based on estimated economic lives, historical experience in abandoning wells, estimated cost to abandon the wells in the future, and federal and state regulatory requirements. The liability is discounted using a credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. The credit-adjusted risk-free rates used to discount the Company's abandonment liabilities range from 6.50 percent to 12.0 percent. Revisions to the liability could occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells.

A reconciliation of the Company's asset retirement obligation liability is as follows:

	For the Three Months Ended March 31,	
	2009	2008
	(In thousands)	
Beginning asset retirement obligation	$ 116,274	$ 108,284
Liabilities incurred	356	4,029
Liabilities settled	(3,006)	(10,597)
Accretion expense	2,301	1,665
Revision to estimated cash flow	2,093	600
Ending asset retirement obligation	$ 118,018	$ 103,981

As of March 31, 2009, accounts payable and accrued expenses contain $8.4 million related to the Company's current asset retirement obligation liability. These estimated retirement costs are associated with an offshore platform that was destroyed during Hurricane Ike in 2008.

Note 11 – Fair Value Measurements

Effective January 1, 2008, the Company partially adopted Statement of Financial Accounting Standards No. 157, "Fair Value Measurements" ("SFAS No. 157") for all financial assets and liabilities measured at fair value on a recurring basis. The statement establishes a framework for measuring fair value and requires enhanced disclosures about fair value measurements. SFAS No. 157 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. The statement establishes market or observable inputs as the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The statement establishes a hierarchy for grouping these assets and liabilities, based on the significance level of the following inputs:

Level 1 – Quoted prices in active markets for identical assets or liabilities

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

Level 3 – Significant inputs to the valuation model are unobservable

Effective January 1, 2009, the Company adopted SFAS No. 157 for all nonfinancial assets and liabilities measured at fair value on a nonrecurring basis, including long-lived assets and assets held for sale measured at fair value under SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," ("SFAS No. 144") and asset retirement obligations initially measured at fair value under SFAS No. 143, "Accounting for Asset Retirement Obligations,"("SFAS No. 143"). The adoption of SFAS No.157 for nonfinancial assets and liabilities did not have a material impact on the Company.

The following is a listing of the Company's financial and nonfinancial assets and liabilities and where they are classified within the hierarchy as of March 31, 2009.

	Level 1		Level 2		Level 3	
			(In thousands)			
Assets:						
Accrued derivative(a)	$	-	$	143,357	$	-
Proved oil and gas properties(b)	$	-	$	-	$	140,019
Liabilities:						
Accrued derivative(a)	$	-	$	20,079	$	-
Net Profits Plan(a)	$	-	$	-	$	154,075

(a) This represents a financial asset or liability that is measured at fair value on a recurring basis.
(b) This represents a nonfinancial asset or liability that is measured at fair value on a nonrecurring basis effective January 1, 2009.

The following is a listing of the Company's financial assets and liabilities that are measured at fair value on a recurring basis and where they are classified within the hierarchy as of December 31, 2008.

	Level 1		Level 2		Level 3	
			(In thousands)			
Assets:						
Accrued derivative	$	-	$	133,190	$	-
Liabilities:						
Accrued derivative	$	-	$	27,920	$	-
Net Profits Plan	$	-	$	-	$	177,366

A financial asset or liability is categorized within the hierarchy based on the lowest level of input that is significant to the fair value measurement. The following is a description of the valuation methodologies used by the Company as well as the general classification of such instruments pursuant to the hierarchy.

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil and gas hedges. Fair values are based upon interpolated data. The Company calculates 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 provide a reasonable and consistent methodology for valuing derivative instruments.

Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value due to the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, 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 spreads, and any change in such spreads since the last measurement date. The majority of the Company's derivative counterparties are members of St. Mary's credit facility bank syndicate. The Company is currently in a net asset position with all of its counterparties as of March 31, 2009.

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 the requirements of SFAS No. 157 and with other marketplace participants, the Company recognizes that third parties may use different methodologies or assumptions to determine the fair value of certain financial instruments that could result in a different estimate of fair value at the reporting date.

Net Profits Plan

The Net Profits Plan is a standalone liability for which there is no available market price, principal market, or market participants. The inputs available for this instrument are unobservable, and therefore classified as Level 3 inputs. The Company employs the income approach, which converts future amounts to a single present value amount. This technique uses the estimate of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk to calculate the fair value. There is a direct correlation between realized oil and gas commodity prices driving net cash flows and the Net Profits Plan liability. If commodity prices fall, the liability is reduced or eliminated.

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 a predominate number of the pools, a discount rate of 12 percent is used to calculate this liability. This rate is 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 price and cost assumptions and the discount rates used in the calculations. The commodity price assumptions are formulated by applying the price that is derived from a rolling average of actual prices realized during the prior 24 months together with adjusted New York Mercantile Exchange ("NYMEX") strip prices for the ensuing 12 months. This average price is adjusted to include the effect of hedge prices for the percentage of forecasted production hedged in the relevant periods. The forecasted non-cash expense associated with this significant management estimate is highly volatile from period to period due to fluctuations that occur in the crude oil and natural gas commodity markets. The Company continually evaluates the assumptions used in this calculation in order to consider the current market environment for oil and gas prices, costs, discount rate, and overall market conditions.

If the commodity prices used in the calculation changed by five percent, the liability recorded at March 31, 2009, would differ by approximately $12 million. A one percentage point decrease in the discount rate would result in an increase to the liability of approximately $8 million, while a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $7 million. Actual cash payments to be made to participants in future periods are dependent on actual production, realized commodity prices, and costs associated with the properties in each individual pool of the Net Profits Plan. Consequently, actual cash payments are inherently different from the amounts estimated.

No published market quotes exist on which to base the Company's estimate of fair value of the Net Profits Plan liability. As such, the recorded fair value is based entirely on the management estimates as described within this footnote. While some inputs to the Company's calculation of the fair value of 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

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table reflects the activity for the liabilities measured at fair value using Level 3 inputs for the three-month period ended March 31, 2009.

		For the Three Months Ended March 31, 2009 (In thousands)
Beginning balance	$	177,366
Net decrease in liability(a)		(19,653)
Net settlements (a)(b)		(3,638)
Transfers in (out) of Level 3		-
Ending balance	$	154,075

(a) Net changes in the Net Profits Plan liability are shown in the Change in Net Profits Plan liability line item of the accompanying consolidated statements of operations.
(b) Settlements represent cash payments made or accrued under the Net Profits Plan.

3.50% Senior Convertible Notes Due 2027

Based on the market price of the 3.50% Senior Convertible Notes, the estimated fair value of the notes was approximately $207 million as of March 31, 2009.

Proved oil and gas properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value if the sum of the expected undiscounted future cash flows is less than net book value pursuant to SFAS No. 144. 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 discount rate is a rate that management believes is representative of current market conditions and includes the following factors: estimate of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The price forecast is based on NYMEX strip pricing, adjusted for basis differentials, for the first five years. Future operating costs are also adjusted as deemed appropriate for these estimates.

The calculation of the discount rate is a significant management estimate based on the best information available and computed to be 12 percent for the quarter ended March 31, 2009. In accordance with SFAS No. 144, of the $2.2 billion worth of long-lived assets, $140.0 million were measured at fair value. The quarterly impairment write-down of $147.0 million is included within the accompanying consolidated statement of operations.

Asset Retirement Obligations

The Company estimates asset retirement obligations pursuant to the provisions of SFAS No. 143. The income valuation technique is utilized by the Company to determine the fair value of the 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.

Refer to Note 8 – Derivative Financial Instruments and Note 10 – Asset Retirement Obligations for more information regarding the Company's hedging instruments and asset retirement obligations.

Note 12 – Impairment of Proved Properties

The Company recorded $147.0 million of proved property impairments for the three months ended March 31, 2009. There was no impairment of proved properties during the first quarter of 2008. A significant decrease in the market price for natural gas, including differentials in effect at March 31, 2009, caused the majority of this non-cash impairment of proved properties. The largest portion of the impairment was $97.3 million related to assets located in the Mid-Continent region. The Company also incurred write-downs associated with proved properties in the Gulf of Mexico and the Company's coalbed methane project at Hanging Woman Basin.

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

This discussion 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

General Overview

We are an independent energy company focused on the development, exploration, exploitation, acquisition, and production of natural gas and crude oil in North America. We generate nearly all our revenues and cash flows from the sale of produced natural gas and crude oil. Our oil and gas reserves and operations are concentrated primarily in various Rocky Mountain basins, including the Williston, Big Horn, Wind River, Powder River, and Greater Green River basins; the Mid-Continent Anadarko and Arkoma basins; the Permian Basin; the tight sandstone reservoirs of East Texas and North Louisiana; the Maverick Basin in South Texas; and the onshore Gulf Coast and offshore Gulf of Mexico. We have developed a balanced and diverse portfolio of proved reserves, development drilling opportunities, and unconventional resource prospects.

Our mission is to deliver outstanding net asset value per share growth to our investors via attractive oil and gas investments. Historically, we have relied on a strategy of growing through niche acquisitions focused in the continental United States. Over the last few years, we have shifted our strategy to focus more on capturing potential resource plays earlier and at a lower cost of entry. This shift was due to the fact that, as we grew, the universe of potential niche acquisition targets became smaller and less impactful to our growth. We believe that this shift will allow for more stable and predictable production and proved reserves growth. Going forward, we will focus on continuing to acquire significant leasehold positions in existing and emerging resource plays in North America. Our strategy is based on the following points:

- Acquire significant leasehold positions in new and emerging resource plays
- Leverage our core competencies in drilling and completions, as well as acquisitions
- Exploit our significant legacy asset production and optimize our asset base through divestitures of non-core assets when appropriate
- Maintain a strong balance sheet while funding the growth of the enterprise

Financial Standing and Liquidity

During and subsequent to the third quarter of 2008, specific issues related to the financial sector have rippled through the broader economy. The failure or takeovers of several large financial institutions has adversely impacted the wider equity, debt, and credit markets. Financial standing and liquidity have become increasingly important as concerns have been raised regarding the pace of drilling activity in the exploration and production industry and the ability of companies to fund their planned activity. In addition, fears of a prolonged global recession or depression leading to declining energy demand have resulted in a significant decline in oil and natural gas prices. We expect our 2009 exploration and development program budget will be at or near our operating cash flows for 2009. Accordingly, we do not anticipate accessing the equity or public debt markets for the remainder of 2009.

We continue to believe we have adequate liquidity available to us through our credit facility. On April 14, 2009, we entered into an amended $1.0 billion senior secured revolving credit facility. The initial borrowing base has been set at $900 million, subject to semi-annual redeterminations based on the bank group's assessment of the value of our oil and natural gas properties. We have a $678 million commitment amount from our bank group. We had $299.0 million and $295.0 million, respectively, drawn on the credit facility at March 31, 2009, and April 28, 2009. Management believes that the current commitment is sufficient for our liquidity needs. To date, we have experienced no issues drawing upon our credit facility. No individual bank participating in the credit facility represents more than 16 percent of the lending commitments under the credit facility. We are monitoring the borrowing environment closely and have frequent discussions with the lending group.

Oil and Gas Prices

Oil and natural gas prices reached significant highs during June and early July of 2008 and have declined significantly since that time. Our financial condition and the results of our operations are significantly affected by oil and natural gas commodity prices, which, can fluctuate dramatically. We sell a majority of our natural gas under contracts that use first of the month index pricing, which means that gas produced in that month is sold at the first of the month price regardless of the spot price on the day the gas is produced. Our crude oil is sold using contracts that pay us either the average of the NYMEX West Texas Intermediate daily settlement or the average of alternative posted prices for the periods in which the crude oil is produced, adjusted for quality, transportation, and location differentials. The following table is a summary of commodity price data for the first quarters of 2009 and 2008 and the fourth quarter of 2008.

	For the Three Months Ended		
	March 31, 2009	December 31, 2008	March 31, 2008
Crude Oil (per Bbl):			
Average NYMEX price	$ 43.08	$ 58.74	$ 97.90
Realized price, before the effects of hedging	$ 34.40	$ 50.17	$ 92.33
Net realized price, including the effects of hedging	$ 44.16	$ 55.63	$ 76.24
Natural Gas (per Mcf):			
Average NYMEX price	$ 4.86	$ 6.82	$ 8.07
Realized price, before the effects of hedging	$ 4.00	$ 5.30	$ 8.53
Net realized price, including the effects of hedging	$ 6.14	$ 7.09	$ 8.69

Average quarterly NYMEX crude oil prices decreased 27 percent from the fourth quarter of 2008 to the first quarter of 2009 from $58.74 per barrel to $43.08 per barrel. Beginning in the third quarter of 2008, the price of crude oil has been pressured downward as a result of a forecasted decrease in global demand, which is a consequence of the broad economic slowdown. The 36-month forward strip price for crude oil at the end of the fourth quarter of 2008 was $62.15 per barrel. At the end of the first quarter of 2009, the 36-month forward contract price remained relatively unchanged at $62.79 per barrel. On April 28, 2009, the 36-month forward strip price had decreased from the end of the first quarter 2009 by two percent to $61.59 per barrel. On April 28, 2009, the near month price was $49.92 per barrel, which was substantially flat compared with the March 31, 2009, near month price of $49.66 per barrel.

Average quarterly NYMEX natural gas prices decreased 29 percent from the fourth quarter of 2008 to the first quarter of 2009 from $6.82 per Mcf to $4.86 per Mcf. Natural gas prices have been and continue to be under downward pressure due to concerns regarding high levels of natural gas in storage, larger anticipated imports of liquefied natural gas, and anemic demand. The 36-month forward strip price for natural gas at the end of the fourth quarter of 2008 was $6.90 per MMBtu. At the end of the first quarter of 2009, the 36-month forward contract price had decreased by

13 percent to $5.97 per MMBtu. As of April 28, 2009, the 36-month forward strip price had declined an additional two percent to $5.85 per MMBtu. On April 28, 2009, the near month price had decreased from the end of the first quarter 2009 by an additional 12 percent to $3.32 per MMBtu.

While changes in quoted NYMEX oil and natural gas prices are generally used as a basis for comparison within our industry, the price we receive for oil and natural gas is affected by quality, energy content, location, and transportation differentials for these products. We refer to this price as our realized price, which excludes the effects of hedging. The slowdown in drilling activity in oil producing regions that resulted from the retreat in oil prices from highs in mid-2008 has helped improve pricing differentials, particularly in the Williston Basin. Differentials for natural gas in the Mid-Continent have widened as regional demand has not kept pace with the growth in supply generated by several successful shale plays in the general vicinity. Our realized price is further impacted by the result of our hedging contracts that are settled in the respective periods. We refer to this price as our net realized price. Our net natural gas and oil price realizations for the three months ended March 31, 2009, were positively impacted by $39.6 million and $16.0 million of realized hedge gains, respectively.

Impairments

We incurred impairment of proved properties totaling $147.0 million for the three months ended March 31, 2009. A significant decrease in the market price for natural gas, including differentials in effect at March 31, 2009, caused the majority of this non-cash impairment of proved properties. The largest portion of the impairment was $97.3 million related to assets located in the Mid-Continent region. We also incurred an impairment associated with proved properties in the Gulf of Mexico and our coalbed methane project at Hanging Woman Basin. Additionally, we incurred inventory write-downs for the three months ended March 31, 2009, totaling $8.6 million as a result of the decrease in the market value of tubular goods and other inventory items.

Hedging Activities

Hedging is an important part of our financial risk management program. The amount of production we hedge is driven by the amount of debt on our consolidated balance sheet and the level of capital commitments and long-term obligations we have in place. In the case of a significant acquisition of producing properties, we will consider hedging in order to lock in a portion of the economics assumed in the acquisition. Taking into account all oil and gas production hedge contracts in place at March 31, 2009, we have hedged anticipated future production of approximately 7 million Bbls of oil, 59 million MMBtu of natural gas, and 1 million Bbls of natural gas liquids through the year 2011. We believe we have established an economic base and cash flow stream for our future operations and our use of collars allows us to participate in a higher oil and gas price environment. Please see Note 8 – Derivative Financial Instruments of Part I, Item 1 of this report for additional information regarding our oil and gas hedges, and see the caption, Summary of oil and gas production hedges in place, later in this section.

Net Profits Plan

Payments made from the Net Profits Plan have been expensed as compensation costs in the amounts of $3.6 million and $21.5 million for the three months ended March 31, 2009, and 2008, respectively. The actual cash payments we make are dependent on actual production, realized prices, and operating and capital costs associated with the properties in each individual pool. Actual cash payments will be inherently different from the estimated liability amounts. More detailed discussion is included in the Comparison of Financial Results and Trends section below and in Note 11 – Fair Value Measurements in Part I, Item 1. An increasing percentage of the costs associated with the payments for the Net Profits Plan are categorized as general and administrative expense as compared to exploration expense. This is a function of the normal departure of employees who previously contributed to exploration efforts. We determined that because of the change in circumstances, a greater percentage of the payments should be recorded as general and administrative expense beginning in 2007. In December 2007, our Board approved an incentive compensation plan restructuring, whereby the Net Profits Plan was replaced with a long-term incentive program utilizing performance shares. As a result, the 2007 Net Profits Plan pool was the last pool established.

The calculation of the estimated liability for the Net Profits Plan is highly sensitive to our price estimates and discount rate assumptions. For example, if we changed the commodity prices in our calculation by five percent, the liability recorded on the balance sheet at March 31, 2009, would differ by approximately $12 million. A one percentage point decrease in the discount rate would result in an increase to the liability of approximately $8 million, while a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $7 million. We frequently re-evaluate the assumptions used in our calculations and consider the possible impacts stemming from the current market environment including current and future oil and gas prices, discount rates, and overall market conditions.

First Quarter 2009 Highlights

Emerging resource play potential. During 2008 the Haynesville shale, the Eagle Ford shale, and the Marcellus shale resource plays emerged in the exploration and development industry. We have exposure to each of these plays which, if successful, could provide for significant future growth in reserves and production. The Haynesville shale emerged early in 2008 in northern Louisiana and East Texas and quickly became the most active resource play in the country. As a result of our previous Cotton Valley and James Lime activity, we had an established acreage position in the area and now estimate that we have approximately 50,000 net acres that may be prospective for the Haynesville shale. Our Eagle Ford shale position in the Maverick Basin in South Texas was built through leasing efforts and a joint venture over the course of 2008. If we earn all of the acreage potential under the joint venture, St. Mary would control roughly 210,000 net acres in this play. Lastly, late in 2008 we entered into two arrangements that could allow us to access 43,000 net acres in the Marcellus shale in north central Pennsylvania.

During the first quarter, we began drilling our first operated wells in the Haynesville and Eagle Ford shales. Subsequent to quarter-end, our well in the Haynesville shale was completed. The well did not perform as we anticipated, and we continue to work with our partner and service providers to better understand the well’s performance. This initial well, drilled in DeSoto Parish, Louisiana, is on acreage that represents a relatively small portion of our total Haynesville acreage position. We are currently drilling our second well targeting the Haynesville in East Texas, where we have a larger portion of our Haynesville acreage. In the Maverick Basin, we continue to drill our first operated horizontal well targeting the Eagle Ford shale. In the Marcellus shale, we have tentative plans to drill our first horizontal wells in the second half of 2009. Our lease terms allow us until the end of 2010 to fulfill our drilling commitments. We may consider deferring our Marcellus testing until 2010.

Financial and production results. We recorded a net loss for the quarter ended March 31, 2009, of $87.6 million or $1.41 per diluted share, which reflects $147.0 million pre-tax impairment of proved properties, as discussed above, compared to first quarter 2008 results of net income of $95.0 million or $1.48 per diluted share.

The table below provides information regarding selected production and financial information for the quarter ended March 31, 2009, and the immediately preceding three quarters. Additional details of per MCFE costs are contained later in this section.

	For the Three Months Ended			
	March 31, 2009	December 31, 2008	September 30, 2008	June 30, 2008
	(In millions, except production sales data)			
Production (BCFE)	28.4	30.0	27.7	28.6
Oil and gas production revenue, excluding the effects of hedging	$ 130.4	$ 190.5	$ 358.5	$ 400.0
Realized oil and gas hedge gain (loss)	$ 55.6	$ 44.8	$ (53.5)	$ (68.4)
Lease operating expense	$ 41.2	$ 47.7	$ 43.6	$ 41.0
Transportation costs	$ 5.5	$ 6.1	$ 6.6	$ 5.6
Production taxes	$ 9.1	$ 11.8	$ 22.5	$ 27.0
DD&A	$ 91.7	$ 95.1	$ 72.4	$ 76.4
Exploration	$ 13.6	$ 17.7	$ 10.7	$ 17.4
Impairment of proved properties	$ 147.0	$ 292.1	$ 0.5	$ 9.6
Abandonment and impairment of unproved properties	$ 3.9	$ 34.7	$ 1.2	$ 2.1
Impairment of goodwill	$ -	$ 9.5	$ -	$ -
General and administrative expense	$ 16.4	$ 12.4	$ 24.1	$ 21.9
Bad debt expense	$ -	$ -	$ 6.7	$ 9.9
Impairment of materials inventory	$ 8.6	$ -	$ -	$ -
Net income (loss)	$ (87.6)	$ (127.1)	$ 87.0	$ 32.5
Percentage change from previous quarter:				
Production (BCFE)	(5)%	8%	(3)%	1%
Oil and gas production revenue, excluding the effects of hedging	(32)%	(47)%	(10)%	29%
Realized oil and gas hedge gain (loss)	24%	(184)%	(22)%	185%
Lease operating expense	(14)%	9%	6%	17%
Transportation costs	(10)%	(8)%	18%	44%
Production taxes	(23)%	(48)%	(17)%	32%
DD&A	(4)%	31%	(5)%	9%
Exploration	(23)%	65%	(39)%	22%
Impairment of proved properties	(50)%	N/M	(95)%	N/A
	(89)%	N/M	(43)%	110%

Abandonment and impairment of unproved properties				
Impairment of goodwill	(100)%	N/A	N/A	N/A
General and administrative expense	32%	(49)%	10%	4%
Bad debt expense	N/A	(100)%	(33)%	N/A
Impairment of materials inventory	N/A	N/A	N/A	N/A
Net income (loss)	(31)%	(246)%	168%	(66)%

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The table below details the regional breakdown of our first quarter 2009 production.

	Mid-Continent	ArkLaTex	Gulf Coast	Permian	Rocky Mountain	Total (1)
First Quarter 2009 Production:						
Oil (MBbl)	73.6	35.5	92.4	509.5	928.8	1,639.8
Gas (MMcf)	8,695.9	4,076.5	1,936.4	986.5	2,819.7	18,515.1
Equivalent (MMCFE)	9,137.6	4,289.8	2,490.7	4,043.3	8,392.3	28,353.7
Avg. Daily Equivalents (MMCFE/d)	101.5	47.7	27.7	44.9	93.2	315.0
Relative percentage	32%	15%	9%	14%	30%	100%

(1) Totals may not add due to rounding

For the first quarter of 2009 our production and oil and gas production revenues were slightly better than we had originally expected. We experienced a decline in our operating margins in the first quarter of 2009, compared with the same period in 2008, due to a decrease in commodity prices and increases in operating costs. For the three months ended March 31, 2009, our operating margin was $4.03 per MCFE compared to $7.26 per MCFE for the same period in 2008.

Outlook for the Remainder of 2009

Unlike prior years, we entered 2009 without a specific capital budget for exploration and development activities. Our plan for the remainder of 2009 is to make capital investments for exploration and development activities at a level at or near our operating cash flows. Given the volatility of commodity prices in recent months, we have established a flexible program to deploy capital rather than set a fixed number.

Our priority in the current environment is to focus our limited capital dollars on the testing of emerging resource plays. Our second priority is the rational development of existing assets. We believe that with the significant decline in commodity prices, the exploration and production industry will continue to slow its level of activity which in turn will lead to a decline in the cost of services provided by the oilfield service industry. We believe the prices for drilling and completion services will continue to decline throughout the rest of 2009 as a result of continued decreasing rig utilization. Accordingly, we have chosen to defer much of our capital investment in development programs with the goal of improving our returns on invested capital. With limited exceptions, we do not have any significant long-term rig commitments or any meaningful issues with potential leasehold expirations. As such, we believe we can be more patient than many of our competitors in choosing when to invest capital. Most of our existing rig commitments expire in the first half of 2009, and we will use very short-term rig contracts to operate a significantly smaller rig fleet throughout 2009 than we used in 2008. We are striving to maintain a high degree of flexibility in the current environment. Our objective is to be able to slow down should economic conditions continue to warrant while preserving the ability to ramp up activity quickly if we deem it to be prudent.

In the Haynesville shale program, 40,000 net acres of our total 50,000 net acres are located in East Texas. Our second Haynesville well has commenced drilling in northern San Augustine County, Texas. After coring the Haynesville section, this well will be drilled down to the deeper Cotton Valley Lime formation for evaluation purposes. We currently expect to complete the well as a vertical Haynesville test. We are also drilling our first operated Eagle Ford shale well in South Texas, where we plan to core that formation and conduct a micro-seismic study. We plan to drill three more operated wells in the Eagle Ford this year, as well as participate in a joint venture that will also target the

Eagle Ford interval. In the Marcellus shale exploration program, we tentatively plan to drill the first of two operated horizontal wells planned for 2009 in the third quarter of 2009. Our drilling commitments in the Marcellus allow us until the end of 2010 to drill. We can elect to defer our activity in this program.

With regard to our development activities, we are currently utilizing only a limited number of rigs. We continue to lay down rigs since we expect that we will be able to secure drilling rigs and well services in the future at a lower cost.

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

Selected Operations Data (In thousands, except sales price, volume, and per MCFE amounts):

	For the Three Months Ended March 31,				Percent Change Between Periods
		2009		2008	
Net production volumes					
Oil (MBbl)		1,640		1,667	(2)%
Natural gas (MMcf)		18,515		18,342	1%
MMCFE (6:1)		28,354		28,347	-%
Average daily production					
Oil (Bbl per day)		18,220		18,323	(1)%
Natural gas (Mcf per day)		205,724		201,565	2%
MCFE per day (6:1)		315,041		311,503	1%
Oil & gas production revenues (1)					
Oil production revenue	$	72,412	$	127,127	(43)%
Gas production revenue		113,625		159,355	(29)%
Total	$	186,037	$	286,482	(35)%
Oil & gas production expense					
Lease operating expense	$	41,248	$	35,105	17%
Transportation costs		5,459		3,877	41%
Production taxes		9,122		20,494	(55)%
Total	$	55,829	$	59,476	(6)%
Average realized sales price (1)					
Oil (per Bbl)	$	44.16	$	76.24	(42)%
Natural gas (per Mcf)	$	6.14	$	8.69	(29)%
Per MCFE Data:					
Average net realized price (1)	$	6.56	$	10.11	(35)%
Lease operating expenses		(1.45)		(1.24)	17%
Transportation costs		(0.19)		(0.14)	36%
Production taxes		(0.32)		(0.72)	(56)%
General and administrative		(0.57)		(0.75)	(24)%
Operating margin	$	4.03	$	7.26	(44)%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$	3.23	$	2.48	30%

(1) Includes the effects of hedging activities

Changes in production volumes, oil and gas production revenues, and costs can reflect the cyclical and highly volatile nature of our industry. We present per MCFE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe require analysis. We anticipate that oil and gas production expenses in absolute dollars will decrease slightly throughout the remainder of 2009 due to the effects that lower commodity prices are anticipated to have on costs to produce oil and natural gas. Many exploration and production companies have begun to slow their activity, which should have a moderating impact on the upward cost pressure we have seen in recent quarters. Production taxes are largely dependent on the prices we receive for oil and natural gas and in the current environment we would expect them to be lower than what we experienced last year. Depreciation, depletion, and amortization generally has been pressured upward in recent years as production related to higher cost properties acquired or developed became a larger percentage of our production mix. In the first quarter of 2009, we saw our DD&A increase due to the impact of lower commodity prices on our internal estimate of proved reserves at March 31, 2009. Lower natural gas prices combined with wider than normal differentials, particularly in the Mid-Continent region, negatively impacted our proved reserve base used to calculate DD&A, which resulted in a higher depletion rate for the quarter. As a result of the impairments we have incurred in the last two quarters, we anticipate that DD&A in subsequent quarters should be lower than the current quarter's $3.23 per MCFE amount. Our general and administrative expense will be impacted by cash payments made under the Net Profits Plan, which generally reflect our realized prices. Part of executing our business plan in 2008 consisted of adding employees, particularly lease operators who manage our operations in the field. The increase in personnel would be expected to drive compensation costs higher in the remainder of 2009. Additionally, there remains a high level of competition for personnel in the exploration and production industry, and we have seen the cost to hire and retain personnel increase significantly.

Average daily production for the first quarter of 2009 increased one percent to 315.0 MMCFE compared with the same period in 2008. For the three months ended March 31, 2009, our average net realized price decreased $3.55 per MCFE to $6.56 per MCFE compared with the same period in 2008. Unit cost decreased for the period as production taxes decreased $0.40 per MCFE to $0.32 per MCFE and general and administrative expense decreased $0.18 per MCFE to $0.57 per MCFE. Lower commodity prices were the principal driver of the decrease in these expenses. Production taxes are highly correlated to commodity prices, and a portion of our general and administrative expense is linked to our profitability and cash flow. These decreases in costs were offset by a $0.21 per MCFE increase in lease operating expenses year over year. Transportation costs also increased $0.05 per MCFE, or 36 percent to $0.19 per MCFE as compared to the same period in 2008.

For the three months ended March 31, 2009, depletion, depreciation, and amortization, including asset retirement obligation accretion expense, increased $0.75 per MCFE to $3.23 per MCFE compared with the same period in 2008. The depletion, depreciation, and amortization increase is a result of a decrease in proved reserves used to calculate DD&A. The decrease in proved reserves is a result of lower realized natural gas prices caused by wider than normal natural gas price differentials, primarily in the Mid-Continent region, and the reduction of proved reserves in our Hanging Woman Basin coalbed methane project. Exploration expense for the first quarter of 2009 was $13.6 million, which was five percent lower than the $14.3 million incurred during the first quarter of 2008. Geological and geophysical expense increased $2.6 million due to an increase in the amount spent for seismic analysis. This increase was offset by a $2.7 million decrease in exploration overhead due to a decrease in Net Profits Plan payments resulting from decreased oil and gas commodity prices.

We present the following table as a summary of information relating to key indicators of financial condition and operating performance that we believe are important.

Financial Information (In thousands, except per share amounts):	March 31, 2009	December 31, 2008	Percent Change Between Periods
Working capital	$ 14,302	$ 15,193	(6)%
Long-term debt	$ 559,805	$ 558,713	-%
Stockholders' equity	$ 1,084,876	$ 1,162,509	(7)%

	For the Three Months Ended March 31, 2009	2008	Percent Change Between Periods
Basic net income (loss) per common share	$ (1.41)	$ 1.51	(193)%
Diluted net income (loss) per common share	$ (1.41)	$ 1.48	(195)%
Basic weighted-average shares outstanding	62,335	62,861	-%
Diluted weighted-average shares outstanding	62,335	64,045	(3)%

We account for our 3.50% Senior Convertible Notes under the treasury stock method. There is no impact on the diluted share calculation for the periods presented since our average stock price for the relevant reporting periods has not exceeded the conversion price. The 3.50% Senior Convertible Notes were issued April 4, 2007, and have not been dilutive for a reporting period since their issuance. We have in-the-money stock options, unvested RSUs, and PSAs that may be potentially dilutive securities. Both basic and diluted earnings per share are presented in the table above. There were no potentially dilutive shares related to in-the-money stock options, unvested RSUs, and PSAs included in the diluted earnings per share calculation for the three months ended March 31, 2009, as we recorded a net loss for the period. A detailed explanation is presented in Note 4 – Earnings per Share, in Part I, Item 1 of this report.

Basic and diluted weighted-average common shares outstanding used in our March 31, 2009, and 2008, earnings per share calculations reflect our stock repurchases, offset by increases in outstanding shares related to stock option exercises, ESPP shares issued, and the settlement of vested RSUs. We issued 15,502 and 27,376 shares of common stock during the three-month periods ended March 31, 2009, and 2008, respectively, as a result of stock option exercises. The first quarter 2008 share issuances were offset by the repurchase of 2,135,600 shares of common stock during the first quarter of 2008 through our stock repurchase plan. There were no shares repurchased during the first quarter of 2009. Additionally, the number of RSUs that vested during the first quarter of 2009 and 2008 were 118,018 and 192,678, respectively.

Overview of Liquidity and Capital Resources

As noted previously in this section, we believe that we have sufficient liquidity and capital resources to execute our business plans for the foreseeable future.

Sources of cash

Based on our current outlook, we plan to keep capital expenditures for our exploration and development activities at a level at or near our operating cash flows in 2009. Accordingly, we do not expect to access the capital markets in 2009. We anticipate that we will continue to evaluate our property base for divestiture candidates that we consider non-core to our strategic goals. We presently have identified assets that we intend to market for sale in 2009 depending on acquisition and divestiture market conditions. However, given our strong financial position we will not sell these properties unless we receive value we consider appropriate.

Our primary sources of liquidity are the cash flows provided by operating activities, debt financing, sales of non-core properties, and access to capital markets. All of these sources can be impacted by the general condition of the broad economy and our industry and by significant fluctuations in oil and gas prices, operating costs, and volumes produced. We have no control over the market prices for oil and natural gas, although we are able to influence the amount of our net realized revenues related to oil and gas sales through the use of derivative contracts. A decrease in market prices would reduce expected cash flow from operating activities and could reduce the borrowing base of our credit facility as well as the value of non-strategic properties we might consider selling. Historically, decreases in market prices have limited our industry's access to the capital markets. Access to the public debt market is currently sporadic and involves higher costs. Credit spreads have increased materially and the volume of transactions being placed in the market are down dramatically. Equity and convertible debt financings are still an available alternative, albeit at high costs. This is a result of the general strength reflected in the balance sheets of the companies in this industry as well as the historically low credit defaults of energy companies. We do not anticipate any need to raise either public debt or equity financing in the foreseeable future. We intend to rely on our credit facility for borrowings. However, a significant transaction could necessitate raising additional public debt or equity financing.

Current credit facility

On April 14, 2009, we entered into an amended $1.0 billion senior secured revolving credit facility with twelve participating banks. No individual lender represents more than 16 percent of the lending commitments under the credit facility. The initial borrowing base has been set at $900 million. We have been provided a $678 million commitment amount by the bank group, which we believe is adequate for our near-term liquidity requirements. The new amended credit facility agreement has a maturity date of July 31, 2012. As of April 28, 2009, we had $381.7 million of available borrowing capacity under this facility. Interest and commitment fees are accrued based on the borrowing base utilization grid located in Note 7 – Long-term Debt in Part I, Item 1 of this report. We have a single letter of credit outstanding under our credit facility in the amount of $1.3 million as of March 31, 2009, through the date of this filing. Such borrowings and letter of credit reduce the amount available under the commitment amount on a dollar-for-dollar basis. Borrowings under the facility are secured by mortgages on the majority of our oil and gas properties.

Our weighted-average interest rate paid in the three-month periods ended March 31, 2009, and 2008, was 4.3 percent and 6.0 percent, respectively, and included fees paid on the unused portion of the previous credit facility's aggregate commitment amount and amortization of the debt discount and deferred financing costs.

We are subject to customary financial and non-financial covenants under our new amended credit facility, which are similar to the covenants under our previous credit facility, including limitations on dividend payments and requirements to maintain certain financial ratios, which include debt to earnings before interest, taxes, depreciation, and amortization ("EBITDA") of less than 3.5 to 1.0 and a current ratio as defined by our credit agreement of not less than 1.0 to 1.0. These covenants are substantially the same as those under our previous credit facility. As of March 31, 2009, our debt to EBITDA ratio and current ratio as defined by our credit agreement, were 0.92 and 1.88, respectively. We are in compliance with all financial and non-financial covenants under our new credit facility.

Uses of cash

We use cash for the acquisition, exploration, and development of oil and gas properties, and for the payment of debt obligations, trade payables, income taxes, common stock repurchases, and stockholder

dividends. In the first three months of 2009 we spent $133.6 million for exploration and development capital expenditures. These amounts differ from the cost incurred amounts based on the timing of cash payments associated with these activities as compared to the accrual based activity upon which the costs incurred amounts are presented. These cash flows were funded using cash inflows from operations and available borrowing capacity under our revolving credit facility.

Expenditures for exploration and development of oil and gas properties and acquisitions are the primary use of our capital resources. We expect our capital and exploration expenditures in 2009 will be at or near operating cash flows. The amount and allocation of future capital expenditures will depend upon a number of factors including the number and size of available economic acquisitions and drilling opportunities, our cash flows from operating and financing activities, and our ability to assimilate acquisitions. Also the impact of oil and gas prices on investment opportunities, the availability of capital and borrowing facilities, and the success of our development and exploratory activities could lead to changes in funding requirements for future development. We regularly review our capital expenditure budget to assess changes in current and projected cash flows, acquisition opportunities, debt requirements, and other factors.

As of the filing date of this report we have Board authorization to repurchase up to 3,072,184 shares of our common stock under our stock repurchase program. Shares may be repurchased from time to time in open market transactions or privately negotiated transactions subject to market conditions and other factors including certain provisions of our existing bank credit facility agreement, compliance with securities laws, and the terms and provisions of our stock repurchase program.

The following table presents amount and percentage changes in cash flows between the three-month periods ended March 31, 2009, and 2008. The analysis following the table should be read in conjunction with our consolidated statements of cash flows in Part I, Item 1 of this report.

	For the Three Months Ended March 31,			Percent
	2009	2008	Change	Change
	(In thousands)			
Net cash provided by operating activities	$ 125,175	$ 142,683	$ (17,508)	(12)%
Net cash used in investing activities	$ 128,267	$ 94,168	$ 34,099	36%
Net cash used in financing activities	$ 828	$ 84,514	$ (83,686)	(99)%

Analysis of cash flow changes between the three months ended March 31, 2009, and March 31, 2008

Operating activities. Cash received from oil and gas production revenue, net of the realized effects of hedging, decreased $59.8 million to $211.9 million for the first quarter of 2009, compared with $271.7 million for the first quarter of 2008. Included in operating revenues for the three-month period ended March 31, 2009, is $55.6 million of net realized hedging gains. A significant portion of the decrease in oil and gas production revenue, net of the realized effects of hedging, was the result of decreases in commodity prices. We received a net cash refund for income taxes in the first three months of 2009 of $10.9 million compared with net cash income taxes paid of $2.1 million for the same period in 2008.

Investing activities. Cash used for investing activities increased $34.1 million for the three months ended March 31, 2009, compared with the same period in 2008. Cash outflows for capital expenditures decreased $27.9 million or 17 percent to $133.6 million for the three months ended March 31, 2009, due to lower well costs and a reduced level of activity as a result of lower commodity prices. Cash outflow relating to the acquisition of oil and gas properties also decreased $53.0 million to $53,000 for the three months ended March 31, 2009, compared with the same period in 2008 due to the lack of major acquisitions in the first three months of 2009. We acquired assets in the Carthage Field during the first quarter of 2008.

These decreases in cash flow were offset by a decrease year over year in proceeds from the sale of oil and gas properties. For the three months ended March 31, 2009, there were no major divestitures compared with the same period in 2008 when we received $130.4 million from the sale of non-core properties to Abraxas.

Financing activities. Net repayments on our credit facility decreased by $7.5 million for the three-month period ended March 31, 2009, compared with the same period in 2008. We spent $77.2 million to repurchase our common stock during the three-month period ended March 31, 2008. There were no share repurchases during the same period in 2009.

Capital Expenditures

The following table sets forth certain historical information regarding the costs incurred by us in our oil and gas activities.

	For the Three Months Ended March 31,			
		2009		2008
	(In thousands)			
Development costs (1)	$	73,763	$	156,706
Exploration costs		21,630		32,619
Acquisitions				
Proved properties		53		31,261
Unproved properties – acquisitions of proved properties (2)		-		22,196
Unproved properties - other		9,369		3,739
Total, including asset retirement obligations (3)	$	104,815	$	246,521

(1) Includes capitalized interest of $470,000 in 2009 and $1.4 million in 2008.
(2) Represents a portion of the allocated purchase price of unproved properties acquired as part of the acquisition of proved properties.
(3) Includes amounts relating to estimated asset retirement obligations of $356,000 in 2009 and $4.0 million in 2008.

Costs incurred for capital and exploration activities during the first three months of 2009 decreased $141.7 million or 57 percent compared to the same period in 2008. Excluding acquisitions, our development and exploration investments decreased $93.9 million compared to the same period in the prior year. This decrease in capital and exploration activities during the first three months of 2009 compared with the same period in 2008 is a result of our decision to invest at or near our operating cash flows for 2009 and to defer some development projects into the second half of 2009 and beyond in order to improve returns on invested capital by taking advantage of expected improved commodity prices and/or lower drilling and completion costs.

We believe our operating cash flows together with the cash available under our credit facility will be sufficient to fund our planned operating, drilling, and acquisition expenditures for the foreseeable future. The amount and allocation of future capital and exploration expenditures will depend upon a number of factors, including the number and size of available economic acquisition and drilling opportunities, our cash flows from operating and financing activities, and our ability to assimilate leasehold and producing property acquisitions. In addition, the impact of oil and natural gas prices on investment opportunities, the availability of capital and borrowing facilities, and the success of our development and exploratory activities may lead to changes in funding requirements for future development.

Commodity price risk and interest rate risk

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

There has been no material change to the natural gas and crude oil price sensitivity analysis previously disclosed. Refer to the corresponding section under Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2008.

Summary of oil and gas production hedges in place

Our oil and natural gas derivative contracts include swap and costless collar arrangements. All contracts are entered into for other-than-trading purposes. Please refer to Note 8 – Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding accounting for our derivative transactions.

Our net realized oil and gas prices are impacted by hedges we have placed on future forecasted production. Hedging is an important part of our financial risk management program. The amount of production we hedge is driven by the amount of debt on our consolidated balance sheet and the level of capital and long-term commitments we have in place. In the case of a significant acquisition of producing properties, we will consider hedging a portion of the anticipated production in order to lock in part of the economics assumed at the time of the acquisition. As of March 31, 2009, and through the date of this filing, our hedged positions of anticipated production through 2011 totaled approximately 7 million Bbls of oil, 59 million MMBtu of natural gas, and 1 million Bbls of natural gas liquids.

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 contracted ceiling price and the index price if the index price is above the contracted ceiling price. No amounts are paid or received if the index price is between the contracted floor and ceiling prices.

The following table describes the volumes, average contract prices, and fair values of contracts we have in place as of March 31, 2009. We seek to minimize basis risk and index the majority of our oil contracts to NYMEX prices and our gas contracts to various regional index prices associated with pipelines in proximity to our areas of gas production.

Oil contracts

Oil Swaps

Contract Period	Volumes (Bbl)	Weighted-Average Contract Price (per Bbl)	Fair Value at March 31, 2009 Asset/(Liability) (In thousands)
Second quarter 2009 - NYMEX WTI	401,000	$ 71.65	$ 7,926
Third quarter 2009 - NYMEX WTI	389,000	$ 71.59	6,274
Fourth quarter 2009 - NYMEX WTI	369,000	$ 71.67	4,938
2010 NYMEX WTI	1,239,000	$ 66.47	4,511
2011 NYMEX WTI	1,032,000	$ 65.36	(1,970)
All oil swaps	3,430,000		$ 21,679

Oil Collars

Contract Period	NYMEX WTI Volumes (Bbl)	Weighted-Average Floor Price (per Bbl)	Weighted-Average Ceiling Price (per Bbl)	Fair Value at March 31, 2009 Asset/(Liability) (In thousands)
Second quarter 2009	380,500	$ 50.00	$ 67.31	$ 1,001
Third quarter 2009	384,500	$ 50.00	$ 67.31	630
Fourth quarter 2009	384,500	$ 50.00	$ 67.31	31
2010	1,367,500	$ 50.00	$ 64.91	(5,785)
2011	1,236,000	$ 50.00	$ 63.70	(10,719)
All oil collars	3,753,000			$ (14,842)

Gas Contracts

Gas Swaps			
Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at March 31, 2009 Asset
	(MMBtu)	(per MMBtu)	(In thousands)
Second quarter 2009			
IF ANR OK	570,000	$ 7.47	$ 2,625
IF CIG	930,000	$ 7.11	4,302
IF EL PASO	300,000	$ 6.64	1,127
IF HSC	2,700,000	$ 8.09	11,993
IF NGPL	120,000	$ 6.63	453
IF PEPL	1,500,000	$ 7.17	6,579
NYMEX Henry Hub	300,000	$ 8.47	1,404
Third quarter 2009			
IF ANR OK	100,000	$ 7.11	355
IF CIG	300,000	$ 6.64	1,122
IF EL PASO	300,000	$ 6.94	1,022
IF HSC	2,680,000	$ 8.25	11,387
IF NGPL	100,000	$ 6.86	330
IF PEPL	360,000	$ 7.47	1,429
IF RELIANT	510,000	$ 3.84	130
NYMEX Henry Hub	420,000	$ 7.76	1,496
Fourth quarter 2009			
IF ANR OK	90,000	$ 7.43	301
IF CIG	150,000	$ 7.42	578
IF EL PASO	300,000	$ 7.01	937
IF HSC	2,620,000	$ 8.60	10,591
IF NGPL	90,000	$ 7.14	280
IF RELIANT	810,000	$ 4.34	267
NYMEX Henry Hub	710,000	$ 7.18	1,551
2010			
IF ANR OK	60,000	$ 7.98	167
IF EL PASO	1,090,000	$ 6.79	1,688
IF HSC	6,080,000	$ 8.40	17,010
IF NGPL	990,000	$ 5.51	270
IF RELIANT	4,200,000	$ 5.32	506
NYMEX Henry Hub	3,750,000	$ 7.13	4,385
2011			
IF EL PASO	880,000	$ 6.34	488
IF HSC	360,000	$ 9.01	827
IF NGPL	480,000	$ 5.98	9
IF RELIANT	1,860,000	$ 5.96	73

NYMEX Henry Hub	2,130,000	$	6.72	199
All gas swap contracts	37,840,000		$	85,883

Gas Collars				
Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at March 31, 2009 Asset/(Liability)
	(MMBtu)	(per MMBtu)	(per MMBtu)	(In thousands)
Second quarter 2009				
IF CIG	600,000	$ 4.75	$ 8.82	$ 1,364
IF HSC	210,000	$ 5.57	$ 9.49	408
IF PEPL	1,375,000	$ 5.30	$ 9.25	3,472
NYMEX Henry Hub	90,000	$ 6.00	$ 10.35	191
Third quarter 2009				
IF CIG	600,000	$ 4.75	$ 8.82	1,135
IF HSC	210,000	$ 5.57	$ 9.49	364
IF PEPL	1,385,000	$ 5.30	$ 9.25	2,642
NYMEX Henry Hub	90,000	$ 6.00	$ 10.35	175
Fourth quarter 2009				
IF CIG	600,000	$ 4.75	$ 8.82	889
IF HSC	210,000	$ 5.57	$ 9.49	299
IF PEPL	1,385,000	$ 5.30	$ 9.25	2,224
NYMEX Henry Hub	90,000	$ 6.00	$ 10.35	130
2010				
IF CIG	2,040,000	$ 4.85	$ 7.08	1,311
IF HSC	600,000	$ 5.57	$ 7.88	337
IF PEPL	4,945,000	$ 5.31	$ 7.61	3,402
NYMEX Henry Hub	240,000	$ 6.00	$ 8.38	154
2011				
IF CIG	1,800,000	$ 5.00	$ 6.32	(11)
IF HSC	480,000	$ 5.57	$ 6.77	(127)
IF PEPL	4,225,000	$ 5.31	$ 6.51	(468)
NYMEX Henry Hub	120,000	$ 6.00	$ 7.25	(20)
All gas collars	21,295,000			$ 17,871

Natural Gas Liquid Contracts

Natural Gas Liquid Swaps			
Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at March 31, 2009 Asset
	(Bbls)	(per Bbl)	(In thousands)
Second quarter 2009	262,000	$ 41.53	$ 4,342
Third quarter 2009	218,000	$ 41.46	3,387
Fourth quarter 2009	70,000	$ 45.95	1,363
2010	140,000	$ 49.59	3,207
2011	20,000	$ 49.01	388
All natural gas liquid swaps	710,000		$ 12,687

Refer to Note 8 – Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding our oil and gas hedges.

Summary of Interest Rate Risk

Market risk is estimated as the potential change in fair value resulting from an immediate hypothetical one percentage point parallel shift in the yield curve. For fixed-rate debt, interest changes affect the fair market value but do not impact results of operations or cash flows. Conversely, interest rate changes for floating-rate debt generally do not affect the fair market value but do impact future results of operations and cash flows, assuming other factors are held constant. The carrying amount of our floating-rate debt typically approximates its fair value. We had $299.0 million of floating-rate debt outstanding as of March 31, 2009. Our fixed-rate debt outstanding, net of debt discount, at this same date was $260.8 million.

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. As of March 31, 2009, we have not been involved in any unconsolidated SPE transactions.

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

Critical Accounting Policies and Estimates

We refer you to the corresponding section in Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2008, and to the footnote disclosures included in Part I, Item 1 of this report.

Additional Comparative Data in Tabular Form:

	Change Between the Three Months Ended March 31, 2009, and 2008
Oil and gas production revenues	
Decrease in oil and gas production revenues,net of hedging (In thousands)	$ 100,445

Components of revenue increases (decreases):

Oil		
Net realized price change per Bbl, including the effects of hedging	$	(32.08)
Net realized price percentage change		(42)%
Production change (MBbl)		(27)
Production percentage change		(2)%
Natural Gas		
Net realized price change per Mcf, including the effects of hedging	$	(2.55)
Net realized price percentage change		(29)%
Production change (MMcf)		173
Production percentage change		1%

Production mix as a percentage of total oil and gas revenue, including the effects of hedging, and production:

	For the Three Months Ended March 31,	
Revenue	2009	2008
Oil	39%	44%
Natural gas	61%	56%
Production		
Oil	35%	35%
Natural gas	65%	65%

Information regarding the components of exploration expense:

	For the Three Months Ended March 31,			
	2009		2008	
Summary of Exploration Expense				
Geological and geophysical expenses	$	4.4	$	1.8
Exploratory dry hole expense		0.1		0.7
Overhead and other expenses		9.1		11.8
Total	$	13.6	$	14.3

Information regarding the effects of oil and gas hedging activity:

	For the Three Months Ended March 31,			
	2009		2008	
Oil Hedging				
Percentage of oil production hedged (MBbl)		48%		57%
Oil volumes hedged (MBbl)		788		953
Increase (decrease) in oil revenue	$	16.0 millionn	$	(26.8 million)
Average realized oil price per Bbl before hedging	$	34.40	$	92.33
Average realized oil price per Bbl after hedging	$	44.16	$	76.24
Natural Gas Hedging				
Percentage of gas production hedged (MMBtu)		48%		39%
Natural gas volumes hedged (MMBtu)	$	9.4 million	$	7.5 million
Increase in gas revenue	$	39.6 millionn	$	2.9 million
Average realized gas price per Mcf before hedging	$	4.00	$	8.53
Average realized gas price per Mcf after hedging	$	6.14	$	8.69

Comparison of Financial Results and Trends between the three months ended March 31, 2009, and 2008

Oil and gas production revenue. Average daily production increased one percent to 315.0 MMCFE for the quarter ended March 31, 2009, compared with 311.5 MMCFE for the quarter ended March 31, 2008. The following table presents the regional changes in our production and oil and gas revenues and costs between the two quarters.

	Average Net Daily Production Added (Lost) (MMCFE)	Pre-Hedge Oil and Gas Revenues Lost (In millions)	Production Costs Increase (Decrease) (In millions)
Mid-Continent	12.1	$ 38.4	$ (1.7)
ArkLaTex	(1.6)	20.8	1.8
Gulf Coast	(14.3)	25.3	(2.6)
Permian	9.5	25.5	0.5
Rocky Mountain	(2.2)	70.0	(1.6)
Total	3.5	$ 180.0	$ (3.6)

Our daily production remained relatively flat for the first quarter of 2009 compared to the same period in 2008. The largest regional increase occurred in the Mid-Continent region as a result of the success in the Woodford shale assets in the Arkoma Basin and strong results from our Deep Springer program in the Anadarko Basin. The production growth in the Permian region is the result of continued development of the Wolfberry assets at Sweetie Peck and Halff East.

The following table summarizes the average realized prices we received in the first quarter of 2009 and 2008, before the effects of hedging. Prices for oil and gas decreased significantly between the two periods.

	For the Three Months Ended March 31,	
	2009	2008
Realized oil price ($/Bbl)	$ 34.40	$ 92.33
Realized gas price ($/Mcf)	$ 4.00	$ 8.53
Realized equivalent price ($/MCFE)	$ 4.60	$ 10.95

The combination of relatively constant production volumes and lower commodity prices between periods resulted in lower oil and gas revenue. We expect this trend to continue throughout 2009 based on current futures market pricing.

Realized oil and gas hedge gain (loss). We recorded a realized hedge gain of $55.6 million for the three-month period ended March 31, 2009, related to settlements on oil and gas hedges, compared with a $24.0 million loss for the same period in 2008, which was primarily due to unfavorable settlements on our oil hedges. At March 31, 2009, we have a current receivable relating to our hedge position of $4.9 million.

Marketed gas system revenue and expense. Marketed gas system revenue decreased $5.5 million to $13.4 million for the quarter ended March 31, 2009, compared with $18.9 million for the comparable period of 2008. Concurrent with the decrease in marketed gas system revenue, marketed gas system expense decreased $4.3 million to $13.4 million for the quarter ended March 31, 2009, compared with $17.7 million for the comparable period of 2008. The net margin has stayed relatively consistent with historical performance. We expect that marketed gas system revenue and expense will continue to coincide with increases and decreases in production and our net realized price.

Gain on sale of proved properties. We had a $599,000 net loss on sale of proved properties for the quarter ended March 31, 2009, compared with a $56.0 million gain on sale for the comparable period of 2008 due to the divestiture of non-core oil and gas properties to Abraxas that occurred in the first quarter of 2008. The final gain on sale of proved properties to Abraxas will be adjusted for normal post-closing adjustments and is expected to be finalized during the second quarter of 2009. We expect to continue to evaluate potential divestitures of non-strategic properties.

Oil and gas production expense. Total production costs decreased $3.6 million, or six percent, to $55.8 million for the first quarter of 2009 from $59.5 million in the comparable period of 2008. Total oil and gas production costs per MCFE decreased $0.14 to $1.96 for the first quarter of 2009, compared with $2.10 for the same period in 2008. This decrease is comprised of the following:

A $0.40 decrease in production taxes on a per MCFE basis due to the decrease in realized prices between periods, particularly in the oil-weighted Rocky Mountain and Permian Basin regions

A $0.21 increase in recurring LOE on a per MCFE basis related to higher costs, particularly in oil-weighted regions, for items such as fuel and fluid disposal, as well as in the ArkLaTex region

A $0.05 increase in overall transportation cost on a per MCFE basis driven by an increase in additional transportation costs incurred on our non-operated properties located in the Rocky Mountain region

Overall workover LOE on a per MCFE basis was essentially flat from period to period.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A increased $21.4 million or 30 percent to $91.7 million for the three-month period ended March 31, 2009, compared with $70.4 million for the same period in 2008. DD&A expense per MCFE increased 30 percent to $3.23 for the three-month period ended March 31, 2009, compared to $2.48 for the same period in 2008. The depletion, depreciation, and amortization increase is primarily a result of a decrease in proved reserves used to calculate DD&A. The decrease in proved reserves is a result of lower realized natural gas prices made worse by wider than normal price differentials, primarily in the Mid-Continent region, and the reduction of proved reserves in our Hanging Woman Basin coalbed methane project.

Exploration. Exploration expense decreased five percent to $13.6 million for the three-month period ended March 31, 2009, compared with $14.3 million for the same period in 2008. Geological and geophysical expense increased $2.6 million due to an increase in the amount spent for seismic analysis. This increase was offset by a $2.7 million decrease in exploration overhead due to decrease in Net Profits Plan payments as a result of decreased oil and gas commodity prices.

Impairment of proved properties. We recorded a $147.0 million impairment of proved oil and gas properties for the three-month period ended March 31, 2009. There were no impairments recorded for the three-month period ended March 31, 2008. This impairment was driven by a significant decrease in realized gas prices, particularly in the Mid-Continent region, as well as a reserve write-down for our coalbed methane project at Hanging Woman Basin.

Impairment of materials inventory. We recorded an $8.6 million impairment of materials inventory for the three-month period ended March 31, 2009. There were no impairments recorded for the three-month period ended March 31, 2008. The inventory write-downs were due to a decrease in the value of tubular goods and other raw materials.

General and administrative. General and administrative expense decreased $4.7 million or 22 percent to $16.4 million for the quarter ended March 31, 2009, compared with $21.1 million for the

comparable period of 2008. G&A expense decreased $0.18 to $0.57 per MCFE for the first quarter of 2009 compared to $0.75 per MCFE for the same three-month period in 2008.

Payments made under the Net Profits Plan decreased $7.1 million for the quarter ended March 31, 2009, compared with the same period in 2008. The decrease was primarily the result of lower commodity prices, which resulted in smaller Net Profits Plan payments to plan participants. As of the end of the first quarter of 2009, 17 of our 21 pools are in payout status. No additional pools are expected to reach payout in 2009. This decrease in Net Profits Plan payments was offset by an increase in base employee compensation, including taxes and benefits, of approximately $3.2 million between the first quarter of 2009 and the first quarter of 2008. The increase is a result of an increase in employee head count. A significant driver of this headcount increase has been the conversion from contract lease operators to internal lease operators.

Cash bonus and long-term incentive compensation expense remained relatively flat from quarter to quarter. A $1.8 million increase in COPAS overhead reimbursements were offset by a $1.0 million dollar decrease in the amount of G&A that was allocated to exploration expense due to the aforementioned decrease in Net Profits Plan payments. COPAS overhead reimbursements from operations increased due to an increase in our operated well count.

Change in Net Profits Plan liability. For the quarter ended March 31, 2009, this non-cash item was a benefit of $23.3 million compared to an expense of $13.6 million for the same period in 2008. Significant decreases in oil and gas commodity prices have decreased the estimated liability for the future amounts to be paid to plan participants. This liability is a significant management estimate. Adjustments to the liability are subject to estimation and may change dramatically from period to period based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, tax rates, and production costs.

Other expense. Other expense increased $4.9 million to $5.6 million for the quarter ended March 31, 2009, compared with $700,000 for the same period in 2008. In the first quarter of 2009, we incurred $2.3 million of expense related to the assignment of a drilling rig contract in our Rocky Mountain region. We also incurred an additional loss related to hurricanes of $2.1 million for the three months ended March 31, 2009, which relates to an increase in our estimate of the remediation cost related to the Vermillion 281 platform that was lost in Hurricane Ike.

Income tax expense. We recorded a benefit from income tax of $53.9 million for the first quarter of 2009 compared to income tax expense of $55.9 million for the first quarter of 2008 resulting in effective tax rates of 38.1 percent and 37.0 percent, respectively. The change in income tax expense is primarily the result of the differences in components of net income discussed above. The increase in effective tax rate from 2008 reflects changes in the effects of other permanent differences including the domestic production activities deduction and to a lesser extent, changes in the mix of the highest marginal state tax rates as a result of acquisition and drilling activity throughout 2008 and 2009. Our cash tax expense decreased for the first quarter of 2009 compared to the same period of 2008 due to the impact on estimated taxable income from reduced revenue resulting from decreased commodity prices. This trend is expected to continue throughout the remainder of 2009 based upon our current projected capital expenditures program and commodity price outlook.

New Accounting Pronouncements

Please see Note 3 – Recent Accounting Pronouncements, Note 7 – Long-term Debt, Note 8 – Derivative Financial Instruments, and Note 11 – Fair Value Measurements under Part I, Item 1 of this report for accounting matters.

Environmental

St. Mary's compliance with applicable environmental regulations has not resulted in any significant capital expenditure or materially adverse effects on our liquidity or results of operations. We believe we are in substantial compliance with environmental regulations and do not currently anticipate that material expenditures will be required in the future. However, we are unable to predict the impact that future compliance with regulations may have on future capital expenditures, liquidity, and results of operations.

Cautionary Information about Forward-Looking Statements

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

The amount and nature of future capital expenditures and the availability of liquidity and capital resources to fund capital expenditures

The drilling of wells and other exploration and development activities and plans, as well as possible future acquisitions

Reserve estimates and the estimates of both future net revenues and the present value of future net revenues that are included in their calculation

Future oil and natural gas production estimates

Our outlook on future oil and natural gas prices 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

Other similar matters such as those discussed in the “Management’s Discussion and Analysis of Financial Condition and Results of Operations” section of this Form 10-Q.

Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments, and other factors that we believe are appropriate under the circumstances. These statements are subject to a number of known and unknown risks and uncertainties which may cause our actual results and performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. These risks are described in the “Risk Factors” section of our 2008 Annual Report on Form 10-K and include such factors as:

The volatility and level of realized oil and natural gas prices

A contraction in demand for oil and natural gas as a result of adverse general economic conditions

The availability of economically attractive exploration, development, and property acquisition opportunities and any necessary financing, including constraints on the availability of opportunities and financing due to currently distressed capital and credit market conditions

Our ability to replace reserves and sustain production

Unexpected drilling conditions and results

Unsuccessful exploration and development drilling

The risks of hedging strategies, including the possibility of realizing lower prices on oil and gas sales as a result of commodity price risk management activities

The uncertain nature of the expected benefits from acquisitions and divestitures of oil and natural gas properties, including uncertainties in evaluating oil and natural gas reserves of acquired properties and associated potential liabilities

The imprecise nature of oil and natural gas reserve estimates

Uncertainties inherent in projecting future rates of production from drilling activities and acquisitions

Declines in the values of our oil and natural gas properties resulting in impairment charges and write-downs

The ability of purchasers of production to pay for amounts purchased

Drilling and operating service availability

Uncertainties in cash flow

The financial strength of hedge contract counterparties and credit facility participants, and the risk that one or more of these parties may not satisfy their contractual commitments

The negative impact that lower oil and natural gas prices could have on our ability to borrow and fund capital expenditures

The potential effects of increased levels of debt financing

Our ability to compete effectively against other independent and major oil and natural gas companies and

Litigation, environmental matters, the potential impact of government regulations, and the use of management estimates.

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. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by securities laws.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item is provided under the captions Commodity price risk and interest rate risk, Summary of oil and gas production hedges in place, and Summary of Interest Rate Risk in Item 2 above and is incorporated herein by reference.

ITEM 4. CONTROLS AND PROCEDURES

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

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

PART II. OTHER INFORMATION

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors as previously disclosed in our Form 10-K for the year ended December 31, 2008, in response to Item 1A of Part I of such Form 10-K.

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

(c) The following table provides information about purchases by the Company or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the fiscal quarter ended March 31, 2009, of shares of the Company's common stock, which is the sole class of equity securities registered by the Company pursuant to Section 12 of the Exchange Act.

PURCHASES OF EQUITY SECURITIES BY ISSUER
AND AFFILIATED PURCHASERS

Period		(a) Total Number of Shares Purchased (1) (2)(3)(4)	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Program	(d) Maximum Number of Shares that May Yet Be Purchased Under the Program (5)
	01/01/09 – 01/31/09	747	$ 20.29	-0-	3,072,184
	02/01/09 – 02/28/09	53,200	$ 13.62	-0-	3,072,184
	03/01/09 – 03/31/09	4,741	$ 12.28	-0-	3,072,184
Total:		58,688	$ 13.60	-0-	3,072,184

(1) Includes a total of 6,500 shares purchased by Anthony J. Best, St. Mary's President and Chief Executive Officer, in open market transactions that were not made pursuant to our stock repurchase program.

(2) Includes a total of 5,000 shares purchased by A. Wade Pursell, St. Mary's Executive Vice President and Chief Financial Officer, in open market transactions that were not made pursuant to our stock repurchase program.

(3) Includes a total of 10,000 shares purchased by William D. Sullivan, a Director of St. Mary, in open market transactions that were not made pursuant to our stock repurchase program.

(4) Includes 37,188 shares withheld (under the terms of grants under the 2006 Equity Incentive Compensation Plan) to offset tax withholding obligations that occur upon the delivery of outstanding shares underlying restricted stock units.

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

The payment of dividends and stock repurchases are subject to covenants in our bank credit facility, including the requirement that we maintain certain levels of stockholders' equity and the limitation that does not allow our annual dividend rate to exceed $0.25 per share.

ITEM 6. EXHIBITS

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

Exhibit	Description
10.1	Third Amended and Restated Credit Agreement dated April 14, 2009 among St. Mary Land & Exploration Company, Wachovia Bank, National Association, as Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on April 20, 2009, and incorporated herein by reference)
10.2	Supplement and Amendment to Deed of Trust, Mortgage, Line of Credit Mortgage, Assignment, Security Agreement, Fixture Filing and Financing Statement for the benefit of Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 14, 2009 (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on April 20, 2009, and incorporated herein by reference)
10.3	Deed of Trust to Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 14, 2009 (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on April 20, 2009, 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 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes – Oxley Act of 2002

* Filed with this report.
** Furnished with this report.

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.

ST. MARY LAND & EXPLORATION COMPANY

May 4, 2009	By:	/s/ ANTHONY J. BEST Anthony J. Best President and Chief Executive Officer
May 4, 2009	By:	/s/ A. WADE PURSELL A. Wade Pursell Executive Vice President and Chief Financial Officer
May 4, 2009	By:	/s/ MARK T. SOLOMON Mark T. Solomon Controller