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

FORM 10-Q

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

For the quarterly period ended September 30, 2006

Commission file number 001-31539

ST. MARY LAND & EXPLORATION COMPANY
(Exact name of registrant as specified in its charter)

Delaware	**41-0518430**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1776 Lincoln Street, Suite 700, Denver, Colorado 80203
(Address of principal executive offices) (Zip Code)

(303) 861-8140
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

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

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

As of October 23, 2006, the registrant had 54,876,768 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)

	September 30, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,016	$ 14,925
Short-term investments	1,450	1,475
Accounts receivable	134,388	165,197
Refundable income taxes	21,495	—
Prepaid expenses and other	22,331	7,283
Accrued derivative asset	48,425	6,799
Deferred income taxes	—	8,252
Total current assets	229,105	203,931
Property and equipment (successful efforts method), at cost:		
Proved oil and gas properties	1,733,187	1,441,959
Less - accumulated depletion, depreciation, and amortization	(595,902)	(497,621)
Unproved oil and gas properties, net of impairment allowance of $9,798 in 2006 and $9,862 in 2005	49,623	44,383
Wells in progress	89,056	55,505
Other property and equipment, net of accumulated depreciation of $9,262 in 2006 and $8,046 in 2005	6,271	5,340
	1,282,235	1,049,566
Noncurrent assets:		
Goodwill	9,452	9,452
Long-term derivative asset	19,191	575
Other noncurrent assets	4,031	5,223
Total noncurrent assets	32,674	15,250
Total Assets	**$ 1,544,014**	**$ 1,268,747**
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 169,657	$ 164,957
Accrued derivative liability	15,113	34,037
Deferred income taxes	17,625	—
Total current liabilities	202,395	198,994
Noncurrent liabilities:		
Long-term credit facility	66,000	—
Convertible notes	99,956	99,885
Asset retirement obligation	71,208	66,078
Net Profits Plan liability	154,195	136,824
Deferred income taxes	203,837	128,296
Accrued derivative liability	54,206	64,137
Other noncurrent liabilities	5,803	5,213
Total noncurrent liabilities	655,205	500,433
Commitments and contingencies		
Stockholders' equity:		
Common stock, $0.01 par value: authorized — 200,000,000 shares; issued: 55,120,282 shares in 2006 and 57,011,740 shares in 2005; outstanding, net of treasury shares: 54,870,282 shares in 2006 and 56,761,740 shares in 2005	551	570
Additional paid-in capital	34,367	123,278
Treasury stock, at cost: 250,000 shares in 2006 and 250,000 shares in 2005	(4,784)	(5,148)
Deferred stock-based compensation	—	(5,593)
Retained earnings	651,693	510,812
Accumulated other comprehensive income (loss)	4,587	(54,599)
Total stockholders' equity	686,414	569,320
Total Liabilities and Stockholders' Equity	**$ 1,544,014**	**$ 1,268,747**

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 September 30, 2006	For the Three Months Ended September 30, 2005	For the Nine Months Ended September 30, 2006	For the Nine Months Ended September 30, 2005
Operating revenues:				
Oil and gas production revenue	$ 188,159	$ 203,144	$ 550,181	$ 501,935
Oil and gas hedge gain (loss)	4,828	(8,441)	14,808	(8,967)
Marketed gas and other revenue	4,252	8,355	12,787	18,508
Gain on sale of proved properties	801	246	7,233	220
Total operating revenues	198,040	203,304	585,009	511,696
Operating expenses:				
Oil and gas production expense	44,998	38,071	129,490	100,418
Depletion, depreciation, amortization, and asset retirement obligation accretion	39,817	36,952	110,118	100,933
Exploration	9,766	10,692	35,872	27,474
Impairment of proved properties	5,259	—	6,548	—
Abandonment and impairment of unproved properties	920	817	3,368	4,506
General and administrative	9,725	9,772	30,940	23,239
Change in Net Profits Plan liability	(3,710)	54,857	17,370	71,253
Marketed gas system and other operating expense	3,975	7,620	12,981	17,569
Unrealized derivative loss (gain)	68	(60)	5,329	1,310
Total operating expenses	110,818	158,721	352,016	346,702
Income from operations	87,222	44,583	232,993	164,994
Nonoperating income (expense):				
Interest income	90	83	1,454	263
Interest expense	(2,170)	(2,344)	(5,098)	(6,562)
Income before income taxes	85,142	42,322	229,349	158,695
Income tax expense	(29,265)	(14,988)	(82,866)	(57,997)
Net income	**$ 55,877**	**$ 27,334**	**$ 146,483**	**$ 100,698**
Basic weighted-average common shares outstanding	55,398	56,640	56,564	56,941
Diluted weighted-average common shares outstanding	64,926	66,738	66,332	66,847
Basic net income per common share	**$ 1.01**	**$ 0.48**	**$ 2.59**	**$ 1.77**
Diluted net income per common share	**$ 0.88**	**$ 0.42**	**$ 2.25**	**$ 1.55**

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 (UNAUDITED)
(In thousands, except share amounts)

	Common Stock		Additional Paid-in	Treasury Stock		Deferred Stock-Based	Retained	Accumulated Other Comprehensive	Total Stockholders'
	Shares	Amount	Capital	Shares	Amount	Compensation	Earnings	Income (Loss)	Equity
Balances, December 31, 2004	**57,458,246**	**$ 574**	**$ 127,374**	**(500,000)**	**$ (5,295)**	**$ (5,039)**	**$ 364,567**	**$ 2,274**	**$ 484,455**
Comprehensive income, net of tax:									
Net income	—	—	—	—	—	—	151,936	—	151,936
Change in derivative instrument fair value	—	—	—	—	—	—	—	(71,522)	(71,522)
Reclassification to earnings	—	—	—	—	—	—	—	14,366	14,366
Minimum pension liability adjustment	—	—	—	—	—	—	—	283	283
Total comprehensive income									95,063
Cash dividends declared, $0.10 per share	—	—	—	—	—	—	(5,691)	—	(5,691)
Treasury stock purchases	—	—	—	(1,175,282)	(28,902)	—	—	—	(28,902)
Retirement of treasury stock	(1,411,356)	(14)	(28,729)	1,411,356	28,743	—	—	—	—
Issuance of common stock under Employee Stock Purchase Plan	28,447	—	601	—	—	—	—	—	601
Sale of common stock, including income tax benefit of stock option exercises	936,403	10	16,619	—	—	—	—	—	16,629

Deferred compensation related to issued restricted stock unit awards, net of forfeitures	—	—	3,404	—	—	(3,404)	—	—	—
Directors' stock compensation	—	—	—	13,926	306	(306)	—	—	—
Accrued stock-based compensation	—	—	4,009	—	—	—	—	—	4,009
Amortization of deferred stock-based compensation	—	—	—	—	—	3,156	—	—	3,156
Balances, December 31, 2005	**57,011,740**	**$ 570**	**$ 123,278**	**(250,000)**	**$ (5,148)**	**$ (5,593)**	**$ 510,812**	**$ (54,599)**	**$ 569,320**
Comprehensive income, net of tax:									
Net income	—	—	—	—	—	—	146,483	—	146,483
Change in derivative instrument fair value	—	—	—	—	—	—	—	68,644	68,644
Reclassification to earnings	—	—	—	—	—	—	—	(9,458)	(9,458)
Total comprehensive income									205,669
Cash dividends declared, $0.10 per share	—	—	—	—	—	—	(5,602)	—	(5,602)
Treasury stock purchases	—	—	—	(3,319,300)	(123,108)	—	—	—	(123,108)
Retirement of treasury stock	(3,275,689)	(33)	(122,598)	3,275,689	122,631	—	—	—	—
Issuance of Directors' shares from treasury	—	—	—	29,827	339	—	—	—	339
Issuance of common stock under Employee Stock Purchase Plan	12,918	—	404	—	—	—	—	—	404
Sale of common stock, including income tax benefit of stock option exercises	1,371,313	14	30,738	—	—	—	—	—	30,752
Adoption of Statement of Financial Accounting Standards No. 123R	—	—	(5,593)	—	—	5,593	—	—	—
Stock-based compensation expense	—	—	8,138	13,784	502	—	—	—	8,640
Balances, September 30, 2006	**55,120,282**	**$ 551**	**$ 34,367**	**(250,000)**	**$ (4,784)**	**$ —**	**$ 651,693**	**$ 4,587**	**$ 686,414**

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 Nine Months Ended September 30, 2006	2005
Reconciliation of net income to net cash provided by operating activities:		
Net income	$ 146,483	$ 100,698
Adjustments to reconcile net income to net cash provided by operating activities:		
Gain on sale of proved properties	(7,233)	(220)
Depletion, depreciation, amortization, and asset retirement obligation accretion	110,118	100,933
Exploratory dry hole expense	4,033	2,514
Abandonment and impairment of oil and gas properties	9,915	4,506
Unrealized derivative loss	5,329	1,310
Change in Net Profits Plan liability	17,370	71,253
Stock-based compensation expense	8,979	5,371
Deferred income taxes	64,612	9,485
Other	398	(38)
Changes in current assets and liabilities:		
Accounts receivable	30,810	(31,437)
Refundable income taxes	(21,495)	—
Prepaid expenses and other	(15,048)	(2,540)
Accounts payable and accrued expenses	(21,612)	36,320
Income tax benefit from the exercise of stock options*	(15,110)	3,991
Net cash provided by operating activities	**317,549**	**302,146**
Cash flows from investing activities:		
Proceeds from sale of oil and gas properties	1,183	1,211
Capital expenditures	(293,977)	(204,835)
Acquisition of oil and gas properties	(9,933)	(73,440)
Other	79	3,792
Net cash used in investing activities	**(302,648)**	**(273,272)**
Cash flows from financing activities:		
Proceeds from credit facility	338,000	234,307
Repayment of credit facility	(272,000)	(220,000)
Income tax benefit from the exercise of stock options*	15,110	—
Proceeds from sale of common stock	16,046	8,208
Repurchase of common stock	(123,108)	(28,347)
Dividends	(2,858)	(2,863)
Net cash used in financing activities	**(28,810)**	**(8,695)**
Net change in cash and cash equivalents	(13,909)	20,179
Cash and cash equivalents at beginning of period	14,925	6,418
Cash and cash equivalents at end of period	**$ 1,016**	**$ 26,597**

* SFAS 123R requires presentation of the income tax benefit from the exercise of stock options to be presented in financing activites subsequent to adoption. The prior period classification is to remain unchanged under SFAS 123R.

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 Nine Months Ended September 30, 2006	2005
	(in thousands)	
Cash paid for interest, net of capitalized interest	$ 8,157	$ 7,998
Cash paid for income taxes	$ 29,849	$ 36,153

Dividends of approximately $2.7 million have been declared by the Company's Board of Directors, but not paid, as of September 30, 2006.

Included in the accounts payable and accrued expenses account balances as of September 30, 2006, and 2005, are $90.5 million and $44.5 million, respectively, of additions to oil and gas properties. These oil and gas property additions are reflected in cash used in investing activities in the periods that the payables are settled.

In February 2006 and March 2005 the Company issued 484,351 and 195,312 restricted stock units, respectively, pursuant to the Company's restricted stock plan. The total expenses associated with the issuances were $16.4 million and $4.5 million, respectively.

In May 2006, July 2006, and May 2005 the Company issued 26,076, 3,751, and 13,926 shares, respectively, of common stock from treasury to its non-employee directors. The issuance in 2005 was pursuant to the Company's non-employee director stock compensation plan and the 2006 issuances were pursuant to the Company's 2006 equity incentive compensation plan. The Company recorded compensation expense related to these issuances of $465,400 and $102,500 for the nine-month periods ended September 30, 2006 and 2005, respectively.

In May 2006 the Company closed a transaction whereby it exchanged non-core oil and gas properties located in the Uinta Basin for oil and gas properties located in Richland County, Montana. This transaction is considered a non-monetary exchange for accounting purposes with a fair value assigned to this transaction of $11.5 million.

In June 2006 the Company hired a new senior executive. In doing so, the Company issued 13,784 shares of stock and recorded compensation expense of approximately $737,000. The new senior executive can earn up to 20,000 additional shares based on performance indicators. Approximately $50,000 worth of expense has been recognized related to the additional shares.

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)

September 30, 2006

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 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 condensed consolidated financial statements of St. Mary have been prepared in accordance with accounting principles generally accepted in the United States for interim financial information. They do not include all information and notes required by generally accepted accounting principles for complete financial statements. Except as disclosed herein, there has been no material change in the information disclosed in the notes to the consolidated financial statements included in St. Mary's Annual Report on Form 10-K for the year ended December 31, 2005. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation of the interim financial information have been included. Operating results for the periods presented are not necessarily indicative of the results that may be expected for the full year.

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, 2005, and are supplemented throughout the footnotes to the financial statements included in this document These unaudited condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes included in the Form 10-K for the year ended December 31, 2005.

Note 3 — Acquisitions

Richland County, Montana Acquisition

On May 15, 2006, the Company closed on a transaction whereby it exchanged non-core oil and gas properties located in the Uinta Basin for oil and gas properties located in Richland County, Montana. The transaction was structured as an Internal Revenue Code Section 1031 tax-deferred exchange. For financial reporting purposes, the transaction is considered a non-monetary exchange and has been accounted for at estimated fair value. The exchange of properties resulted in recognition of a gain of approximately $7 million. The final purchase accounting allocation and gain determination will be dependent on finalization of post-closing adjustments associated with revenue, expenses, and costs incurred between the effective date and the date of closing. The Company expects that this allocation will be completed prior to the end of 2006.

Wold Acquisition

On August 1, 2005, the Company acquired oil and gas properties from Wold Oil Properties, Inc. ("Wold") for $37.1 million in cash. The Company allocated the purchase price based on the fair value of the acquired assets and liabilities. The allocation of the purchase price resulted in recording $43.9 million to proved and unproved oil and gas properties, a $7.0 million asset retirement obligation, and a net $232,000 to other assets.

Agate Acquisition

On January 5, 2005, the Company acquired Agate Petroleum, Inc. ("Agate") in exchange for $40.0 million in cash. The Company allocated the purchase price based on the estimated fair value of the acquired assets and liabilities. The Company acquired $4.6 million in cash from Agate, and the allocation of the purchase price resulted in recording $41.9 million to proved and unproved oil and gas properties, $1.1 million to net current liabilities, $9.5 million to goodwill, a deferred income tax liability of $13.5 million, and a $1.4 million asset retirement obligation.

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 during each period. The shares represented by vested restricted stock units 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 of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Adjusted net income is used for the if-converted method and is derived by adding interest expense paid on the Company's 5.75% Senior Convertible Notes due 2022 (the "Convertible Notes") back to net income and then adjusting for non-discretionary items that are based on income and that would have changed had the Convertible Notes been converted at the beginning of the period. Potentially dilutive securities of the Company consist of in-the-money outstanding options to purchase the Company's common stock, shares into which the Convertible Notes may be converted, and unvested restricted stock units.

The shares underlying the grants of restricted stock units are included in the diluted earnings per share calculation beginning with the grant date of units regardless of whether the shares are vested or unvested. Following the lapse of the restriction period, the shares underlying the units will be issued and thereby included in the number of issued and outstanding shares.

The dilutive effects of stock options and unvested restricted stock units are considered in the detailed calculation below. There were no anti-dilutive securities related to stock options or restricted stock units for any periods presented.

Shares associated with the conversion feature of the Convertible Notes are accounted for using the if-converted method as described above and are considered in the detailed calculation below. A total of 7,692,307 potentially dilutive shares related to the Convertible Notes were included in the calculation of diluted net income per common share for the three-month and nine-month periods ended September 30, 2006, and 2005. The Convertible Notes were issued in March 2002 and can be called by the Company in March 2007.

Prior to the adoption of Statement of Financial Accounting Standards No. 123R, "Share-Based Payment" ("SFAS No. 123R") on January 1, 2006, the Company accounted for share-based awards under the recognition and measurement provisions of Accounting Principles Board Opinion No. 25, "Accounting

for Stock Issued to Employees" ("ABP Opinion No. 25") and related interpretations. Under this method no compensation cost was reflected in net income for issued stock options as all stock options had an exercise price equal to the market value of the underlying common stock on the date of grant. Therefore, in calculating potential diluted common shares for purposes of EPS the amount of compensation cost for stock options measured was not included in the calculation since no expense had been recognized by the Company for stock options.

Effective January 1, 2006, the Company adopted SFAS No. 123R using the modified-prospective transition method. Under that transition method prospective compensation expense includes: (a) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the grant date fair value estimated in accordance with the original provisions of SFAS No. 123, and (b) compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123R. Therefore, in calculating assumed proceeds and potential common shares for purposes of EPS, the Company began including the unrecognized compensation expense for stock options as of January 1, 2006, based on the grant date fair value.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2006	2005	2006	2005
	(In thousands, except per share amounts)			
Net income	$ 55,877	$ 27,334	$ 146,483	$ 100,698
Adjustments to net income for dilution:				
Add: interest expense not incurred if Convertible Notes converted	1,597	1,597	4,740	4,740

Less: other adjustments	(16)	(16)	(47)	(47)
Less: income tax effect of adjustment items	(543)	(564)	(1,696)	(1,715)
Net income adjusted for the effect of dilution	$ 56,915	$ 28,351	$ 149,480	$ 103,676
Basic weighted-average common shares outstanding	55,398	56,640	56,564	56,941
Add: dilutive effects of stock options and unvested restricted stock units	1,836	2,406	2,076	2,214
Add: dilutive effect of Convertible Notes using if-converted method	7,692	7,692	7,692	7,692
Diluted weighted-average common shares outstanding	64,926	66,738	66,332	66,847
Basic earnings per common share	$ 1.01	$ 0.48	$ 2.59	$ 1.77
Diluted earnings per common share	$ 0.88	$ 0.42	$ 2.25	$ 1.55

Note 5 — Compensation Plans

Cash Bonus Plan

The Company has a cash bonus plan that allows participants to receive a cash bonus of up to 50 percent of their aggregate base salary. Any awards under the cash bonus plan are based on a combination of Company and individual performance. The Company accrues cash bonus expense related to the current year's performance. The cash bonus expenses for the three-month periods ended September 30, 2006, and 2005, were $687,000 and $3.2 million, respectively, and the cash bonus expenses for the nine-month

periods ended September 30, 2006, and 2005, were $3.4 million and $4.8 million, respectively. Cash bonuses related to the 2006 performance year are expected to be paid in the first quarter of the subsequent year.

Net Profits Plan

Under the Company's Net Profits Interest Bonus Plan (the "Net Profits Plan"), oil and gas wells that are completed or acquired during a year are designated within a specific pool. Key employees recommended by senior management and designated as participants by the Company's Compensation Committee of the Board of Directors and employed by the Company on the last day of that year become entitled to bonus payments after the Company has received net cash flows returning 100 percent of all costs associated with that pool. Thereafter, ten percent of future net cash flows generated by the pool are allocated among the participants and distributed at least annually. The portion of net cash flows from the pool to be allocated among the participants increases to 20 percent after the Company has recovered 200 percent of the total costs for the pool, including payments made under the Net Profits Plan at the ten percent level. The Net Profits Plan has been in place since 1991. Pool years prior to and including 2005 are fully vested. Pool years beginning in 2006 will carry a vesting period of three years, whereby one-third is vested at the end of the year for which participation is designated and one-third vests each of the following two anniversary dates. Beginning with the 2006 pool, the maximum benefit to full participants from a particular year's pool will be limited to 300 percent of a participating individual's salary paid during the year to which the pool relates.

In a separate calculation, the Company records the estimated liability for 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 15 percent is used to calculate this liability and 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 the price assumptions and discount rates used in the calculations. The commodity price assumptions are currently formulated by applying a price that is derived from a rolling average of actual prices realized over the prior 24 months together with adjusted New York Mercantile Exchange, Inc., ("NYMEX") strip prices for the ensuing 12 months for a total of 36 months of data. This average is supplemented by including the effect of hedge prices for the percentage of forecasted production hedged in the relevant period. The forecasted expense associated with this significant management estimate is highly volatile from period to period due to fluctuations that occur in the oil and natural gas commodity markets. Higher commodity prices experienced in recent years have moved more pools into payout status. The Company continually evaluates the assumptions used in this calculation in order to include the current market environment for oil and gas prices, discount rates, and overall market conditions.

The following table presents the changes in the estimated future liability attributable to the Net Profits Plan. These amounts relate to the realized results for the periods presented from oil and gas operations for the properties associated with the respective pools that have achieved payout status.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2006	2005	2006	2005
	(In thousands)		(In thousands)	
Liability balance for Net Profits Plan as of the beginning of the period	$ 157,904	$ 46,957	$ 136,824	$ 30,561
Increase in liability	3,043	60,988	37,937	84,952
Reduction in liability for cash payments made or accrued and recognized as compensation expense	(6,752)	(6,131)	(20,566)	(13,699)
Liability balance for Net Profits Plan as of the end of the period	$ 154,195	$ 101,814	$ 154,195	$ 101,814

The calculation of the estimated liability for the Net Profits Plan is highly sensitive to price estimates and discount rate assumptions. For example, if the commodity prices in the calculation were changed by ten percent, the liability recorded at September 30, 2006, would differ by approximately $32 million. A one percentage point change in the discount rate would result in a change of approximately $7 million. Actual cash payments to be made in future periods are dependent on realized actual production, prices, and costs associated with the properties in each individual pool of the Net Profits Plan. Consequently, actual cash payments will be inherently different from the amounts estimated.

The Company records changes in the present value of estimated future payments under the Net Profits Plan as a separate item in the consolidated statements of operations. The change in the estimated liability is recorded as an expense or benefit in the current period. The amount recorded associated with the change in the estimated liability is not allocated to general and administrative costs or exploration costs because it is an estimate at the current time of the adjustment to the liability that is associated with the future net cash flows from oil and gas properties in the respective pools rather than current period realized performance. The table below presents the estimated allocation of the change in the liability if the Company did allocate the adjustment to these specific line items:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2006	2005	2006	2005
	(In thousands)		(In thousands)	
General and administrative expense	$ (1,627)	$ 26,758	$ 7,337	$ 34,889
Exploration expense	(2,083)	28,099	10,033	36,364
Total	$ (3,710)	$ 54,857	$ 17,370	$ 71,253

Equity Incentive Compensation Plan

There are several components to the equity compensation plan that are described in this section. The various types of grants are a result of when the equity awards were granted by the Company. For example, the Company ceased issuing stock options in 2004 and began issuing restricted stock or restricted stock units to employees. The disclosures reflect the culmination of the disclosure requirements for all equity awards still outstanding.

In May 2006, the stockholders approved the 2006 Equity Incentive Compensation Plan (the "2006 Plan") to authorize the issuance of restricted stock, restricted stock units, non-qualified stock options, incentive stock options, stock appreciation rights, and stock-based awards to key employees, consultants, and members of the Board of Directors of St. Mary or any affiliate of St. Mary. The 2006 Plan serves as the successor to the St. Mary Land & Exploration Company Stock Option Plan, the St. Mary Land & Exploration Company Incentive Stock Option Plan, the St. Mary Land & Exploration Company Restricted Stock Plan, and the St. Mary Land & Exploration Company Non-Employee Director Stock Compensation Plan (collectively referred to as the "Predecessor Plans"). All grants of equity are now made out of the 2006 Plan, and no further grants will be made under the Predecessor Plans. Each outstanding award under a Predecessor Plan immediately prior to the effective date of the 2006 Plan continues to be governed solely by the terms and conditions of the instruments evidencing such grants or issuances.

Effective January 1, 2006, the Company adopted SFAS 123R using the modified-prospective transition method. Under that transition method, compensation expense recognized in the nine months ended September 30, 2006, includes: (a) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the grant date fair value estimated in accordance with the original provisions of SFAS No. 123, and (b) compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123R.

As of September 30, 2006, 2.6 million shares of common stock remained available for grant under the 2006 Plan. Any issuance of a direct share benefit such as an outright grant of common stock, a grant of a restricted share or a restricted stock unit counts as two shares for each share issued against the amount eligible to be granted under the 2006 Plan. Each stock option and similar instrument granted counts as one share for each share issued against the eligible shares authorized to be issued under the 2006 Plan.

St. Mary anticipates granting restricted stock and restricted stock units under the 2006 Plan for the foreseeable future. However, the Company does have outstanding stock option grants under the Predecessor Plans. The following sections describe the details of restricted stock units and stock options outstanding as of September 30, 2006.

Restricted Stock Incentive Program Under the Equity Incentive Compensation Plan

The Company has a long-term incentive program whereby grants of restricted stock or restricted stock units ("RSUs") have been awarded to eligible employees, consultants, and members of the Board of Directors. Restrictions and vesting periods for the awards are determined at the discretion of the Board of Directors and are set forth in the award agreements. Each RSU represents a right for one share of the Company's common stock to be delivered upon settlement of the award at the end of a specified period. These grants are determined annually based on a formula consistent with the cash bonus plan.

St. Mary issued 484,351 RSUs on February 28, 2006, related to 2005 performance and 195,312 RSUs on March 15, 2005, related to 2004 performance. The total fair value associated with these issuances was $16.4 million in 2006 and $4.5 million in 2005 as measured on the respective grant dates. The granted RSUs vest 25 percent immediately upon grant and 25 percent on each of the next three anniversary dates of the grant. Compensation expense is recorded monthly over the vesting period of the award. The vested shares underlying the RSU grants will be issued on the third anniversary of the grant, at which time the shares carry no further restrictions. As of September 30, 2006, there was a total of 1,072,152 RSUs outstanding, of which 552,562 were vested. Total compensation expense related to the RSUs for the three-month periods ended September 30, 2006, and 2005, was $1.6 million and $3.0 million, respectively, and total compensation expense related to the RSUs for the nine-month periods ended September 30, 2006, and 2005, was $6.9 million and $5.3 million, respectively. The 2006

period includes $1.2 million of compensation expense for the estimated value of grants expected to be issued in 2007 related to the 2006 performance year.

Stock Awards Under the Equity Incentive Compensation Plan

As part of hiring a new senior executive in the second quarter of 2006, St. Mary granted a special common stock award of 20,000 shares which vested immediately upon commencement of employment. Approximately $728,000 of compensation expense was recorded related to this award. In addition to this award, the employee may earn an additional 20,000 shares contingent on the Company meeting certain performance conditions. The fair value of this award will be recorded to compensation expense over the vesting period. As of September 30, 2006, approximately $50,000 of compensation expense had been recorded related to the contingent award.

A summary of the status and activity of non-vested RSUs for the nine-month period ended September 30, 2006, is presented below.

	Shares	Weighted-Average Grant-Date Fair Value
Non-vested, at December 31, 2005	356,099	$ 18.91
Granted	504,351	$ 33.92
Vested	(295,852)	$ 25.88
Forfeited	(45,008)	$ 28.14
Non-vested, at September 30, 2006	519,590	$ 28.71

In measuring compensation expense from the grant of RSUs, SFAS No. 123R requires companies to estimate the fair value of the award on the grant date. The fair value of RSUs has been measured using the Black-Scholes option-pricing model. The fair value of the RSUs is inherently less than the market value of an unrestricted security; accordingly a fair value calculation is performed to determine the fair value of the grant. The Company's computation of expected volatility was based on the historic volatility of St. Mary's common stock. The Company's computation of expected life was determined based on historical experience of similar awards, giving consideration to the contractual terms of the stock-based awards, vesting schedules, and expectations of future employee behavior. The interest rate for periods within the contractual life of the award was based on the U.S. Treasury constant maturity yield at the time of grant. The fair values of granted RSUs were estimated using the following weighted-average assumptions:

	For the Nine Months Ended September 30, 2006	2005
Risk free interest rate:	4.70%	4.03%
Dividend yield:	0.25%	0.38%
Volatility factor of the expected market price of the Company's common stock:	36.60%	26.70%
Expected life of the awards (in years):	3	3

Upon the adoption of SFAS No. 123R, the deferred compensation balance of $5.6 million related to outstanding RSU awards was reclassified to additional paid-in-capital within the shareholders' equity section of the balance sheet. This deferred compensation balance had been recorded in accordance with APB Opinion No. 25. The Company had recorded compensation expense in periods prior to January 1, 2006, for restricted stock awards based on the intrinsic value on the date of grant. The intrinsic value

was recorded as deferred compensation in a separate component of shareholders' equity and was amortized to compensation expense over the vesting period. SFAS No. 123R requires expense recognized subsequent to the adoption date to be based on fair value.

Stock Option Grants Under the Equity Incentive Compensation Plan

The Company has previously granted stock options under the St. Mary Land & Exploration Company Stock Option Plan and Incentive Stock Option Plan. The last issuance of stock options was December 31, 2004. Stock options to purchase shares of the Company's common stock had been issued to eligible employees and members of the Board of Directors. All options granted to date under the option plans have been granted at exercise prices equal to the respective closing market price of the Company's common stock on the grant dates, which generally occurred on the last date of a fiscal period. All stock options granted under the option plans are exercisable for a period of up to ten years from the date of grant.

During the nine-month period ended September 30, 2006, the Company recognized stock-based compensation expense of approximately $1.6 million related to unvested stock options that were outstanding as of January 1, 2006. There was no cumulative effect adjustment from the adoption of SFAS No. 123R.

Prior to adopting SFAS No. 123R, all tax benefits resulting from the exercise of stock options were presented as operating cash flows in the consolidated statement of cash flows. SFAS No. 123R requires cash flows resulting from excess tax benefits to be classified as a part of cash flows from financing activities. Excess tax benefits are realized tax benefits from tax deductions for exercised options in excess of the deferred tax asset attributable to stock compensation costs for such options. As a result of adopting SFAS No. 123R, $15.1 million of excess tax benefit for the nine months ended September 30, 2006, has been classified as a financing cash inflow. Cash received from option exercises under all share-based payment arrangements for the three-month periods ended September 30, 2006, and 2005, was $1.1 million and $1.7 million, respectively, and cash received from option exercises under all share-based payment arrangements for the nine-month periods ended September 30, 2006, and 2005, was $15.6 million and $7.9 million, respectively.

The following table illustrates the effect on operating results and per share information had the Company accounted for share-based compensation in accordance with SFAS No. 123R for the periods indicated:

	For the Three Months Ended September 30, 2005	For the Nine Months Ended September 30, 2005
	(In thousands, except per share amounts)	
Net income -		
As reported:	$ 27,334	$ 100,698
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	1,925	3,344
Less: Stock-based employee compensation expense determined under fair value-based method for all awards, net of related income tax effects	(2,335)	(4,775)
Pro forma net income	$ 26,924	$ 99,267
Basic net income per share -		
As reported	$ 0.48	$ 1.77
Pro forma	$ 0.48	$ 1.74
Diluted net income per share -		
As reported	$ 0.42	$ 1.55
Pro forma	$ 0.42	$ 1.53

For purposes of these pro forma disclosures, the estimated fair value of the options and employee stock purchase plan ("ESPP") grants are amortized to expense over the awards' vesting periods. The effects of applying SFAS No. 123R in the pro forma disclosure are not necessarily indicative of actual future amounts.

The fair value of options and ESPP grants has been measured at the date of grant using the Black-Scholes option-pricing model. No options were granted during the nine-month periods ended September 30, 2006, and 2005. For the ESPP offering periods during 2006, the Company has expensed $186,000 based on the estimated fair value on the respective grant dates.

The following table summarizes the stock options outstanding as of September 30, 2006, as well as activity during the nine months then ended:

	Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value (In thousands)
Outstanding at beginning of period	4,698,243	$ 12.21		
Exercised	(1,371,313)	$ 11.41		
Forfeited	(87,005)	$ 14.33		
Outstanding at end of period	3,239,925	$ 12.48	5.56	$ 78,480
Exercisable at end of period	3,046,324	$ 12.43	5.51	$ 73,958

As of September 30, 2006, there was $659,000 of total unrecognized compensation cost related to unvested stock option awards.

The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options that have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of highly subjective assumptions including the expected stock price volatility. The Company's stock options have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, it is management's opinion that the valuations afforded by the existing models are different from the value that the options would realize if traded in the market.

Note 6 — Income Taxes

Income tax expense for the three-month and nine-month periods ended September 30, 2006, and 2005, differs from the amounts that would be provided by applying the statutory U.S. Federal income tax rate to income before income taxes primarily due to the effect of state income taxes, percentage depletion, the estimated effect of the domestic production activities deduction allowed under the American Jobs Creation Act of 2004, and other permanent differences.

	For the Three Months Ended September 30, (In thousands)		For the Nine Months Ended September 30, (In thousands)	
	2006	2005	2006	2005
Current portion of income tax expense (benefit):				
Federal	$ (766)	$ 21,867	$ 17,374	$ 45,360
State	102	1,738	880	3,152
Deferred portion of income tax expense (benefit):	29,929	(8,617)	64,612	9,485
Total income tax expense	$ 29,265	$ 14,988	$ 82,866	$ 57,997
Effective tax rates	34.4%	35.4%	36.1%	36.5%

The change in tax rate in the current quarter from the previous year reflects differences between the two quarters in the composition of the estimated highest marginal state tax rate as a result of 2006 Texas legislation instituting a new margin tax that will be effective for future tax periods and different impacts of acquisition and drilling activity between periods. It also reflects differing effects from the Company's estimate of the effect of the domestic production activities deduction, estimated percentage depletion and the possible impact of state tax permanent differences.

Note 7 — Long-term Debt

Revolving Credit Facility

The Company executed an Amended and Restated Credit Agreement on April 7, 2005, to replace its previous credit facility. This credit facility specifies a maximum loan amount of $500 million and has a maturity date of April 7, 2010. Borrowings under the facility are secured by a pledge in favor of the lenders of collateral that includes certain oil and gas properties and the common stock of the material subsidiaries of the Company. The borrowing base under the credit facility as authorized by the bank group is currently $900 million, and is subject to regular semi-annual re-determinations. The borrowing base re-determination process considers the value of St. Mary's oil and gas properties and other assets, as

determined by the bank syndicate. The Company has elected an aggregate commitment amount of $200 million under the credit facility. The Company will expand the commitment amount in December 2006, in order to pay for the acquisition described in Note 12. The Company must comply with certain financial and non-financial covenants. Interest and commitment fees are accrued based on the borrowing base utilization percentage table below. Euro-dollar loans accrue interest at LIBOR plus the applicable margin from the utilization table, and Alternative Base Rate (ABR) 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 consolidated statements of operations.

Borrowing base utilization percentage	<50%	≥50%<75%	≥75%<90%	≥90%
Euro-dollar loans	1.000%	1.250%	1.500%	1.750%
ABR loans	0.000%	0.250%	0.250%	0.500%
Commitment fee rate	0.250%	0.300%	0.375%	0.375%

The Company had $66 million in loans outstanding under its revolving credit agreement as of September 30, 2006.

5.75% Senior Convertible Notes Due 2022

As of September 30, 2006, the Company had $100 million in outstanding borrowings under the Convertible Notes. The Convertible Notes provide for the payment of contingent interest of up to an additional 0.5 percent during six-month interest periods based on the note trading price before the beginning of the particular six-month period. Under that provision, interest was accrued at a total rate of 6.25 percent for the three-month and nine-month periods ended September 30, 2006, and 2005. Based on the trading price of the Convertible Notes over the determination period, the Company will be subject to the contingent interest payments for the period from September 15, 2006, to March 14, 2007. The Company has the option to call the Convertible Notes in March 2007. By doing so, the Convertible Note holders will have the right to convert the Convertible Notes to shares at the conversion price of $13 per share.

Weighted-Average Interest Rate Paid

The weighted-average interest rates paid for the three-month periods ended September 30, 2006, and 2005, were 7.5 percent and 7.2 percent, respectively, including commitment fees paid on the unused portion of the credit facility aggregate commitment, amortization of deferred financing costs, amortization of the contingent interest embedded derivative associated with the Convertible Notes, and the effects of interest rate swaps. The weighted-average interest rates paid for the nine-month periods ended September 30, 2006 and 2005, were 7.9 percent and 7.1 percent, respectively. Capitalized interest costs for the Company for the three-month periods ended September 30, 2006, and 2005 were $896,000 and $516,000, respectively, and capitalized interest costs for the nine-month periods ended September 30, 2006, and 2005, were $2.3 million and $1.4 million, respectively.

Note 8 — Derivative Financial Instruments

The Company recognized a net gain of $4.5 million from its derivative contracts for the three-month period ended September 30, 2006, compared to a net loss of $8.7 million for the same period in 2005. Comparative amounts for the nine months ended September 30, 2006, and 2005, were a net gain of $8.9 million and a net loss of $10.5 million, respectively.

The following table summarizes derivative instrument gain (loss) activity:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2006	2005	2006	2005
	(In thousands)		(In thousands)	
Derivative contract settlements realized in oil and gas hedge gain (loss)	$ 4,828	$ (8,441)	$ 14,808	$ (8,967)
Ineffective portion of hedges qualifying for hedge accounting included in unrealized derivative loss	(433)	(306)	(6,187)	(1,328)
Non-qualified derivative contracts included in unrealized derivative loss	366	365	859	17
Interest rate derivative contract settlements	(275)	(275)	(550)	(247)
Total	$ 4,486	$ (8,657)	$ 8,930	$ (10,525)

Oil and Gas Commodity Hedges

To mitigate a portion of the potential exposure to adverse market changes, the Company has entered into various derivative contracts. The Company's derivative contracts in place include swap and collar arrangements for the sale of oil and natural gas. Please refer to the tables under *Summary of Oil and Gas Production Hedges in Place* in Part I, Item 2, Management's Discussion and Analysis of Financial Condition and Results of Operations, for details regarding the Company's hedged volumes and associated prices. As of September 30, 2006, the Company has hedge contracts in place through 2011 for a total of approximately 10 million Bbls and 77 million MMBtu of anticipated production. Subsequent to quarter end, the Company has hedged additional oil and gas volumes in conjunction with the Permian acquisition described in Note 12. 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 attempts to qualify its oil and natural gas derivative instruments as cash flow hedges for accounting purposes. As of September 30, 2006, all oil and natural gas derivative instruments qualified as cash flow hedges for accounting purposes. The estimated fair value of oil and natural gas derivative contracts designated and qualifying as cash flow hedges under Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities ("SFAS No. 133"), was a net liability of $1.4 million at September 30, 2006.

Gains or losses from the settlement of oil and gas derivative contracts are reported in the total operating revenues section on the consolidated statements of operations. Changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in unrealized derivative loss (gain) in the consolidated statement of operations.

The Company seeks to minimize ineffectiveness by entering into oil derivative contracts indexed to NYMEX and gas 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 sale contracts, this results in hedges that are highly correlated with the underlying hedged item.

Unrealized derivative losses for the three-month periods ended September 30, 2006, and 2005, were $433,000 and $306,000, respectively, from the ineffective portion of oil and natural gas derivative contracts. Amounts for the nine-month periods ended September 30, 2006, and 2005, were net losses of $6.2 million and $1.3 million, respectively.

As of September 30, 2006, the amount of unrealized gain related to oil and gas commodity hedges, net of deferred income taxes, to be reclassified from accumulated other comprehensive income to oil and gas production operating revenues in the next twelve months was $22.6 million.

Interest Rate Derivative Contracts

The Company has various interest rate derivative contracts. There are offsetting trades that have fixed the future payments under these derivative contracts. The fair value of the interest rate derivatives was a liability of $255,000 as of September 30, 2006. The Company recorded net derivative gain in the consolidated statements of operations of $128,000 for the three-month period ended September 30, 2006, and a net gain of $132,000 for the three-month period ended September 30, 2005, from mark-to-market adjustments for these derivatives. Comparative amounts for the nine-month periods ended September 30, 2006, and 2005, were a net derivative gain of $391,000 and a net derivative loss of $344,000, respectively. These derivatives do not qualify for fair value hedge treatment under SFAS No. 133 and related pronouncements.

Convertible Note Derivative Instruments

The contingent interest provision of the Convertible Notes is considered an embedded equity-related derivative that is not clearly and closely related to the fair value of an equity interest and therefore must be separately accounted for as a derivative instrument. The value of the derivative at issuance of the Convertible Notes in March 2002 was $474,000. This amount was recorded as a decrease to the Convertible Notes payable in the consolidated balance sheets. Interest expense for each three-month period includes $24,000 of amortization of this derivative. The unrealized derivative loss (gain) line in the consolidated statements of operations includes net gains of $238,000 and $233,000 for the three-month periods ended September 30, 2006, and 2005, respectively, and $468,000 and $361,000 for the nine-month periods ended September 30, 2006, and 2005, respectively, from mark-to-market adjustments for this derivative. The derivatives had no net fair value at September 30, 2006.

Note 9 — Pension Benefits

The Company's employees participate in 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 "Non-qualified 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 Non-qualified Pension Plan:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2006	2005	2006	2005
	(In thousands)		(In thousands)	
Service cost	$ 422	$ 346	$ 1,264	$ 1,039
Interest cost	163	134	489	401
Expected return on plan assets	(107)	(94)	(297)	(283)
Amortization of net actuarial loss	74	60	222	181
Net periodic benefit cost	$ 552	$ 446	$ 1,678	$ 1,338

Gains and losses in excess of ten percent of the greater of the benefit obligation and the market-related value of assets are amortized over the average remaining service period of active participants.

Contributions

St. Mary contributed $1.3 million to the Qualified Pension Plan during the second quarter of 2006. No further contributions are planned for the remainder of 2006.

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 consolidated balance sheets. The Company depletes the amount added to proved oil and gas property costs and recognizes accretion expense in connection with 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 consolidated statement of cash flows.

The Company's estimated asset retirement obligation liability is based on historical experience in abandoning wells, estimated economic lives, estimates as to the 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 7.25 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 September 30,		For the Nine Months Ended September 30,	
	2006	2005	2006	2005
	(In thousands)		(In thousands)	
Beginning asset retirement obligation	$ 69,011	$ 44,383	$ 66,078	$ 40,911
Liabilities incurred	1,106	8,813	2,864	11,212
Liabilities settled	(131)	(499)	(1,293)	(858)
Accretion expense	1,222	850	3,559	2,282
Ending asset retirement obligation	$ 71,208	$ 53,547	$ 71,208	$ 53,547

Note 11 — Repurchase of Common Stock

Stock Repurchase Program

In July 2006 the Company's Board of Directors approved an increase to the remaining authorized number of shares that can be repurchased under the Company's original authorization approved in August 1998 by an additional 5,473,182 shares. As of the date of this filing the Company has Board authorization to repurchase up to six million shares of common stock. 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 credit facility agreement and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow and borrowings under the credit facility.

During the first six months of 2006, the Company repurchased a total of 3,319,300 shares of its common stock under the program at a weighted-average price of $37.09 per share, including commissions. No additional shares were repurchased under the program during the third quarter of 2006. In July 2006 the Company retired 3,275,689 shares of treasury stock.

Note 12 — Subsequent Event

On November 1, 2006, the Company signed a purchase and sale agreement to purchase the working and net revenue interests, as well as the underlying leasehold interest in oil and gas assets in West Texas from two private parties for $250 million in cash funded from the Company's existing credit agreement. The properties target producing formations in the Spraberry interval. The Company estimates that proved reserves attributable to the acquisition are 78.1 BCFE, which are producing approximately 16.0 MMCFED net. The properties are approximately 79 percent oil and 21 percent natural gas and associated liquids. The acquired interests will be operated by St Mary, and have an average working interest of 95 percent and net revenue interest of approximately 71 percent. It is anticipated that the acquisition will close by December 15, 2006.

This transaction adds high working interest, low risk properties to the Company's portfolio and increases our presence in our Permian Basin core area. The acquisition adds a multi-year drilling program to the Company's inventory of projects with potential for downspacing that has the potential to have meaningful upside.

A third party has a contractual right to purchase up to an undivided twenty percent of the working interest in the transaction. This third party's right must be exercised concurrent with closing of the transaction.

St. Mary has hedged the first five years of oil volume production in conjunction with this transaction using swaps. The average annual prices for these swaps are between $65.15 and $68.04 per Bbl. The Company has also hedged the anticipated production for residual natural gas over a five year period at a weighted average NYMEX equivalent price of approximately $7.70 per MMBTU and natural gas liquids for the first two years.

Note 13 —Recent Accounting Pronouncements

In July 2006 the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109" ("FIN 48"), which clarifies the accounting for uncertainty in tax positions. FIN 48 will require that the Company recognize the impact of a tax position in its financial statements if the technical merits of that position indicate that the position is more likely than not of being sustained upon audit. The provisions of FIN 48 will be effective as of the beginning of the Company's 2007 fiscal year, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. The Company is currently evaluating the impact of adopting FIN 48 on its financial statements.

In September 2006 the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" ("SAB 108"), to address diversity in practice in quantifying financial statement misstatements. SAB 108 requires misstatements to be quantified based on their impact on each of our financial statements and related disclosures. SAB 108 provides for registrants to correct prior year financial statements for immaterial errors in subsequent filings of prior year financial statements and does not require previously filed reports to be amended. SAB 108 will be effective for the Company as of December 31, 2006. The SAB also allows for a one-time transitional cumulative effect adjustment to retained earnings as of January 1, 2006 for errors that were not previously deemed material, but are material under the guidance in SAB 108. Based on its evaluation at this time, the Company does not expect the adoption of this standard to have any effect on its historical financial statements.

In September 2006 the FASB issued Statement of Financial Accounting Standards No. 157, "Fair Value Measurements" ("SFAS No. 157"), which defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. The provisions of SFAS No. 157 will be effective as of the beginning of the Company's 2008 fiscal year. The Company is currently evaluating the impact SFAS No. 157 will have on its financial statements.

In September 2006 the FASB issued Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an amendment of FASB Statements No. 87, 88, 106, and 132(R)" ("SFAS No. 158"). SFAS No. 158 will require that the Company recognize the excess of the Projected Benefit Obligation over the fair value of the plans' assets of its Qualified and Non-qualified Pension Plans as a liability in the 2006 year-end balance sheet. The cumulative balance sheet entry will be recorded against accumulated other comprehensive income. This statement does not affect how an entity computes its benefit expense recognized in the income statement. The Company estimates the impact of adopting SFAS No. 158 to be an increase to the liability of approximately $3 million to $6 million, with no impact to the statement of operations or cash flows. The Company currently uses December 31 as the measurement date for measuring the fair value of the plan assets, and accordingly will not be affected by this transition provision of SFAS 158 as it relates to valuing the plan assets.

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

This discussion contains forward-looking statements. Please refer to "Cautionary Information About Forward-Looking Statements" at the end of this item for an explanation of these types of statements.

General Overview

We are an independent energy company focused on the exploration, exploitation, development, acquisition, and production of natural gas and crude oil in the United States. We earn greater than 90 percent of our revenues from the sale of produced natural gas and crude oil. These sales also comprise the vast majority of our cash flows from operations. Our oil and gas reserves and operations are concentrated 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 tight sandstone and limestone reservoirs of East Texas and North Louisiana; the Permian Basin; onshore Gulf Coast and offshore Gulf of Mexico. We have developed a portfolio of proved reserves, development drilling opportunities, resource development opportunities, and non-conventional gas prospects.

Third Quarter 2006 Operating and Financial Highlights

Our third quarter net income was a record at $55.9 million or $0.88 per diluted share compared to third quarter 2005 results of $27.3 million or $0.42 per diluted share. Production for the third quarter was 23.2 BCFE. This represents a three percent increase from the second quarter 2006 and is basically flat from the previous third quarter. Per MCFE lease operating expense and transportation expense increased $0.33 to $1.40 as compared to a year ago. We are seeing increased lease operating expense in every region compared to last year due to a combination of increased equipment and service cost and more workover activity. The increase in commodity prices over the past several years has led to increased levels of drilling activity and has created an incentive to perform maintenance and workover activity on wells and infrastructure which may not have been performed in lower commodity price environments. While the demand for equipment and services has increased dramatically, the available supply from vendors has not increased at the same rate. Accordingly, equipment and service providers have been able to raise their prices in a period where we were increasing our activity. Most significantly, workover activity has increased as we repaired and upgraded properties associated with recent acquisitions in the Rockies. The economic viability of these workover projects is subjected to the same rigorous evaluation process as our decisions to drill a well. Additionally, we had several high-dollar workover operations on a few high-value properties in the Mid-Continent and the Rockies. Production taxes decreased $0.04 to $0.54 per MCFE.

This third quarter represents the third consecutive quarter of sequential growth in production and we are forecasting sequential growth in the fourth quarter of 2006 as well. These increases occurred despite shut-in production on a significant royalty well and delays in securing drilling rigs. We entered into agreements to acquire an additional $21 million of oil and gas properties during the third quarter, of which $5 million is located in the Rockies and closed during the quarter. The remaining $16 million includes properties located in the Permian and Anadarko Basins and closed during the fourth quarter. However, in this competitive acquisition market, these acquisitions will not have as significant an impact on our production as we had forecast for our 2006 acquisitions budget.

Our DD&A, including ARO accretion expense, increased $0.12 to $1.72 per MCFE during the quarter. This increase is attributed to a slightly lower denominator in the DD&A calculation for the third quarter resulting from a reduction in tail reserves due to lower commodity prices used in the reserve preparation as of quarter end. Additionally, our per MCFE finding cost of oil and gas reserves has

increased in recent years, reflecting the aforementioned cost increases. We discuss these financial results and trends in more detail below.

Acquisition of Permian Basin Oil and Gas Properties

On November 1, 2006, we signed a purchase and sale agreement with an undisclosed seller to purchase the working and revenue interests, as well as the underlying leasehold interest in oil and gas assets in West Texas from two private parties for $250 million in cash funded from our existing credit agreement. The properties are located in the Midland Basin and target the producing formations in the Spraberry interval and will be part of our Permian core area. We estimate that proved reserves attributable to the acquisition are 78.1 BCFE, which are producing approximately 16.0 MMCFED, net. The properties are approximately 79 percent oil and 21 percent natural gas and associated liquids. The acquired interests will be 100 percent operated, with average working interest of 95 percent and net revenue interest of approximately 71 percent. It is anticipated that the acquisition will close by December 15, 2006.

This transaction adds high working interest, low risk properties to our portfolio and increases our presence in the Permian Basin. The acquisition adds a multi-year drilling program to our inventory of projects with potential for downspacing that could have meaningful upside.

A third party has a contractual right to purchase up to an undivided twenty percent of the working interest in the transaction. This third party's right must be exercised concurrent with closing of the transaction.

We have hedged the first five years of oil volume production in conjunction with this transaction using swaps. The average annual prices for these swaps are between $65.15 and $68.04 per Bbl. We hedged the residual natural gas production over a five year period at a weighted average NYMEX equivalent price of approximately $7.70 per MMBTU. An additional two years of anticipated natural gas liquids production have also been hedged.

Oil and Gas Prices

Our results of operations and financial condition are significantly affected by oil and natural gas commodity prices, which can fluctuate dramatically. We sell the majority of our natural gas on contracts which use first of the month (also frequently referred to as bid week) 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 it is produced. Our crude oil is sold on contracts that pay us the average of the posted prices for the period in which the crude oil is sold.

The average Henry Hub bid week natural gas price decreased by four percent and the average NYMEX oil price remained flat between the second quarter and third quarter of 2006. While average quarterly bid week natural gas prices remained relatively flat between the second and third quarters of 2006, both were down substantially relative to the first quarter of 2006. Spot prices weakened materially through the last half of September, which resulted in a Henry Hub bid week price for October 2006 of $4.20 per MMBtu. Although the spot prices at Henry Hub have increased since the end of September, there has been an overall decrease in the 36-month forward strip price for natural gas. For example, the average 36-month strip for Henry Hub was $8.73 per MMBtu at June 30, 2006, and was $7.49 per MMBtu as of September 30, 2006. Most analysts suggest that the primary reasons for this decrease in price are historically high levels of natural gas in storage resulting from mild weather in the last 12 months and less hurricane activity in the Gulf of Mexico this year compared to last year.

Crude oil prices reached an all-time high early in the third quarter of 2006 as ongoing tensions in the Middle East escalated. The price of crude oil then decreased significantly over the course of the quarter as hostilities in the Middle East eased. Consequently, the average NYMEX crude oil price was essentially flat between the second and third quarters of this year. The average crude oil price in the third quarter was $70.48 per barrel. However, included in this price was movement of prices within the quarter. For example, the average price in July was $74.46 per barrel compared to $63.90 per barrel in September. On a percentage basis, the differential for crude oil was consistent throughout the third quarter of 2006. The three year NYMEX strip at the end of the third quarter of 2006 has decreased to $66.84 per Bbl compared to $74.39 per Bbl at the end of July.

While the changes in the quoted NYMEX oil and Henry Hub natural gas prices are generally used as a basis for comparison within the industry, the realized price that we receive for oil and natural gas is effected by quality, energy content, and transportation differentials for these products. We refer to this price as our net realized price and it excludes the effects of hedging. Our realized price is further impacted by the result of our hedging contracts that have settled over the corresponding months. We refer to this price as our net realized price, including the effects of hedging.

	For the Three Months Ended September 30, 2006	For the Nine Months Ended September 30, 2006
Natural Gas (per MMBtu):		
NYMEX price	$ 6.53	$ 7.47
Net realized price	$ 6.41	$ 6.70
Net realized price, including the effects of hedging	$ 7.14	$ 7.44

Crude Oil (per Bbl):				
NYMEX price	$	70.48	$	68.22
Net realized price	$	65.02	$	61.83
Net realized price, including the effects of hedging	$	61.28	$	58.41

Our natural gas price realizations for the three months ended September 30, 2006, were improved by $10.4 million of realized hedging gains while our oil price realization was negatively impacted by $5.6 million of realized hedging losses. For the nine months ended September 30, 2006, our natural gas price realizations were improved by $30.1 million of realized hedging gains and our oil price realization was negatively impacted by $15.3 million of realized hedging losses. Our reported differentials for natural gas in the third quarter of 2006 are improved from the prior quarter. This is due to unanticipated updated information received on gas producing properties operated by others relating to prior quarters, the impact of which benefited us in the third quarter. Overall, we believe we receive natural gas prices similar to those of our competitors and we expect that our differentials will be $0.65 to $0.75 in the fourth quarter of 2006.

Cost Environment

We believe there is a highly dynamic relationship between service costs and commodity prices and that it is not possible to predict when the break-over point of one relative to the other will occur. Increases in rig rates, field service costs, workover costs, and materials prices continue to pressure the exploration and production sector. Cost escalation in the service sector continues to affect our business. Scarcity of equipment and services has compounded this issue in many of our regions, but we are beginning to note instances where equipment and service availability seems to be improving. With the forward commodity price curves softening between ten to twenty percent, we expect that the rate of cost

increases will slow and that a leveling or even a decrease in service costs may follow. That being said, we believe we can not predict the timing of changes in the cost environment. We know that in most cases, a phase of extended commodity price increases is followed by increases in service costs and that extended decreases in prices lead to a decrease in service costs. The concern for the exploration and production industry is the period when commodity prices decline and the costs either continue to escalate or remain at high levels. This period of time is particularly challenging to manage. As a result, we evaluate current economics on an individual investment basis, as part of our normal investment decision process. We have a formal process for establishing our drilling budget, and our prospect inventory and our strong balance sheet give us the flexibility to adjust this budget as additional opportunities arise or as the expected economics of our planned activities change.

As of the current time, our exploration and development budget for 2006 is $492 million which contemplates the current cost environment. The current budget reflects the timing of drilling projects which have been impacted by service availability issues, timing of permitting, and the postponement of selected projects due to unfavorable economics in the current price and cost environment. The acquisition budget reflects oil and gas property acquisitions of approximately $35 million, which have closed through the date of this filing, $16 million of which closed after the end of the third quarter. We anticipate closing on an additional $250 million of property transactions before the end of the calendar year. The Permian acquisition of oil and gas properties solidifies our platform for growth in this core area with an additional inventory of high working interest, low risk drilling opportunities.

Hedging Activities

We have an active hedging program in which we hedge the first two to five years of an acquisition's risked production, as well as a portion of our existing forecast production on a discretionary basis. In the fourth quarter of 2005, we hedged a significant portion of anticipated future production from our currently producing properties using zero-cost collars. These contracts were a supplement to our previous swap and collar contracts. In January 2006, we hedged a portion of specific forecast natural gas production for 2006 and 2007 using swap contracts. Additionally, we hedged anticipated future production in conjunction with the execution of our stock repurchase program in the second quarter of this year. In conjunction with the stock repurchase program, we hedged an amount of reserves that were represented by the proportionate number of total outstanding shares repurchased.

Taking into account all oil and gas production hedge contracts placed through September 30, 2006, we have hedged approximately 10 million Bbls and 77 million MMBtu of our anticipated crude oil production through the year 2011. We have hedged an estimated 60 percent of our remaining 2006 forecast oil production volumes and 35 percent of our remaining 2006 forecast natural gas production volumes using both zero-cost collars and swap contracts. In conjunction with the Permian Basin acquisition, we hedged additional anticipated production for the five years subsequent to closing. The average annual prices for these oil swaps are between $65.15 and $68.04 per Bbl. Although a smaller component of the overall value from the acquisition, we also hedged natural gas liquids covering the first two years and natural gas for the first five years after the acquisition. Using current differentials, we estimate that the break-even NYMEX prices for the natural gas commodities derivatives is approximately $8.39 per MMBtu over the remainder of 2006. For crude oil, we essentially participate in the market from prices of approximately $53 per Bbl to approximately $71 per Bbl. This will become more weighted to the higher end of the range because of the swaps recently executed in conjunction with the acquisition. Below the floor, our realizations should be better than NYMEX pricing and above the ceiling price our realization should be less than NYMEX pricing.

Primarily because of the basis expansion affecting oil in the Rockies, we recorded approximately $433,000 of ineffectiveness related to our derivative contracts in the third quarter of 2006 and $6.2 million related to ineffectiveness was recorded for the nine months ended September 30, 2006. Despite this ineffectiveness, we continue to have adequate correlation to maintain the accounting designation for these derivatives as cash flow hedges. Please see Note 8 — Derivative Financial Instruments in 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.

Share Repurchase Program

During the third quarter of 2006, our Board authorized an increase in the number of shares available for repurchase under the plan by an additional 5,473,182 shares to a total of six million shares. Management plans to continue to evaluate the repurchase of common stock as a part of our business plan. We evaluate the market price of our common stock relative to our assessment of net asset value per share. To the extent the market price is sufficiently below what we believe to be the net asset value per share, we will repurchase shares under the program. As of the end of September 2006, we had 6,000,000 shares remaining for authorized repurchase. In April and May of 2006, we repurchased 3,319,300 shares under the share repurchase program.

Net Profits Plan

Current period cash payments and accruals that have been expensed as compensation costs under the Net Profits Plan total $6.8 million and $20.6 million for the three-month and nine-month periods ended September 30, 2006, respectively. These amounts are slightly lower than originally budgeted due to increased capital spending in existing payout pools, a decrease in the timing of payout for newer pools, and a relative decrease in natural gas prices since the time the 2006 budget was developed. 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.

With respect to the accounting estimate of the liability associated with future estimated payments from our Net Profits Plan, we have recorded $17.4 million of expense for the nine month period ended September 30, 2006. We note that this liability has decreased by $3.7 million from June 30, 2006, to September 30, 2006. This decrease in the quarter is related to the decrease in the overall commodity price environment over the last quarter, as described earlier. While we have forecast that this liability will again increase in the fourth quarter of this year, it is not possible to predict this with certainty due to the impact that commodity prices and reserve estimates have on the valuation of this estimated liability. Based on current projections, we estimate that the total expense for the full year 2006 related to the change in the estimated liability associated with future estimated payments from our Net Profits Plan that will be recorded in the statement of operations will be approximately $28 million. Please see the additional discussion and analysis in the *Comparison of Financial Results and Trends* section below.

The calculation of the estimated liability associated with the Net Profits Plan requires management to prepare an estimate of future amounts payable from the Net Profits Plan. On a monthly basis, we calculate estimates of the payments to be made for each individual pool under the Net Profits Plan. The underlying principal factors for our estimates are forecasted oil and gas production from the properties that comprise each individual pool, price assumptions, cost assumptions, and discount rate. In most cases, the cash flow streams used in these calculations will span more than 20 years. We generally use a 15 percent discount rate to calculate the present value of these future payments, and the resulting amount is recorded as a liability. Commodity prices impact the calculated cash flows during periods after payout and can dramatically affect the timing of the estimated date of payout of the individual pools. Our commodity price assumptions are currently determined from an average of actual prices realized over the prior 24 months together with adjusted NYMEX strip prices for the ensuing 12 months for a total of 36 months of data. This average is supplemented by including the effect of hedge prices for the percentage of forecasted hedged production in the relevant period. 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 ten percent, the liability recorded on the balance sheet at September 30, 2006, would differ by approximately $32 million. A one

percentage point change in the discount rate would result in a change of approximately $7 million. We frequently evaluate the assumptions used in our calculations to evaluate the possible impacts stemming from the current market environment, including current and future oil and gas prices, discount rates, and overall market conditions.

Stock-Based Compensation

On January 1, 2006, we adopted SFAS No. 123R, *Share Based Payments*, which requires the measurement of compensation expense for all stock-based awards made to employees and directors. The stock-based awards specific to us include stock options, employee stock purchases under the Employee Stock Purchase Plan, and restricted stock units granted under the Restricted Stock Plan and future restricted stock units to be granted under the Equity Incentive Compensation Plan. We adopted SFAS No. 123R using the modified prospective transition method. Our consolidated financial statements as of and for the three-months and nine-months ended September 30, 2006, reflect the impact of SFAS No. 123R. Total stock-based compensation expense for the three and nine months ended September 30, 2006, was approximately $2.6 million and $9.2 million, respectively, which included $691,000 and $1.8 million, respectively, of expenses related to stock options and employee stock purchases under the ESPP recognized under SFAS No. 123R. Upon adoption of SFAS No. 123R, we have expensed all costs associated with grants to individuals that do not have a future service requirement due to their existing term of service to us or due to the fact that their age implies that any such awards are immediately vested.

As part of hiring a new senior executive in the second quarter of 2006, we granted a special stock award of 20,000 shares which vested immediately upon commencement of employment. Approximately $728,000 of compensation expense was recorded related to this award. An additional award has been issued whereby the employee may earn an additional 20,000 shares contingent on certain service and performance conditions. The fair value of this award will be recorded to compensation expense over the vesting period based on an assessment of the likelihood of achievement of the performance condition. As of September 30, 2006, approximately $50,000 of compensation expense had been recorded related to this award.

First Nine Months of 2006 Operating and Financial Highlights

In the first nine months of 2006 our net income was $146.5 million or $2.25 per diluted share compared to the first nine months of 2005 income of $100.7 million or $1.55 per diluted share. Production for the first nine months of 2006 was 67.7 BCFE. This represents a three percent increase from the same period a year ago. Per MCFE lease operating expense and transportation expense increased $0.34 to $1.37 as compared to a year ago. The year to date activity increase over the last year's comparable period is due to increased costs and higher levels of workover activity. An increase in commodity prices over the past several years has led to increased levels of drilling and maintenance activity. Production taxes increased $0.04 to $0.54 per MCFE and DD&A, including ARO accretion expense, increased $0.09 to $1.63 per MCFE. We discuss these financial results and trends in more detail below.

In addition to the acquisitions described in the third quarter, we closed on a transaction in May 2006, whereby we exchanged non-core oil and gas properties located in the Uinta Basin for oil and gas properties located in Richland County, Montana. The transaction was structured as an Internal Revenue Code Section 1031 tax-deferred exchange. For financial reporting purposes, the transaction is considered a non-monetary transaction and has been accounted for at estimated fair value, effectively resulting in the exchange being considered two separate transactions: a sale of oil and gas properties and a purchase of oil and gas properties. The exchange of properties resulted in recognition of a book gain of approximately $7 million.

The table below provides information regarding selected production and financial information for the quarter ended September 30, 2006, and the immediately preceding three quarters. Additional details of per MCFE costs are contained later in this section.

	For the Three Months Ended			
	September 30, 2006	June 30, 2006	March 31, 2006	December 31, 2005
	(In millions, except production sales data)			
Production sales (BCFE)	23.2	22.6	22.0	21.9

Oil and gas production revenues, excluding the effects of hedging	$ 188.2	$ 178.0	$ 184.1	$ 231.6
Lease operating expense	$ 30.1	$ 28.3	$ 26.3	$ 23.8
Transportation costs	$ 2.4	$ 2.8	$ 2.9	$ 2.6
Production taxes	$ 12.5	$ 12.2	$ 12.0	$ 16.1
General and administrative expense	$ 9.7	$ 10.4	$ 10.8	$ 9.5
Net income	$ 55.9	$ 40.1	$ 50.5	$ 51.2
Percentage change from previous quarter:				
Production (MCFE)	3%	3%	—%	(5)%
Oil and gas production revenues, excluding the effects of hedging	6%	(3)%	(21)%	14%
Lease operating expense	6%	8%	11%	4%
Transportation costs	(14)%	(3)%	12%	44%
Production taxes	2%	2%	(25)%	20%
General and administrative expense	(7)%	(4)%	14%	(3)%
Net income	39%	(21)%	(1)%	88%

Regional summary and Outlook for the Remainder of 2006

While oil and gas prices remain highly volatile and service costs have continued to increase, we have an inventory of drilling prospects that is attractive in various price and cost environments. We believe we will continue to have access to the drilling rigs we currently operate and are actively seeking an increase in our drilling rig inventory. Adding new rigs may remain a challenge because of the competitive state of the rig market, however we have seen recent indications that the rig market may be softening on a relative basis since rates are holding constant and contract terms seem to be more favorable for producers relative to our experience over the last 24 months. The absolute level of the escalated rig and other service costs will be closely monitored for the remainder of this year and as we develop our budget for 2007, particularly in marginal gas projects where economics have been pressured as natural gas prices declined due to historically high natural gas storage.

The overall acquisition market remains highly competitive, and we believe that we will be successful in transactions where we have a good working knowledge of the area and we are able to evaluate the technical merits of a project. We tend to avoid highly marketed transactions as these appear to be very aggressively bid by acquirers. We continue to maintain a disciplined approach to acquisitions as we actively evaluate acquisition opportunities and the potential impact such transactions will have on net asset value per share. Over the remainder of 2006 we will continue to execute our business plan, including the following:

- *Permian Core Area* — We will close on the $250 million acquisition of oil and gas properties and integrate these operations into our existing regional structure. Additionally, we have been more active on a drilling program in West

Texas which accounts for the increased capital expenditures for the region, on top of the focus on our HJSA prospect and our Parkway Delaware waterflood.

- *Rockies Conventional* — In the third quarter, we successfully completed 16 wells and drilled one dry hole in the Rockies. In the Bakken play, six wells were completed successfully during the quarter with four wells completing and two wells drilling as of quarter-end. We continue to exploit the Bakken using a combination of grass roots drilling and re-entry wells. Despite recent industry reports promoting the prospectivity of the North Dakota Bakken, we have generally been disappointed with the results we see there and are not actively drilling farther east of the Montana/North Dakota state line. We plan to participate in 40 wells in the Bakken in 2006. We also plan to continue taking advantage of our expertise in the Red River formation and plan to participate in approximately 50 wells exploring the potential of a horizontal program in the Madison and Nisku formations as well as exploring the opportunity to drill infill wells in the Bakken in Montana. In the Southern Rockies, we recently secured a rig that will be dedicated to drilling four wells through year end in the Wamsutter region targeting the Almond and Lewis formations through year end. We are also continuing our activity targeting the Tensleep oil zone in the Four Bear, Murphy Dome, Quealy Dome, and Big Sand Draw fields.

- *Rockies — Hanging Woman Basin Coalbed Natural Gas* — As of the date of this filing, we have drilled a total of 330 wells in our Hanging Woman Basin coalbed natural gas project, of which 252 wells are currently producing. We plan to drill over 140 wells during 2006. Current production for the project is approximately 12.2 MMCFD gross, 8.1 MMCFD net.

  We have recently completed two of the horizontal wells planned to test the deeper coals. One or two more horizontal wells are planned this year to test the Roberts and deeper Kendrick coals. Horizontal completion techniques have successfully been used in similar coals in Oklahoma and Australia. Our water discharge permits for these wells have been approved, and dewatering efforts are underway. Gas associated with these wells is expected to show in the next two months. With respect to permitting wells on federal acreage in Montana, the supplemental environmental impact statement required by the Ninth Circuit Court of Appeals is anticipated to be completed in June of 2007. However, Montana continues to issue permits for wells on state and fee acreage. We are also evaluating different development alternatives for this project as a whole including the pattern of drilling, the spacing unit for selected areas of the play and the pace of development.

- *Mid-Continent* — At the Centrahoma field, our horizontal efforts have been focused on the drilling to the Woodford shale formations. We have been operating two rigs in the field and will be adding a third rig in the fourth quarter of 2006. At quarter end, we had completed five wells targeting the Woodford shale formation. The most recent two wells have utilized a refined completion technique that resulted in a significantly higher initial production rate than the previous four wells. We are considering re-fracturing previously drilled horizontal wells in the Woodford utilizing this refined completion technique. In addition to the Woodford formation, we believe there is potential in the Wapanucka limestone and the Cromwell sandstone. We have recently increased our acreage position at Centrahoma to 30,000 net, 46,000 gross acres. We plan to participate in 39 Centrahoma wells in 2006, most of which are horizontal.

  The Paggi Broussard #2 well, which is an offset well to the Paggi Broussard #1 well at our Constitution field, began production in July 2006. As of quarter end, the Paggi Broussard #2 was producing at a gross production rate of 28.0 MMCF and 1,500 Bbls of condensate per day.

In Northeast Mayfield, we successfully completed six wells during the third quarter. Six wells were completing and three wells were drilling as of the end of the third quarter. We operate two drilling rigs in the field. As the Atoka/Granite Wash program at Northeast Mayfield is sensitive to natural gas prices, we hedged approximately two-thirds of the production of our anticipated 2006 drilling program at the beginning of the year to protect our economics. We continue to evaluate the economics of proposed wells before drilling to ensure the wells meet minimum economic thresholds, although non-economic factors such as rig utilization for operated rigs are also considered in that decision.

· *ArkLaTex* — During the third quarter, we successfully completed 25 wells out of 27 attempts in the region. We continue to see improved results from refined stimulation techniques at the Spider field. There are three wells planned in the Spider field in the last three months of the year. In Elm Grove, development continues to advance southward onto acreage where we have higher working interests. Sixteen wells are budgeted in Elm Grove for the last three months of the year where two to three non-operated rigs are running at any one time. Additionally, initial results from recompletions using coiled tubing fracturing treatments targeting the upper Cotton Valley and Hosston formations appear encouraging. Based on preliminary discussion with the operator of this field, there appears to be a significant amount of activity in the foreseeable future at Elm Grove.

· *Gulf Coast* — We have had five successes in six attempts through the end of the quarter in our low to moderate risk Direct Hydrocarbon Indicator exploration program in the Gulf Coast. We are utilizing our DHI expertise to advance our inventory of projects. For the remainder of the year, our activities will focus on bringing on line the discoveries found this year. We have as many as three additional DHI prospects that could be drilled this year, depending on rig and service availability. At Judge Digby we had two successful wells and two successful re-completions this year. However, no more activity is planned for 2006 in the field. On our fee lands, a significant royalty well has been shut in for several months due to mechanical issues in the well bore. We do not anticipate production will be back on line until early 2007.

· Our revised production guidance for the full year 2006 is forecast to be between 92 BCFE and 93 BCFE, which exceeds 2005 reported production of 87.4 BCFE by approximately six percent. This growth is being driven primarily through drilling, workover and recompletion activities.

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

Selected Operations Data (In Thousands, Except Price and Per MCFE Amounts):

	For the Three Months Ended September 30, 2006	For the Three Months Ended September 30, 2005	% of Change Between Periods	For the Nine Months Ended September 30, 2006	For the Nine Months Ended September 30, 2005	% of Change Between Periods
Net production volumes						
Natural gas (Mcf)	14,182	13,894	2%	40,994	39,125	5%
Oil (Bbl)	1,496	1,534	(2)%	4,454	4,396	1%
MCFE (6:1)	23,160	23,100	—%	67,717	65,502	3%
Average daily production						
Natural gas (Mcf per day)	154,154	151,021	2%	150,162	143,315	5%
Oil (Bbls per day)	16,265	16,678	(2)%	16,314	16,103	1%
MCFE per day (6:1)	251,742	251,090	—%	248,046	239,932	3%
Oil & gas production revenues(1)						
Gas production	$ 101,294	$ 108,847	(7)%	$ 304,854	$ 272,958	12%
Oil production	91,693	85,856	7%	260,135	220,010	18%
Total	$ 192,987	$ 194,703	(1)%	$ 564,989	$ 492,968	15%
Oil & gas production expense						
Lease operating expenses	$ 30,109	$ 22,915	31%	$ 84,733	$ 62,313	36%
Transportation costs	2,371	1,758	35%	7,966	5,451	46%
Production taxes	12,518	13,398	(7)%	36,791	32,654	13%
Total	$ 44,998	$ 38,071	18%	$ 129,490	$ 100,418	29%
Average realized sales price(1)						
Natural gas (per Mcf)	$ 7.14	$ 7.83	(9)%	$ 7.44	$ 6.98	7%
Oil (per Bbl)	$ 61.28	$ 55.95	10%	$ 58.41	$ 50.05	17%
Per MCFE Data:						
Average net realized price(1)	$ 8.33	$ 8.43	(1)%	$ 8.34	$ 7.53	11%
Lease operating expense	(1.30)	(0.99)	31%	(1.25)	(0.95)	32%
Transportation costs	(0.10)	(0.08)	25%	(0.12)	(0.08)	50%
Production taxes	(0.54)	(0.58)	(7)%	(0.54)	(0.50)	8%
General and administrative	(0.42)	(0.42)	—%	(0.46)	(0.35)	31%
Operating profit	$ 5.97	$ 6.36	(6)%	$ 5.97	$ 5.65	6%
Depletion, depreciation and amortization, and abandonment liability accretion	$ 1.72	$ 1.60	7%	$ 1.63	$ 1.54	6%

(1) Includes the effects of our hedging activities

The preceding table is presented as a summary of information relating to those key indicators of financial condition and operating performance that we believe to be most important. We present per MCFE information since we use this information to evaluate our performance relative to our peers and to measure trends that we believe require analysis. Our period to period comparison of financial results presented later provides additional details for the per MCFE differences between reported periods.

We expect oil and gas production expenses to generally correspond with oil and gas prices. Accordingly, as realized prices change, production taxes will change directionally. Lease operating expense will be impacted by competition for scarce resources in the oil and gas service sector. We have seen increases in seismic data costs from period to period. Depreciation, depletion, and amortization will increase due to the higher costs associated with finding and acquiring crude oil and natural gas. The remaining information in the table relates to information we have provided in operations update press releases and is intended to supplement the discussion above.

	For the Three Months Ended September 30,		% of Change Between Periods	For the Nine Months Ended September 30,		% of Change Between Periods
	2006	2005		2006	2005	
Basic Weighted-Average Shares Outstanding	55,398	56,640	(2)%	56,564	56,941	(1)%
Diluted Weighted-Average Shares Outstanding	64,926	66,738	(3)%	66,332	66,847	(1)%
Basic Net Income Per Common Share	$ 1.01	$ 0.48	110%	$ 2.59	$ 1.77	46%
Diluted Net Income Per Common Share	$ 0.88	$ 0.42	110%	$ 2.25	$ 1.55	45%

Overview of Liquidity and Capital Resources

Financial Information (In Thousands, Except Per Share Amounts):

	September 30, 2006	December 31, 2005	% of Change Between Periods
Working Capital	$ 26,710	$ 4,937	441%
Long-Term Debt	$ 165,956	$ 99,885	66%
Stockholders' Equity	$ 686,414	$ 569,320	21%

Including the effect of the $250 million oil and gas property acquisition that is scheduled to close by December 15, 2006, we believe that we have sufficient liquidity and capital resources to execute our business plans for the foreseeable future.

Sources of Cash

Our primary sources of liquidity are the cash provided by operating activities and debt financing. We believe that we can access capital markets if needed, although we have no current plans to do so.

Our Current Credit Facility

We have a $500 million credit facility agreement with Wachovia Bank, Wells Fargo Bank, and eight other participating banks. This credit facility has a borrowing base currently set at $900 million, and we have elected a commitment amount of $200 million. We anticipate increasing our commitment amount in early December 2006 in order to fund the $250 million acquisition of oil and gas properties. The credit agreement was entered into on April 7, 2005 and has a maturity date of April 7, 2010. We must comply with certain financial and non-financial covenants, and we are currently in compliance with all of those covenants. Interest and commitment fees are accrued based on the borrowing base utilization percentage. Euro-dollar loans accrue interest at LIBOR plus the applicable margin from the utilization table, and Alternate Base Rate loans accrue interest at prime plus the applicable margin from the utilization table. This table is located in Note 7 of Part I, Item 1 of this report. Borrowings under the facility are secured by the majority of our oil and gas properties and a pledge of the common stock of our material subsidiary companies.

Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the consolidated statements of operations. Our loan balance of $66 million on September 30, 2006, was comprised of $64 million of Euro-dollar based borrowing and $2 million of ABR borrowing. As of November 1, 2006, our total outstanding borrowings under the credit facility had been increased to $76 million of Euro-dollar based borrowing and $17 million of ABR borrowing. As of September 30, 2006, we had a cash and short-term investment balance of $2.5 million.

Our weighted-average interest rate paid in the first nine months of 2006 was7.9 percent and included fees paid on the unused portion of the credit facility aggregate commitment amount, amortization of deferred financing costs, amortization of the contingent interest embedded derivative associated with the Convertible Notes, and the effects of interest rate swaps.

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 nine months of 2006 we spent $303.9 million on oil and gas exploration and development and acquisitions using cash flows from operations. We also made cash payments for income taxes of $29.8 million. We estimate that approximately 20 to 25 percent of our total income tax expense for 2006 will be payable on a current basis and we expect to make a refund claim for a significant portion of our current year cash payments immediately after year end.

Through the nine months ended September 30, 2006, we have repurchased a total of3,319,300 shares of our common stock for a total of $123.1 million. We evaluate the market price of our common stock relative to our own assessment of net asset value per share. 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.

During 2006 we have paid $2.9 million in dividends to our stockholders. We have also declared and accrued $2.7 million for dividends to be paid in November

2006. Our intention is to continue to make dividend payments for the foreseeable future subject to our future cash flows, our financial condition, capital requirements, possible credit facility covenants, and other currently unexpected factors that may arise.

The following table presents amounts and percentage changes in cash flows between the nine-month periods ended September 30, 2006, and September 30, 2005. 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 Nine Months Ended September 30, 2006	For the Nine Months Ended September 30, 2005	Change	Percent Change
	(In thousands)			
Net cash provided by operating activities	$ 317,549	$ 302,146	$ 15,403	5%
Net cash used in investing activities	$ (302,648)	$ (273,272)	$ (29,376)	11%
Net cash used in financing activities	$ (28,810)	$ (8,695)	$ (20,115)	231%

Analysis of cash flow changes between the nine months ended September 30, 2006, and September 30, 2005

Operating activities. Cash received from oil and gas sales, including the effects of hedging, increased $158.9 million to $614.6 million for the nine-month period ended September 30, 2006, from $455.7 million for the nine-month period ended September 30, 2005. This increase was the result of a three percent increase in production and an 11 percent increase in our net realized prices between the two periods. Net cash payments made for income taxes decreased $6.3 million. The future operating cash flow impact on the hedged production using zero-cost collars will have the effect of reducing the sensitivity to movements in oil and gas prices to the extent prices fall outside of the collar range.

Investing activities. Total cash outflow for 2006 capital expenditures, as adjusted for accruals, increased $89.1 million, or 44 percent, due to increased drilling activity. Cash outflow related to the acquisition of oil and gas properties decreased $63.5 million, or 86 percent, due to increased competitiveness in the acquisition market, compared to the same period in 2005.

Financing activities. We received $7.8 million more from the sale of our common stock in 2006 due to the increases in stock option exercises and shares issued under the ESPP. We had a $15.1 million increase in income tax benefit from the exercise of stock options, and we received $51.7 million more in proceeds from our credit facility in the first nine months of 2006 compared to the same period in 2005. These amounts were offset by an increase of $94.8 million spent in order to repurchase common stock on the open market under our stock repurchase plan in the first nine months of 2006 compared with the same period in 2005.

Capital Expenditures Forecast

We use our capital resources primarily for the exploration and development of oil and gas properties and for acquisitions. Our capital expenditure forecast for drilling is $492 million this year, excluding non-cash asset retirement obligation relating to capitalized assets. Anticipated ongoing 2006 exploration and development expenditures and budgeted gross wells for each of our core areas are presented in the following table. The timing of drilling and completion of wells is variable and will differ from these estimates.

	Exploration and Development Expenditures (In millions)	Gross Well Count
Mid-Continent region	$ 176	137
Rocky Mountain region	132	175
ArkLaTex region	74	97
Gulf Coast region	59	13
Coalbed natural gas	32	147
Permian Basin region	19	32
	$ 492	601

Including the $250 million oil and gas property acquisition, which we expect to close by December 15, 2006, we anticipate a total of $285 million of acquisitions for 2006. We regularly review our capital expenditure budget to reflect changes in current and projected cash flows, acquisition opportunities, drilling opportunities, debt requirements, regional cost inflation, and other factors. The above allocations are subject to change based on these factors.

The following table sets forth certain information regarding the costs incurred by us in our oil and gas property acquisition, exploration, and development activities, whether capitalized or expensed.

	For the Nine Months Ended September 30, 2006	For the Nine Months Ended September 30, 2005
	(In thousands)	
Development costs	$ 248,168	$ 179,222
Exploration costs	100,068	51,180
Acquisitions:		
Proved	21,660	83,783
Unproved	—	2,849
Leasing activity	19,597	10,696
Total, including asset retirement obligation	$ 389,493	$ 327,730

The costs we incurred for capital and exploration activities during the first nine months of 2006 increased $61.8million or 19 percent compared to the same period in 2005. Excluding acquisitions, our development and exploration spending has increased $117.8 million compared to the same nine-month period in the prior year.

We believe that internally generated cash flows in addition to the cash available under our credit facility will be sufficient to fund our planned operational, 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 acquisitions we make. 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 may lead to changes in funding requirements for future development.

Financing alternatives

The debt and equity financing capital markets remain attractive to energy companies that operate in the exploration and production segment. This is a result of strong commodity prices and the general strength reflected in the balance sheets of the companies in this segment. As our combined cash balance and availability under our existing credit facility are significant, we are not currently considering accessing the capital markets in 2006. If additional development or acquisition opportunities arise that exceed our currently available resources, we may consider other forms of financing, including the public offering or private placement of equity or debt securities.

Commodity Price Risk and Interest Rate Risk

We are exposed to market risks, including the effects of changes in oil and gas commodity prices and changes in interest rates as discussed below and under the captions *Summary of Oil and Gas Production Hedges in Place* and *Summary of Interest Rate Hedges in Place.* Since we produce and sell natural gas and crude oil, our financial results are affected when prices for these commodities fluctuate. In order to reduce the impact of fluctuations in commodity prices, we enter into hedging transactions. 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 convertible notes, but do affect the fair value of that debt. We anticipate that all hedge and derivative contract transactions will occur as expected.

There has been no material change to the natural gas and crude oil price sensitivity analysis previously disclosed. Please see the corresponding section under Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2005.

Summary of Oil and Gas Production Hedges in Place

Our oil and natural gas derivative contracts include swap and collar arrangements. All contracts are entered into for other than trading purposes.

Our net realized oil and gas prices are impacted by hedges we have placed on future forecasted production. We enter into hedges of existing production around the time we make acquisitions of producing oil and gas properties. Our intent has been to lock in a significant portion of an equivalent amount of existing production to the prices we used to evaluate the risked economics of our acquisition. We also hedge a portion of our forecasted production on a discretionary basis.

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 per unit of production 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 only if the index price is above the contracted ceiling price.

The following tables describe the volumes, average contract prices, and fair value of contracts we have in place as of September 30, 2006. As of September 30, 2006, our hedged positions totaled 10 million Bbls and 77 million MMBTU of anticipated future production through 2011. This table does not include any swaps entered into subsequent to September 30, 2006, associated with the Permian Basin oil and gas property acquisition described earlier. We seek to minimize basis risk and therefore, the

majority of our oil contracts are indexed to NYMEX prices and our gas contracts to various regional index prices associated with pipelines in proximity to our areas of gas sales.

Oil Contracts

Oil Swaps

Contract Period	Volumes (Bbl)		Weighted-Average Contract Price (Per Bbl)		Fair Value at September 30, 2006 Asset/(Liability) (In thousands)
Fourth quarter 2006					
NYMEX WTI	172,686	$	52.32	$	(2,015)
IF Bow River	30,000	$	37.54		(178)
First quarter 2007					
NYMEX WTI	112,410	$	47.73		(2,074)
IF Bow River	30,000	$	37.42		(179)
Second quarter 2007					
NYMEX WTI	98,072	$	45.89		(2,082)
IF Bow River	34,000	$	39.74		(317)
Third quarter 2007					
NYMEX WTI	93,684	$	44.58		(2,148)
IF Bow River	12,000	$	39.86		(142)
Fourth quarter 2007					
NYMEX WTI	90,620	$	44.49		(2,090)
2008					
NYMEX WTI	84,000	$	65.30		(280)

2009			
NYMEX WTI	36,000	$ 70.00	77
All oil swap contracts			$ (11,428)

Oil Collars

Contract Period	NYMEX WTI Volumes (Bbl)	Weighted-Average Floor Price (Per Bbl)	Weighted-Average Ceiling Price (Per Bbl)	Fair Value at September 30, 2006 Asset/(Liability) (In thousands)
Fourth quarter 2006	739,000	$ 52.23	$ 72.76	$ (256)
First quarter 2007	756,000	$ 51.60	$ 72.76	(1,093)
Second quarter 2007	736,000	$ 51.59	$ 72.77	(1,747)
Third quarter 2007	716,000	$ 51.58	$ 72.78	(2,149)
Fourth quarter 2007	689,000	$ 51.58	$ 72.81	(2,284)
2008	1,668,000	$ 50.00	$ 69.82	(8,856)
2009	1,526,000	$ 50.00	$ 67.31	(9,460)
2010	1,367,500	$ 50.00	$ 64.91	(8,289)
2011	1,236,000	$ 50.00	$ 63.70	(6,804)
All oil collars				$ (40,938)

Gas Contracts

Gas Swaps

Contract Period	Volumes (MMBtu)	Weighted-Average Contract Price (Per MMBtu)	Fair Value at September 30, 2006 Asset/(Liability) (In thousands)
Fourth quarter 2006			
IF ANR OK	1,020,000	$ 9.06	$ 4,751
IF PEPL	1,070,000	$ 6.78	2,008
IF CIG	1,080,000	$ 6.47	2,186
IF NGPL	550,000	$ 10.24	2,859
IF Center Point	160,000	$ 5.71	254
IF HSC	80,000	$ 7.93	189
First quarter 2007			
IF ANR OK	440,000	$ 11.05	1,778
IF PEPL	960,000	$ 9.04	2,013
IF CIG	1,050,000	$ 8.13	1,714
IF NGPL	890,000	$ 10.92	3,501
IF HSC	110,000	$ 9.43	243
Second quarter 2007			
IF ANR OK	420,000	$ 8.35	744
IF PEPL	960,000	$ 7.63	1,062
IF CIG	1,050,000	$ 6.88	1,327
IF NGPL	840,000	$ 8.23	1,415
IF HSC	120,000	$ 8.00	117
Third quarter 2007			
IF ANR OK	400,000	$ 8.39	615
IF PEPL	960,000	$ 8.05	1,204
IF CIG	870,000	$ 6.89	891
IF NGPL	800,000	$ 8.46	1,296
IF HSC	140,000	$ 8.37	149
Fourth quarter 2007			
IF ANR OK	380,000	$ 8.92	634
IF PEPL	960,000	$ 8.69	1,399
IF CIG	780,000	$ 7.56	778
IF NGPL	750,000	$ 8.88	1,227
IF HSC	160,000	$ 8.78	175
2008			
IF CIG	3,120,000	$ 7.48	2,317
IF PEPL	3,840,000	$ 8.51	5,254

IF HSC	300,000	$	8.84	294
2009				
IF CIG	1,710,000	$	7.79	1,181
IF PEPL	1,920,000	$	8.35	1,807
All gas swap contracts				$ 45,382

Gas Collars

Contract Period	Volumes (MMBtu)		Weighted-Average Floor Price (Per MMBtu)		Weighted-Average Ceiling Price (Per MMBtu)		Fair Value at September 30, 2006 Asset/(Liability) (In thousands)
Fourth quarter 2006							
IF ANR OK	100,000	$	7.00	$	9.82	$	342
IF PEPL	655,000	$	7.90	$	14.07		1,935
IF CIG	390,000	$	7.23	$	12.51		1,137
IF HSC	400,000	$	8.10	$	14.20		1,141
NYMEX Henry Hub	270,000	$	8.63	$	15.54		812
First quarter 2007							
IF PEPL	2,180,000	$	8.23	$	14.71		4,102
IF CIG	830,000	$	7.34	$	13.48		1,226
IF HSC	350,000	$	8.31	$	14.42		610
NYMEX Henry Hub	220,000	$	9.00	$	16.15		410
Second quarter 2007							
IF PEPL	2,040,000	$	7.03	$	9.19		1,965
IF CIG	800,000	$	6.41	$	7.87		859
IF HSC	320,000	$	7.66	$	9.10		312
NYMEX Henry Hub	190,000	$	8.00	$	9.45		202
Third quarter 2007							
IF PEPL	1,920,000	$	7.02	$	9.24		1,506
IF CIG	760,000	$	6.41	$	7.87		668
IF HSC	300,000	$	7.66	$	9.10		228
NYMEX Henry Hub	200,000	$	8.00	$	9.45		176
Fourth quarter 2007							
IF PEPL	1,820,000	$	7.00	$	9.28		823
IF CIG	730,000	$	6.41	$	7.87		243
IF HSC	270,000	$	7.66	$	9.10		113
NYMEX Henry Hub	180,000	$	8.00	$	9.45		42
2008							
IF PEPL	6,600,000	$	6.28	$	9.42		1,125
IF CIG	2,880,000	$	5.60	$	8.72		(146)
IF HSC	960,000	$	6.57	$	9.70		7
NYMEX Henry Hub	480,000	$	7.00	$	10.57		47
2009							
IF PEPL	5,510,000	$	5.30	$	9.25		(1,615)
IF CIG	2,400,000	$	4.75	$	8.82		(1,114)
IF HSC	840,000	$	5.57	$	9.49		(225)
NYMEX Henry Hub	360,000	$	6.00	$	10.35		(51)
2010							
IF PEPL	4,945,000	$	5.31	$	7.61		(3,480)
IF CIG	2,040,000	$	4.85	$	7.08		(1,791)
IF HSC	600,000	$	5.57	$	7.88		(354)
NYMEX Henry Hub	240,000	$	6.00	$	8.38		(121)
2011							
IF PEPL	4,225,000	$	5.31	$	6.51		(3,415)
IF CIG	1,800,000	$	5.00	$	6.32		(1,713)
IF HSC	480,000	$	5.57	$	6.77		(385)
NYMEX Henry Hub	120,000	$	6.00	$	7.25		(85)
All gas collars						$	5,536

Please see 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 Hedges in Place

We have various interest rate derivative contracts which are represented by offsetting trades that have fixed the future payments under these contracts. The fair value of the interest rate derivatives was a liability of $255,000 as of September 30, 2006. We recorded a net derivative gain in the consolidated statements of operations of $128,000 for the three-month period ended September 30, 2006, compared with a net gain of $132,000 for the same period in 2005, from mark-to-market adjustment for these derivatives. Comparative amounts for the nine-month periods ended September 30, 2006, and 2005, were a net derivative gain of $391,000 and a net derivative loss of $344,000, respectively. These derivatives do not qualify for fair value hedge treatment under SFAS No. 133 and related pronouncements.

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 rate 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 floating-rate debt of $66 million outstanding as of September 30, 2006 and our fixed rate debt outstanding at this same date was $100 million associated with the Convertible Notes. Based on the character of our debt outstanding as of the end of the period, we do not believe there is any cash flow impact that could result from a change in interest rates.

Schedule of Contractual Obligations

The following table summarizes our future estimated principal payments and minimum lease payments for the periods specified (in millions):

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-Term Debt	$ 169.1	$ —	$ —	$ 66.0	$ 103.1
Operating Leases	9.7	2.6	4.9	1.5	0.7
Other Long-Term Liabilities	30.9	13.2	9.1	6.3	2.3
Total	$ 209.7	$ 15.8	$ 14.0	$ 73.8	$ 106.1

For purposes of the table we assume that the holders of our Convertible Notes will not exercise the conversion feature. If the holders do exercise their conversion feature, we will not have to repay the $100 million, and our common shares outstanding will increase by 7,692,307 shares.

This table includes our 2006 estimated pension liability payment of approximately $1.6 million expected to be paid in the second quarter of 2007, but excludes the remaining unfunded portion of our estimated pension liability of $1.5 million since we cannot determine with accuracy the timing of future payments.

The table also includes future estimated net oil and natural gas derivative payments of $20.9 million based on futures market prices as of September 30, 2006. This amount excludes estimated oil and natural gas receipts of $61.4 million. The net of these two amounts of $40.5 million represents the intrinsic value of our swap and collar arrangements and differs in amount from our recorded fair value, which as of September 30, 2006, was a net liability of $1.4 million. Both the intrinsic value and fair value will change as oil and natural gas commodity prices change. Please refer to the discussion above under the caption *Summary of Oil and Gas Production Hedges in Place* in Part I, Item 2, Management's Discussion and Analysis of Financial Condition and Results of Operations and to Note 8 — Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding our oil and gas hedges.

The table does not include estimated payments associated with our Net Profits Plan. We record a liability for the estimated future payments. However, predicting the precise timing and amount of the liability payments is contingent upon realized pricing, costs, and production from the underlying oil and gas properties. We have excluded asset retirement obligations because we are not able to precisely predict the timing for these amounts. The Net Profits Plan, pension liabilities, and asset retirement obligations are discussed in Note 7, Note 8, and Note 9, respectively, of Part IV Item 15 of our Form 10-K for the year ended December 31, 2005, and also in Note 5, Note 9, and Note 10, respectively, of Part I, Item 1 of this report.

Four leases for office space will expire in year one and two office space lease will expire in year two. Estimated costs to replace these leases are not included in the table above.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet financing other than operating leases, nor do we have any unconsolidated subsidiaries.

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, 2005, and to the notes to our consolidated financial statements included in Part I, Item 1 of this report.

Additional Comparative Data in Tabular Form:

Oil and gas production revenues	Change Between the Three Months Ended September 30, 2006, and 2005	Change Between the Nine Months Ended September 30, 2006, and 2005
Increase (decrease) in oil and gas production revenues, net of hedging (in thousands)	$ (1,716)	$ 72,021
Components of Revenue Increases (Decreases):		
Natural Gas		
Realized price change per Mcf	$ (0.69)	$ 0.46
Realized price percentage change	(9)%	7%

Production change (MMcf)	288	1,869
Production percentage change	2%	5%
Oil		
Realized price change per Bbl	$ 5.33	$ 8.36
Realized price percentage change	10%	17%
Production change (MBbl)	(38)	58
Production percentage change	(2)%	1%

Our Product Mix as a Percentage of Total Oil and Gas Revenue and Production:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2006	2005	2006	2005
Revenue				
Natural gas	52%	56%	54%	55%
Oil	48%	44%	46%	45%
Production				
Natural gas	61%	60%	61%	60%
Oil	39%	40%	39%	40%

Information Regarding the Components of Exploration Expense:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
Summary of Exploration Expense (in millions)	2006	2005	2006	2005
Geological and geophysical expenses	$ 1.8	$ 1.4	$ 6.1	$ 4.9
Exploratory dry hole expense	0.4	0.4	4.0	2.5
Overhead and other expenses	7.6	8.9	25.8	20.1
Total	$ 9.8	$ 10.7	$ 35.9	$ 27.5

Information Regarding the Effects of Oil and Gas Hedging Activity:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2006	2005	2006	2005
Natural Gas Hedging				
Percentage of gas production hedged	47%	22%	42%	22%
Natural gas MMBtu hedged	7.1 million	3.2 million	18.3 million	9.0 million
Increase (decrease) in gas revenue	$ 10.4 million	$ (2.8 million)	$ 30.1 million	$ 929,000
Average realized gas price per Mcf before hedging	$ 6.41	$ 8.03	$ 6.70	$ 6.95
Average realized gas price per Mcf after hedging	$ 7.14	$ 7.83	$ 7.44	$ 6.98
Oil Hedging				
Percentage of oil production hedged	64%	23%	67%	19%
Oil volumes hedged (MBbl)	962	352	2,987	853
Decrease in oil revenue	$ (5.6 million)	$ (5.7 million)	$ (15.3 million)	$ (9.9 million)
Average realized oil price per Bbl before hedging	$ 65.02	$ 59.66	$ 61.83	$ 52.30
Average realized oil price per Bbl after hedging	$ 61.28	$ 55.95	$ 58.41	$ 50.05

Comparison of Financial Results and Trends between the Quarters ended September 30, 2006, and 2005

Oil and gas production revenue. Average net daily production increased to 251.7 MMCFE per day for the third quarter of 2006, compared with 251.1 MMCFE per day for the same quarter in 2005. The following table presents specific components that contributed to the increase in revenue between the two quarters:

	Average Net Daily Production Added (MMCFE)	Oil and Gas Revenue Added (In millions)	Production Costs Added (In millions)
Williston Basin Middle Bakken Play	2.9	$ 3.5	$ 0.9
Other wells completed in 2005 and 2006	47.0	7.6	2.2
Wold acquisition	5.1	4.1	2.2
Other acquisitions	3.1	2.9	0.2
Total	58.1	$ 18.1	$ 5.5

The revenue increases in this table also reflect the difference in oil and gas prices received between the comparable periods. The production increases are offset by natural declines in production from older properties to result in the net increase in production between the quarters presented. Additional production costs reflect increases resulting from inflation and competition for resources.

Oil and gas production expense. Total production costs increased $6.9 million, or 18 percent, to $45.0 million for the third quarter of 2006 from $38.1 million in the comparable period of 2005. Total oil and gas production costs per MCFE increased $0.29 to $1.94 for the third quarter of 2006, compared with $1.65 for the same quarter in 2005. This increase is comprised of the following:

- A $0.05 decrease in overall production taxes which was comprised of a $0.06 decrease in the Rockies due to a decrease in production which was partially offset by increases in production taxes in our other regions;

- A $0.03 increase in overall transportation cost which was comprised of a $0.02 increase in the Rocky Mountain region and a $0.01 increase in the Mid-Continent region;
- A $0.18 increase in recurring LOE related to a continued increase in costs for oil and gas service sector resources; and
- A $0.13 overall increase in LOE relating to workover costs, due to a significant increase in workover activity in the Rockies.

General and administrative. General and administrative expenses remained relatively unchanged, decreasing to $9.7 million for the third quarter of 2006, compared with $9.8 million for the comparable period of 2005.

G&A per MCFE for the third quarter of 2006 also remained flat at $0.42 per MCFE compared to the same quarter in 2005. A12 percent increase in employee count has contributed to an increase in base employee compensation of approximately 19 percent, or $900,000, between the third quarter of 2006 and the third quarter of 2005. The current period realized expense associated with the Net Profits Plan has increased by $600,000 in 2006 compared with the same quarter in 2005. The increase in Net Profits Plan payments is the result of higher oil prices, which has the effect of increasing the absolute amount of payments as well as accelerating the time it takes for pools to reach payout status. As of the end of the third quarter 16 of our 19 pools are currently in payout status. No additional pools are expected to reach payout during 2006. Despite the increase in our employee count, G&A remained flat due to a lower accrued cash bonus and RSU component. A decrease in the estimated bonus percentage also resulted in a decrease in the cash bonus expense of approximately $2.5 million to approximately $700,000 for the quarter ended September 30, 2006, compared with $3.2 million for the quarter ended September 30, 2005.

RSU bonus expense is approximately $1.4 million lower for the third quarter of 2006 than in the same quarter in 2005. The decrease is due to an overall decrease in our estimated bonus percentage. This amount is also affected by the increase in amortization of expense associated with stock-based compensation expense. We are now recording expense covering four periods of RSU grants compared with only three grants at this same time last year. This increase is offset by a decrease in RSU bonus expense for the third quarter ended September 30, 2006, compared with the same period in 2005, which reflects an evaluation of our overall performance based on our internal analysis of reserve replacement, production, and net asset value per share growth factors. As a result of the implementation of SFAS No. 123R on January 1, 2006, we recorded approximately $700,000 of compensation expense in the third quarter of 2006 related to the fair value of stock options granted in prior years. No compensation expense for stock options was recorded in periods prior to the adoption of SFAS No. 123R.

The above amounts combined with a net $1.2 million increase in other G&A expense, including payroll tax and 401(k) contribution expense, were offset by a $1.3 million decrease in the amount of G&A that was allocated to exploration expense due to the aforementioned incentive plan decreases and a $900,000 increase in COPAS overhead reimbursements. COPAS overhead reimbursements from operations increased due to an increase in our operated well count from our drilling program.

Exploration Expense. Exploration expense decreased approximately $900,000, or nine percent, to $9.8 million for the third quarter of 2006, compared with $10.7 million for the comparable period of 2005. The decrease is partially due to an approximate $1.3 million decrease in compensation allocated to exploration expense related to the above described decrease in cash bonus expense. This decrease is partially offset by a $400,000 increase in geological and geophysical expense.

Change in Net Profits Plan Liability. For the third quarter of 2006, this non-cash expense was a benefit of $3.7 million compared to an expense of $54.9 million for the same quarter in 2005. Each quarter's calculation relates to the specific circumstances of the quarter. The direction of commodity price change in the third quarter of 2006 was downward, compared to the significant increase realized in the third quarter of 2005. 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.

Income taxes. Income tax expense totaled $29.3 million for the third quarter of 2006 and $15.0 million for the third quarter of 2005 resulting in effective tax rates of 34.4 percent and 35.4 percent, respectively. The effective rate change from 2005 reflects changes in the mix of the highest marginal state tax rates as a result of enacted Texas margin tax legislation, acquisition and drilling activity and also reflects other permanent differences including differing estimated effects between years of the domestic production activities deduction, estimated percentage depletion and the possible impact of state income taxes.

Comparison of Financial Results and Trends between the nine months ended September 30, 2006 and 2005

Oil and gas production revenue. Average net daily production increased three percent to 248.0 MMCFE per day for the nine months ended September 30, 2006, compared with 239.9 MMCFE per day for the nine months ended September 30, 2005. The following table presents specific components that contributed to the increase in revenue between the two periods:

	Average Net Daily Production Added (MMCFE)	Oil and Gas Revenue Added (In millions)	Production Costs Added (In millions)
Williston Basin Middle Bakken Play	3.3	$ 11.7	$ 2.0
Other wells completed in 2005 and 2006	43.8	50.1	7.8
Wold acquisition	5.3	11.9	6.5
Other acquisitions	1.3	3.7	0.2
Total	53.7	$ 77.4	$ 16.5

The revenue increases in this table also reflect the difference in oil and gas prices received between the comparable periods. The production increases are offset by natural declines in production from older properties resulting in the net increase in production between the periods presented. Additional production costs reflect increases resulting from inflation and competition for resources.

Oil and gas production expense. Total production costs increased $29.1 million, or 29 percent, to $129.5 million for the nine months ended September 30, 2006, from $100.4 million for the nine months ended September 30, 2005. Total oil and gas production costs per MCFE increased $0.38 to $1.91 for the nine months ended September 30, 2006, compared with $1.53 for the nine months ended September 30, 2005. This increase is comprised of the following:

- A $0.05 increase in production taxes, comprised mainly of a $0.04 increase in our Mid-Continent region resulting from higher natural gas revenues;
- A $0.03 increase in overall transportation cost which was comprised of a $0.04 increase in the Rocky Mountain region that was partially offset by decreases in the other regions;
- A $0.17 increase in recurring LOE related to continued increases in costs for oil and gas service sector resources; and
- A $0.13 overall increase in LOE relating to workover charges, due to a $0.12 increase in workover expense in the Rockies, as well as single-well workover costs in the Mid-Continent and Gulf Coast regions.

General and administrative. General and administrative expenses increased $7.7 million, or 33 percent, to $30.9 million for the nine months ended September 30, 2006, compared with $23.2 million for the nine months ended September 30, 2005.

G&A increased $0.11 to $0.46 per MCFE for the nine months ended September 30, 2006 compared to $035 per MCFE for the nine months ended September 30, 2005 as G&A grew at a faster rate than the three percent increase in production. A 12 percent increase in employee count has contributed to an increase in base employee compensation of approximately 18 percent, or $2.6 million, between the nine-month period of 2006 and the nine-month period of 2005. Oil and gas price increases have triggered additional Net Profits Plan payouts and have increased the amounts payable to plan participants. Consequently, the current period realized expense associated with the Net Profits Plan has increased by $6.9 million in 2006 compared with the same period in 2005. Despite our increased employee count, our G&A remained flat due to a lower accrued cash bonus and RSU component. Furthermore, the decrease in the bonus percentage resulted in a decrease in the accrued cash bonus expense of $1.4 million to $3.4 million for the nine months ended September 30, 2006, compared with $4.8 million for the nine months ended September 30, 2005.

RSU bonus expense is $1.7 million higher for the nine months ended September 30, 2006, than in the same nine months in 2005, which is caused by the increase in amortization of stock-based compensation expense. We are now recording expense for four periods of RSU grants compared with only three grants at this same time last year. In 2006 we have the inclusion of the grant made in 2006 for 2005 performance and the additional accrual of the expense estimated for the 2006 plan year. This increase is partially offset by the decrease in RSU bonus expense for the nine-month period ended September 30, 2006, compared with the same period in 2005, which reflects an evaluation of our overall performance based on reserve replacement, production, and net asset value per share growth factors.

As a result of the implementation of SFAS No. 123R on January 1, 2006, we recorded $1.8 million of compensation expense in 2006 related to stock options and the ESPP. The above amounts combined with a net $4.4 million increase in other G&A expense, including payroll tax and 401(k) contribution expense, were offset by a $5.7 million increase in the amount of G&A that was allocated to exploration expense due to the aforementioned incentive plan increases as well as increases in the size of our technical exploration staff and a $2.6 million increase in COPAS overhead reimbursements. COPAS overhead reimbursements from operations increased due to an increase in our operated well count from our drilling program.

Exploration Expense. Exploration expense increased $8.4 million, or 31 percent, to $35.9 million for the nine-month period ended September 30, 2006, compared with $27.5 million for the comparable period of 2005. The increase is partially due to a $5.7 million increase in general exploration overhead, of which approximately $4.0 million is related to increases in payments made under the Net Profits Plan and approximately $1.7 million is related to increases in the size of our geologic and exploration staff. Additionally, the increase in exploration expense is partially related to an approximate $1.5 million increase in exploratory dry hole expense and a $1.2 million increase in geological and geophysical expense.

Change in Net Profits Plan Liability. For the nine months ended September 30, 2006, this non-cash expense decreased $53.9 million to $17.4 million from $71.3 million for the nine months ended September 30, 2005. This decrease reflects our estimation of the effect of decreases in the overall commodity price environment. 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.

Income taxes. Income tax expense totaled $82.9 million for the nine months ended September 30, 2006,and $58.0 million for the nine months ended September 30, 2005, resulting in effective tax rates of 36.1 percent and 36.5 percent, respectively. The effective rate change from 2005 reflects changes in the mix of the highest marginal state tax rates as a result of enacted Texas margin tax legislation, acquisition and drilling activity and also reflects other permanent differences including differing estimated effects

between years of the domestic production activities deduction, estimated percentage depletion and the possible impact of state taxes.

Accounting Matters

We refer you to Note 2 and Note 5 of Part I, Item 1 of this report for information regarding accounting matters.

Environmental

St. Mary's compliance with applicable environmental regulations has not resulted in any significant capital expenditures or materially adverse effects on our liquidity or results of operations. We believe that we are in substantial compliance with environmental regulations, and we do not currently expect that any material expenditure will be required in the foreseeable 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 includes certain statements that may be deemed to be "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 that St. Mary's management expects, believes, or anticipates will or may occur in the future are forward-looking statements. The words "will," "believe," "budget," "anticipate," "intend," "estimate," "forecast," "plan," "expect," "project," and similar expressions are intended to identify forward - looking statements, although not all forward-looking statements contain such identifying words. Examples of forward-looking statements may include discussion of such matters as:

- *the amount and nature of future capital, development, and exploration expenditures,*
- *the drilling of wells,*
- *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 gas production estimates,*
- *repayment of debt,*
- *business strategies,*
- *expansion and growth of operations, including acquisitions of oil and gas properties,*
- *recent legal developments, and*
- *other similar matters.*

These statements are based on certain 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 we believe are appropriate under the circumstances. Such statements are subject to a number of assumptions, risks, and uncertainties, including such factors as the volatility and level of oil and natural gas prices, the availability of attractive exploration, development, and property acquisition opportunities and any necessary financing, the pending nature of the reported agreement for the acquisitions of properties in our Permian core area and the ability to complete the acquisition, the uncertain nature of the expected benefits from the acquisition of oil and gas properties and the ability to successfully integrate acquisitions, the risks of various exploration and hedging strategies, unexpected drilling conditions and results, unsuccessful exploration and development drilling, lower prices realized on oil and gas sales resulting from our commodity price risk management activities, production rates and reserve replacement, the imprecise nature of estimating oil and gas reserves, uncertainties inherent in projecting future rates of production from drilling activities and acquisitions, drilling and operating service availability and risks,

uncertainties in cash flow, the financial strength of hedge contract counterparties, the negative impact that lower oil and natural gas prices could have on our ability to borrow, our ability to compete effectively against other independent and major oil and gas companies, litigation, environmental matters, the potential impact of government regulations, the use of management estimates, and other matters discussed in the "Risk Factors" section of our 2005 Annual Report on Form 10-K and subsequent Quarterly Reports on Form 10-Q. Readers are cautioned that forward-looking statements are not guarantees of future performance and that actual results or developments may differ materially 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.

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 Hedges in Place*" contained 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 are 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 that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

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

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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

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, 2005.

ITEM 6. EXHIBITS

The following exhibits are filed or furnished as part of this report:

Exhibit	Description
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
99.1*	Audit Committee Pre-Approval of Non-Audit Services

* Filed with this Form 10-Q
** Furnished with this Form 10-Q

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

November 2, 2006	By:	/s/ MARK A. HELLERSTEIN Mark A. Hellerstein Chief Executive Officer
November 2, 2006	By:	/s/ DAVID W. HONEYFIELD David W. Honeyfield Vice President - Chief Financial Officer, Secretary and Treasurer
November 2, 2006	By:	/s/ GARRY A. WILKENING Garry A. Wilkening Vice President - Administration and Controller

Exhibit 31.1

CERTIFICATION

I, Mark A. Hellerstein, certify that:

1. I have reviewed this quarterly report on Form 10-Q of St. Mary Land & Exploration Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 2, 2006

/S/ MARK A. HELLERSTEIN

Mark A. Hellerstein
Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, David W. Honeyfield, certify that:

1. I have reviewed this quarterly report on Form 10-Q of St. Mary Land & Exploration Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 2, 2006

/s/ DAVID W. HONEYFIELD
David W. Honeyfield
Chief Financial Officer

Exhibit 32.1

CERTIFICATION
PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report on Form 10-Q of St. Mary Land & Exploration Company (the “Company”) for the quarterly period ended September 30, 2006 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Mark A. Hellerstein, as Chief Executive Officer of the Company, and David W. Honeyfield, as Chief Financial Officer of the Company, each hereby certifies, pursuant to and solely for the purpose of 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to the best of his knowledge and belief, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ MARK A. HELLERSTEIN
Mark A. Hellerstein
Chief Executive Officer
November 2, 2006

/s/ DAVID W. HONEYFIELD
David W. Honeyfield
Chief Financial Officer
November 2, 2006

Exhibit 99.1

Audit Committee Pre-Approval of Non-Audit Services

On July 20, 2006, the Audit Committee of the Board of Directors of St. Mary Land & Exploration Company approved in advance certain non-audit services to be performed by Deloitte & Touche LLP, St. Mary's independent auditor. These non-audit services were corporate income tax compliance services in the third quarter of 2006.