ST MARY LAND & EXPLORATION CO
Form 10-Q
November 04, 2008

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, 2008

Commission file number 001-31539

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

| | |
|---|---|
| Delaware<br>(State or other jurisdiction of incorporation or organization) | 41-0518430<br>(I.R.S. Employer Identification No.) |
| 1776 Lincoln Street, Suite 700, Denver, Colorado<br>(Address of principal executive offices) | 80203<br>(Zip Code) |

(303) 861-8140

(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o

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

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

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

Yeso No þ

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

As of October 28, 2008, the registrant had 62,191,539 shares of common stock, $0.01 par value, outstanding.

ST. MARY LAND & EXPLORATION COMPANY

INDEX


| | | | |
|---|---|---|---|
| Part I. | FINANCIAL INFORMATION | | PAGE |
| | Item 1. | Financial Statements (Unaudited) | |
| | | Consolidated Balance Sheets<br>September 30, 2008, and December 31, 2007 | 3 |
| | | Consolidated Statements of Operations<br>Three and Nine Months Ended September 30, 2008, and 2007 | 4 |
| | | Consolidated Statements of Stockholders' Equity and Comprehensive Income<br>September 30, 2008, and December 31, 2007 | 5 |
| | | Consolidated Statements of Cash Flows<br>Nine Months Ended September 30, 2008, and 2007 | 6 |
| | | Notes to Consolidated Financial Statements<br>September 30, 2008 | 8 |
| | Item 2. | Management's Discussion and Analysis of Financial Condition and Results of Operations | 32 |
| | Item 3. | Quantitative and Qualitative Disclosures About Market Risk<br>(included within the content of Item 2) | 64 |
| | Item 4. | Controls and Procedures | 64 |
| Part II. | OTHER INFORMATION | | |
| | Item 1. | Legal Proceedings | 64 |
| | Item 1A. | Risk Factors | 64 |
| | Item 6. | Exhibits | 66 |

PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

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

| ASSETS | | September 30, 2008 | | December 31, 2007 |
|---|---|---|---|---|
| Current assets: | | | | |
| Cash and cash equivalents | $ | 5,396 | $ | 43,510 |
| Short-term investments | | 1,012 | | 1,173 |
| Accounts receivable, net of allowance for doubtful accounts of $16,739 in 2008 and $152 in 2007 | | 182,598 | | 159,149 |
| Refundable income taxes | | 4,583 | | 933 |
| Prepaid expenses and other | | 18,598 | | 14,129 |
| Accrued derivative asset | | 48,155 | | 17,836 |
| Deferred income taxes | | 26,187 | | 33,211 |
| Total current assets | | 286,529 | | 269,941 |
| | | | | |
| Property and equipment (successful efforts method), at cost: | | | | |
| Proved oil and gas properties | | 3,134,922 | | 2,721,229 |
| Less - accumulated depletion, depreciation, and amortization | | (927,895) | | (804,785) |
| Unproved oil and gas properties, net of impairment allowance of $9,903 in 2008 and $10,319 in 2007 | | 166,916 | | 134,386 |
| Wells in progress | | 149,009 | | 137,417 |
| Oil and gas properties held for sale less accumulated depletion, depreciation, and amortization | | 25,653 | | 76,921 |
| Other property and equipment, net of accumulated depreciation of $13,154 in 2008 and $11,549 in 2007 | | 9,959 | | 9,230 |
| | | 2,558,564 | | 2,274,398 |
| | | | | |
| Other noncurrent assets: | | | | |
| Goodwill | | 9,452 | | 9,452 |
| Accrued derivative asset | | 6,934 | | 5,483 |
| Other noncurrent assets | | 12,049 | | 12,406 |
| Total other noncurrent assets | | 28,435 | | 27,341 |
| | | | | |
| Total Assets | $ | 2,873,528 | $ | 2,571,680 |
| | | | | |
| LIABILITIES AND STOCKHOLDERS' EQUITY | | | | |
| Current liabilities: | | | | |
| Accounts payable and accrued expenses | $ | 348,549 | $ | 254,918 |
| Accrued derivative liability | | 118,314 | | 97,627 |

| | | | | |
|---|---|---|---|---|
| Deposit associated with oil and gas properties held for sale | | - | | 10,000 |
| Total current liabilities | | 466,863 | | 362,545 |
| | | | | |
| Noncurrent liabilities: | | | | |
| Long-term credit facility | | 170,000 | | 285,000 |
| Senior convertible notes | | 287,500 | | 287,500 |
| Asset retirement obligation | | 101,346 | | 96,432 |
| Asset retirement obligation associated with oil and gas properties held for sale | | 4,087 | | 8,744 |
| Net Profits Plan liability | | 258,307 | | 211,406 |
| Deferred income taxes | | 343,046 | | 257,603 |
| Accrued derivative liability | | 224,870 | | 190,262 |
| Other noncurrent liabilities | | 8,599 | | 8,843 |
| Total noncurrent liabilities | | 1,397,755 | | 1,345,790 |
| | | | | |
| Commitments and contingencies | | | | |
| | | | | |
| Stockholders' equity: | | | | |
| Common stock, $0.01 par value: authorized - 200,000,000 shares; | | | | |
| issued: 62,360,826 shares in 2008 and 64,010,832 shares in 2007; | | | | |
| outstanding, net of treasury shares: 62,183,839 shares in 2008 | | | | |
| and 63,001,120 shares in 2007 | | 624 | | 640 |
| Additional paid-in capital | | 91,503 | | 170,070 |
| Treasury stock, at cost: 176,987 shares in 2008 and 1,009,712 shares in 2007 | | (2,011) | | (29,049) |
| Retained earnings | | 1,090,059 | | 878,652 |
| Accumulated other comprehensive loss | | (171,265) | | (156,968) |
| Total stockholders' equity | | 1,008,910 | | 863,345 |
| | | | | |
| Total Liabilities and Stockholders' Equity | $ | 2,873,528 | $ | 2,571,680 |

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, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| Operating revenues and other income: | | | | |
| Oil and gas production revenue | $ 358,508 | $ 228,497 | $ 1,068,901 | $ 638,357 |
| Realized oil and gas hedge gain (loss) | (53,491) | 10,173 | (145,837) | 36,160 |
| Marketed gas system revenue | 24,219 | 7,414 | 65,415 | 31,240 |
| Gain (loss) on sale of proved properties | (4,992) | - | 54,063 | - |
| Other revenue | (156) | 603 | 590 | 9,090 |
| Total operating revenues and other income | 324,088 | 246,687 | 1,043,132 | 714,847 |
| | | | | |
| Operating expenses: | | | | |
| Oil and gas production expense | 72,724 | 54,970 | 205,825 | 157,618 |
| Depletion, depreciation, amortization and asset retirement obligation liability accretion | 72,362 | 59,061 | 219,070 | 162,677 |
| Exploration | 10,669 | 12,562 | 42,378 | 42,655 |
| Impairment of proved properties | 564 | - | 10,130 | - |
| Abandonment and impairment of unproved properties | 1,231 | 937 | 4,295 | 3,886 |
| General and administrative | 24,145 | 15,805 | 67,149 | 44,962 |
| Bad debt expense | 6,650 | - | 16,592 | - |
| Change in Net Profits Plan liability | (34,867) | 3,143 | 46,901 | 6,948 |
| Marketed gas system expense | 22,960 | 7,278 | 60,918 | 29,454 |
| Unrealized derivative (gain) loss | (4,429) | (2,880) | 802 | 2,224 |
| Other expense | 7,753 | 460 | 9,155 | 1,577 |
| Total operating expenses | 179,762 | 151,336 | 683,215 | 452,001 |
| | | | | |
| Income from operations | 144,326 | 95,351 | 359,917 | 262,846 |
| | | | | |
| Nonoperating income (expense): | | | | |
| Interest income | 239 | 355 | 395 | 612 |
| Interest expense | (5,359) | (4,082) | (15,858) | (13,885) |
| | | | | |
| Income before income taxes | 139,206 | 91,624 | 344,454 | 249,573 |
| Income tax expense | (51,159) | (33,971) | (126,861) | (92,735) |
| | | | | |
| Net income | $ 88,047 | $ 57,653 | $ 217,593 | $ 156,838 |
| | | | | |
| | 62,187 | 63,424 | 62,254 | 61,364 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Basic weighted-average common shares outstanding | | | | | | | | |
| Diluted weighted-average common shares outstanding | | 63,078 | | 64,727 | | 63,327 | | 64,917 |
| Basic net income per common share | $ | 1.42 | $ | 0.91 | $ | 3.50 | $ | 2.56 |
| Diluted net income per common share | $ | 1.40 | $ | 0.89 | $ | 3.44 | $ | 2.43 |

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 Shares | Common Stock Amount | Additional Paid-in Capital | Treasury Stock Shares | Treasury Stock Amount | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total Stockholders' Equity |
|---|---|---|---|---|---|---|---|---|
| Balances, December 31, 2006 | 55,251,733 | $ 553 | $ 38,940 | (250,000) | $ (4,272) | $ 695,224 | $ 12,929 | $ 743,374 |
| Comprehensive income, net of tax: | | | | | | | | |
| Net income | - | - | - | - | - | 189,712 | - | 189,712 |
| Change in derivative instrument fair value | - | - | - | - | - | - | (154,497 ) | (154,497 ) |
| Reclassification to earnings | - | - | - | - | - | - | (15,470 ) | (15,470 ) |
| Minimum pension liability adjustment | - | - | - | - | - | - | 70 | 70 |
| Total comprehensive income | | | | | | | | 19,815 |
| Cash dividends, $ 0.10 per share | - | - | - | - | - | (6,284 ) | - | (6,284 ) |
| Treasury stock purchases | - | - | - | (792,216) | (25,957) | - | - | (25,957 ) |
| Issuance of common stock under Employee Stock Purchase Plan | 29,534 | - | 919 | - | - | - | - | 919 |
| Conversion of 5.75% Senior Convertible Notes due 2022 to common stock, including income tax benefit of conversion | 7,692,295 | 77 | 106,854 | - | - | - | - | 106,931 |
| Issuance of common stock upon settlement of RSUs following expiration of restriction period, | 302,370 | 3 | (4,569) | - | - | - | - | (4,566 ) |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| net of shares used for tax withholdings | | | | | | | | |
| Sale of common stock, including income tax benefit of stock option exercises | 733,650 | 7 | 19,011 | - | - | - | - | 19,018 |
| Stock-based compensation expense | 1,250 | - | 8,915 | 32,504 | 1,180 | - | - | 10,095 |
| Balances, December 31, 2007 | 64,010,832 | $ 640 | $ 170,070 | (1,009,712) | $ (29,049) | $ 878,652 | $ (156,968) | $ 863,345 |
| Comprehensive income, net of tax: | | | | | | | | |
| Net income | - | - | - | - | - | 217,593 | - | 217,593 |
| Change in derivative instrument fair value | - | - | - | - | - | - | (51,474) | (51,474) |
| Reclassification to earnings | - | - | - | - | - | - | 37,176 | 37,176 |
| Minimum pension liability adjustment | - | - | - | - | - | - | 1 | 1 |
| Total comprehensive income | | | | | | | | 203,296 |
| Cash dividends, $ 0.10 per share | - | - | - | - | - | (6,186) | - | (6,186) |
| Treasury stock purchases | - | - | - | (2,135,600) | (77,150) | - | - | (77,150) |
| Retirement of treasury stock | (2,945,212) | (29) | (103,237) | 2,945,212 | 103,266 | - | - | - |
| Issuance of common stock under Employee Stock Purchase Plan | 17,626 | - | 579 | - | - | - | - | 579 |
| Issuance of common stock upon settlement of RSUs following expiration of restriction period, net of shares used for tax withholdings | 413,500 | 4 | (6,484) | - | - | - | - | (6,480) |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Sale of common stock, including income tax benefit of stock option exercises | 860,330 | 9 | 21,020 | - | - | - | - | 21,029 |
| Stock-based compensation expense | 3,750 | - | 9,555 | 23,113 | 922 | - | - | 10,477 |
| | | | | | | | | |
| Balances, September 30, 2008 | 62,360,826 | $ 624 | $ 91,503 | (176,987) | $ (2,011) | $ 1,090,059 | $ (171,265 ) | $ 1,008,910 |

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

-5-

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

| | For the Nine Months Ended September 30, 2008 | 2007 |
|---|---|---|
| Cash flows from operating activities: | | |
| Reconciliation of net income to net cash provided by operating activities: | | |
| Net income | $ 217,593 | $ 156,838 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Loss related to hurricanes | 6,980 | - |
| (Gain) loss on insurance settlement | 1,600 | (6,340) |
| Gain on sale of proved properties | (54,063) | - |
| Depletion, depreciation, amortization, and asset retirement obligation liability accretion | 219,070 | 162,677 |
| Bad debt expense | 16,592 | - |
| Exploratory dry hole expense | 6,583 | 12,714 |
| Impairment of proved properties | 10,130 | - |
| Abandonment and impairment of unproved properties | 4,295 | 3,886 |
| Unrealized derivative loss | 802 | 2,224 |
| Change in Net Profits Plan liability | 46,901 | 6,948 |
| Stock-based compensation expense* | 10,477 | 8,606 |
| Deferred income taxes | 101,231 | 79,289 |
| Other | (3,496) | (5,168) |
| Changes in current assets and liabilities: | | |
| Accounts receivable | (39,455) | (208) |
| Refundable income taxes | (3,650) | 4,587 |
| Prepaid expenses and other | 2,029 | 28,035 |
| Accounts payable and accrued expenses | 34,763 | 27,552 |
| Excess tax benefit from the exercise of stock options | (10,281) | (7,658) |
| Net cash provided by operating activities | 568,101 | 473,982 |
| | | |
| Cash flows from investing activities: | | |
| Proceeds from insurance settlement | - | 7,064 |
| Proceeds from sale of oil and gas properties | 155,203 | 324 |
| Capital expenditures | (494,492) | (500,111) |
| Acquisition of oil and gas properties | (83,433) | (32,650) |
| Deposits for acquisition of oil and gas assets | - | (15,310) |
| Deposits to short-term investments | 161 | (1,153) |
| Receipts from short-term investments | - | 1,450 |
| Other | (9,984) | 29 |

| | | | | |
|---|---|---|---|---|
| Net cash used in investing activities | | (432,545) | | (540,357) |
| | | | | |
| Cash flows from financing activities: | | | | |
| Proceeds from credit facility | | 832,000 | | 553,914 |
| Repayment of credit facility | | (947,000) | | (732,914) |
| Repayment of short-term note payable | | - | | (4,469) |
| Excess tax benefit from the exercise of stock options | | 10,281 | | 7,658 |
| Net proceeds from issuance of senior convertible debt | | - | | 280,664 |
| Proceeds from sale of common stock | | 11,327 | | 6,342 |
| Repurchase of common stock | | (77,202) | | (25,904) |
| Dividends paid | | (3,076) | | (3,140) |
| Net cash provided by (used in) financing activities | | (173,670) | | 82,151 |
| | | | | |
| Net change in cash and cash equivalents | | (38,114) | | 15,776 |
| Cash and cash equivalents at beginning of period | | 43,510 | | 1,464 |
| Cash and cash equivalents at end of period | $ | 5,396 | $ | 17,240 |

* Stock-based compensation expense is a component of exploration expense and general and administrative expense on the consolidated statements of operations. During the periods ended September 30, 2008, and 2007, respectively, approximately $3.8 million and $2.6 million of stock-based compensation expense was included in exploration expense. During the periods ended September 30, 2008, and 2007, respectively, approximately $6.7 million and $6.0 million of stock-based compensation expense was included in general and administrative expense.

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

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

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

| | For the Nine Months Ended September 30, | | | |
|---|---|---|---|---|
| | 2008 | | 2007 | |
| | (in thousands) | | | |
| Cash paid for interest | $ | 14,483 | $ | 13,476 |
| Cash paid or (refunded) for income taxes | $ | 18,943 | $ | (1,048) |

Dividends of approximately $3.1 million have been declared by the Company's Board of Directors, but not paid, as of September 30, 2008.

In September 2008, the Company hired a new senior executive. Upon commencement of employment, the Company issued 15,496 shares of restricted stock awards to the senior executive, of which half will vest on December 15, 2009 and the remaining half to vest on December 15, 2010, provided on such vesting dates the executive is employed by the Company. The total fair value of the issuance was $600,005.

In August 2008 the Company issued 465,751 Performance Share Awards to employees as equity-based compensation pursuant to the Company's 2006 Equity Incentive Compensation Plan. The total fair value of the issuance equaled $12.3 million.

During the first nine months of 2008 and 2007, the Company issued 427,607 and 98,664 restricted stock units to employees as equity-based compensation, respectively, pursuant to the Company's 2006 Equity Incentive Compensation Plan. The total fair value of the issuances were $23.3 million and $3.1 million, respectively.

As of September 30, 2008, and 2007, $159.5 million and $102.6 million, respectively, are included in the balances of oil and gas properties and accounts payable and accrued expenses. These oil and gas property additions are reflected in cash used in investing activities in the periods that the payables are settled.

In May 2008 and 2007 the Company issued 23,113 and 26,292 shares, respectively, of common stock from treasury to its non-employee directors pursuant to the Company's 2006 Equity Incentive Compensation Plan. The Company recorded compensation expense related to these issuances of approximately $922,000 and $855,000 for the nine-month periods ended September 30, 2008, and 2007, respectively.

In June 2006 the Company hired a new senior executive. In February 2008 and February 2007 the Company issued 3,750 and 1,250 shares of stock, respectively, to the senior executive, as the Company achieved certain performance metrics. The total fair value of these issuances were $141,900 and $45,012, respectively.

In March 2007 the Company called the 5.75% Senior Convertible Notes for redemption. All of the note holders elected to convert the 5.75% Senior Convertible Notes to common stock. As a result, the Company issued 7,692,295 shares of common stock on March 16, 2007, in exchange for the $100 million of 5.75% Senior Convertible Notes. The conversion was executed in accordance with the conversion provisions of the original indenture. Additionally, the conversion resulted in a $7.0 million decrease in non-current deferred income taxes and a corresponding increase in additional paid-in capital that is a result of the recognition of the cumulative excess tax benefit earned by the Company associated with the contingent interest feature of this note.

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, 2008

Note 1 – The Company and Business

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

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 ("GAAP") for complete financial statements. However, except as disclosed herein, there has been no material change in the information disclosed in the notes to consolidated financial statements included in St. Mary's Annual Report on Form 10-K/A for the year ended December 31, 2007. In the opinion of management, all adjustments, consisting of normal recurring accruals that are considered necessary for fair presentation of the interim financial information, have been included. Operating results for the periods presented are not necessarily indicative of expected results for the full year.

Certain 2007 amounts in the unaudited condensed consolidated financial statements have been reclassified to correspond to the 2008 presentation. As a result of a change in circumstances in 2007, distributions being made and accrued for under the Net Profits Interest Bonus Plan (the "Net Profits Plan") for former employees who were involved in geologic, geophysical, or exploration activities are now classified and fully allocated to general and administrative expense rather than exploration expense. Distributions accrued or made to current employees engaged in geologic, geophysical, or exploration activities continue to be classified as exploration expense. The entire impact of this change for 2007 was recorded in the fourth quarter. The quarterly financial information presented for 2007 throughout the accompanying unaudited condensed consolidated financial statements has been reclassified to reflect the change. The reclassification had no impact on total operating expenses, income from operations, income before income taxes, net income, basic net income per common share, or diluted net income per common share, as it was simply a reclassification between two line items within the accompanying consolidated statements of operations. Refer to Note 14 of Part II, Item 8 within the Form 10-K/A for the year ended December 31, 2007, for further discussion.

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/A for the year ended December 31, 2007, and are supplemented throughout the footnotes of this document. It is suggested that these unaudited condensed consolidated financial statements be read in conjunction with the consolidated financial statements and notes included in the Form 10-K/A for the year ended December 31, 2007.

Note 3 – Acquisitions, Divestitures, Variable Interest Entities, and Assets Held for Sale

Greater Green River Divestiture

In June 2008 the Company completed the divestiture of certain non-strategic oil and gas properties located in the Rocky Mountain region. The cash received at closing, net of commission costs, was $21.7 million. The final sales price is subject to normal post-closing adjustments and is expected to be finalized during the fourth quarter of 2008. The estimated gain on sale of proved properties related to the divestiture is approximately $697,000 and may be impacted by the previously mentioned post-closing adjustments. The Company determined that this sale does not qualify for discontinued operations accounting under Financial Accounting Standards Board (“FASB”) Emerging Issues Task Force Issue No. 03-13 (“EITF No. 03-13”).

Abraxas Divestiture

On January 31, 2008, the Company completed the divestiture of certain non-strategic oil and gas properties located primarily in the Rocky Mountain and Mid-Continent regions to Abraxas Petroleum Corporation and Abraxas Operating, LLC. The cash received at closing, net of commission costs, was $129.6 million. The final sale price is subject to normal post-closing adjustments and is expected to be finalized during the fourth quarter of 2008. The estimated gain on sale of proved properties related to the divestiture is approximately $55.7 million and may be impacted by the previously mentioned post-closing adjustments. The Company determined that this sale does not qualify for discontinued operations accounting under EITF No. 03-13. These assets were classified as assets held for sale as of December 31, 2007.

Williston Basin Acquisition

On August 13, 2008, the Company acquired oil and gas properties located in the Bakken and Three Forks formations in the Williston Basin for $20.2 million of cash. After normal purchase price adjustments, the Company allocated $3.6 million to proved oil and gas properties and $16.6 million to unproved oil and gas properties. The Company also recorded $56,000 in asset retirement obligation liability associated with the acquired properties. The acquisition was funded with cash on hand and borrowings under the Company’s existing credit facility. The final purchase price is subject to normal post-closing adjustments and is expected to be finalized during the fourth quarter of 2008.

Carthage Acquisition

On March 21, 2008, the Company acquired oil and gas properties located primarily in the Carthage Field in Panola County, Texas for $49.2 million of cash. After normal purchase price adjustments, the Company allocated $29.1 million to proved oil and gas properties, $20.6 million to unproved oil and gas properties, and a net $215,000 to other liabilities. The Company also recorded $341,000 in asset retirement obligation liability associated with the acquired properties. The acquisition was funded with cash on hand and borrowings under the Company’s existing credit facility. During the second quarter of 2008, the Company acquired additional interests in the majority of these properties for $8.0 million.

Rockford Acquisition

On October 4, 2007, the Company completed the purchase of certain oil and gas properties in the Gold River project area targeting the Olmos shallow gas formation located primarily in Webb and Dimmit Counties, Texas. The assets were purchased from Rockford Energy Partners II, LLC for $149.0 million. After normal purchase price adjustments, the Company allocated $127.3 million to proved oil and gas properties, $23.1 million to unproved oil and gas properties, and a net $292,000 to other assets. The Company also recorded $1.7 million in asset retirement obligation liability associated with the acquired properties. The acquisition was funded with cash on hand and borrowings under the Company’s existing

credit facility. The acquired properties are adjacent to the Catarina project area. The Company hedged the equivalent of the first three years of risked natural gas production and the first two years of associated risked natural gas liquids production related to this acquisition.

Catarina Acquisition

On June 1, 2007, the Company acquired oil and gas properties located primarily in the Catarina project area in Webb County, Texas in exchange for $30.0 million of cash. After normal purchase price adjustments, the Company allocated $29.9 million to proved oil and gas properties, $535,000 to unproved oil and gas properties, and $215,000 to other assets. The Company also recorded $623,000 in asset retirement obligation liability associated with the acquired properties. The acquisition was funded with cash on hand and borrowings under the Company's existing credit facility.

Like-Kind Exchanges and Variable Interest Entities

The Carthage acquisition described above was structured to qualify as the first step of a reverse like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended (the "IRC") and Internal Revenue Service ("IRS") Revenue Procedure 2000-37. Prior to closing on the acquisition, the Company assigned all of its rights and duties under the purchase and sale agreement to NBF Reverse Exchange, LLC, an indirect wholly-owned subsidiary of Comerica Incorporated, which further assigned all of its rights and duties under the purchase and sale agreement to St. Mary Acquisition, LLC ("SMA, LLC"), a company unaffiliated with St. Mary. The Carthage Field assets were acquired by NBF Reverse Exchange, LLC as an exchange accommodation titleholder. On September 12, 2008, the reverse like-kind exchange was completed and SMA, LLC, became a wholly owned subsidiary of St. Mary. Subsequent to September 30, 2008, the Carthage Field assets were transferred to St. Mary by merger. As of the filing date of this report, SMA, LLC is inactive and does not hold any assets and its status with the Secretary of State of Texas has been terminated.

From the date of closing the Carthage acquisition on March 21, 2008, through October 10, 2008, the assets held by SMA, LLC, were leased by St. Mary under a triple net lease whereby St. Mary had the benefits and risks of all revenues and costs attributed to the properties. The Carthage assets were managed by St. Mary under the terms of a management agreement with SMA, LLC. The second step of the like-kind exchange was partially completed in conjunction with the divestiture of certain non-core oil and gas properties discussed above under Greater Green River Divestiture. The funds from this transaction were deposited in an account owned by Comerica Incorporated as qualified intermediary in this transaction. On September 12, 2008, the funds from this transaction were moved into the Company's operating cash account upon completion of the like-kind exchange.

In connection with the reverse like-kind exchange described above, St. Mary loaned an amount equal to the purchase price of the assets to SMA, LLC. Based on the provision of FASB Interpretation No. 46(R), "Consolidation of Variable Interest Entities" ("FIN 46(R)"), the Company determined that SMA, LLC was a variable interest entity for which St. Mary was the primary beneficiary. Accordingly, SMA, LLC was consolidated into St. Mary subsequent to the completion of the purchase of oil and gas properties on March 21, 2008. As a result of the consolidation, St. Mary is recognizing all oil and gas reserves and production as well as all revenues and expenses attributed to the Carthage acquisition as of the March 21, 2008, acquisition date. The loan to SMA, LLC was repaid subsequent to September 30, 2008.

The Rockford acquisition of the Gold River assets described above was also structured to qualify as the first step of a reverse like-kind exchange under Section 1031 of the IRC, and IRS Revenue Procedure 2000-37. Prior to closing on the Rockford acquisition, the Company assigned all of its rights and duties under the purchase and sale agreement to NBF Reverse Exchange, LLC, an indirect wholly-owned subsidiary of Comerica Incorporated, which further assigned all of its rights and duties under the purchase and sale agreement to St. Mary Land & Exploration Acquisition, LLC

(“SMLEA, LLC”), a company unaffiliated with St. Mary.  The Gold River assets were acquired by NBF Reverse Exchange, LLC as an exchange accommodation titleholder. SMLEA, LLC held the assets pursuant to a qualified exchange accommodation agreement until January 31, 2008, when the second step of the like-kind exchange was completed in conjunction with the divestiture of certain non-core oil and gas properties discussed above under Abraxas Divestiture and St. Mary acquired all of the limited liability company interests of SMLEA, LLC from NBF Reverse Exchange, LLC. As of the date of closing of the Rockford acquisition on October 4, 2007, through February 7, 2008, the assets held by SMLEA, LLC, were leased by St. Mary under a triple net lease whereby St. Mary enjoyed the benefits and risks of all revenues and costs attributed to the properties. The Gold River assets were managed by St. Mary under the terms of a management agreement with SMLEA, LLC. On February 7, 2008, the Gold River assets were transferred to St. Mary. As of this filing date SMLEA, LLC, is inactive and does not hold any assets.

In connection with the reverse like-kind exchange described above, St. Mary loaned an amount equal to the purchase price of the assets to SMLEA, LLC. Based on the provision of FIN 46(R), the Company determined that SMLEA, LLC is a variable interest entity for which St Mary is the primary beneficiary. Accordingly, SMLEA, LLC was consolidated into St. Mary subsequent to the completion of the purchase of oil and gas properties on October 4, 2007. As a result of the consolidation, St. Mary recognized all oil and gas reserves and production as well as all revenues and expenses attributed to the Rockford acquisition beginning on October 4, 2007. The loan to SMLEA, LLC was repaid on February 7, 2008.

Assets Held for Sale

As of September 30, 2008, the Company is engaged in marketing for sale certain non-core oil and gas properties located in the Rocky Mountain, Gulf Coast, and Mid-Continent regions. In accordance with Statement of Financial Accounting Standards No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets”, these properties have been separately presented in the accompanying consolidated balance sheet at the lower of carrying value or fair value less the cost to sell. The accompanying consolidated balance sheet as of September 30, 2008, presents $25.7 million of assets held for sale, net of accumulated depletion, depreciation and amortization. Assets held for sale were measured at carrying value, which was less than fair value less cost to sell as of September 30, 2008. Subsequent changes to fair value less the cost to sell will impact the measurement of assets held for sale if the fair value is determined to be less than the carrying value of the assets. Asset retirement obligation liabilities of $4.1 million related to these properties have also been reclassified to liabilities associated with oil and gas properties held for sale on the consolidated balance sheet as of September 30, 2008. The Company determined that these sales do not qualify for discontinued operations accounting under EITF No. 03-13.

Note 4 – Earnings per Share

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

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

The restricted shares underlying the grants of RSUs are included in the basic and diluted earnings per share calculations as described above. Following the lapse of the restriction periods, the shares

underlying the units will be issued and therefore will be included in the number of issued and outstanding shares.

Prior to the March 16, 2007, conversion of the Company's 5.75% Senior Convertible Notes due 2022 (the "5.75% Senior Convertible Notes"), potentially dilutive shares associated with this instrument were accounted for using the if-converted method for the determination of diluted earnings per share. Adjusted net income used in the if-converted method was derived by adding interest expense paid on the 5.75% Senior Convertible Notes back to net income and then adjusting for nondiscretionary items that are based on net income and would have changed had the 5.75% Senior Convertible Notes been converted at the beginning of the period. The 5.75% Senior Convertible Notes were called for redemption by the Company on March 16, 2007, and all of the note holders elected to convert the notes to shares of the Company's common stock. The Company issued 7.7 million common shares in connection with the conversion of the 5.75% Senior Convertible Notes. Upon conversion, these shares were included in the calculation of weighted-average common shares outstanding. There were no potentially dilutive shares related to the 5.75% Senior Convertible Notes included in the diluted earnings per share calculation for the three-month and nine-month periods ended September 30, 2008. Approximately 2.1 million potentially dilutive shares related to the 5.75% Senior Convertible Notes were included in the diluted earnings per share calculation for the nine-month period ended September 30, 2007. There were no potentially dilutive shares related to the 5.75% Senior Convertible Notes included in the diluted earnings per share calculation for the three-month period ended September 30, 2007.

The Company's 3.50% Senior Convertible Notes, which were issued April 4, 2007, have a net-share settlement right whereby each $1,000 principal amount of notes may be surrendered for conversion for cash in an amount equal to the principal amount and, if applicable, shares of common stock for the amount in excess of the principal amount. The treasury stock method is used to measure the potentially dilutive impact of shares associated with that conversion feature. The 3.50% Senior Convertible Notes have not been dilutive for any reporting period that they have been outstanding and therefore do not impact the diluted earnings per share calculation for the three-month and nine-month periods ended September 30, 2008, and 2007.

On August 1, 2008, the Company granted 465,751 PSAs for the three-year performance period ended July 31, 2011. At the end of each grant's three-year performance period, a multiplier will be applied to all vested PSAs to determine the number of common shares issued. The number of common shares issued is contingent upon the satisfaction of certain market conditions. The number of potentially dilutive shares related to the PSAs is based on the number of shares, if any, which would be issuable if the end of the reporting period were the end of the contingency period. There were no potentially dilutive shares related to the PSAs included in the diluted earnings per share calculation for the three-month and nine-month periods ended September 30, 2008. We refer you to Note 5 – Compensation Plans for additional information regarding PSAs.

The treasury stock method is used to measure the dilutive impact of stock options, RSUs, and PSAs. The dilutive effect of stock options and unvested RSUs is considered in the detailed calculation below. The RSU transitional awards granted on June 30, 2008, are anti-dilutive for the nine-month period ended September 30, 2008. There were no anti-dilutive securities related to stock options, RSUs, or PSAs for the three-month period ended September 30, 2008, and the three-month and nine-month periods ended September 30, 2007.

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, | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| | (In thousands, except per share amounts) | | | |
| Net Income | $ 88,047 | $ 57,653 | $ 217,593 | $ 156,838 |
| Adjustments to net income for dilution: | | | | |
| Add: interest expense not incurred if 5.75% Convertible Notes converted | - | - | - | 1,284 |
| Less: other adjustments | - | - | - | (13) |
| Less: income tax effect of adjustment items | - | - | - | (471) |
| Net income adjusted for the effect of dilution | $ 88,047 | $ 57,653 | $ 217,593 | $ 157,638 |
| | | | | |
| Basic weighted-average common stock outstanding | 62,187 | 63,424 | 62,254 | 61,364 |
| Add: dilutive effect of stock options and unvested RSUs | 891 | 1,303 | 1,073 | 1,471 |
| Add: dilutive effect of 5.75% Convertible Notes using if-converted method | - | - | - | 2,082 |
| Diluted weighted-average common shares outstanding | 63,078 | 64,727 | 63,327 | 64,917 |
| | | | | |
| Basic net income per common share | $ 1.42 | $ 0.91 | $ 3.50 | $ 2.56 |
| Diluted net income per common share | $ 1.40 | $ 0.89 | $ 3.44 | $ 2.43 |

Note 5 – Compensation Plans

Cash Bonus Plan

The Company has a cash bonus plan, under which the Company has established a performance measure framework whereby selected employee participants can be awarded an annual cash bonus. As amended by the Board of Directors on March 28, 2008, the plan document provides that no participant may receive an annual bonus under the plan of more than 200 percent of his or her base salary. As the plan is currently administered, any awards under the plan are based on Company and regional performance, and are then further refined by individual performance. The Company accrues cash bonus expense based upon the current year's performance. In February 2008 the Company paid $3.5 million for cash bonuses earned in the 2007 performance year and in February 2007 paid $1.8 million earned in the 2006 performance year. Included in the general and administrative and exploration expense line items in the accompanying consolidated statements of operations is the cash bonus expense related to the specific performance year of $2.7 million and $1.3 million for the three-month periods ended September 30, 2008, and 2007, respectively. Total cash bonus expense for the nine-month periods ended September 30, 2008, and 2007, was $7.2 million, and $3.8 million, respectively.

Equity Incentive Compensation Plan

There are several components to equity compensation that are described in this section. Varying types of equity awards have been granted by the Company in different periods.

Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123(R), "Share Based Payment" ("SFAS No. 123(R)") using the modified-prospective transition method. Under the transition method, compensation expense recognized in 2007 and 2008, 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 provision of Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation", 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 provision of SFAS No. 123(R).

As of September 30, 2008, approximately 1.5 million shares of common stock remained available for grant under the 2006 Equity Incentive Compensation Plan (the "2006 Equity Plan"). The 2006 Equity 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"). An amendment and restatement of the 2006 Equity Plan was approved by the Company's stockholders at the 2008 annual stockholders' meeting held on May 21, 2008. For an 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 ("RSU") grant, each direct share benefit issued counts as two shares against the number of shares available to be granted under the 2006 Equity Plan. The issuance of a PSA is considered a direct share benefit under the 2006 Equity Plan. At the end of each grant's three-year performance period a multiplier ranging between zero and two is applied to each performance share so that each performance share granted has the potential to result in the issuance of two shares of common stock. Consequently, each performance share granted counts as four shares against the number of shares available to be granted under the 2006 Equity Plan. Stock options granted count as one share for each instruments issued against the number of shares available to be granted under the 2006 Equity Plan.

The Company does have outstanding stock option grants under the Predecessor Plans and RSU awards under both the Predecessor Plans and the 2006 Equity Plan. The following sections describe the details of RSU grants, stock options, and PSAs outstanding as of September 30, 2008.

Performance Share Awards

In late 2007 St. Mary transitioned to PSA grants as the primary form of long-term equity incentive compensation for eligible employees in place of grants of RSUs and the awarding of interests in the Net Profits Plan. On August 1, 2008, the Company granted 465,751 PSAs. PSAs represent the right to receive, upon settlement of the PSAs after the completion of three-year performance period ending July 31, 2011, a number of shares of the Company's common stock that may be from zero to two times the number of PSAs granted on the award date. The number of shares issued depends on the extent to which the Company's performance criteria have been achieved and the extent to which the PSAs have vested. The performance criteria for the PSAs are based on a combination of the Company's cumulative total shareholder return ("TSR") for the performance periods and the relative measure of the Company's TSR compared with the cumulative TSR of certain peer companies for the performance period. The PSAs will vest 1/7th on August 1, 2009, 2/7 ths August 1, 2010, and 4/7ths on August 1, 2011.

Total stock-based compensation expense related to PSAs for both the three-month and nine-month periods ended September 30, 2008, was $789,000. There was no stock-based compensation expense related to PSAs for the three-month and nine-month periods ended September 30, 2007.

In measuring compensation expense related to the grant of PSAs, SFAS No. 123(R) requires companies to estimate the fair value of the award on the grant date. The fair value of PSAs has been measured under a stochastic process method using the Geometric Brownian Motion Model ("GBM Model"). A stochastic process is a mathematically defined equation that can create a series of outcomes over time. These outcomes are not deterministic in nature, which means that by iterating the equations

multiple times, different results will be obtained for those iterations. In the case of the Company's PSAs, the Company cannot predict with certainty the path its stock price or the stock price of its peers will take over the three-year performance period. By using a stochastic simulation the Company can create multiple prospective stock pathways, statistically analyze these simulations, and ultimately make inferences to the most likely path the stock price will take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the GBM Model, is deemed an appropriate method by which to determine the fair value of the PSAs. The fair value of the Company's PSAs granted on August 1, 2008, was $12.3 million.

A summary of the status and activity of PSAs for the nine-month period ended September 30, 2008, is presented in the following table.

| | PSAs | | Weighted-Average Grant-Date Fair Value |
|---|---|---|---|
| At January 1, 2008 | - | $ | - |
| Granted | 465,751 | $ | 26.48 |
| Vested | - | $ | - |
| Forfeited | (518) | $ | 26.48 |
| At September 30, 2008 | 465,233 | $ | 26.48 |

Restricted Stock Incentive Program Under the Equity Incentive Compensation Plan

The Company historically had a long-term incentive program whereby grants of restricted stock or RSUs were awarded to eligible employees, consultants, and members of the Board of Directors. Restrictions and vesting periods for the awards were determined at the discretion of the Board of Directors and were 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 were determined annually based on a formula consistent with the cash bonus plan.

St. Mary issued 158,744 RSUs on February 28, 2008, related to 2007 performance and 78,657 RSUs on February 28, 2007, related to 2006 performance. The total fair value associated with these issuances was $6.0 million in 2008 and $2.5 million in 2007 as measured on the respective grant dates. The granted RSUs vest 25 percent immediately upon grant and 25 percent on each of the first three anniversary dates of the grant.

St. Mary also issued 18,986 and 20,007 RSUs for various grants to certain employees during the nine-month periods ended September 30, 2008, and 2007, respectively. These grants have various vesting periods. The total fair value associated with these issuances was $726,000 in 2008 and $643,000 in 2007 as measured on the respective grant dates.

St. Mary issued 265,373 RSUs on June 30, 2008, as a transitional award between the old RSU program and the new PSA program. The total fair value associated with this issuance was $17.2 million as measured on the grant date. One third of the granted RSUs vests on December 15th in 2008, 2009, and 2010, respectively. Compensation expense is recorded monthly over the vesting period of the award. For RSUs awarded prior to 2006, vested shares of common stock underlying the RSU grants were issued on the third anniversary of the grant, at which time the shares carried no further restrictions. For all awards subsequent to the 2005 RSU grant, St. Mary has eliminated the restriction period that extends beyond the vesting period so shares are now issued without restriction upon vesting, rather than on the third anniversary of the award. This change was effected for existing awards in 2007 within the safe harbor adoption provisions of the newly enacted U.S. Treasury regulations interpreting the IRC provisions governing deferred compensation. A mutual election of the employee and the Company was required to

effect this change for each outstanding award. Essentially all of the awards were modified by mutual election, and as such the incremental value associated with the removal of this restriction period is being amortized over the remaining service period for these awards. For grants made beginning with the 2006 grant period, the Company is using the accelerated amortization method as described in FASB Interpretation No. 28, "Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans – an interpretation of APB Opinions No. 15 and 25," whereby approximately 48 percent of the total estimated compensation expense is recognized in the first year of the vesting period. As of September 30, 2008, a total of 500,942 RSUs were outstanding, of which 7,091 were vested. The total RSU compensation expense for the three-month periods ended September 30, 2008, and 2007, was $3.2 million and $2.1 million, respectively, and the total RSU compensation expense for the nine-month periods ended September 30, 2008, and 2007, was $9.3 million and $7.1 million, respectively. As of September 30, 2008, there was $15.7 million of total unrecognized compensation expense related to unvested RSU awards. The unrecognized compensation expense is being amortized through 2011.

During the first three quarters of 2008, the Company has converted 587,437 RSUs, which relate to those awards granted in 2008, 2007, and 2006, into common stock based on the amended terms of the RSU awards. The Company and the majority of the grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and the award agreements. As a result, the Company issued net 413,500 shares of common stock associated with these grants. The remaining 173,937 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon the delivery of the shares underlying those RSUs.

During the first three quarters of 2007, the Company converted 427,059 RSUs, which related to the awards granted in 2004, into common stock. The Company and the majority of the grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and the award agreements. As a result, the Company issued net 302,370 shares of common stock associated with these grants. The remaining 124,689 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon the delivery of the shares underlying those RSUs.

In measuring compensation expense related to the grant of RSUs, SFAS No. 123(R) requires companies to estimate the fair value of the award on the grant date. For grants prior to January 1, 2008, the Company had a restriction period beyond vesting. Therefore, the fair value of the RSUs was inherently less than the market value of an unrestricted share of St. Mary's common stock. The fair value of RSUs had been measured using the Black-Scholes option-pricing model. 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 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 RSU awards granted in the nine-month period ended September 30, 2007 were estimated using the following weighted-average assumptions:

| | September 30, 2007 |
|---|---|
| Risk free interest rate: | 4.6% |
| Dividend yield: | 0.3% |
| Volatility factor of the market price of the Company's common stock: | 32.2% |
| Expected life of the awards (in years): | 3 |

Beginning January 1, 2008, RSU awards no longer have a restriction beyond vesting. Therefore fair value of an RSU award is equal to the market value of the underlying stock on the date of the grant.

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 stock award whereby the employee could earn an additional 5,000 shares over a four-year period, beginning in 2006, and an additional 15,000 shares if certain net asset value growth targets are met over that period. The fair value of this award is being recorded as compensation expense over the vesting period. In February 2008 and February 2007 the Company issued 3,750 and 1,250 shares of stock, respectively, to the senior executive. The total fair value of these issuances was $141,900 and $45,012 respectively.

A summary of the status and activity of non-vested RSUs for the nine-month period ended September 30, 2008, is presented in the following table.

| | RSUs | | Weighted-Average Grant-Date Fair Value |
|---|---|---|---|
| Non-vested, at January 1, 2008 | 289,385 | $ | 32.26 |
| Granted | 443,103 | $ | 53.87 |
| Vested | (200,899) | $ | 32.43 |
| Forfeited | (37,738) | $ | 37.62 |
| Non-vested, at September 30, 2008 | 493,851 | $ | 50.97 |

Stock Option Grants Under the Equity Incentive Compensation Plan

The Company 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. 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 were granted at exercise prices equal to the respective closing market price of the Company's underlying 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.

There was no stock-based compensation expense for the three-month period ended September 30, 2008, related to stock options that were outstanding and unvested as of January 1, 2006. Total stock-based compensation related to these stock options equaled $27,000 for the three-month period ended September 30, 2007. The total stock-based compensation expense related to stock options for the nine-month periods ended September 30, 2008, and 2007, was $17,000 and $409,000, respectively. There was no cumulative effect adjustment for the adoption of SFAS No. 123(R). As of September 30, 2008, there were no unvested stock options outstanding.

Prior to adopting SFAS No. 123(R), all tax benefits resulting from the exercise of stock options were presented as operating cash flows in the accompanying consolidated statements of cash flows. SFAS No. 123(R) requires cash flows resulting from excess tax benefits to be classified as 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. The Company has recorded $10.3 million and $7.7 million of excess tax benefits for the nine-month periods ended September 30, 2008, and 2007, respectively, as cash inflows from financing activities. Cash received from option exercises for the nine-month periods ended September 30, 2008, and 2007, equaled $10.7 million and $5.9 million, respectively.

The following table summarizes the nine-month activity for stock options outstanding as of September 30, 2008:

| | Options | | Weighted-Average Exercise Price | Weighted Average Remaining Contractual Term (In years) | | Aggregate Intrinsic Value (In thousands) |
|---|---|---|---|---|---|---|
| Outstanding, beginning of period | 2,385,500 | $ | 12.62 | | | |
| Exercised | (860,330) | $ | 12.49 | | | |
| Forfeited | - | $ | - | | | |
| Outstanding, end of period | 1,525,170 | $ | 12.69 | 3.89 | $ | 35,024 |
| Vested, or expect to vest end of period | 1,525,170 | | | | $ | 35,024 |
| Exercisable, end of period | 1,525,170 | $ | 12.69 | 3.89 | $ | 35,024 |

As of September 30, 2008, there was no unrecognized compensation cost related to unvested stock option awards.

Net Profits Plan

Under the Company's Net Profits Plan, all oil and gas wells that were completed or acquired during a year were designated within a specific pool. Key employees recommended by senior management and designated as participants by the Company's Compensation Committee of the Board of Directors and employed by the Company on the last day of that year became entitled to payments under the Net Profits Plan 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 was an active compensation program from 1991 through 2007. Pool years prior to and including 2005 are fully vested. The 2006 and 2007 pool years are subject to a vesting schedule and include a cap whereby the maximum benefits to participants from a particular year's pool is limited to 300 percent of a participating individual's adjusted base salary paid during the year to which the pool relates. In December 2007 the Board approved a restructuring of the Company's incentive compensation programs. The change in the incentive compensation structure was designed to replace the RSU and Net Profits Plan programs with a single long-term equity incentive compensation program utilizing performance shares. As a result, the 2007 Net Profits Plan pool was the last pool established by the Company.

The Company records changes in the present value of estimated future payments under the Net Profits Plan as a separate item in the accompanying consolidated statements of operations. The change in the estimated liability is recorded as a non-cash expense or benefit in the current period. The amount recorded as an expense or benefit associated with the change in the estimated liability is not allocated to general and administrative expense or exploration expense because it is associated with the future net cash flows from oil and gas properties in the respective pools rather than with results realized in the current period. The table below presents the estimated allocation of the expense related to the change in the Net Profits Plan liability if the Company did allocate the adjustment to these specific functional line items based on the current allocation of actual distributions being made by the Company. Of the payments made under the Net Profits Plan, 11 percent and 23 percent would have been classified as exploration expense in the accompanying consolidated statements of operations for the three-month periods ended September 30, 2008, and 2007, respectively. Of the payments made under the Net Profits Plan, 33 percent and 22 percent would have been classified as exploration expense in the accompanying consolidated

statements of operations for the nine-month periods September 30, 2008, and 2007, respectively. As time progresses, less of the distribution relates to prospective exploration efforts as more of the distributions are made to employees who have terminated employment and therefore do not provide ongoing exploration support.

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| | (In thousands) | | | |
| General and administrative expense | $ (30,965) | $ 2,406 | $ 31,347 | $ 5,431 |
| Exploration expense | (3,902) | 737 | 15,554 | 1,517 |
| Total | $ (34,867) | $ 3,143 | $ 46,901 | $ 6,948 |

Note 6 – Income Taxes

Income tax expense for the three-month and nine-month periods ended September 30, 2008, and 2007, differs from the amount that would be provided by applying the statutory U.S. federal income tax rate to income before income taxes as a result of the estimated effect of the domestic production activities deduction, percentage depletion, the effect of state income taxes, and other permanent differences.

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| | (In thousands) | | | |
| Current portion of income tax expense: | | | | |
| Federal | $ 5,415 | $ 6,512 | $ 24,155 | $ 11,494 |
| State | 509 | 627 | 1,475 | 1,952 |
| Deferred portion of income tax expense: | 45,235 | 26,832 | 101,231 | 79,289 |
| Total income tax expense | $ 51,159 | $ 33,971 | $ 126,861 | $ 92,735 |
| Effective tax rates | 36.8% | 37.1% | 36.8% | 37.2% |

A change in the Company's tax rates between reported periods will generally reflect differences in its estimated highest marginal state tax rate due to changes in the composition of income between state tax jurisdictions resulting from Company activities. Changes in the effects of estimates for the domestic production activities deduction, percentage depletion, and the possible impact of permanent differences related to state income tax calculations caused in part by fluctuating commodity prices can also cause the rates to vary.

The Company or its subsidiaries file income tax returns in the U.S. federal jurisdiction and in various states. With few exceptions, the Company is no longer subject to U.S. federal or state income tax examinations by tax authorities for years before 2004. The Internal Revenue Service completed audits for the 2000, 2002, and 2003 tax years during the quarter ended March 31, 2007. There was no change to the provision for income tax as a result of these examinations.

In 2007 the Company received a $3.1 million refund of income tax and interest from a carryback of net operating losses to the 2000 tax year. An additional $980,000 was received in the first quarter of 2008 for income tax refunds and accrued interest resulting from a carry-over of minimum tax credits to the 2003 tax year. These amounts have been previously recognized by the Company. The Internal Revenue Service initiated an audit of the Company's 2005 tax year that began on April 24, 2008, and is ongoing.

The Company adopted the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," on January 1, 2007. There was no financial statement adjustment required as a result of

-19-

adoption. At adoption, the Company had a long-term liability for an unrecognized tax benefit of $1.0 million and an accumulated interest liability of $92,000. The entire amount of unrecognized tax benefit would affect the Company's effective tax rate if recognized. Interest expense associated with income tax is recorded as interest expense in the accompanying consolidated statements of operations. Penalties associated with income tax are recorded in general and administrative expense in the accompanying consolidated statements of operations.

Note 7 – Long-term Debt

Revolving Credit Facility

The Company's revolving credit facility 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 the majority of the Company's oil and gas properties and the common stock of any material subsidiaries of the Company. The borrowing base under the credit facility as authorized by the bank group as of the date of this filing is $1.4 billion and is subject to regular semi-annual redeterminations. The borrowing base redetermination process considers the value of St. Mary's oil and gas properties and other assets, as determined by the bank syndicate. The Company has elected an aggregate commitment amount of $500 million under the credit facility. The Company must comply with certain financial and non-financial covenants under the terms of its credit facility agreement, including the limitation of the Company's annual dividend rate to no more than $0.25 per share. The Company is in compliance with all financial and non-financial covenants under the credit facility. Interest and commitment fees are accrued based on the borrowing base utilization percentage table below. Eurodollar loans accrue interest at London Interbank Offered Rate ("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 $500 million aggregate commitment amount and are included in interest expense in the accompanying consolidated statements of operations.

| Borrowing base | | | | |
|---|---|---|---|---|
| Utilization percentage | <50% | >50%<75% | >75%<90% | >90% |
| Eurodollar loans | 1.000% | 1.250% | 1.500% | 1.750% |
| ABR loans | 0.000% | 0.000% | 0.250% | 0.500% |
| Commitment fee rate | 0.250% | 0.300% | 0.375% | 0.375% |

The Company had $170.0 million and $198.0 million outstanding under its revolving credit agreement as of September 30, 2008, and October 28, 2008, respectively. The Company had $330 million and $302 million of available borrowing capacity under this facility as of September 30, 2008, and October 28, 2008, respectively.

5.75% Senior Convertible Notes Due 2022

The Company called for redemption of its 5.75% Senior Convertible Notes on March 16, 2007. The call for redemption resulted in the note holders electing to convert the notes to common stock in accordance with the conversion provision in the original indenture. The 5.75% Senior Convertible Note holders converted all $100 million of the 5.75% Senior Convertible Notes to common shares at a conversion price of $13.00 per share. The Company issued 7.7 million common shares in connection with the conversion.

3.50% Senior Convertible Notes Due 2027

On April 4, 2007, the Company issued $287.5 million aggregate principal amount of 3.50% Senior Convertible Notes. The 3.50% Senior Convertible Notes mature on April 1, 2027, unless converted prior to maturity, redeemed, or purchased by the Company. The 3.50% Senior Convertible Notes are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and any future unsecured senior debt and senior in right of payment to any future subordinated debt.

Holders may convert their notes based on a conversion rate of 18.3757 shares of the Company's common stock per $1,000 principal amount of the 3.50% Senior Convertible Notes (which is equal to an initial conversion price of approximately $54.42 per share), subject to adjustment, contingent upon and only under the following circumstances: (1) if the closing price of the Company's common stock reaches specified thresholds or the trading price of the notes falls below specified thresholds, (2) if the notes are called for redemption, (3) if specified distributions to holders of the Company's common stock are made or specified corporate transactions occur, (4) if a fundamental change occurs, or (5) during the ten trading days prior to, but excluding, the maturity date. The notes and underlying shares have been registered under a shelf registration statement. If the Company becomes involved in a material transaction or corporate development, it may suspend trading of the 3.50% Senior Convertible Notes as provided by the prospectus. In the event the suspension period exceeds 45 days within any three-month period or 90 days within any twelve-month period, the Company will be required to pay additional interest to all holders of the 3.50% Senior Convertible Notes, not to exceed a rate per annum of 0.50 percent of the issue price of the 3.50% Senior Convertible Notes; provided that no such additional interest shall accrue after April 4, 2009.

Upon conversion of the 3.50% Senior Convertible Notes, holders will receive cash or common stock or any combination thereof as elected by the Company. At any time prior to the maturity date of the notes, the Company has the option to unilaterally and irrevocably elect to net share settle its obligations upon conversion of the notes in cash, and if applicable, shares of common stock. If the Company makes this election, then the Company will pay the following to holders for each $1,000 principal amount of notes converted in lieu of shares of common stock: (1) an amount in cash equal to the lesser of (i) $1,000 or (ii) the conversion value determined in the manner set forth in the indenture for the 3.50% Senior Convertible Notes, and (2) if the conversion value exceeds $1,000, the Company will also deliver, at its election, cash or common stock or a combination of cash and common stock with respect to the remaining value deliverable upon conversion. Currently, it is the Company's intention to net share settle the 3.50% Senior Convertible Notes. However, the Company has not made this a formal legal irrevocable election and thereby reserves the right to settle the 3.50% Senior Convertible Notes in any manner allowed under the offering memorandum as business conditions warrant.

If a holder elects to convert the notes in connection with certain events that constitute a change of control before April 1, 2012, the Company will pay, to the extent described in the related indenture, a make-whole premium by increasing the conversion rate applicable to the 3.50% Senior Convertible Notes. In addition, the Company will pay contingent interest in cash, commencing with any six-month period beginning on or after April 1, 2012, if the average trading price of a note for the five trading days ending on the third trading day immediately preceding the first day of the relevant six-month period equals 120 percent or more of the principal amount of the 3.50% Senior Convertible Notes.

On or after April 6, 2012, the Company may redeem for cash all or a portion of the 3.50% Senior Convertible Notes at a redemption price equal to 100 percent of the principal amount of the notes to be redeemed plus accrued and unpaid interest, if any, up to but excluding the applicable redemption date. Holders of the 3.50% Senior Convertible Notes may require the Company to purchase all or a portion of their notes on each of April 1, 2012, April 1, 2017, and April 1, 2022, at a purchase price equal to 100 percent of the principal amount of the notes to be repurchased plus accrued and unpaid interest, if any, up to but excluding the applicable purchase date. On April 1, 2012, the Company may pay the purchase price in cash, in shares of common stock, or in any combination of cash and common stock. On April 1, 2017, and April 1, 2022, the Company must pay the purchase price in cash. Based on the market price of the 3.50% Senior Convertible Notes, the estimated fair value of the notes was approximately $271 million as of September 30, 2008.

Weighted-Average Interest Rate Paid and Capitalized Interest Costs

The weighted-average interest rates paid for the three-month periods ended September 30, 2008, and 2007, were 4.4 percent and 5.1 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 5.75% Senior Convertible Notes for 2007, and the effect of interest rate swaps. The weighted-average interest rates paid for the nine-month periods ended September 30, 2008, and 2007, were 4.7 percent and 5.9 percent, respectively. The outstanding loan balance as of September 30, 2008, increased in comparison to the outstanding loan balances as of September 30, 2007, while the three-month and nine-month period rates associated with the balances decreased. The decrease is attributed to significantly lower LIBOR and Prime rates for the specified periods in 2008 compared to 2007. Capitalized interest costs for the three-month period ended September 30, 2008, and 2007, were $751,000 and $1.2 million, respectively. Additionally, capitalized interest costs for the nine-month period ended September 30, 2008, and 2007, were $2.8 million and $3.8 million, respectively.

Note 8 – Derivative Financial Instruments

Oil and Natural 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, natural gas, and natural gas liquids. 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, 2008, the Company has hedge contracts in place through 2011 for a total of approximately 9 million Bbls of anticipated crude oil production, 64 million MMBtu of anticipated natural gas production, and 1 million Bbls of anticipated natural gas liquids production.

The Company attempts to qualify its oil, natural gas, and natural gas liquids derivative instruments as cash flow hedges for accounting purposes under Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS No. 133"), and related pronouncements. The Company formally documents all relationships between the derivative instruments and the hedged production, as well as the Company's risk management objective and strategy for the particular derivative contracts. This process includes linking all derivatives that are designated as cash flow hedges to the specific forecasted sale of oil, natural gas, or natural gas liquids at its physical location. The Company also formally assesses (both at the derivative's inception and on an ongoing basis) whether the derivatives being utilized have been highly effective at offsetting changes in the cash flows of hedged production and whether those derivatives may be expected to remain highly effective in future periods. If it is determined that a derivative has ceased to be highly effective as a hedge, the Company will discontinue hedge accounting prospectively. If hedge accounting is discontinued and the derivative remains outstanding, the Company will recognize all subsequent changes in its fair value on the Company's consolidated statements of operations for the period in which the change occurs. As of September 30, 2008, all oil, natural gas, and natural gas liquid derivative instruments qualified as cash flow hedges for accounting purposes. The Company anticipates that all forecasted transactions will occur by the end of their originally specified periods. All contracts are entered into for other than trading purposes.

The fair value of oil and natural gas derivative contracts designated and qualifying as cash flow hedges under SFAS No. 133 was a net liability balance of $288.1 million at September 30, 2008. The Company realized a net loss of $53.5 million and a net gain of $10.2 million from its oil and natural gas derivative contracts for the three-month periods ended September 30, 2008, and 2007, respectively. The Company realized a net loss of $145.8 million and a net gain of $36.2 million from its oil and natural gas derivative contracts for the nine-month periods ended September 30, 2008, and 2007, respectively.

At September 30, 2008, the Company had no margin collateral deposits with hedge counterparties. As of December 31, 2007, the Company had $2.0 million on deposit with a hedge counterparty. Generally, the Company's hedge liability to its counterparties is secured under the terms of the Company's credit facility agreement. One counterparty to the Company's hedges is not a participant in the Company's credit facility agreement, and this counterparty requires a dollar for dollar margin to be posted as collateral for mark-to-market liabilities that exceed a certain limit.

After-tax changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings upon the sale of the hedged production. As of September 30, 2008, the amount of unrealized loss, net of unrealized gains and net of deferred income taxes, to be reclassified from accumulated other comprehensive income to oil and natural gas production operating revenues in the next twelve months is equal to $64.9 million.

Any change in fair value resulting from ineffectiveness is recognized currently in unrealized derivative gain (loss) in the accompanying consolidated statements of operations. Unrealized derivative gain (loss) for the three-month periods ended September 30, 2008, and 2007, includes net gains of $4.4 million and $2.9 million respectively, from ineffectiveness related to oil and natural gas derivative contracts. Unrealized derivative gain (loss) for both the nine-month periods ended September 30, 2008, and 2007, includes net losses of $800,000 and $2.2 million, respectively, from ineffectiveness related to oil and natural gas derivative contracts.

Gains or losses from the settlement of oil and gas derivative contracts are reported in the total operating revenues section of the accompanying consolidated statements of operations.

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

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| | (In thousands) | | | |
| Derivative contract settlements included in oil and gas hedge gain (loss) | $ (53,491) | $ 10,173 | $ (145,837) | $ 36,160 |
| Ineffective portion of hedges qualifying for hedge accounting included in derivative gain (loss) | 4,429 | 4,336 | (802) | (889) |
| Non-qualifying derivative contracts included in derivative gain (loss) | - | (1,456) | - | (1,335) |
| Interest rate derivative contract settlements included in interest expense | (476) | - | (1,017) | (283) |
| Total gain (loss) | $ (49,538) | $ 13,053 | $ (147,656) | $ 33,653 |

Interest Rate and Convertible Note Derivative Instruments

In relation to the Company's 5.75% Senior Convertible Notes converted in March 2007, the Company entered into a fixed-to-floating interest rate swap on $50 million of principal in October 2003, and entered into a floating-to-fixed rate swap for the same notional amount of $50 million in April 2005 in order to effectively offset the initial fixed-to-floating interest rate swap. The Company recorded a net derivative loss in interest expense of $283,000 for the nine-month period ended September 30, 2007. There was no net derivative loss recorded in interest expense for the three-month period ended September 30, 2007.

In September 2007 the Company entered into a one year floating-to-fixed interest rate derivative contract for a notional amount of $75 million.  Under the agreement, the Company paid a fixed rate of 4.9 percent and was paid a variable rate based on the one-month LIBOR rate.  The interest rate derivative contract was measured at fair value using quoted prices in active markets.  The interest rate swap was a highly liquid, non-complex, non-structured instrument.  This derivative qualified for cash flow hedge treatment under SFAS No. 133 and related pronouncements.  The Company recorded net derivative losses in interest expense of $476,000 and $1.0 million in the accompanying consolidated statements of operations for the three-month and nine-month periods ended September 30, 2008, respectively, related to the interest rate derivative contract.  This instrument was settled in the third quarter of 2008.

The contingent interest provision of the 3.50% Senior Convertible Notes is a derivative instrument.  As of September 30, 2008, the value of the derivative was determined to be immaterial.

Note 9 – Pension Benefits

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

Components of Net Periodic Benefit Cost

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

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| | (In thousands) | | | |
| Service cost | $ 460 | $ 478 | $ 1,379 | $ 1,433 |
| Interest cost | 222 | 198 | 665 | 595 |
| Expected return on plan assets | (168) | (135) | (503) | (405) |
| Amortization of net actuarial loss | 40 | 55 | 121 | 164 |
| Net Periodic benefit cost | $ 554 | $ 596 | $ 1,662 | $ 1,787 |

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

Contributions

The Company has contributed $2.5 million to the Qualified Pension Plan during the first three quarters of 2008.  Presently, the Company believes it will contribute an additional $300,000 to the Nonqualified Pension Plan during the remainder of the year.

Note 10 – Asset Retirement Obligations

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

The Company's estimated asset retirement obligation liability is based on estimated economic lives, historical experience in abandoning wells, estimated cost to abandon the wells in the future, and federal and state regulatory requirements. The liability is discounted using a credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. The credit-adjusted risk-free rates used to discount the Company's abandonment liabilities range from 6.50 percent to 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, | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| | (In thousands) | | | |
| Beginning asset retirement obligation | $ 106,486 | $ 90,554 | $ 108,284 | $ 77,242 |
| Liabilities incurred | 1,073 | 2,702 | 7,162 | 7,443 |
| Liabilities settled | (4,039) | (3,380) | (16,509) | (4,678) |
| Accretion expense | 1,954 | 1,465 | 5,337 | 4,215 |
| Revision to estimated cash flow | 6,373 | 651 | 7,573 | 7,770 |
| Ending asset retirement obligation | $ 111,847 | $ 91,992 | $ 111,847 | $ 91,992 |

Accounts payable and accrued expenses contain $6.4 million and $6.9 million related to the Company's current asset retirement obligation liability as of September 30, 2008, and 2007, respectively. Accounts payable and accrued expenses contain $3.1 million related to the Company's current asset retirement obligation liability as of December 31, 2007. As of September 30, 2008, September 30, 2007, and December 31, 2007, the accounts payable and accrued expenses balances include amounts for the estimated retirement costs associated with an off-shore platform that was destroyed during Hurricane Rita in 2005. Retirement of the platform was substantially completed as of September 30, 2008. Please refer to Note 13 – Insurance Settlement for additional details. Additionally, the September 30, 2008, amount includes an accrual in excess of the Company's maximum insurance policy limit for the remediation of the Vermilion 281platform and other properties damaged in Hurricane Ike in September 2008.

Note 11 – Fair Value Measurements

Effective January 1, 2008, the Company partially adopted Statement of Financial Accounting Standards No. 157, "Fair Value Measurements" ("SFAS No. 157") for all financial assets and liabilities measured at fair value on a recurring basis. The statement establishes a framework for measuring fair value and requires enhanced disclosures about fair value measurements. SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exact price) in an orderly transaction between market participants at the measurement date. The statement establishes market or observable inputs as the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The statement establishes a hierarchy for grouping these assets and liabilities, based on the significance level of the following inputs:

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

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

- Level 3 – Significant inputs to the valuation model are unobservable

The following is a listing of the Company's assets and liabilities required to be measured at fair value on a recurring basis and where they are classified within the hierarchy as of September 30, 2008:

| | Level 1 | Level 2 | Level 3 |
|---|---|---|---|
| | | (In thousands) | |
| Assets: | | | |
| Accrued derivative | $ - | $ 55,089 | $ - |
| Liabilities: | | | |
| Accrued derivative | $ - | $ 343,184 | $ - |
| Net Profits Plan | $ - | $ - | $ 258,307 |

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

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil and gas hedges and the interest rate swap. Fair values are based upon interpolated data. The Company derives internal valuation estimates taking into consideration the counterparties' credit ratings, the Company's credit rating, and the time value of money and then compares that to the counterparties' mark-to-market statements. The considered factors result in an estimated exit-price for each asset or liability under a market place participant's view. Management believes that this approach provides a reasonable, non-biased, verifiable, and consistent methodology for valuing derivative instruments.

Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value due to the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. The Company monitors the counterparties' credit ratings and may ask counterparties to post collateral if their ratings deteriorate. In some instances the Company will attempt to novate the trade with a more stable counterparty.

Valuation adjustments are necessary to reflect the effect of the Company's credit quality on the fair value of any liability position with a counterparty. This adjustment takes into account any credit enhancements, such as collateral margin that the Company may have posted with a counterparty, as well as any letters of credit between the parties. The methodology to determine this adjustment is consistent with how the Company evaluates counterparty credit risk, taking into account the Company's credit rating, current credit spreads, and any change in such spreads since the last measurement date. The majority of the Company's derivative counterparties are members of St. Mary's secured bank syndicate. The Company is currently in a net liability position with all of its counterparties as of September 30, 2008.

The methods described above may result in a fair value estimate that may not be indicative of net realizable value or may not be reflective of future fair values and cash flows. While the Company believes that the valuation methods utilized are appropriate and consistent with the requirements of SFAS No. 157 and with other marketplace participants, the Company recognizes that third parties may use different

-26-

methodologies or assumptions to determine the fair value of certain financial instruments that could result in a different estimate of fair value at the reporting date.

Commodity Derivative Assets and Liabilities – The Company has a variety of derivatives including commodity swaps and collars for the sale of oil, natural gas, and natural gas liquids. Standard oil and gas activities expose the Company to varying degrees of commodity price risk. To mitigate a portion of this risk, the Company may enter into natural gas, crude oil, and natural gas liquids derivatives to lower the commodity price risk associated with an acquisition or when market conditions are favorable. The Company values these derivatives using index prices, mark-to-market statements received from counterparties, the Company's credit adjusted borrowing rate, and also factors in the time value of money. As the value is derived from numerous factors, all of the Company's commodity derivative assets and liabilities are classified as having Level 2 inputs.

Interest Rate Derivative Assets and Liabilities – The Company had one interest rate swap agreement in place for the notional amount of $75 million, which was settled in the third quarter of 2008. This instrument effectively caused a portion of the Company's floating rate debt to become fixed rate debt and was held with a major financial institution. A mark-to-market valuation that took into consideration anticipated cash flows from the transaction using quoted market prices, other economic data and assumptions, and pricing indications used by other market participants was used to value the swap. Given the degree of varying assumptions used to value the swap, it was deemed to use Level 2 inputs.

Net Profits Plan

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

The Company records the estimated fair value of the long-term liability for estimated future payments under the Net Profits Plan based on the discounted value of estimated future payments associated with each individual pool. The calculation of this liability is a significant management estimate. For a predominate number of the pools, a discount rate of 12 percent is used to calculate this liability. This rate is intended to represent the best estimate of the present value of expected future payments under the Net Profits Plan.

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

As noted above, the calculation of the estimated liability for the Net Profits Plan is also highly sensitive to price estimates and discount rate assumptions. For example, if the commodity prices used in the calculation changed by five percent, the liability recorded at September 30, 2008, would differ by approximately $30 million. A one percentage point decrease in the discount rate would result in an increase to the liability of approximately $15 million, while a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $14 million. Actual cash payments to be made to participants 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 are inherently different from the amounts estimated.

No published market quotes exist on which to base the Company's estimate of fair value of the Net Profits Plan liability. As such, the recorded fair value is based entirely on the management estimates that are described within this footnote. While some inputs to the Company's calculation of the fair value of the Net Profits Plan's future payments are from published sources, others, such as the discount rate and the expected future cash flows, are derived from the Company's own calculations and estimates. The following table reflects the activity for the liabilities measured at fair value using Level 3 inputs for the three-month and nine-month periods ended September 30, 2008:

| | For the Three Months Ended September 30, 2008 | For the Nine Months Ended September 30, 2008 |
|---|---|---|
| | (In thousands) | |
| Beginning balance | $ 293,174 | $ 211,406 |
| Net increase (decrease) in liability(a) | (24,451) | 92,832 |
| Net settlements (a)(b) | (10,416) | (45,931) |
| Transfers in (out) of Level 3 | - | - |
| Ending balance | $ 258,307 | $ 258,307 |

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

Refer to Note 8 – Derivative Financial Instruments, and Note 5 – Compensation Plans, for more information regarding the Company's hedging instruments and the Net Profits Plan, respectively. Additionally, refer to Note 7 – Long-term Debt for the disclosure of the September 30, 2008, fair value of the 3.50% Senior Convertible Notes Due 2027.

Note 12 – Repurchase and Retirement of Common Stock

Stock Repurchase Program

During the first quarter of 2008 St. Mary repurchased 2,135,600 shares of its outstanding common stock in the open market at a weighted-average price of $36.13 per share, including commissions, for a total of $77.1 million. As of the date of this filing, the Company has Board authorization to repurchase up to 3,072,184 additional shares of common stock. The shares may be repurchased from time to time in open market transactions or in 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 revolving credit facility. Additionally, in March 2008, the Company's Board of Directors approved a resolution to retire 2,945,212 shares of treasury stock. St. Mary did not repurchase any shares of common stock under the program during the second or third quarters of 2008.

St. Mary repurchased 790,816 shares of common stock under the program during the third quarter of 2007 at a weighted-average price of $32.76 per share, including commissions, for a total of $25.9 million. St. Mary did not repurchase any shares of common stock under the program during the first half of 2007.

Note 13 – Insurance Settlement

In April 2007 the Company reached a global insurance settlement for reimbursement of damages sustained during Hurricane Rita in 2005. St. Mary's net amount of the final settlement was approximately $33 million. As a result of this settlement, the company recorded a gain of $6.3 million in other revenue in the accompanying consolidated statement of operations for the nine months ended September 30, 2007. The Company experienced significant weather-related and other delays in its retirement efforts and consequently incurred additional retirement costs for the offshore platform. As of September 30, 2008, the Company has recorded a gain of $3.6 million associated with the insurance settlement. The Company's retirement efforts are substantially complete as of the date of this filing and the Company expects adjustments to the gain to be completed during the fourth quarter of 2008. Any variation between actual and estimated retirement costs will impact the final determination of the gain associated with the insurance settlement.

Note 14 – SemGroup Bankruptcy

On July 22, 2008, SemGroup, L.P. and certain of its North American subsidiaries (collectively referred to herein as "SemGroup") filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware. Certain SemGroup entities purchase a portion of the Company's crude oil production. As a result of the SemGroup bankruptcy filing the Company recorded an allowance for doubtful accounts and bad debt expense of $16.6 million as of September 30, 2008, of which $6.7 million was recognized as bad debt expense during the three-month period ended September 30, 2008, and $9.9 million was recognized during the three-month period ended June 30, 2008. The Company believes that it has fully allowed for all potential uncollectible amounts and believes that it has no remaining exposure resulting from this bankruptcy. In an effort to maximize its recovery, the Company has filed the appropriate pleadings and is participating in certain adversary proceedings in the SemGroup bankruptcy case to establish the Company's secured and priority claims. The matter does not have a material adverse effect on the Company's liquidity or overall financial position.

Note 15 – Hurricanes Gustav and Ike

During the third quarter of 2008, assets in which the Company has an interest were impacted by Hurricanes Gustav and Ike. The Company incurred damage to two wells and to its production facilities located at Goat Island in Galveston Bay and minor damages to several other properties. The Vermilion 281 production platform was lost in Hurricane Ike. The Company currently estimates that it will incur $26 million associated with the clean up, assessment of damages, and remediation associated with this platform.

The Company maintains insurance that it expects to utilize with regard to the lost platform and damage to several other properties. Due to the severe damage caused by the hurricane, the Company currently expects the total storm related costs to exceed the maximum insurance policy limit. During the third quarter of 2008, the Company wrote off the carrying value of the Vermilion 281 platform, as well as the carrying value associated with the production facility assets located at Goat Island. Additionally, the Company established an accrual for the estimate of the remediation and various other property damage repair costs the Company expects to incur in excess of its maximum insurance policy limit. As a result, the Company has recorded a $7.0 million loss, which is included in other expense in the accompanying consolidated statement of operations for the third quarter of 2008. Any variation between actual and estimated storm related costs will impact the final determination of the loss.

Note 16 – Recent Accounting Pronouncements

In September 2006 the FASB issued SFAS No. 157, which defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. Where applicable, this statement simplifies and codifies fair value related guidance previously issued within

generally accepted accounting principles. SFAS No. 157 was effective for the Company on January 1, 2008. The Company partially adopted SFAS No. 157 pursuant to FASB Staff Position No. FAS 157-2, "Effective Date of FASB Statement No. 157" ("FSP No. FAS 157-2"), which delayed the effective date of SFAS No. 157 for all nonrecurring fair value measurements of nonfinancial assets and nonfinancial liabilities until fiscal years beginning after November 15, 2008. FSP No. FAS 157-2 states that a measurement is recurring if it happens at least annually and defines nonfinancial assets and nonfinancial liabilities as all assets and liabilities other than those meeting the definition of a financial asset or financial liability in Statement of Financial Accounting Standards No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" ("SFAS No. 159"). The statement also notes that if SFAS No. 157 is not applied in its entirety, the Company must disclose (1) that it has only partially adopted SFAS No. 157 and (2) that categories of assets and liabilities recorded or disclosed at fair value to which the statement was not applied.

The Company adopted FSP No. 157-2 as of January 1, 2008, electing to partially adopt SFAS No. 157. The Company did not apply SFAS No. 157 to nonrecurring fair value measurements of nonfinancial assets and nonfinancial liabilities, including nonfinancial long-lived assets measured at fair value for an impairment assessment under Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-lived Assets", and asset retirement obligations initially measured at fair value under the statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations". The Company is still required to apply SFAS No. 157 to recurring financial and non-financial instruments, which affects the fair value disclosure of the Company's financial derivatives within the scope of SFAS No. 133. The partial adoption of SFAS No. 157 did not have a material impact on the Company's consolidated financial statements. Please refer to Note 11 – Fair Value Measurements.

In February 2007 the FASB issued SFAS No. 159, which expands the use of fair value accounting but does not affect existing standards that require assets or liabilities to be carried at fair value. SFAS No. 159 allows entities to choose, at specified election dates, to use fair value to measure eligible financial assets and liabilities that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item's fair value in subsequent reporting periods must be recognized in current earnings. SFAS No. 159 also establishes presentation and disclosure requirements designed to draw comparisons between entities that elect different measurement attributes for similar assets and liabilities. SFAS No. 159 was effective for the Company on January 1, 2008. The Company did not elect the fair value option. There was no impact on the Company's consolidated financial statements.

In December 2007 the FASB issued Statement of Financial Accounting Standards No. 141(R), "Business Combinations" (SFAS No. 141(R)"), which requires the acquiring entity in a business combination to recognize and measure all assets and liabilities assumed in the transaction and any non-controlling interest in the acquiree at fair value as of the acquisition date. The statement also establishes guidance for the measurement of the acquirer shares issued in consideration for a business combination, the recognition of contingent consideration, the accounting treatment for pre-acquisition gain and loss contingencies, the treatment of acquisition related transaction costs, and the recognition of changes in the acquirer's income tax valuation allowance and deferred taxes. SFAS No. 141(R) is effective for fiscal years beginning after December 15, 2008, and is to be applied prospectively as of the beginning of the fiscal year in which the statement is applied. Early adoption is not permitted. SFAS No. 141(R) will be effective for the Company beginning with the 2009 fiscal year. The Company is currently evaluating the potential impact of SFAS No. 141(R) on its consolidated financial statements, but the nature and magnitude of the specific effects will depend upon the nature, terms, and size of the acquisitions the Company consummates after the effective date.

In December 2007 the FASB issued Statement of Financial Accounting Standards No. 160, "Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51" (SFAS No. 160"), which establishes accounting and reporting standards that require noncontrolling interests to be reported as a component of equity. The statement also requires that changes in a parent's ownership

-30-

interest while the parent retains its controlling interest be accounted for as equity transactions and that any retained noncontrolling equity investment upon the deconsolidation of a subsidiary be initially measured at fair value. SFAS No. 160 is effective for fiscal years beginning after December 15, 2008, and is to be applied prospectively as of the beginning of the fiscal year in which the statement is applied. The Company will be required to adopt SFAS No. 160 beginning with its 2009 fiscal year. The Company is currently evaluating the potential impact, if any, of the adoption of SFAS No. 160 on its consolidated financial statements.

In March 2008 the FASB issued Statement of Financial Accounting Standard No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133" ("SFAS No. 161"), which requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. The statement requires fair value disclosures of derivative instruments and their gains and losses to be in tabular format, the potential effect on the entity's liquidity from the credit-risk-related contingent features to be disclosed, and cross-referencing within the footnotes. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The Company will be required to adopt SFAS No. 161 beginning with its 2009 fiscal year. The Company is currently evaluating the potential impact, if any, of the adoption of SFAS No. 161 on its consolidated financial statements.

In May 2008, the FASB issued FASB Staff Position APB 14-1, "Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement)" (FSP APB 14-1), which establishes bifurcation accounting for convertible debt instruments that may be settled in cash upon conversion. FSP APB 14-1 states that such instruments should be valued without the conversions feature and should be classified as debt and that the remaining proceeds should be recorded as equity to represent the cash settlement option. For instruments within the scope of FSP APB 14-1, debt discounts shall be amortized over the expected life of a similar liability that does not have an associated equity component. Amortization of the debt discount will result in increased interest expense in the statement of operations. FSP APB 14-1 will also yield lower earnings per share dilution than typical convertible bonds. FSP APB 14-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008. The Company will be required to adopt FSP APB 14-1 beginning with its 2009 fiscal year, and early adoption is not permitted. FSP APB 14-1 must be applied retrospectively to all periods presented for any instrument within the scope of FSP APB 14-1 that was outstanding during any of the periods presented. FSP APB 14-1 changes the accounting treatment for the Company's 3.50% Senior Convertible Notes, and will increase the Company's non-cash interest expense for its past and future reporting periods. In addition, it will reduce the Company's long-term debt and increase the Company's stockholders' equity for past reporting periods. The Company is currently evaluating the full impact of FSP APB 14-1 on its consolidated financial statements.

In May 2008 the FASB issues SFAS No. 162, "The Hierarchy of Generally Accepted Accounting Principles"("SFAS No. 162"), which identifies a consistent framework for selecting accounting principles to be used in preparing financial statements for nongovernmental entities that are presented in conformity with United States GAAP. The current GAAP hierarchy was criticized due to its complexity, ranking position of FASB Statements of Financial Accounting Concepts, and the fact that it is directed at auditors rather than entities. SFAS No. 162 is effective November 15, 2008. The FASB does not expect that SFAS No. 162 will cause a change in current practice, and the Company does not believe that SFAS No. 162 will have an impact on its financial statements, financial position, and results of operations or cash flows.

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

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

Overview of the Company

General Overview

We are an independent energy company focused on the exploration, exploitation, development, acquisition, and production of natural gas and crude oil in the United States. Our recurring revenues and cash flows are generated almost entirely from the sale of produced natural gas and crude oil. Our oil and gas reserves and operations are located primarily in the following areas:

- Various Rocky Mountain basins, including the Williston, Big Horn, Wind River, Powder River, and Greater Green River Basins

- The Anadarko and Arkoma basins of the Mid-Continent

- The Permian Basin

- East Texas and North Louisiana

- The greater Maverick Basin in South Texas

- The onshore Gulf Coast and offshore Gulf of Mexico

We have developed a balanced and diverse portfolio of proved reserves, development drilling opportunities, and unconventional resource projects.

Our primary objective is growing our net asset value per share. Over the long term we believe that growing net asset value per share leads to superior stock price performance. A focus on net asset value per share provides us the flexibility to pursue a variety of projects that we believe will create value. We also believe that our regional diversity and the balance between oil and natural gas in our reserves are advantages we can leverage to build value for our stockholders.

Financial Standing and Liquidity

During and subsequent to the third quarter of 2008, specific issues related to the financial sector have rippled through the broader economy. The failure or takeovers of several large financial institutions has adversely impacted the wider equity, debt, and credit markets. Financial standing and liquidity have become increasingly important as concerns have been raised regarding the pace of drilling activity in the exploration and production industry and the ability of companies to fund their planned activity. In addition, fears of global recession have resulted in a significant decline in oil and natural gas prices. Our planned exploration and production capital expenditures budget of $758 million for 2008 is expected to be near our discretionary cash flow for the year. Moreover, we are currently in the process of budgeting for our 2009 exploration and development program, and we expect that program will be at or within our discretionary cash flow for 2009. Accordingly, we do not currently expect to require additional amounts of financing to execute our plans for the remainder of 2008 or during 2009, and we do not anticipate accessing the equity or public debt markets for the remainder of 2008 or during 2009. We have spent $83.4 million on acquisitions and $77.2

million for share repurchases in 2008. However, these have largely been offset by divestitures of non-strategic properties that have provided $155.2 million in proceeds.

We continue to believe we have adequate liquidity available to us through our credit facility. On October 1, 2008, the lending group redetermined our reserve-backed borrowing base under the credit facility at an amount of $1.4 billion. Based on our expected needs, we have elected a $500 million commitment amount. These terms are identical to the terms which were in place in the previous six months prior to the redetermination. We had $170.0 million and $198.0 million, respectively, drawn on the credit facility at September 30, 2008, and October 28, 2008. Management believes that the current commitment is sufficient and that if necessary we could request a higher commitment amount from the lending group, although it would likely be at different terms and interest rates than are currently in place. To date, we have experienced no issues drawing upon our credit facility and all eleven participating banks have continued to fund. No individual bank participating in the credit facility represents more than 11 percent of the lending commitments under the credit facility. We are monitoring the borrowing environment closely and have frequent discussions with the lending group to ensure we are aware of the latest developments. One of the co-lead banks in the credit facility, Wachovia, has agreed to be acquired by the other co-lead bank, Wells Fargo. The transaction is expected to close by year-end, but is not anticipated to result in any changes to the terms of our credit facility.

Oil and Gas Prices

Oil and natural gas prices reached significant highs during June and early July of 2008 and have declined significantly since that time. The results of our operations and financial condition are significantly affected by oil and natural gas commodity prices, which can fluctuate dramatically. We sell a majority of our natural gas under contracts that use first of the month index pricing, which means that gas produced in that month is sold at the first of the month price regardless of the spot price on the day the gas is produced. Our crude oil is sold using contracts that pay us the average of either the NYMEX West Texas Intermediate daily settlement or the average of alternative posted prices for the periods in which the crude oil is produced, adjusted for quality, transportation, and location differentials. The following table is a summary of commodity price data for the third and second quarters of 2008 and the third quarter of 2007.

| | For the Three Months Ended | | |
|---|---|---|---|
| | September 30, 2008 | June 30, 2008 | September 30, 2007 |
| Crude Oil (per Bbl): | | | |
| NYMEX price | $ 117.98 | $ 123.98 | $ 75.38 |
| Realized price, before the effects of hedging | $ 111.97 | $ 120.20 | $ 71.68 |
| Net realized price, including the effects of hedging | $ 83.30 | $ 88.40 | $ 67.56 |
| Natural Gas (per Mcf): | | | |
| NYMEX price | $ 10.09 | $ 10.80 | $ 6.13 |
| Realized price, before the effects of hedging | $ 9.96 | $ 10.83 | $ 5.98 |
| Net realized price, including the effects of hedging | $ 9.51 | $ 9.97 | $ 7.03 |

Average quarterly NYMEX crude oil prices decreased five percent from the second quarter of 2008 to the third quarter of 2008 from $123.98 per barrel to $117.98 per barrel. The price of crude oil is decreasing as a result of a forecasted decrease in global demand, which is a consequence of a broader economic slowdown stemming from the financial turmoil that has taken place in recent months. The 36-month forward strip price for crude oil at the end of the second quarter of 2008 was $139.34 per barrel. At the end of the third quarter of 2008, the 36-month forward contract had decreased by 26 percent to $103.72 per barrel. By October 28, 2008, the 36-month forward strip price had declined an additional 32 percent to $70.40 per barrel.

Average quarterly NYMEX natural gas prices decreased seven percent from the second quarter of 2008 to the third quarter of 2008 from $10.80 per Mcf to $10.09 per Mcf. The 36-month forward strip price for natural gas at the end of the second quarter of 2008 was $11.91 per MMBtu. At the end of the third quarter of 2008, the 36-month forward contract had decreased 30 percent to $8.36 per MMBtu. As of October 28, 2008, the 36-month forward strip price had declined an additional 12 percent to $7.39 per MMBtu. Natural gas prices have been pressured downward in recent months as a result of a forecasted decrease in global demand and over concerns of forecasted excess gas supply that will be generated from significant activity in the exploration and production industry, specifically the ramp up in the number of horizontal wells planned in a number of new shale plays across the United States.

While changes in quoted NYMEX oil and Henry Hub natural gas prices are generally used as a basis for comparison within our industry, the price we receive for oil and natural gas is affected by quality, energy content, location, and transportation differential for these products. We refer to this price as our realized price, which excludes the effects of hedging. We are beginning to see wider differentials for both oil and natural gas in recent months in regions that have high levels of industry activity. In particular, differentials for oil in the Williston Basin have been pressured as activity in the area has accelerated in recent months and differentials for natural gas in the Mid-Continent have widened as regional demand has not kept pace with the growth in supply generated by several successful shale plays in the general vicinity. Our realized price is further impacted by the result of our hedging contracts that are settled in the respective periods. We refer to this price as our net realized price. Our net natural gas price realization for the three months ended September 30, 2008, was negatively impacted by $8.1 million of realized hedge losses and our net oil price realization was negatively impacted by $45.4 million of realized hedge losses. On a percentage basis, we currently have hedged more forecasted crude oil production than forecasted natural gas production using a combination of swaps and costless collars.

Effects of Hurricanes Gustav and Ike

During the third quarter of 2008, assets in which we have an interest were impacted by Hurricanes Gustav and Ike. We lost the Vermilion 281 producing platform in the Gulf of Mexico and incurred damage to our production facilities in Galveston Bay. The most impactful damage caused by the storm was to power and processing facilities and infrastructure in the Gulf Coast area, causing us to shut-in production throughout the Gulf Coast region. Production from certain Gulf Coast properties continues to be shut-in as of the date of this report. Many of the facilities damaged by these storms are involved in the processing and transporting of natural gas and oil produced in areas other than the Gulf Coast or Gulf of Mexico. As a result, we have experienced production disruptions in the Permian, Mid-Continent, and Gulf Coast regions while damaged facilities were repaired. The overall impact from the recent hurricanes in the Gulf of Mexico did not have a material impact on our financial position or results of operations.

As mentioned above, the Vermilion 281 production platform was lost in Hurricane Ike. Our net production from Vermilion 281 was approximately 263 MCFED before the storm, and we had an estimated 382 MMCFE of proved reserves as of September 1, 2008. We are in the process of assessing and remediating the damage related to the Vermilion 281 platform. As of the filing date of this report, we estimate that we will incur $26 million associated with the clean up, assessment of damages, and remediation associated with this platform.

Hurricane Ike caused damage to two wells and our production facilities located at Goat Island in Galveston Bay. Restoration is largely dependent on repairs to our transportation, storage, and processing facilities. As of the filing date of this report, we currently estimate that we will incur a net $1 million to rebuild the production facilities.

We also incurred minor damage to outside-operated properties from the hurricanes. Restoration of the remaining shut-in production is largely dependent on repairs to transportation and processing facilities which are owned and operated by other operators and facility owners.

We maintain insurance that we expect to utilize with regard to the lost platform and repairs to various other properties. Due to the severe damage caused by the hurricane, we currently expect the remediation costs related to the platform and the repairs to various other properties will exceed the maximum insurance policy limit. During the third quarter of 2008, we wrote off the carrying value of the Vermilion 281 platform, as well as the carrying value associated with the production facility assets located at Goat Island. Additionally, we established an accrual for our estimate of the remediation and various other property damage repair costs we expect to incur in excess of our maximum insurance policy limit. As a result, we recorded a $7.0 million loss for the third quarter of 2008, which is included in other expense in the accompanying consolidated statement of operations. Any variation between actual and estimated remediation and damage repair costs will impact the final determination of the loss.

Hedging Activities

We have a hedging program that has been built primarily on hedges related to acquisitions where we hedge the first two to five years of an acquisition's risked production. We also occasionally hedge a portion of our existing forecasted production on a discretionary basis. Taking into account all oil and natural gas production hedge contracts in place through September 30, 2008, we have hedged approximately 9 million Bbls of oil, 64 million MMBtu of natural gas, and 1 million Bbls of natural gas liquids for anticipated future production through the year 2011. No additional hedges have been entered into between September 30, 2008, and the filing date of this report. As of October 28, 2008, the approximate fair value of oil and natural gas derivative contracts designated and qualifying as cash flow hedges under SFAS No. 133 was a net asset balance of $32 million.

Recent events in the financial sector have increased the awareness of potential risks associated with hedge counterparties. As of September 30, 2008, we were in a net liability position with all of the counterparties with whom we hedge. As of October 28, 2008, we are in a net asset position with five of our counterparties and a net liability position with four of our counterparties. We have performed a financial and credit review of those specific counterparties and currently believe we will not have any material issues regarding collectability of any net receivables that may arise in the future. The majority of the counterparties with whom we hedge are also participants in our credit facility. Under this arrangement, these counterparties do not require us to post margin collateral for potential hedging liabilities since they are secured by our oil and natural gas assets and the common stock of our material subsidiaries furnished as collateral under our credit facility. We were not required to post margin with any hedge counterparties as of September 30, 2008, and through the filing date of this report. Refer to 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.

Net Profits Plan

Payments made for cash distributions under the Net Profits Plan are recorded as either general and administrative expense or exploration expense. These payments totaled $10.4 million and $45.9 million for the three-month and nine-month periods ended September 30, 2008. 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 long-term liability amount. Additional discussion is included in the analysis in the Comparison of Financial Results and Trends sections below. An increasing percentage of the costs associated with payments for the Net Profits Plan are recorded as general and administrative expense compared to exploration expense. This is a function of the normal departure of employees who previously contributed to exploration efforts. We determined that all of the payments to individuals no longer employed by St. Mary should be recorded as general and administrative expense beginning in 2007.

With respect to the accounting estimate of the liability associated with future estimated payments from our Net Profits Plan, we decreased the long-term liability associated with this item to $258.3 million

as of September 30, 2008, which resulted in a benefit of $34.9 million for the three-month period ended September 30, 2008. This decrease is related to a decrease in the estimated future net revenues used to calculate the liability, driven by overall commodity price decreases from the prior quarter. We expect approximately $55 million of cash payments to be made or accrued during 2008. However, it is not possible to predict this with a high degree of certainty due to the sensitivity of the liability to commodity prices and reserve estimates. The Company will not be adding new Net Profits Plan pools prospectively as this compensation program has been replaced with a different long-term incentive compensation program, as described in Note 5 in Part I, Item 1 of this report. Beginning in 2008, regular annual grants from the restricted stock units program and the Net Profits Plan are being replaced with grants of PSAs under our 2006 Equity Plan. The Company will continue to make payments from the existing Net Profits Plan pools and will continue to make prospective adjustments to the long-term Net Profits Plan liability as necessary.

The calculation of the estimated liability associated with the Net Profits Plan requires management to prepare an estimate of future amounts payable from the plan. On a monthly basis, we calculate estimates of the payments to be made for each individual pool. 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. 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 a rolling 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 anticipated hedge prices for the percentage of forecasted hedged production in the relevant future periods.

The calculation of the estimated liability for the Net Profits Plan is highly sensitive to our price estimates and discount rate assumption. For example, if we changed the commodity prices in our calculation by five percent, the liability recorded on the balance sheet at September 30, 2008, would differ by approximately $30 million. A one percentage point decrease in the discount rate would result in an increase to the liability of approximately $15 million, while a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $14 million. We frequently re-evaluate the assumptions used in our calculation and consider the possible impacts stemming from the current market environment including current and future oil and gas prices, discount rates, and overall market conditions.

Performance Share Plan

During the fourth quarter of 2007 we made the decision to grant PSAs in place of RSUs as the primary form of long-term equity incentive compensation for certain employees. Our Board of Directors approved an amendment and restatement of the 2006 Equity Incentive Compensation Plan on March 28, 2008, and the amended plan was approved by stockholders at our annual stockholders' meeting on May 21, 2008. We granted the first award of performance shares on August 1, 2008. The fair value associated with this grant equaled $12.3 million. PSAs provide target awards that are earned over a three-year performance period. We believe this new long-term incentive plan is more transparent and will be more widely understood by our employees and our stockholders. Target awards will be made at the beginning of the performance measurement period and will have a back-end weighted vesting schedule and a multiplier factor based on total stockholder return (TSR) and performance relative to our peers. At the conclusion of the three-year performance measurement period, our TSR will be measured and compared against a pre-established performance index consisting of companies similar to us. Depending on the results of that measurement, the actual award made to a participant will be between zero and two times the target award. The only market or performance condition that results in an early payout determination is a change of control. This plan and the cash bonus plan will be widely utilized within the organization, ensuring that the performance of all eligible employees and executives is measured against consistent performance conditions.

Third Quarter 2008 Highlights

On July 22, 2008, SemGroup filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware. Certain SemGroup entities purchased a portion of the Company’s crude oil production prior to SemGroup’s petition for bankruptcy protection. As a result of the SemGroup bankruptcy filing, we recorded an allowance for doubtful accounts and bad debt expense of $9.9 million in the second quarter of 2008 and increased the allowance and the expense to $16.6 million during the third quarter of 2008. We believe that we have fully allowed for all potential uncollectible amounts and believe that we have no remaining exposure resulting from this bankruptcy. In an effort to maximize our recovery, we have filed the appropriate pleadings and are party to certain adversary proceedings in the SemGroup bankruptcy case to establish our secured and priority claims. This matter does not have a material adverse effect on our liquidity or overall financial position.

On September 8, 2008, A. Wade Pursell commenced employment as Executive Vice President and Chief Financial Officer.

Our net income for the quarter ended September 30, 2008, was $88.0 million or $1.40 per diluted share compared to 2007 results of $57.7 million or $0.89 per diluted share. We discuss these financial results and trends in more detail below.

The table below details the regional breakdown of our third quarter 2008 production.

| | Mid-Continent | ArkLaTex | Permian | Gulf Coast | Rocky Mountain | Total(1) |
|---|---|---|---|---|---|---|
| Third Quarter 2008 Production: | | | | | | |
| Oil (MBbl) | 86.0 | 44.7 | 410.1 | 51.2 | 990.7 | 1,582.6 |
| Gas (MMcf) | 7,738.7 | 4,377.0 | 756.4 | 2,765.7 | 2,573.8 | 18,211.5 |
| Equivalent (MMCFE) | 8,254.8 | 4,645.0 | 3,217.0 | 3,072.8 | 8,517.8 | 27,707.4 |
| Avg. Daily Equivalents (MMCFE/per day) | 89.7 | 50.5 | 35.0 | 33.4 | 92.6 | 301.2 |
| Relative percentage | 30% | 17% | 12% | 11% | 30% | 100% |

(1) Totals may not add due to rounding

The table below provides information regarding selected production and financial information for the quarter ended September 30, 2008, and the three most recent preceding quarters. Additional details of per MCFE costs are presented later in this section.

| | For the Three Months Ended | | | |
|---|---|---|---|---|
| | September 30, 2008 | June 30, 2008 | March 31, 2008 | December 31, 2007 |
| | (In millions, except production sales data) | | | |
| Production (BCFE) | 27.7 | 28.6 | 28.3 | 28.5 |
| Oil and gas production revenue, excluding the effects of hedging | $ 358.5 | $ 400.0 | $ 310.4 | $ 273.7 |
| Realized oil and gas hedge gain (loss) | $ (53.5) | $ (68.4) | $ (24.0) | $ (11.7) |
| Lease operating expense | $ 43.6 | $ 41.0 | $ 35.1 | $ 37.8 |
| Transportation costs | $ 6.6 | $ 5.6 | $ 3.9 | $ 3.8 |
| Production taxes | $ 22.5 | $ 27.0 | $ 20.5 | $ 19.1 |
| DD&A | $ 72.4 | $ 76.4 | $ 70.4 | $ 64.8 |
| Exploration | $ 10.7 | $ 17.4 | $ 14.3 | $ 16.0 |
| General and administrative expense | $ 24.1 | $ 21.9 | $ 21.1 | $ 15.1 |
| Net income | $ 88.0 | $ 33.6 | $ 96.0 | $ 32.8 |
| | | | | |
| Percent change from previous quarter: | | | | |
| Production (BCFE) | (3)% | 1% | (1)% | 4% |
| Oil and gas production revenues, excluding the effects of hedging | (10)% | 29% | 13% | 20% |
| Realized oil and gas hedge gain (loss) | (22)% | 185% | 105% | (215)% |
| Lease operating expense | 6% | 17% | (7)% | 2% |
| Transportation costs | 18% | 44% | 3% | 19% |
| Production taxes | (17)% | 32% | 7% | 28% |
| DD&A | (5)% | 9% | 8% | 10% |
| Exploration | (39)% | 22% | (11)% | 27% |
| General and administrative expense | 10% | 4% | 39% | (4)% |
| Net income | 162% | (65)% | 192% | (43)% |

First Nine Months 2008 Highlights

We have begun to more actively optimize our portfolio of assets as part of our overall strategic goals and objectives. As part of this strategy, on January 31, 2008, we completed the divestiture of certain non-strategic oil and gas properties located primarily in the Rocky Mountain and Mid-Continent regions to Abraxas Petroleum Corporation and Abraxas Operating, LLC. The cash received at closing was $129.6 million, net of commission costs. The economics of the transaction were further enhanced by utilizing a tax-advantaged exchange structure that will allow us to defer most of the gain on the sale. In June 2008 the Company completed the divestiture of certain non-strategic oil and gas properties located in the Greater Green River Basin. The cash received at closing, net of all commission costs, was $21.7 million. The final sales price is subject to normal post-closing adjustments and is expected to be finalized during the fourth quarter of 2008. We also utilized a tax-advantaged exchange structure for this divestiture. During the first nine months of 2008 we recorded a $54.1 million gain on sale of proved properties, which included the gain from the Abraxas and Greater Green River divestitures, as well as other smaller divestitures.

On March 21, 2008, we closed on the acquisition of predominantly natural gas properties located in the Carthage Field in Panola County, Texas. Total cash paid for the acquisition was $49.2 million, net of customary closing adjustments. The acquisition was funded with cash on hand and borrowings under our existing revolving credit facility. At the acquisition date, we estimated proved reserves associated with this acquisition of approximately 25 BCFE. This acquisition was structured to qualify as the first step of a reverse like-kind exchange. The second step of the like-kind exchange was partially completed in conjunction with the divestiture of certain non-core oil and gas properties located in the Greater Green River Basin.

Throughout the first quarter of 2008, we repurchased a total of 2,135,600 shares of our common stock in the open market. The shares were repurchased at a weighted-average cost of $36.13 per share, including commissions, using cash on hand and borrowings under our revolving credit facility. We repurchased the shares under our existing Board-authorized stock repurchase program. As of the filing date of this report, we are authorized to repurchase 3,072,184 additional shares under this program. Consistent with our view of treating large share repurchases as acquisitions, we have hedged production volumes equal to the amount of reserves represented by the repurchased shares in proportion to the total number of shares outstanding. Our management continues to evaluate opportunities to repurchase common stock as a part of our business plan.

Our net income for the nine months ended September 30, 2008, was $217.6 million or $3.44 per diluted share compared to 2007 results of $156.8 million or $2.43 per diluted share. We discuss these financial results and trends in more detail below.

The table below details the regional breakdown of our first three quarters of 2008 production.

| | Mid-Continent | ArkLaTex | Permian | Gulf Coast | Rocky Mountain | Total(1) |
|---|---|---|---|---|---|---|
| First three quarters of 2008 Production: | | | | | | |
| Oil (MBbl) | 274.7 | 117.1 | 1,251.9 | 194.3 | 3,056.5 | 4,894.5 |
| Gas (MMcf) | 22,526.4 | 12,716.7 | 2,417.8 | 10,052.7 | 7,524.7 | 55,238.2 |
| Equivalent (MMCFE) | 24,174.3 | 13,419.3 | 9,929.3 | 11,218.8 | 25,863.7 | 84,605.3 |
| Avg. Daily Equivalents (MMCFE/per day) | 88.2 | 49.0 | 36.2 | 40.9 | 94.4 | 308.8 |
| Relative percentage | 28% | 16% | 12% | 13% | 31% | 100% |

(1) Totals may not add due to rounding

Outlook for the Remainder of 2008

Commodity prices and drilling and well completion costs are the most significant drivers of our business. Oil and natural gas prices have declined significantly since June and early July of 2008, and forecasted natural gas and crude oil futures prices for the remainder of the year are currently lower than those used to prepare our 2008 budget. However, we evaluate whether the forecasted future commodity prices at the time we propose to drill or elect to participate in the drilling of a well with a partner meet our economic criteria given the commodity and cost environment at that time. We believe that we will continue to see volatility in the prices for oil and gas, particularly regional prices in areas where there is significant industry activity.

With respect to costs, we have seen a dramatic increase in costs to drill and complete oil and natural gas wells during the last several years. Over this time period we have generally been able to access the rigs and services required to carry out our drilling program due in large part to our longstanding relationships with contractors and suppliers. Strong commodity prices in the first half of 2008 led to increased levels of capital investment in the exploration and production segment, and as a result, service providers increased their prices and access to equipment and services became more limited. Shortages of some items used in the drilling and completion of wells, principally drill pipe and sand, have been common in recent months. However, the recent turmoil in the financial markets and declining realized and forecasted commodity prices have led many industry participants to announce decreases to their current and forecasted drilling activity. As a result, we are beginning to see more drilling and completion equipment and services become available. Our assessment is that this trend will continue and will result in lower prices for these goods and services. However it should be noted that drilling and services availability are influenced strongly by regional factors.

As described above, management believes that we have the financial resources and liquidity to continue to execute our plan for 2008. We also believe that we have the rigs and services contracted to carry out our current program, which is described as follows:

- Mid-Continent – Our plans for the remainder of 2008 in the Mid-Continent region include operating three to four rigs in the horizontal Woodford Shale program in the Arkoma Basin, and continuing our development and exploration activities in the Anadarko Basin. In the Anadarko Basin, our technical team in the region is evaluating whether horizontal development could improve or enhance the economics of the various washes that exist in the basin. We also plan to continue exploiting a deeper formation of the Anadarko Basin where the Company has seen successful results over the past several quarters.

- ArkLaTex – Activity in the ArkLaTex for 2008 has primarily focused on programs that target the Cotton Valley and the James Lime formation. We plan to operate one horizontal rig in these programs for the remainder of the year. We are currently drilling our first horizontal Haynesville shale well at the Spider Field in DeSoto Parish, Louisiana. Additionally, we plan to monitor a number of competitor wells being drilled in East Texas targeting the Haynesville interval. A significant amount of our acreage we believe is prospective for the Haynesville shale is in East Texas. We will also perform a number of vertical tests in the Floyd shale in Northwestern Mississippi to test the potential of our acreage.

- Permian Basin – Our programs in the Permian for the remainder of 2008 are focused primarily on two tight oil programs that target the Wolfberry section of the basin. We currently have four operated rigs running in our Sweetie Peck program. We have been testing the viability of 40-acre downspacing in three pilot areas at Sweetie Peck and are encouraged by the early results of these tests. Drilling wells on 40-acre spacing has the potential to add meaningful reserves. We also plan to continue participating in Wolfberry wells at our Halff East program. Our operating team in the region continues to generate and evaluate a number of potential new exploration ideas in the region, and we will test several of these projects in 2008.

- Gulf Coast – As a result of the disruptions caused by Hurricanes Gustav and Ike, the remainder of 2008 will require some efforts to restore production that was lost or deferred due to these storms. While the impacts of the hurricanes on our operations and financial position in the Gulf Coast are not material, our operating personnel must still devote a meaningful amount of time to these efforts. For the majority of the properties impacted, in which we and our operating partners have an interest, restoration efforts will involve relatively minor repairs to facilities and infrastructure. A small number of properties will require more extensive repair work which will likely extend into 2009. Our operations group in the region will also begin planning for the remediation of our operated Vermilion 281 platform, which was lost when it was toppled in Hurricane Ike.

The Maverick Basin will be an area of significant activity for us for the remainder of 2008. Our current efforts are focused on the Pearsall and Eagleford shales, where we and several other operators have seen positive results from horizontal wells in both formations. We have been actively acquiring positions targeting both the Pearsall and Eagleford shales through grass roots leasing efforts, joint ventures, and acquisitions over the past 18 months.  We continue to operate one rig that is drilling wells targeting another zone of interest, the shallow Olmos gas formation.

- Rockies – Industry attention in the Williston Basin has been focused on activity targeting the Bakken and Three Forks formations in North Dakota.  We have seen progression of the play toward areas where we have acreage.  St. Mary drilled three horizontal Bakken tests during the second quarter along the county line between Burke and Mountrail Counties in North Dakota. While the wells have shown modest production rates, we do not believe that the area will be commercially effective for development in the current commodity price and cost environment for the Bakken.  We have one drilling rig which will begin drilling horizontal Bakken and Three Forks wells in a newly acquired acreage position during the fourth quarter of 2008.  Declining oil prices combined with widening differentials and restricted pipeline takeaway capacity are potential limiting factors for development in the Williston Basin.

Our planned drilling program described above is dynamic, and there are a number of factors that could impact our decisions to invest capital in one or all of these regions.  Commodity prices, well costs, service and supply availability, and program performance are a few of the factors that individually or in combination could change the scale or relative allocation of our drilling budget.

We continue to evaluate large numbers of acquisition and leasehold opportunities, both in our regional offices and at our corporate headquarters.  We have a strong track record of identifying and executing economic acquisitions.  In recent months, we have actively evaluated a number of projects that are very early in their development, and we continue to pursue several of these projects.  This is consistent with the shift in our acquisition strategy to focus on targets that have unproved potential and drilling upside.

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

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

| | For the Three Months Ended September 30, 2008 | For the Three Months Ended September 30, 2007 | Percent Change Between Periods | For the Nine Months Ended September 30, 2008 | For the Nine Months Ended September 30, 2007 | Percent Change Between Periods |
|---|---|---|---|---|---|---|
| Net production volumes | | | | | | |
| Oil (MBbl) | 1,583 | 1,796 | (12)% | 4,895 | 5,203 | (6)% |
| Natural gas (MMcf) | 18,212 | 16,675 | 9% | 55,238 | 47,743 | 16% |
| MMCFE (6:1) | 27,707 | 27,453 | 1% | 84,605 | 78,962 | 7% |
| | | | | | | |
| Average daily production | | | | | | |
| Oil (Bbl per day) | 17,203 | 19,526 | (12)% | 17,863 | 19,060 | (6)% |
| Natural gas (Mcf per day) | 197,952 | 181,249 | 9% | 201,599 | 174,881 | 15% |
| MCFE per day (6:1) | 301,167 | 298,405 | 1% | 308,778 | 289,240 | 7% |
| | | | | | | |
| Oil & gas production revenues (1) | | | | | | |
| Oil production revenue | $ 131,840 | $ 121,365 | 9% | $ 404,333 | $ 313,118 | 29% |
| Gas production revenue | 173,177 | 117,305 | 48% | 518,731 | 361,399 | 44% |
| Total | $ 305,017 | $ 238,670 | 28% | $ 923,064 | $ 674,517 | 37% |
| | | | | | | |
| Oil & gas production expense | | | | | | |
| Lease operating expense | $ 43,624 | $ 36,861 | 18% | $ 119,704 | $ 102,615 | 17% |
| Transportation costs | 6,638 | 3,169 | 109% | 16,139 | 11,775 | 37% |
| Production taxes | 22,462 | 14,940 | 50% | 69,982 | 43,228 | 62% |
| Total | $ 72,724 | $ 54,970 | 32% | $ 205,825 | $ 157,618 | 31% |
| | | | | | | |
| Average realized sales price (1) | | | | | | |
| Oil (per Bbl) | $ 83.30 | $ 67.56 | 23% | $ 82.61 | $ 60.18 | 37% |
| Natural gas (per Mcf) | $ 9.51 | $ 7.03 | 35% | $ 9.39 | $ 7.57 | 24% |
| | | | | | | |
| Per MCFE Data: | | | | | | |
| Average net realized price (1) | $ 11.01 | $ 8.69 | 27% | $ 10.91 | $ 8.54 | 28% |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Lease operating expenses | | (1.57) | | (1.34) | 17% | | (1.41) | | (1.30) | 8% |
| Transportation costs | | (0.24) | | (0.12) | 100% | | (0.19) | | (0.15) | 27% |
| Production taxes | | (0.81) | | (0.54) | 50% | | (0.83) | | (0.55) | 51% |
| General and administrative | | (0.87) | | (0.58) | 50% | | (0.79) | | (0.57) | 39% |
| Operating profit | $ | 7.52 | $ | 6.11 | 23% | $ | 7.69 | $ | 5.97 | 29% |
| | | | | | | | | | | |
| Depletion, depreciation, amortization, and asset retirement obligation liability accretion | $ | 2.61 | $ | 2.15 | 21% | $ | 2.59 | $ | 2.06 | 26% |

(1) Includes the effects of hedging activities

-42-

Financial Information (In thousands, except per share amounts):

| | September 30, 2008 | December 31, 2007 | Percent Change Between Periods |
|---|---|---|---|
| Working deficit | $ (180,334) | $ (92,604) | 95% |
| Long-term debt | $ 457,500 | $ 572,500 | (20)% |
| Stockholders' equity | $ 1,008,910 | $ 863,345 | 17% |

| | For the Three Months Ended September 30, | | Percent Change Between Periods | For the Nine Months Ended September 30, | | Percent Change Between Periods |
|---|---|---|---|---|---|---|
| | 2008 | 2007 | | 2008 | 2007 | |
| Basic net income per common share | $ 1.42 | $ 0.91 | 56% | $ 3.50 | $ 2.56 | 37% |
| Diluted net income per common share | $ 1.40 | $ 0.89 | 57% | $ 3.44 | $ 2.43 | 42% |
| | | | | | | |
| Basic weighted-average shares outstanding | 62,187 | 63,424 | (2)% | 62,254 | 61,364 | 1% |
| Diluted weighted-average shares outstanding | 63,078 | 64,727 | (3)% | 63,327 | 64,917 | (2)% |

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

Changes in production volumes, oil and gas production revenues, and costs generally reflect the cyclical and highly volatile nature of our industry. We present per MCFE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends that we believe require analysis. We anticipate that oil and gas production expenses will hold flat for the remainder of 2008. Broader concerns over the general economy have resulted in lower commodity prices, which drive some of the direct costs of services used to produce oil and natural gas. Additionally, many exploration and production companies have begun to slow their activity, which should have a moderating impact on the upward cost pressure we have seen in recent quarters. Production taxes are largely dependent on the prices we receive for oil and natural gas, which we are not able to predict. Depreciation, depletion, and amortization will generally be pressured upward as production related to higher cost properties acquired or developed in recent years becomes a larger percentage of our production mix. Our general and administrative expense will be impacted by cash payments made from the Net Profits Plan, which are impacted by realized prices. Part of executing our business during the first three quarters of 2008 consisted of adding employees. The increase in personnel drives general and administrative costs higher. Additionally, competition for personnel in the exploration and production industry remains highly competitive, and we have seen the cost to hire and retain personnel increase significantly.

We have in-the-money stock options, unvested RSUs, and PSAs that may be potentially dilutive securities. These dilutive securities affect our earnings per share. Consequently, both basic and diluted earnings per share are presented in the table above. We account for our 3.50% Senior Convertible Notes under the treasury stock method. There is no impact on the diluted share calculation for the periods presented since the Company's average stock price for the relevant reporting periods has not exceeded the conversion price. The 3.50% Senior Convertible Notes were issued

April 4, 2007, and have not been dilutive for a reporting period since their issuance. There were no potentially dilutive shares related to the PSAs included in the diluted earnings per share calculation for the three-month and nine-month periods ended September 30, 2008. A detailed explanation is presented in Note 4 – Earnings Per Share, in Part I, Item 1 of this report.

Basic and diluted weighted-average common shares outstanding used in our earnings per share calculations for the three-month periods ended September 30, 2008, and 2007, reflect an increase in outstanding shares related to stock option exercises. We issued 860,330 and 471,320 shares of common stock during the nine-month period ended September 30, 2008, and 2007, respectively, as a result of stock option exercises. Additionally, during the first nine months of 2008 and 2007, we issued 413,500 and 302,370 shares of common stock, respectively, as a result of the settlement of RSUs by the issuance of common stock in accordance with the terms of the RSU grants.

Overview of Liquidity and Capital Resources

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

Sources of cash

Based on our current forecast, we project that our 2008 cash flows from operations will be near our planned capital investment budget for exploration and development. Accordingly, we do not expect to access the capital markets for the remainder of 2008. Net cash proceeds from the sale of oil and gas properties totaled $155.2 million for the nine-month period ended September 30, 2008, which includes proceeds related to the Abraxas and Greater Green River Basin divestitures completed in January and June of 2008, respectively. We anticipate that we will continue to evaluate our property base for divestiture candidates that are not considered to be strategic to our growth.

Our primary sources of liquidity are the cash provided by operating activities, debt financing, sales of non-core properties, and access to capital markets. All of these sources can be impacted by the general condition of our industry and by significant fluctuations in oil and gas prices, operating costs, and volumes produced. We have no control over the market prices for oil and natural gas, although we are able to influence the amount of our net realized revenues related to oil and gas sales through the use of derivative contracts. A decrease in oil and gas prices would reduce expected cash flow from operating activities and could reduce the size of the borrowing base provided under our credit facility as well as the value of non-strategic properties we might consider selling. Capital markets have been experiencing extreme volatility and disruptions, and in recent weeks the volatility and disruptions have reached unprecedented levels. Those circumstances, along with the recent decline in oil and natural gas prices, have constrained the availability of public debt and equity financing for exploration and production companies. However, we do not anticipate any need to raise either public debt or equity financing in the foreseeable future to fund our ongoing operations. We intend to rely on our current revolving credit facility for borrowings. However, a significant transaction could necessitate the need to raise additional public debt or equity financing. Given our cash flows from operating activities and our available borrowing capacity under the credit facility, we believe we have sufficient liquidity to fund ongoing operational obligations and budgeted capital expenditures for the remainder of 2008 and 2009.

Current credit facility

We have a revolving credit facility agreement with Wachovia Bank, Wells Fargo Bank, and nine other participating banks. No individual lender represents more than 11 percent of the lending commitments under the credit facility. On October 1, 2008, the lending group redetermined our reserve-based borrowing base under the credit facility at the previous amount of $1.4 billion. We have elected a commitment amount of $500 million. We believe this commitment level is adequate for our near-term liquidity requirements. This credit facility agreement has a maturity date of April 7, 2010. As of October 28, 2008, we had $302 million of available borrowing capacity under this facility. Interest and commitment fees are accrued based on the borrowing base utilization table located in Note 7 – Long-term Debt in Part I, Item 1 of this report. Borrowings under the facility reduce the amount available under the commitment amount on a dollar-for-dollar basis. Borrowings under the facility are secured by mortgages

-44-

on the majority of our oil and gas properties and a pledge of the common stock of any material subsidiary companies.

Our weighted-average interest rate paid in the three-month and nine-month periods ended September 30, 2008, was 4.4 percent and 4.7 percent, respectively, and included fees paid on the unused portion of the credit facility's aggregate commitment amount and amortization of deferred financing costs associated with the 3.50% Senior Convertible Notes.

We are subject to customary financial and non-financial covenants under our credit facility, including limitations on dividend payments and requirements to maintain certain financial ratios, which include debt to earnings before interest, taxes, depreciation, and amortization ("EBITDA") of less than 3.5 to 1.0 and a current ratio as defined by our credit agreement of not less than 1.0 to 1.0. As of September 30, 2008, our debt to EBITDA ratio and current ratio as defined by our credit agreement, were 0.56 and 1.77, respectively. We are in compliance with all financial and non-financial covenants under this credit facility and expect to be in compliance for the foreseeable future.

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 2008 we spent $494.5 million for exploration and development capital expenditures, $83.4 million for property acquisitions, and $77.2 million for share repurchases. These cash outflows were funded using cash inflows from operations, proceeds from asset divestitures, and borrowings under our revolving credit facility.

Expenditures for exploration and development of oil and gas properties and acquisitions are the primary use of our capital resources. We currently anticipate spending approximately $758 million for development and exploration expenditures in 2008. The amount and allocation of future capital expenditures will depend upon a number of factors including the number and size of available economic acquisitions and drilling opportunities. In addition, the impact of oil and gas prices on investment opportunities, the availability of capital and borrowing facilities, and the success of our development and exploratory activities could lead to changes in funding requirements for future development. We regularly review our capital investment budget to assess changes in current and projected cash flows, acquisition opportunities, debt requirements, and other factors.

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

On May 12, 2008, we paid $3.1 million in dividends to stockholders of record as of the close of business May 2, 2008. As of September 30, 2008, we have accrued for $3.1 million in dividends to be paid to stockholders of record as of the close of business October 31, 2008. Our intention is to continue to make these semi-annual dividend payments at the rate of $0.05 per share for the foreseeable future subject to our future cash flows, our financial condition, possible credit facility covenants, and other currently unexpected factors which could arise.

The following table presents amount and percentage changes in cash flows between the nine-month periods ended September 30, 2008, and 2007. 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, | | | |
|---|---|---|---|---|
| | 2008 | 2007 | Change | Percent Change |
| | (In thousands) | | | |
| Net cash provided by operating activities | $ 568,101 | $ 473,982 | $ 94,119 | 20% |
| Net cash used in investing activities | $ (432,545) | $ (540,357) | $ 107,812 | (20)% |
| Net cash provided by (used in) financing activities | $ (173,670) | $ 82,151 | $ (255,821) | (311)% |

Analysis of cash flow changes between the nine months ended September 30, 2008 and September 30, 2007

Operating activities. Cash received from oil and gas production revenue, net of the realized effects of hedging, increased $266.9 million to $937.6 million for the nine-month period ended September 30, 2008, compared with $670.7 million for the nine-month period ended September 30, 2007. Included in operating revenues for the nine-month period ended September 30, 2008, is $145.8 million of net realized hedging losses. A 37 percent increase in oil and gas production revenue, net of the realized effects of hedging, was the result of a seven percent increase in production and a 28 percent increase in our net realized price after hedging. Net cash payments made for income taxes in the first nine months of 2008 increased $20.0 million relative to the same period in 2007.

Investing activities. Total cash outflow during the nine months ended September 30, 2008, for capital expenditures, leasehold, and drilling activities decreased $5.6 million or one percent to $494.5 million. Cash proceeds from the sale of oil and gas properties totaled $155.2 million for the nine-month period ended September 30, 2008, which includes proceeds related to the Abraxas and Greater Green River Basin divestitures completed in January and June of 2008, respectively. Total cash outflow for the nine months ended September 30, 2008, relating to the acquisition of oil and gas properties increased $50.8 million to $83.4 million due to the acquisition of assets at Carthage Field. At September 30, 2007, we had paid a $15.3 million deposit related to the Rockford acquisition that closed in October of 2007. We received $7.1 million less in proceeds from insurance settlement for the nine-month period ended September 30, 2008, compared with the same period in 2007. Other cash flows from investing activities for the nine-month period ended September 30, 2008, include the refunding of a $10.0 million deposit related to the Abraxas divestiture.

Financing activities. Net repayments on our credit facility decreased by $64.0 million for the nine-month period ended September 30, 2008, compared with the same period in 2007. Cash flows from financing activities for the nine months ended September 30, 2007, included a $4.5 million repayment on a short-term note payable. We spent $51.3 million more to repurchase shares of our common stock during the nine-month period ended September 30, 2008, compared with the same period in 2007. We received $280.7 million less in the nine-month period ended September 30, 2008, compared to the same period in 2007 due to the issuance of our 3.50% Senior Convertible Notes in the second quarter of 2007. Our excess tax benefit attributed to the exercise of stock options increased by $2.6 million for the nine-month period ended September 30, 2008, compared with the same period in 2007. We received $5.0 million more from the sale of common stock for the nine-month period ended September 30, 2008, compared to the same period in 2007.

Capital expenditure forecast

We use our capital resources primarily for the exploration and development of oil and gas properties and for acquisitions. Our 2008 capital expenditures forecast for drilling is approximately $758 million. This amount excludes non-cash asset retirement obligation capitalized assets. In the third quarter of 2008 we increased our capital investment budget from $661 million to $758 million in order to expand our level of activity in the Woodford shale, the Wolfberry tight oil program at Halff East, and the horizontal Bakken program, as well as to drill our first two horizontal Haynesville shale wells. We also increased the capital investment budget in the Permian region to reflect increased leasing activity. Anticipated 2008 exploration and development expenditures for each of our regions are presented in the following table.

| | Exploration and Development Investment Budget |
|---|---|
| | (In millions) |
| Mid-Continent region | $ 167 |
| ArkLaTex region | 190 |
| Permian region | 150 |
| Gulf Coast region | 86 |
| Rocky Mountain region | 165 |
| | $ 758 |

We regularly review our capital investment budget to reflect the changes in current and projected cash flows, acquisition opportunities, drilling opportunities, debt requirements, regional cost inflation, service and supply availability, and other factors. We project that our exploration and development budget will be near our anticipated operating cash flows for 2008. Of our 2008 capital expenditures budget of $758 million, we have spent $529.4 million through September 30, 2008.

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

| | For the Nine Months Ended September 30 | |
|---|---|---|
| | 2008 | 2007 |
| | (In thousands) | |
| Development costs (1) | $ 456,135 | $ 411,076 |
| Exploration costs | 73,232 | 98,650 |
| Acquisitions | | |
| Proved properties | 41,393 | 32,876 |
| Unproved properties – acquisitions of proved properties (2) | 42,389 | (225) |
| Unproved properties - other | 20,154 | 35,686 |
| Total, including asset retirement obligation (3) | $ 633,303 | $ 578,063 |

(1) Includes capitalized interest of $2.8 million in 2008 and $3.8 million in 2007.
(2) Represents a portion of the allocated purchase price of unproved properties acquired as part of the acquisition of proved properties. Refer to Note 3 in Part I, Item I of this report for additional information.
(3) Includes amounts relating to estimated asset retirement obligations of $8.8 million in 2008 and $7.4 million in 2007.

Costs incurred for capital and exploration activities during the first nine months of 2008 increased $55.2 million or 10 percent compared to the same period in 2007.  Excluding acquisitions, our development and exploration investments increased $19.6 million compared to the same period in the prior year.  This increase was a result of our drilling efforts progressing at a faster pace in the first nine months of 2008 compared with the same period in 2007. The $35.6 million increase in acquisitions is primarily attributable to the acquisition of oil and gas properties located in the Carthage Field in East Texas. We have experienced significant capital cost inflation over the past three years. These cost increases explain a portion of the year-over-year increase in development and exploration costs.

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

Commodity price risk and interest rate risk

We are exposed to market risk, including the effects of changes in oil and natural gas prices and changes in interest rates, as discussed above. Since we produce and sell crude oil, natural gas, and natural gas liquids, our financial results are affected when prices for these commodities fluctuate as they are doing presently. In order to reduce the impact of the fluctuations in commodity prices, we may 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 the 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. Refer to the corresponding section under Part II, Item 7 of our Annual Report on Form 10-K/A for the year ended December 31, 2007.

Summary of oil and gas production hedges in place

Our oil and natural gas derivative contracts include swap and costless collar arrangements. All contracts are entered into for other-than-trading-purposes. As of September 30, 2008, all oil, natural gas, and natural gas liquid derivative instruments qualified as cash flow hedges for accounting purposes.

Our net realized oil and natural gas prices are impacted by hedges we have placed on forecasted production. We have historically entered into hedges of existing production around the time we make acquisitions of producing oil and gas properties. Our intent has been to fix the price on a significant portion of an equivalent amount of existing production of our forecasted production on a discretionary basis. As of September 30, 2008, our hedged positions totaled approximately 9 million Bbls of crude oil, 64 million MMBtu of natural gas, and 1 million Bbls of natural gas liquids of anticipated future production through 2011. We have not entered into any new hedges from September 30, 2008, through the filing date of this report.

In a typical commodity swap agreement, if the agreed-upon published third-party price is lower than the swap fixed price, we receive the difference between the index price per unit of production and contracted 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 contracted floor price if the index price is below the floor price. We pay the difference between the contracted ceiling price and the index price only if the index price is above the contracted ceiling price. No amounts are paid or received if the index price is between the contracted floor and ceiling prices.

Our oil and natural gas derivative contracts are accounted for using fair value as defined under SFAS No. 157. Level 2 inputs, as defined by SFAS No. 157, are used to measure fair value and include internal valuation estimates that consider forward price quotes from active markets, third party pricing services, counterparties' credit ratings, our credit rating, and the time value of money. The considered factors result in an estimated exit-price for each asset or liability under a market place participant's view.

Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value due to the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. Deterioration in a counterparty's credit will result in a lower valuation of our derivative assets. We monitor the counterparties' credit ratings using two different ratings agencies and may ask counterparties to post collateral if their ratings deteriorate. In some instances we will attempt to novate the trade to obtain a more stable counterparty. While the ratings of our counterparties have decreased over the past several months, the decreases have been slight. In the event that we determine the likelihood that a counterparty will not default ceases to be probable, the hedge relationship will no longer qualify for hedge accounting prospectively. If hedge accounting is discontinued and the derivative remains outstanding, we will recognize all subsequent changes in fair value on our consolidated statement of operations for the period in which the change occurs. Valuation adjustments are necessary to reflect the effect of our credit quality on the fair value of any liability position with a counterparty. This adjustment takes into account any credit enhancements, such as collateral margin that we may have posted with a counterparty, as well as any letters of credit between the parties. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our credit rating, current credit spreads, and any change in such spreads since the last measurement date. The majority of our derivative counterparties are members of our lending group. Deterioration in our credit will result in a lower valuation of our derivative liability. As of September 30, 2008, we were in a net liability position with all of our counterparties.

The methods described above may result in a fair value estimate that may not be indicative of net realizable value or may not be reflective of future fair values and cash flows. While we believe that the valuation methods utilized are appropriate and consistent with the requirements of SFAS No. 157 and with other marketplace participants, we recognize that third parties may use different methodologies or assumptions to determine the fair value of certain financial instruments that could result in a different estimate of fair value at the reporting date.

The following tables describe the volumes, average contract prices, and fair value of contracts we have in place as of September 30, 2008.

Oil Contracts

| Oil Swaps | | | |
|---|---|---|---|
| Contract Period | Volumes<br>(Bbl) | Weighted-Average Contract Price<br>(Per Bbl) | Fair Value at September 30, 2008 (Liability)<br>(In thousands) |
| Fourth quarter 2008 | | | |
| NYMEX WTI | 451,000 | $ 71.83 | $ (12,798) |
| WCS | 15,000 | $ 50.42 | (431) |
| 2009 | | | |
| NYMEX WTI | 1,570,000 | $ 71.64 | (46,534) |
| 2010 | | | |
| NYMEX WTI | 1,239,000 | $ 66.47 | (43,560) |
| 2011 | | | |
| NYMEX WTI | 1,032,000 | $ 65.36 | (35,981) |
| All oil swap contracts | 4,307,000 | | $ (139,304) |

| Oil Collars | | | | |
|---|---|---|---|---|
| Contract Period | NYMEX WTI Volumes<br>(Bbl) | Weighted-Average Floor Price<br>(Per Bbl) | Weighted-Average Ceiling Price<br>(Per Bbl) | Fair Value at September 30, 2008 (Liability)<br>(In thousands) |
| Fourth quarter 2008 | 519,000 | $ 58.19 | $ 78.43 | $ (12,764) |
| 2009 | 1,526,000 | $ 50.00 | $ 67.31 | (54,509) |
| 2010 | 1,367,500 | $ 50.00 | $ 64.91 | (52,934) |
| 2011 | 1,236,000 | $ 50.00 | $ 63.70 | (47,182) |
| All oil collars | 4,648,500 | | | $ (167,389) |

Gas Contracts

| Gas Swaps | | | | | |
|---|---|---|---|---|---|
| Contract Period | Volumes | | Weighted-Average Contract Price | Fair Value at September 30, 2008 Asset/(Liability) | |
| | (MMBtu) | | (per MMBtu) | (In thousands) | |
| | | $ | 8.07 | 1,568 | |
| IF ANR OK | | 380,000 | $ | 8.92 | 789 |
| IF EL PASO | | 210,000 | $ | 7.17 | 49 |
| IF HSC | | 160,000 | $ | 8.78 | 199 |
| 2008 | | | | | |
| IF CIG | | 3,120,000 | $ | 7.48 | 2,381 |
| IF PEPL | | 3,840,000 | $ | 8.51 | 5,401 |
| IF NGPL | | 920,000 | $ | 6.99 | (45 ) |
| IF EL PASO | | 1,060,000 | $ | 7.22 | (24 ) |
| IF HSC | | 300,000 | $ | 8.84 | 274 |
| 2009 | | | | | |
| IF CIG | | 1,710,000 | $ | 7.79 | 1,143 |
| IF PEPL | | 1,920,000 | $ | 8.35 | 1,840 |
| IF NGPL | | 440,000 | $ | 7.11 | (38 ) |
| IF EL PASO | | 1,200,000 | $ | 7.11 | (125 ) |
| 2010 | | | | | |
| IF NGPL | | 60,000 | $ | 7.60 | (1 ) |
| IF EL PASO | | 1,090,000 | $ | 6.79 | (77 ) |
| 2011 | | | | | |
| IF EL PASO | | 880,000 | $ | 6.34 | (117 ) |
| All gas swap contracts | | | | | $ 44,035 |

*Gas Collars*

| Contract Period | Volumes (MMBtu) | Weighted-Average Floor Price (per MMBtu) | Weighted-Average Ceiling Price (per MMBtu) | Fair Value at December 31, 2006 Asset/(Liability) (in thousands) |
|---|---|---|---|---|
| First quarter 2007 | | | | |
| IF CIG | 830,000 | $ 7.34 | $ 13.48 | $ 2,231 |
| IF PEPL | 2,180,000 | $ 8.23 | $ 14.71 | 5,792 |
| IF HSC | 350,000 | $ 8.31 | $ 14.42 | 834 |
| NYMEX Henry Hub | 140,000 | $ 9.00 | $ 16.15 | 601 |
| Second quarter 2007 | | | | |
| IF CIG | 800,000 | $ 6.41 | $ 7.87 | 1,229 |
| IF PEPL | 2,040,000 | $ 7.03 | $ 9.19 | 2,867 |
| IF HSC | 320,000 | $ 7.66 | $ 9.10 | 443 |
| NYMEX Henry Hub | 190,000 | $ 8.00 | $ 9.45 | 281 |
| Third quarter 2007 | | | | |
| IF CIG | 760,000 | $ 6.41 | $ 7.87 | 1,076 |
| IF PEPL | 1,920,000 | $ 7.02 | $ 9.24 | 2,188 |
| IF HSC | 300,000 | $ 7.66 | $ 9.10 | 326 |
| NYMEX Henry Hub | 200,000 | $ 8.00 | $ 9.45 | 246 |
| Fourth quarter 2007 | | | | |
| IF CIG | 730,000 | $ 6.41 | $ 7.87 | 744 |
| IF PEPL | 1,820,000 | $ 7.00 | $ 9.28 | 1,416 |
| IF HSC | 270,000 | $ 7.66 | $ 9.10 | 146 |
| NYMEX Henry Hub | 180,000 | $ 8.00 | $ 9.45 | 85 |
| 2008 | | | | |
| IF CIG | 2,880,000 | $ 5.60 | $ 8.72 | (87) |
| IF PEPL | 6,600,000 | $ 6.28 | $ 9.42 | 1,240 |
| IF HSC | 960,000 | $ 6.57 | $ 9.70 | (90) |
| NYMEX Henry Hub | 480,000 | $ 7.00 | $ 10.57 | 32 |
| 2009 | | | | |
| IF CIG | 2,400,000 | $ 4.75 | $ 8.82 | (1,031) |
| IF PEPL | 5,510,000 | $ 5.30 | $ 9.25 | (1,807) |
| IF HSC | 840,000 | $ 5.57 | $ 9.49 | (339) |
| NYMEX Henry Hub | 360,000 | $ 6.00 | $ 10.35 | (94) |
| 2010 | | | | |
| IF CIG | 2,040,000 | $ 4.85 | $ 7.08 | (1,264) |
| IF PEPL | 4,945,000 | $ 5.31 | $ 7.61 | (2,699) |
| IF HSC | 600,000 | $ 5.57 | $ 7.88 | (303) |
| NYMEX Henry Hub | 240,000 | $ 6.00 | $ 8.38 | (93) |
| 2011 | | | | |
| IF CIG | 1,800,000 | $ 5.00 | $ 6.32 | (1,067) |
| IF PEPL | 4,225,000 | $ 5.31 | $ 6.51 | (2,260) |
| IF HSC | 480,000 | $ 5.57 | $ 6.77 | (267) |
| NYMEX Henry Hub | 120,000 | $ 6.00 | $ 7.25 | (49) |
| All gas collars | | | | $ 10,327 |

**Natural Gas Liquid Contracts**

*Natural Gas Liquid Swaps**

| | Volumes (gal) | Weighted-Average Contract Price (per gal) | Fair Value at December 31, 2006 Asset/(Liability) (in thousands) |
|---|---|---|---|
| First quarter 2007 | 2,142,000 | $ 0.89 | $ (50 ) |
| Second quarter 2007 | 2,184,000 | $ 0.89 | (31 ) |
| Third quarter 2007 | 2,310,000 | $ 0.89 | (43 ) |
| Fourth quarter 2007 | 2,436,000 | $ 0.88 | (98 ) |
| 2008 | 12,684,000 | $ 0.87 | (605 ) |
| 2009 | 11,718,000 | $ 0.86 | (619 ) |
| All natural gas liquid swaps | | | $ (1,446 ) |

* Natural gas liquid swaps are comprised of OPIS Mont. Belvieu TET Propane (34%), OPIS Mont. Belvieu Purity Ethane (32%), OPIS Mont. Belvieu NON-TET Isobutane (15%), OPIS Mont. Belvieu NON-TET Natural Gasoline (14%), and OPIS Mont. Belvieu NON-TET Normal Butane (5%).

**Hedge Contracts Entered Into After December 31, 2006**

*Gas Swaps*

| Contract Period | Volumes (MMBtu) | Weighted-Average Contract Price (per MMBtu) |
|---|---|---|
| First quarter 2007 | | |
| IF ANR OK | 10,000 | $ 5.96 |
| IF HSC | 80,000 | $ 6.85 |
| Second quarter 2007 | | |
| IF ANR OK | 200,000 | $ 6.08 |
| IF HSC | 240,000 | $ 7.18 |
| Third quarter 2007 | | |
| IF ANR OK | 420,000 | $ 6.37 |
| IF HSC | 240,000 | $ 7.56 |
| Fourth quarter 2007 | | |
| IF ANR OK | 470,000 | $ 6.79 |
| IF HSC | 240,000 | $ 8.08 |
| 2008 | | |
| IF ANR OK | 920,000 | $ 7.15 |
| IF HSC | 960,000 | $ 7.92 |
| 2009 | | |
| IF ANR OK | 440,000 | $ 7.38 |
| IF HSC | 160,000 | $ 8.55 |
| 2010 | | |
| IF ANR OK | 60,000 | $ 7.98 |

<u>*Natural Gas Liquid Swaps*</u>*

| | Volumes (gal) | Weighted-Average Contract Price (per gal) |
|---|---|---|
| First quarter 2007 | 248,600 | $ 0.91 |
| Second quarter 2007 | 783,100 | $ 0.91 |
| Third quarter 2007 | 822,700 | $ 0.91 |
| Fourth quarter 2007 | 846,300 | $ 0.91 |
| 2008 | 3,447,400 | $ 0.89 |
| 2009 | 554,500 | $ 0.89 |

* Natural gas liquid swaps are comprised of OPIS Mont. Belvieu TET Propane (34%), OPIS Mont. Belvieu Purity Ethane (32%), OPIS Mont. Belvieu NON-TET Isobutane (15%), OPIS Mont. Belvieu NON-TET Natural Gasoline (14%), and OPIS Mont. Belvieu NON-TET Normal Butane (5%).

Please see Note 10 Derivative Financial Instruments in Part IV, Item 15 of this report for additional information regarding our oil and gas hedges.

*Summary of Interest Rate Hedges in Place*

We entered into fixed-to-floating interest rate swaps on $50 million of principal in October 2003. Due to continuing increases in interest rates, we entered into a floating-to-fixed interest rate swap in April 2005, through March 20, 2007, for this same notional amount of $50 million in order to effectively offset our fixed-to-floating interest rate swaps. Under the floating-to-fixed interest rate swap, we will be paid a variable interest rate of 235 basis points above the six-month LIBOR rate as determined on the semi-annual settlement date and will pay a fixed interest rate of 6.85 percent. The impact of this instrument, when combined with the other interest rate swaps, is that we have fixed our net liability related to the interest rate swaps, and we will pay a 1.1 percent interest factor on $50 million of notional debt through March 2007. The payment dates of the swap match exactly with the interest payment dates of the convertible notes and the fixed-to-floating interest rate swaps.

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 $334.0 million of floating rate debt outstanding as of December 31, 2006. Our fixed rate debt outstanding at this same date was $100.0 million associated with the Convertible Notes.

Please see Note 10 of Part IV, Item 15 of this report for additional information regarding our interest rate swaps.

*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 | $ 335.6 | $ 1.6 | $ | $ 334.0 | $ |
| Operating Leases | 14.0 | 3.0 | 7.4 | 3.0 | 0.6 |
| Other Long-Term Liabilities | 211.2 | 51.0 | 62.8 | 62.9 | 34.5 |
| Total | $ 560.8 | $ 55.6 | $ 70.2 | $ 399.9 | $ 35.1 |

This table includes our 2006 estimated pension liability payment of approximately $2.0 million expected to be paid in the second quarter of 2007. The table also includes the remaining unfunded portion of our estimated pension liability of $4.0 million even though we recognize that we cannot determine with accuracy the timing of future payments. We have made payments of $1.3 million, $1.1 million, and $1.3 million in 2006, 2005, and 2004, respectively, towards the pension liability. We have also excluded repayment of the Senior Convertible Notes as it is expected that this issuance will be converted to 7,692,300 common shares in March 2007. We have included in other long-term liabilities six years of undiscounted forecast payments for the Net Profits Plan. Payments are expected to be similar on an annual basis for the years beyond what is shown in this table. The value recorded on the balance sheet reflects the impact of discounting and therefore differs from the amounts disclosed in this table. The variability in the amount of the payments will be a direct reflection of commodity prices, capital expenditures, and operating costs in future periods. Predicting the timing of payments associated with this liability is contingent upon estimates of appropriate discount factors, adjusting for risk and time-value, and upon a number of factors that we cannot control. The scheduled repayment of the long-term credit facility is in 2010. Accordingly, it has been disclosed in the table as such. Since this is a revolving credit facility, the actual payments will vary significantly. We anticipate refinancing this obligation. We have excluded asset retirement obligations because we are not able to accurately predict the precise timing for these amounts. Pension liabilities and asset retirement obligations are discussed in Note 8 and Note 9 of Part IV, Item 15, respectively, and the Net Profits Plan is discussed in Note 7 of Part IV, Item 15 of this report.

This table also includes estimated oil and natural gas derivative payments of $13.1 million based on futures market prices as of December 31, 2006. This amount represents only the cash outflows; it does not include oil and gas receipts of $120.7 million that would be paid based on December 31, 2006, market prices. The net of $107.6 million represents cash flows from the intrinsic value of our swap and collar arrangements and differs in amount from our recorded fair value, which as of December 31, 2006, was a net asset of $13.7 million. The fair value considers time value and volatility that affect the ultimate fair value. 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 II, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and to Note 10 Derivative Financial Instruments in Part IV, Item 15 of this report for additional information regarding our oil and gas hedges.

We believe that we will continue to pay annual dividends of at least $0.10 per share. We anticipate making cash payments for income taxes, dependent on net income and capital spending.

*Off-Balance Sheet Arrangements*

We do not have any off-balance sheet financing nor do we have any unconsolidated subsidiaries.

**Critical Accounting Policies and Estimates**

We are engaged in the exploration, exploitation, development, acquisition, and production of natural gas and crude oil. Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these consolidated financial statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses as well as the disclosure of contingent assets and liabilities as of the date of our financial statements. We base our decisions affecting the estimates we use on historical experience and various other sources that are believed to be reasonable under the circumstances. Actual results may differ from the estimates we calculate due to changing business conditions or unexpected circumstances. Policies we believe are critical to understanding our business operations and results of operations are detailed below. For additional information on our significant accounting policies you should see Note 1 Summary of Significant Accounting Policies, Note 9 Asset Retirement Obligations, and Note 12 Disclosures About Oil and Gas Producing Activities in Part IV, Item 15 of this report.

*Oil and gas reserve quantities.* Estimated reserve quantities and the related estimates of future net cash flows are the most important estimates for an exploration and production company because they affect the perceived value of our Company, are used in comparative financial analysis ratios and are used as the basis for the most significant accounting estimates in our financial statements. This includes the periodic calculations of depletion, depreciation, and impairment for our proved oil and gas properties and the estimates of our liability for future payments under the Net Profits Plan. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. Future cash inflows and future production and development costs are determined by applying benchmark prices and costs, including transportation, quality, and basis differentials, in effect at the end of each period to the estimated quantities of oil and gas remaining to be produced as of the end of that period. Expected cash flows are reduced to present value using a discount rate that depends upon the purpose for which the reserve estimates will be used. For example, the standardized measure calculation required by SFAS No. 69, Disclosures about Oil and Gas Producing Activities, requires a ten percent discount rate to be applied. Although reserve estimates are inherently imprecise, and estimates of new discoveries and undeveloped locations are more imprecise than those of established producing oil and gas properties, we make a considerable effort in estimating our reserves, including using independent reserve engineering consultants. We expect that periodic reserve estimates will change in the future as additional information becomes available or as oil and gas prices and operating and capital costs change. We evaluate and estimate our oil and gas reserves at December 31 and June 30 of each year. For purposes of depletion, depreciation, and impairment, reserve quantities are adjusted at all interim periods for the estimated impact of additions and dispositions. Changes in depletion, depreciation, or impairment calculations caused by changes in reserve quantities or net cash flows are recorded in the period that the reserve estimates change.

The following table presents information regarding reserve changes from period to period that reflect changes from items we do not control, such as price, and from changes resulting from better information due to production history and well performance. These changes do not require a capital expenditure on our part, but may have resulted from capital expenditures we incurred to develop other estimated proved reserves.

| | Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2006 | | 2005 | | 2004 | |
| | MMCFE Change | Percent of total Additions | MMCFE Change | Percent of total Additions | MMCFE Change | Percent of total Additions |
| Revisions resulting from price changes | (52,176 ) | (23 )% | 23,095 | 10 % | 16,206 | 11 % |
| Revisions resulting from performance | 66,264 | 29 % | 10,817 | 5 % | (26,127 ) | (18 )% |
| Total | 14,088 | 6 % | 33,912 | 15 % | (9,921 ) | (7 )% |

Over the three-year period, we added 596.3 BCFE of reserves. Of these, 51.0 BCFE, or nine percent, was a result of changes in estimates based on the performance of our oil and gas properties. A 12.9 BCFE reduction in reserves was a result of price changes. As previously noted, oil and gas prices are volatile, and estimates of reserves are inherently imprecise. Consequently, we anticipate we will continue to experience these types of changes.

The following table reflects the estimated MMCFE change and percentage change to our total reported reserve volumes from the described hypothetical changes:

| | Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2006 | | 2005 | | 2004 | |
| | MMCFE Change | Percent Change | MMCFE Change | Percent Change | MMCFE Change | Percent Change |
| A 10% decrease in pricing | (28,220 ) | (3 )% | (28,940 ) | (4 )% | (16,672 ) | (3 )% |
| A 10% decrease in proved undeveloped reserves | (20,006 ) | (2 )% | (14,554 ) | (2 )% | (9,839 ) | (1 )% |

Additional reserve information can be found in the reserve table and discussion included in Item 2 of Part I of this report.

*Successful efforts method of accounting.* Generally accepted accounting principles provide for two alternative methods for the oil and gas industry to use in accounting for oil and gas producing activities. These two methods are generally known in our industry as the full cost method and the successful efforts method. Both methods are widely used. The methods are different enough that in many circumstances the same set of facts will provide materially different financial statement results within a given year. We have chosen the successful efforts method of accounting for our oil and gas producing activities, and a detailed description is included in Note 1 of Part IV, Item 15 of this report.

*Revenue recognition.* Our revenue recognition policy is significant because revenue is a key component of our results of operations and our forward-looking statements contained in our analyses of liquidity and capital resources. We derive our revenue primarily from the sale of produced natural gas and crude oil. We report revenue as the gross amounts we receive before taking into account production taxes and transportation costs, which are reported as separate expenses. Revenue is recorded in the month our production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to a purchaser. At the end of each month we make estimates of the amount of production delivered to the purchaser and the price we will receive. We use our knowledge of our properties, their historical performance, the anticipated effect of weather conditions during the month of production, NYMEX and local spot market prices, and other factors as the basis for these estimates. Variances between our estimates and the actual amounts received are recorded in the month payment is received. A ten percent change in our year-end revenue accrual would have impacted net income before tax by $9.5 million in 2006.

*Crude oil and natural gas hedging.* Our crude oil and natural gas hedging contracts usually qualify for cash flow deferral hedge accounting under SFAS No. 133. Under this accounting pronouncement a majority of the gain or loss from a contract qualifying as a cash flow hedge is deferred as to statement of operations recognition. The position reflected in the statement of operations is based on the actual settlements with the counterparty. If our natural gas and crude oil hedge contracts did not qualify for hedge accounting treatment or we chose not to use this hedge accounting methodology, our periodic statements of operations could include significant changes in the estimate of non-cash derivative gain or loss due to swings in the value of these contracts. Consequently, we would report a different amount for oil and gas hedge loss in our statements of operations. These fluctuations could be especially significant in a volatile pricing environment such as what we have encountered over the last three years. Net income after tax would have increased or (decreased) for 2006, 2005, and 2004 by the following amounts: $69.1 million, ($57.2 million), and $17.1 million, respectively, if our hedges did not qualify as cash flow deferral hedges under SFAS No. 133.

*Change in Net Profits Plan Liability.* We record the estimated liability of future payments for our Net Profit Plan. The estimated liability is calculated based on a number of assumptions, including estimates of oil and gas reserves, recurring and workover lease operating expense, product and ad valorem tax rates, present value discount factors, and pricing assumptions. Additional discussion is included in the analysis in the above section titled *Overview of the Company*, under the heading *Net Profits Plan*.

*Asset retirement obligations.* We are required to recognize an estimated liability for future costs associated with the abandonment of our oil and gas properties. We base our estimate of the liability on our historical experience in abandoning oil and gas wells projected into the future based on our current understanding of federal and state regulatory requirements. Our present value calculations require us to estimate the economic lives of our properties, assume what future inflation rates apply to external estimates, and determine what credit adjusted risk-free rate to use. The statement of operations impact of these estimates is reflected in our depreciation, depletion, and amortization calculations and occurs over the remaining life of our oil and gas properties.

*Valuation of long-lived and intangible assets.* Our property and equipment is recorded at cost. An impairment allowance is provided on unproved property when we determine that the property will not be developed or the carrying value will not be realized. We evaluate the realizability of our proved properties and other long-lived assets whenever events or changes in circumstances indicate that impairment may be appropriate. Our impairment test compares the expected undiscounted future net revenues from a property, using escalated pricing, with the related net capitalized costs of the property at the end of each period. When the net capitalized costs exceed the undiscounted future net revenue of a property, the cost of the property is written down to our estimate of fair value, which is determined by applying a discount rate that we believe is indicative of the current market. Our criteria for an acceptable internal rate of return are subject to change over time. Different pricing assumptions or discount rates could result in a different calculated impairment.

*Income taxes.* We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements in accordance with SFAS No. 109, Accounting for Income Taxes . This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Additionally, our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared, therefore we estimate the tax basis of our assets and

liabilities at the end of each period as well as the effects of tax rate changes, tax credits, and net operating and capital loss carryforwards and carrybacks. Adjustments related to differences between the estimates we used and actual amounts we reported are recorded in the period in which we file our income tax returns. These adjustments and changes in our estimates of asset recovery could have an impact on our results of operations. A one percent change in our effective tax rate would have affected our calculated income tax expense by $2.8 million for the year ended December 31, 2006.

*Stock-based compensation.* We have historically accounted for stock-based compensation using the intrinsic value recognition and measurement principles detailed in APB No. 25. No stock-based employee compensation expense relating to stock options has been reflected in our expense as all options granted under our plans had an exercise price equal to the market value of the underlying common stock on the date of grant. We used the Black-Scholes option valuation model to calculate the disclosures required under SFAS No. 123. As of January 1, 2006, we adopted the provisions of SFAS No. 123(R). This statement requires us to record expense associated with the fair value of stock-based compensation. As a result of adoption of this statement, we recorded compensation expense associated with unvested stock options totaling $1.9 million under the modified-prospective adoption method. We have recorded expense associated with the issuance of restricted stock units since the plan was adopted in 2004 and units were first issued. Going forward this expense will decrease on a relative per share basis for all units that have already been issued because the accounting standard requires cost recognition using fair value estimates of the restricted stock units, rather than intrinsic value.

**Additional Comparative Data in Tabular Format:**

| | **Change Between Years** | |
|---|---|---|
| **Oil and Gas Production Revenues:** | **2006 and 2005** | **2005 and 2004** |
| Increase in oil and gas production revenues (in thousands) | $ 47,908 | $ 297,687 |
| *Components of Revenue Increases (Decreases):* | | |
| Oil | | |
| Realized price change per Bbl | $ 5.67 | $ 18.40 |
| Realized price percentage change | 11 % | 57 % |
| Production change (MBbl) | 130 | 1,128 |
| Production percentage change | 2 % | 23 % |
| Natural Gas | | |
| Realized price change per Mcf | $ (0.53 ) | $ 2.38 |
| Realized price percentage change | (7 )% | 43 % |
| Production change (MMcf) | 4,646 | 5,204 |
| Production percentage change | 9 % | 11 % |

*Our product mix as a percentage of total oil and gas revenue and production:*

| | **Years Ended December 31,** | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| Revenue | | | |
| Oil | 45 % | 42 % | 38 % |
| Natural Gas | 55 % | 58 % | 62 % |
| Production | | | |
| Oil | 39 % | 41 % | 38 % |
| Natural Gas | 61 % | 59 % | 62 % |

*Information regarding the effects of oil and gas hedging activity:*

| | Years Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| Oil Hedging | | | |
| Percentage of oil production hedged | 66 % | 24 % | 45 % |
| Oil volumes hedged (MBbl) | 4,021 | 1,419 | 2,156 |
| Decrease in oil revenue | $ (16.6 million) | $ (13.3 million) | $ (34.8 million) |
| Average realized oil price per Bbl before hedging | $ 59.33 | $ 53.18 | $ 39.77 |
| Average realized oil price per Bbl after hedging | $ 56.60 | $ 50.93 | $ 32.53 |
| Natural Gas Hedging | | | |
| Percentage of gas production hedged | 40 % | 25 % | 25 % |
| Natural gas volumes hedged (MMBtu) | 24.2 million | 14.0 million | 12.9 million |
| Increase (decrease) in gas revenue | $ 44.7 million | $ (9.2 million) | $ (15.5 million) |
| Average realized gas price per Mcf before hedging | $ 6.58 | $ 8.08 | $ 5.85 |
| Average realized gas price per Mcf after hedging | $ 7.37 | $ 7.90 | $ 5.52 |

*Information regarding the components of exploration expense:*

| Summary of Exploration Expense (in millions) | Years Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| Geological and geophysical expenses | $ 9.5 | $ 7.9 | $ 7.3 |
| Exploratory dry holes | 10.2 | 8.1 | 4.2 |
| Overhead and other expenses | 32.2 | 28.9 | 17.1 |
| Total | $ 51.9 | $ 44.9 | $ 28.6 |

**Comparison of Financial Results and Trends between 2006 and 2005**

*Oil and gas production revenues.* Average net daily production increased 6 percent to a record 254.2 MMCFE for 2006 compared with 239.4 MMCFE in 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 | 6.2 | 23.5 | 2.5 |
| Wold acquisition | 3.1 | 9.2 | 5.2 |
| Other wells completed in 2006 and 2005 | 47.2 | 80.8 | 15.3 |
| Other acquisitions | 2.9 | 9.7 | 1.4 |
| Total | 59.4 | 123.2 | 24.4 |

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 years presented. Additional production costs reflect increases resulting from inflation and competition for resources.

*Oil and gas realized hedge gain (loss).* The 225 percent increase in total oil and gas hedge gain to $28.2 million was caused by a change in the composition of our hedge position and changes in oil and gas commodity prices.

*Oil and gas production expenses.* Total production costs increased $33.7 million or 24 percent to $176.6 million for 2006, from $142.9 million in 2005. Our current year acquisition of properties added

$1.4 million of incremental production costs, prior year acquisitions of properties added $5.2 million of incremental production costs, and other wells completed in 2005 and 2006 added $15.3 million of incremental production costs in 2006 that were not reflected in 2005. We experienced an increase in production taxes consistent with the increase in revenue from higher realized prices.

Total oil and gas production costs per MCFE increased $0.27 to $1.90 for 2006, compared with $1.64 for 2005. This increase is comprised of the following:

- A $0.02 decrease in production taxes, due to a $0.04 decrease in our Rocky Mountain region resulting from an increase in new production, which qualifies for incentive tax rates, that was partially offset by a minor increase in our Mid-Continent region resulting from higher natural gas revenues;

- A $0.03 increase in overall transportation cost, due to an increase in the Rocky Mountain region resulting from a change in the sale measurement point, as well as newly drilled wells with higher transportation costs;

- A $0.20 increase in recurring LOE related to continued increases in costs for oil and gas service sector resources; and

- A $0.06 overall increase in LOE relating to workover charges, mainly due to activity in the Rockies.

*Depreciation, Depletion, Amortization, and Impairment.* DD&A increased $21.8 million or 16% to $154.5 million in 2006 compared with $132.8 million in 2005. DD&A expense per MCFE increased 10% to $1.67 in 2006 compared to $1.52 in 2005. This increase reflects overall upward cost pressure in the industry and specifically our acquisitions and drilling in 2006 and 2005 that added costs at a higher per unit rate. The DD&A per MCFE rate was further affected by downward adjustments to reserves due to pricing differences between December 31, 2006 and December 31, 2005.

St. Mary recorded a $7.2 million impairment of proved oil and gas properties in 2006 compared with no impairment in 2005. This impairment was mainly due to declining performance and downward adjustments to reserves for properties located in East Texas.

*Exploration expense.* Exploration expense increased $7.0 million or 15 percent to $51.9 million in 2006 compared with $44.9 million for 2005. This increase is due to a $3.3 million increase in exploration overhead related to increases in payments made under the Net Profits Plan and increases in the size of our geologic and exploration staff. Additionally, the increase in exploration expense is partially related to an approximate $2.0 million increase in exploratory dry hole expense and a $1.5 million increase in geologic and geophysical expense to support a larger overall program.

*General and administrative.* General and administrative expenses increased $6.1 million or 19 percent to $38.9 million for 2006, compared with $32.8 million for 2005. G&A increased $0.05 to $0.42 per MCFE for 2006 compared to $0.37 per MCFE for the period in 2005 as G&A grew at a faster rate than the three percent increase in production.

A 16 percent increase in employee count has contributed to an increase in base employee compensation of approximately 18 percent, or $3.5 million, between the year ended December 31, 2006, and the same 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 increased by $5.4 million in 2006 compared with the same period in 2005. A decrease in the bonus percentage resulted in a decrease in the accrued cash bonus expense of $5.0 million to $2.8 million for the year ended December 31, 2006, compared with $7.8 million for the year ended December 31, 2005.

RSU bonus expense is $1.5 million higher for the year ended December 31, 2006, than the year ended December 31, 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 while there were 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 a decrease in RSU bonus expense for the year ended December 31, 2006, compared with the same period in 2005. This decrease correlates to the decrease in cash bonus expense and reflects an evaluation of our overall performance for 2006 including reserve replacement, production, and net asset value per share growth factors.

As a result of the implementation of SFAS No. 123(R) on January 1, 2006, we recorded $2.2 million of compensation expense in 2006 related to stock options and the ESPP. The above amounts combined with a net $5.1 million increase in other G&A expense, including payroll tax and 401(k) contribution expense, were offset by a $3.2 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 $3.4 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.

*Change in Future Net Profits Plan Liability.* For the year ended December 31, 2006, this expense decreased $82.5 million to $23.8 million from $106.3 million for 2005. This decrease reflects a smaller change in future oil and gas prices as compared to 2005 when we experienced significant increases in prices. Since the prices used in the calculation were much more comparable in the year-end 2006 calculation to that of the 2005 calculation, the degree of increase was much less in 2006. 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, production tax rates, and production costs.

*Interest expense.* Interest expense increased by $308,000 to $8.5 million for 2006 compared to $8.2 million for 2005. The increase reflects an increase in our average outstanding borrowings and higher interest rates on the floating rate portion of our long-term debt. We also capitalized $3.5 million in 2006 compared to $1.9 million in 2005.

*Income tax expense.* Income tax expense totaled $105.3 million for 2006 and $86.3 million in 2005, resulting in effective tax rates of 35.7 percent and 36.3 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, the benefit of estimated percentage depletion for both federal and state income taxes, acquisition and drilling activity, and also reflects other permanent differences including differing estimated effects between years of the domestic production activities deduction.

The current portion of income tax expense in 2006 is $30.5 million compared to $80.8 million in 2005. These amounts are 29 percent and 94 percent of total income tax expense for the respective periods. The decrease resulted from a significant increase in drilling activity, whereby we deduct intangible drilling costs in the year it is incurred and reduce current taxable income. We project that the current portion of taxable income will be similar in 2007.

**Comparison of Financial Results and Trends between 2005 and 2004**

*Oil and gas production revenues.* Average net daily production increased 16 percent to 239.4 MMCFE for 2005 compared with 206.0 MMCFE in 2004. 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 | 19.9 | 37.5 | 1.3 |
| Paggi-Broussard 1 | 16.3 | 37.5 | 0.9 |
| Border acquisition | 8.3 | 18.2 | 2.1 |
| Agate acquisition | 7.0 | 15.2 | 5.0 |
| Goldmark acquisition | 3.9 | 7.0 | 3.9 |
| Wold acquisition | 3.2 | 8.5 | 3.1 |
| Other wells completed in 2004 and 2005 | 27.6 | 105.3 | 15.2 |
| Other acquisitions | 0.8 | 2.3 | 0.8 |
| Total | 87.0 | 231.5 | 32.3 |

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 years presented. Additional production costs reflect increases resulting from inflation and competition for resources.

*Oil and gas realized hedge gain (loss).* The 55 percent decrease in total oil and gas hedge loss to $22.5 million was caused by a change in the composition of our hedge position and changes in oil and gas commodity prices. During 2004, we had significant hedge positions related to contracts entered into for acquisitions that closed in 2002 and 2003. These hedges were at lower fixed contract prices that resulted in a larger realized hedge loss during 2004. These hedges expired in late 2004.

*Oil and gas production expenses.* Total production costs increased $47.4 million or 50 percent to $142.9 million for 2005, from $95.5 million in 2004. Our 2005 acquisition of properties added $8.1 million of incremental production costs, prior year acquisitions of properties added $6.8 million of incremental production costs, and other wells completed in 2004 and 2005 added $15.2 million of incremental production costs in 2005 that were not reflected in 2004. We experienced an increase in production taxes consistent with the increase in revenue from higher realized prices.

Total oil and gas production costs per MCFE increased $0.37 to $1.64 for 2005, compared with $1.27 for 2004. This increase is comprised of the following:

- An $0.08 increase in production taxes in our Mid-Continent region resulting from higher natural gas revenues and the suspension of Oklahoma severance tax incentives in 2005 due to average natural gas prices in excess of price caps;

- An $0.11 increase in production taxes due to higher revenue from crude oil in our Rocky Mountain and Permian regions;

- A $0.01 increase in production taxes in our ArkLaTex and Gulf coast regions reflecting higher natural gas prices offset by additional benefits from severance tax incentive credits received from Louisiana and Texas;

- A $0.12 increase in recurring LOE reflecting a $0.03 increase due to the start-up activity in our Hanging Woman Basin coalbed methane project, a general seven percent increase that we had forecast and cost increases we had not forecast in our budget process;

67

- A $0.05 increase in workover LOE reflecting a $0.04 increase in our Rocky Mountain region.

*Depreciation, Depletion, Amortization, and Impairment.* DD&A increased $40.6 million or 44% to $132.8 million in 2005 compared with $92.2 million in 2004. DD&A expense per MCFE increased 25% to $1.52 in 2005 compared to $1.22 in 2004. This increase reflects drilling and service cost inflation in 2005 and 2004 that added costs at a higher per unit rate.

*Exploration expense.* Exploration expense increased 57 percent in 2005. The most significant component of our increase to exploration expense was $12.0 million for exploration overhead related to increased payments made under the Net Profits Plan and the increased size of our geologic and exploration staff.

*General and administrative.* General and administrative expenses increased $10.8 million or 49 percent to $32.8 million for 2005, compared with $22.0 million for 2004. G&A increased $0.08 to $0.37 per MCFE for 2005 compared to $0.29 per MCFE for the period in 2004. The primary driver for the increase in G&A expense per MCFE is the increase in payments under the Net Profits Plan.

A 20 percent increase in employee count resulted in an increase in base employee compensation of $2.9 million between the year ended December 31, 2005, and the same period of 2004. Oil and gas price increases triggered additional Net Profits Plan payouts and increased the amounts payable to plan participants. Consequently, the period realized expense associated with the Net Profits Plan increased by $12.8 million in 2005. The increase in Net Profits Plan payments was the result of the significantly higher oil and gas prices received, which had the effect of increasing the absolute amount of payments as well as accelerating the time it takes for pools to reach payout. Thirteen of our 19 pools were in payout status as of the end of 2005. The cash bonus and RSU bonus was $8.3 million higher than the previous year as a result of our overall performance, which includes an evaluation of reserve replacement, production increases and net asset value per share enhancement.

The incentive plan compensation increases combined with a net $1.8 million increase in other compensation expense were partially offset by increases in COPAS overhead reimbursements and allocation of G&A to exploration expense. COPAS overhead reimbursement from operations increased $3.1 million due to an increase in operated well count resulting from our drilling and acquisition programs. The amount of G&A we allocated to exploration expense increased $11.9 million due to incentive plan payment increases and increases in our technical exploration staff.

*Change in Future Net Profits Plan Liability.* For the year ended December 31, 2005, this expense increased $81.9 million to $106.3 million from $24.4 million for 2004. This increase reflected our estimation of the effect of a sustained higher price environment and the impact of hedge contracts entered into in 2005 on the performance of individual pools as previously described. 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.

*Interest expense.* Interest expense increased by $2.0 million to $8.2 million for 2005 compared to $6.2 million for 2004. The increase reflected an increase in our average outstanding borrowings and higher interest rates on the floating rate portion of our long-term debt. Additionally, we received benefits from fixed-to-floating interest rate swaps in effect during 2004 that were effectively offset by floating-rate-to-fixed-rate interest rate swaps we entered into in April 2005.

*Income tax expense.* Income tax expense totaled $86.3 million for 2005 and $53.7 million in 2004, resulting in effective tax rates of 36.3 percent and 36.8 percent, respectively. The effective rate change from 2004 to 2005 reflected changes in the mix of the highest marginal state tax rates as a result of acquisition and drilling activity and also reflected other permanent differences including the estimated effect of the domestic production activities deduction from the American Jobs Creation Act of 2004.

The current portion of income tax expense in 2005 was $80.8 million compared to $22.5 million in 2004. These amounts were 94 percent and 42 percent of total income tax expense for the respective periods. The difference resulted from increased estimated taxable income caused by the higher price environment, a decreased estimated percentage of deductible intangible drilling costs relative to gross revenue, and the effect of the change in Net Profit Plan liability, which is not currently deductible.

**Other Liquidity and Capital Resource Information**

*Pension Benefits*

Substantially all of our employees who meet age and service requirements participate in a non-contributory defined benefit pension plan. On December 31, 2006, the Company adopted the recognition and disclosure provisions of 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 requires the Company to recognize the funded status (i.e., the difference between the fair value of plan assets and the projected benefit obligation) of its pension plan in the December 31, 2006 consolidated balance sheet as either and asset or a liability, with a corresponding adjustment to accumulated other comprehensive income, net of tax. At December 31, 2006, we have recorded a $2.6 million pre-tax loss in accumulated other comprehensive income as a result of this new pronouncement. We believe this obligation will be funded from future cash flow from operating activities. For purposes of calculating our obligation under the plan, we have used an expected return on plan assets of 7.5 percent. We think this rate of return is appropriate over the long-term given the 60 percent equity and 40 percent debt securities mix of investment of plan assets and the historical rate of return provided by equity and debt securities since the 1920s. Our estimated rate of return was 14.1 percent for 2006 and was 7.8 percent for 2005. The difference in investment income using our projected rate of return compared to our actual rates of return for the past two years was not material and will not have a material effect on the results of operation or cash flow from operating activities in future years.

For the 2006 plan year, a 0.40 percentage point increase in the discount rate combined with a 0.25 percentage point increase in the estimated rate of future compensation increases caused a $433,474 decrease in the projected benefit obligation of the plan. We do not believe this change was material and project that it will not have a material effect on the results of operations or on cash flow from operating activities in future periods.

We also have a supplemental non-contributory defined benefit pension plan that covers certain management employees. There are no plan assets for this plan. For the 2006 plan year, a 0.40 percentage point increase in the discount rate combined with a 0.25 percentage point increase in the estimated rate of future compensation increases caused a $100,834 decrease in the projected benefit obligation for this plan. This plan s accumulated benefit obligation was $1.5 million at December 31, 2006, and $1.1 million at December 31, 2005. We believe this obligation will be funded from future cash flow from operating activities.

**Accounting Matters**

On December 31, 2006, the Company adopted SFAS No. 158. As a result of adopting this standard, the Company is required to recognize the funded status (i.e., the difference between the fair value of plan assets and the projected benefit obligation) of its pension plan in the December 31, 2006, consolidated balance sheet as a liability, with a corresponding adjustment to accumulated other comprehensive income, net of tax. The underfunded status of the plan of $6 million at December 31, 2006 is recognized in the consolidated balance sheet as a long-term accrued pension liability.

See Note 8 Pension Benefits in Part IV, Item 15 of this report for additional information regarding the effects of adopting SFAS No. 158.

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 of tax positions. FIN 48 will require the Company to recognize the impact of a tax position in its financial statements only if the technical merits of that position indicate that the position is more likely than not of being sustained upon audit. The Company has evaluated the impact of FIN 48 as of the January 1, 2007 adoption date and determined there will be no impact to its 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.

**Environmental**

St. Mary s compliance with applicable environmental regulations has not resulted in any significant capital expenditures or materially adverse effects to our liquidity or results of operations. We believe we are in substantial compliance with environmental regulations and foresee that no material expenditures will be incurred in the future. However, we are unable to predict the impact that future compliance with regulations may have on future capital expenditures, liquidity, and results of operations.

## **ITEM 7A.** 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 in Item 7 above and is incorporated herein by reference.

## **ITEM 8.** FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The Consolidated Financial Statements that constitute Item 8 follow the text of this report. An index to the Consolidated Financial Statements and Schedules appears in Item 15(a) of this report.

## **ITEM 9.** CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

## **ITEM 9A.** 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 to ensure that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

We carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this Annual Report on Form 10-K. 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 Annual Report on Form 10-K. 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.

**MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING**

To the Stockholders of St. Mary Land & Exploration Company

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. The Company s internal control over financial reporting is designed 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. The Company s internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company s assets that could have a material effect on the financial statements.

Because of the inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the Company s internal control over financial reporting as of December 31, 2006. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control Integrated Framework*.

Based on our assessment and those criteria, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2006.

The Company s independent registered public accounting firm has issued an attestation report on management s assessment of the Company s internal controls over financial reporting. That report immediately follows this report.

/s/ MARK A. HELLERSTEIN
Mark A. Hellerstein
Chairman and CEO
February 22, 2007

/s/ DAVID W. HONEYFIELD
David W. Honeyfield
Vice President CFO, Secretary & Treasurer
February 22, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
St. Mary Land & Exploration Company and Subsidiaries

We have audited management s assessment, included in the accompanying Management s Report on Internal Control over Financial Reporting, that St. Mary Land & Exploration Company and subsidiaries (the Company ) maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the Company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed by, or under the supervision of, the company s principal executive and principal financial officers, or persons performing similar functions, and effected by the company s board of directors, management, and other personnel 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. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management s assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2006, of the Company, and our report dated February 22, 2007, expressed an unqualified opinion on those financial statements and includes an explanatory paragraph for the change in method of accounting for stock-based compensation and defined benefit pension plans.

/S/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 22, 2007

73

**ITEM 9B.** OTHER INFORMATION

None.

**PART III**

**ITEM 10.** DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item concerning St. Mary s Directors and corporate governance is incorporated by reference to the information provided under the captions Election of Directors, Nominees for Election of Directors, Corporate Governance and Board and Committee Meetings in St. Mary s definitive proxy statement for the 2007 annual meeting of stockholders to be filed within 120 days from December 31, 2006. The information required by this Item concerning St. Mary s executive officers is incorporated by reference to the information provided in Part I Item 4A EXECUTIVE OFFICERS OF THE REGISTRANT, included in this Form 10-K.

The information required by this Item concerning compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated by reference to the information provided under the caption Section 16(a) Beneficial Ownership Reporting Compliance in St. Mary s definitive proxy statement for the 2007 annual meeting of stockholders to be filed within 120 days from December 31, 2006.

**ITEM 11.** EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information provided under the captions, Director Compensation, Executive Compensation, Compensation Committee Interlocks and Insider Participation, Compensation Committee Report, Retirement Plans, and Employee Agreements and Termination of Employment and Change-in-Control Arrangements in St. Mary s definitive proxy statement for the 2007 annual meeting of stockholders to be filed within 120 days from December 31, 2006.

**ITEM 12.** SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item concerning security ownership of certain beneficial owners and management is incorporated by reference to the information provided under the caption Security Ownership of Certain Beneficial Owners and Management in St. Mary s definitive proxy statement for the 2007 annual meeting of stockholders to be filed within 120 days from December 31, 2006.

The information required by this Item concerning securities authorized for issuance under equity compensation plans is incorporated by reference to the information provided under the caption Equity Compensation Plans in Part II, Item 5 Market for Registrant s Common Equity, Related Stockholder Matters, and Issuer Purchases of Equity Securities, included in this Form 10-K.

**ITEM 13.** CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this Item is incorporated by reference to the information provided under the caption Certain Relationships and Related Transactions in St. Mary s definitive proxy statement for the 2007 annual meeting of stockholders to be filed within 120 days from December 31, 2006.

**ITEM 14.** PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item is incorporated by reference to the information provided under the caption Independent Accountants in St. Mary s definitive proxy statement for the 2007 annual meeting of stockholders to be filed within 120 days from December 31, 2006.

**PART IV**

**ITEM 15.** EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

*(a)(1) and (a)(2) Financial Statements and Financial Statement Schedules:*


| | |
|---|---|
| Audit Report of Independent Registered Public Accounting Firm | F-1 |
| Consolidated Balance Sheets | F-2 |
| Consolidated Statements of Operations | F-3 |
| Consolidated Statements of Stockholders Equity and Comprehensive Income | F-4 |
| Consolidated Statements of Cash Flows | F-6 |
| Notes to Consolidated Financial Statements | F-8 |


All other schedules are omitted because the required information is not applicable or is not present in amounts sufficient to require submission of the schedule or because the information required is included in the Consolidated Financial Statements and Notes thereto.

*(b) Exhibits.* The following exhibits are filed or furnished with or incorporated by reference into this report on Form 10-K:

| Exhibit **Number** | **Description** |
|---|---|
| 2.1 | Purchase and Sale Agreement dated November 1, 2006 among Henry Petroleum LP, Henry Holding LP, Henry Group, Entre Energy Partners LP, and St. Mary Land & Exploration Company (filed as Exhibit 2.1 to the registrant s Current Report on Form 8-K on December 18, 2006 and incorporated herein by reference) |
| 3.1 | Restated Certificate of Incorporation of St. Mary Land & Exploration Company as amended on May 25, 2005 (filed as Exhibit 3.1 to the registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 and incorporated herein by reference) |
| 3.2 | Restated By-Laws of St. Mary Land & Exploration Company as amended on March 27, 2003 (filed as Exhibit 3.2 to the registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2003 and incorporated herein by reference) |
| 4.1 | Shareholder Rights Plan adopted on July 15, 1999 (filed as Exhibit 4.1 to the registrant s Quarterly Report on Form 10-Q/A for the quarter ended June 30, 1999 and incorporated herein by reference) |
| 4.2 | First Amendment to Shareholders Rights Plan dated March 15, 2002 as adopted by the Board of Directors on July 19, 2001 (filed as Exhibit 4.2 to the registrant s Annual Report on Form 10-K for the year ended December 31, 2001 and incorporated herein by reference) |
| 4.3 | Second Amendment to Shareholder Rights Plan dated April 24, 2006 (filed as Exhibit 4.1 to the registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2006 and incorporated herein by reference) |
| 10.1 | Stock Option Plan, as Amended on May 22, 2003 (filed as Exhibit 99.1 to the registrant s Registration Statement on Form S-8 (Registration No. 333-106438) and incorporated herein by reference) |
| 10.2 | Incentive Stock Option Plan, as Amended on May 22, 2003 (filed as Exhibit 99.2 to registrant s Registration Statement on Form S-8 (Registration No. 333-106438) and incorporated herein by reference) |

| | |
|---|---|
| 10.3 | Cash Bonus Plan (filed as Exhibit 10.5 to the registrant s Registration Statement on Form S-1 (Registration No. 33-53512) and incorporated herein by reference) |
| 10.4 | Summary Plan Description/Pension Plan dated December 30, 1994 (filed as Exhibit 10.35 to the registrant s Annual Report on Form 10-K for the year ended December 31, 1994 and incorporated herein by reference) |
| 10.5 | Non-qualified Unfunded Supplemental Retirement Plan, as amended (filed as Exhibit 10.8 to the registrant s Registration Statement on Form S-1 (Registration No. 33-53512) and incorporated herein by reference) |
| 10.6 | Employee Stock Purchase Plan (filed as Exhibit 10.48 filed to the registrant s Annual Report on Form 10-K (for the year ended December 31, 1997 and incorporated herein by reference) |
| 10.7 | First Amendment to Employee Stock Purchase Plan dated February 27, 2001 (filed as Exhibit 10.1 to the registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2001 and incorporated herein by reference) |
| 10.8 | Second Amendment to the Employee Stock Purchase Plan dated February 18, 2005 (filed as Exhibit 10.48 to the registrants Annual Report on Form 10-K for the year ended December 31, 2004 and incorporated herein by reference) |
| 10.9 | Form of Change of Control Severance Agreements (filed as Exhibit 10.1 to the registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001 and incorporated herein by reference) |
| 10.10 | Amendment to Form of Change of Control Severance Agreement (filed as Exhibit 10.9 to the registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 and incorporated herein by reference) |
| 10.11 | Employment Agreement of Mark A. Hellerstein (filed as Exhibit 10.15 to the registrant s Registration Statement on Form S-1 (Registration No. 33-53512) and incorporated herein by reference) |
| 10.12 | Amendment to Employment Agreement of Mark A. Hellerstein, dated December 16, 2005 (filed as Exhibit 10.3 to the registrant s Current Report on Form 8-K filed on December 19, 2005 and incorporated herein by reference) |
| 10.13 | 5.75% Senior Convertible Notes due 2022 Indenture dated March 13, 2002 (filed as Exhibit 10.26 to the registrant s Annual Report on Form 10-K for the year ended December 31, 2001 and incorporated herein by reference) |
| 10.14 | Amendment to and Extension of Office Lease dated as of December 14, 2001 (filed as Exhibit 10.45 to the registrant s Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference) |
| 10.15 | Non-Employee Director Stock Compensation Plan as adopted on March 27, 2003 (filed as Exhibit 10.1 to the registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 and incorporated herein by reference) |
| 10.16 | Restricted Stock Plan as adopted on April 18, 2004 (filed as Exhibit 10.1 to the registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 and incorporated herein by reference) |

| | |
|---|---|
| 10.17 | Amendment to Restricted Stock Plan, dated December 15, 2005 (filed as Exhibit 10.2 to the registrant s Current Report on Form 8-K filed on December 19, 2005 and incorporated herein by reference) |
| 10.18 | Form of Restricted Stock Unit Award Agreement under the Restricted Stock Plan (filed as Exhibit 10.1 to the registrant s Current Report on Form 8-K filed on March 15, 2005 and incorporated herein by reference) |
| 10.19 | Amended and Restated Credit Agreement dated as of April 7, 2005 among St. Mary Land & Exploration Company, Wachovia Bank, National Association, as Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference) |
| 10.20 | 2006 Equity Incentive Compensation Plan (filed on May 17, 2006 as Exhibit 99.1 to the registrant s Registration Statement on Form S-8 (Registration No. 333-134221) and incorporated herein by reference) |
| 10.21 | Form of Non-Employee Director Restricted Stock Award Agreement (filed as Exhibit 10.2 to the registrant s Current Report on Form 8-K filed on May 18, 2006 and incorporated herein by reference) |
| 10.22 | Guaranty Agreement by St. Mary Energy Company in favor of Wachovia Bank, National Association, as Administrative Agent, dated April 7, 2005 (filed as Exhibit 10.2 to the registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference) |
| 10.23 | Guaranty Agreement by Nance Petroleum Corporation in favor of Wachovia Bank, National Association, as Administrative Agent, dated April 7, 2005 (filed as Exhibit 10.3 to the registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference) |
| 10.24 | Guaranty Agreement by NPC Inc. in favor of Wachovia Bank, National Association, as Administrative Agent, dated April 7, 2005 (filed as Exhibit 10.4 to the registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference) |
| 10.25 | Pledge and Security Agreement between St. Mary Land & Exploration Company and Wachovia Bank, National Association, as Administrative Agent, dated April 7, 2005 (filed as Exhibit 10.5 to the registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference) |
| 10.26 | Pledge and Security Agreement between Nance Petroleum Corporation and Wachovia Bank, National Association, as Administrative Agent, dated April 7, 2005 (filed as Exhibit 10.6 to the registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference) |
| 10.27 | First Supplement and Amendment to Deed of Trust, Mortgage, Line of Credit Mortgage, Assignment, Security Agreement, Fixture Filing and Financing Statement for the benefit of Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 7, 2005 (filed as Exhibit 10.7 to the registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference) |

| | |
|---|---|
| 10.28 | Deed of Trust St. Mary Land & Exploration to Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 7, 2005 (filed as Exhibit 10.8 to the registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference) |
| 10.29 | Net Profits Interest Bonus Plan, as Amended on December 15, 2005 (filed as Exhibit 10.1 to the registrant s Current Report on Form 8-K filed on December 19, 2005 and incorporated herein by reference) |
| 10.30 | Summary of Charitable Contributions in Honor of Thomas E. Congdon (filed as Exhibit 10.4 to the registrant s Current Report on Form 8-K filed on December 19, 2005 and incorporated herein by reference) |
| 10.31 | Summary of 2006 Base Salaries for Named Executive Officers (filed as Exhibit 10.5 to the registrant s Current Report on Form 8-K filed on December 19, 2005 and incorporated herein by reference) |
| 10.32 | Employment Agreement of A.J. Best dated May 1, 2006 (filed as Exhibit 10.1 to the registrant s Current Report on From 8-K filed on May 4, 2006 and incorporated herein by reference) |
| 10.33* | Summary of 2007 Compensation Arrangements for Non-Employee Directors |
| 12.1* | Computation of Ratio of Earnings to Fixed Charges |
| 14.1 | Code of Business Conduct and Ethics (filed as Exhibit 14.1 to the registrant s Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference) |
| 21.1* | Subsidiaries of Registrant |
| 23.1* | Consent of Deloitte & Touche LLP |
| 23.2* | Consent of Ryder Scott Company, L.P. |
| 23.3* | Consent of Netherland, Sewell & Associates, Inc. |
| 24.1* | Power of Attorney (included in signature page hereof) |
| 31.1* | Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002 |
| 31.2* | Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002 |
| 32.1** | Certification pursuant to U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002 |

---

* Filed with this Form 10-K.

** Furnished with this Form 10-K.

Exhibit constitutes a management contract or compensatory plan or arrangement

*(c) Financial Statement Schedules.* See Item 15(a) above.

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors and Stockholders of
St. Mary Land & Exploration Company and Subsidiaries

We have audited the accompanying consolidated balance sheets of St. Mary Land & Exploration Company and subsidiaries (the Company ) as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of St. Mary Land & Exploration Company and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 and Note 8 to the financial statements, the Company changed its method of accounting and disclosure for stock based compensation and its defined benefit plans in 2006.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 22, 2007, expressed an unqualified opinion on management s assessment of the effectiveness of the Company s internal control over financial reporting and an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 22, 2007

F-1

**PART II. FINANCIAL INFORMATION**

**ITEM 8.** FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

| | **December 31, 2006** | **December 31, 2005** |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 1,464 | $ 14,925 |
| Short-term investments | 1,450 | 1,475 |
| Accounts receivable | 142,721 | 165,197 |
| Refundable income taxes | 7,684 | |
| Prepaid expenses and other | 17,485 | 7,283 |
| Accrued derivative asset | 56,136 | 6,799 |
| Deferred income taxes | | 8,252 |
| Total current assets | 226,940 | 203,931 |
| Property and equipment (successful efforts method), at cost: | | |
| Proved oil and gas properties | 2,063,911 | 1,441,959 |
| Less accumulated depletion, depreciation, and amortization | (630,051) | (497,621) |
| Unproved oil and gas properties, net of impairment allowance of $9,425 in 2006 and $9,862 in 2005 | 100,118 | 44,383 |
| Wells in progress | 97,498 | 55,505 |
| Other property and equipment, net of accumulated depreciation of $9,740 in 2006 and $8,046 in 2005 | 6,988 | 5,340 |
| | 1,638,464 | 1,049,566 |
| Noncurrent assets: | | |
| Goodwill | 9,452 | 9,452 |
| Long-term derivative asset | 16,939 | 575 |
| Other noncurrent assets | 7,302 | 5,223 |
| Total noncurrent assets | 33,693 | 15,250 |
| **Total Assets** | **$ 1,899,097** | **$ 1,268,747** |
| **LIABILITIES AND STOCKHOLDERS EQUITY** | | |
| Current liabilities: | | |
| Accounts payable and accrued expenses | $ 171,834 | $ 164,957 |
| Short-term note payable | 4,469 | |
| Accrued derivative liability | 13,100 | 34,037 |
| Deferred income taxes | 14,667 | |
| Total current liabilities | 204,070 | 198,994 |
| Noncurrent liabilities: | | |
| Long-term credit facility | 334,000 | |
| Convertible notes | 99,980 | 99,885 |
| Asset retirement obligation | 77,242 | 66,078 |
| Net Profits Plan liability | 160,583 | 136,824 |
| Deferred income taxes | 224,518 | 128,296 |
| Accrued derivative liability | 46,432 | 64,137 |
| Other noncurrent liabilities | 8,898 | 5,213 |
| Total noncurrent liabilities | 951,653 | 500,433 |
| Commitments and contingencies | | |
| Stockholders equity: | | |
| Common stock, $0.01 par value: authorized 200,000,000 shares; issued: 55,251,733 shares in 2006 and 57,011,740 shares in 2005; outstanding, net of treasury shares: 55,001,733 shares in 2006 and 56,761,740 shares in 2005 | 553 | 570 |
| Additional paid-in capital | 38,940 | 123,278 |
| Treasury stock, at cost: 250,000 shares in 2006 and 250,000 shares in 2005 | (4,272) | (5,148) |
| Deferred stock-based compensation | | (5,593) |
| Retained earnings | 695,224 | 510,812 |
| Accumulated other comprehensive income (loss) | 12,929 | (54,599) |
| Total stockholders equity | 743,374 | 569,320 |
| **Total Liabilities and Stockholders Equity** | **$ 1,899,097** | **$ 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**
**(In thousands, except per share amounts)**

| | For the Years Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| Operating revenues: | | | |
| Oil and gas production revenue | $ 730,737 | $ 733,544 | $ 463,617 |
| Realized oil and gas hedge gain (loss) | 28,176 | (22,539) | (50,299) |
| Marketed gas revenue | 20,936 | 25,269 | 15,551 |
| Gain on sale of proved properties | 6,910 | 222 | 1,803 |
| Other revenue | 942 | 3,094 | 2,427 |
| Total operating revenues | 787,701 | 739,590 | 433,099 |
| Operating expenses: | | | |
| Oil and gas production expense | 176,590 | 142,873 | 95,518 |
| Depletion, depreciation, amortization, and asset retirement obligation liability accretion | 154,522 | 132,758 | 92,223 |
| Exploration | 51,889 | 44,931 | 28,560 |
| Impairment of proved properties | 7,232 | | 494 |
| Abandonment and impairment of unproved properties | 4,301 | 5,780 | 1,420 |
| General and administrative | 38,873 | 32,756 | 22,004 |
| Change in Net Profits Plan liability | 23,759 | 106,263 | 24,398 |
| Marketed gas system operating expense | 18,526 | 24,164 | 14,230 |
| Unrealized derivative loss | 7,094 | 1,615 | 260 |
| Other expense | 2,649 | 2,456 | 2,077 |
| Total operating expenses | 485,435 | 493,596 | 281,184 |
| Income from operations | 302,266 | 245,994 | 151,915 |
| Nonoperating income (expense): | | | |
| Interest income | 1,576 | 456 | 557 |
| Interest expense | (8,521) | (8,213) | (6,244) |
| Income before income taxes | 295,321 | 238,237 | 146,228 |
| Income tax expense | (105,306) | (86,301) | (53,749) |
| **Net income** | **$ 190,015** | **$ 151,936** | **$ 92,479** |
| Basic weighted-average common shares outstanding | 56,291 | 56,907 | 57,702 |
| Diluted weighted-average common shares outstanding | 65,962 | 66,894 | 66,894 |
| **Basic net income per common share** | **$ 3.38** | **$ 2.67** | **$ 1.60** |
| **Diluted net income per common share** | **$ 2.94** | **$ 2.33** | **$ 1.44** |

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

F-3

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

| | Common Stock Shares | Common Stock Amount | Additional Paid-in Capital | Treasury Stock Shares | Treasury Stock Amount | Deferred Stock-Based Compensation | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total Stockholders Equity |
|---|---|---|---|---|---|---|---|---|---|
| **Balances, December 31, 2003** | **58,490,246** | **$ 584** | **$ 146,070** | **(2,005,400 )** | **$ (16,057 )** | **$** | **$ 274,937** | **$ (14,881 )** | **$ 390,653** |
| Comprehensive income, net of tax: | | | | | | | | | |
| Net income | | | | | | | 92,479 | | 92,479 |
| Change in derivative instrument fair value | | | | | | | | (14,795 ) | (14,795 ) |
| Reclassification to earnings | | | | | | | | 31,849 | 31,849 |
| Minimum pension liability adjustment | | | | | | | | 101 | 101 |
| Total comprehensive income | | | | | | | | | 109,634 |
| Cash dividends, $0.05 per share | | | | | | | (2,849 ) | | (2,849 ) |
| Repurchase of common stock from Flying J | | | (19,406 ) | | | | | | (19,406 ) |
| Treasury stock purchases | | | | (978,600 ) | (16,336 ) | | | | (16,336 ) |
| Retirement of treasury stock | (2,458,800 ) | (24 ) | (26,725 ) | 2,458,800 | 26,749 | | | | |
| Issuance of common stock under Employee Stock Purchase Plan | 27,748 | | 375 | | | | | | 375 |
| Sale of common stock, including income tax benefit of stock option exercises | 1,399,052 | 14 | 17,832 | | | | | | 17,846 |
| Deferred compensation related to issued restricted stock unit awards, net of forfeitures | | | 8,122 | | | (8,122 ) | | | |
| Directors stock compensation | | | | 25,200 | 349 | | | | 349 |
| Accrued stock-based compensation | | | 1,106 | | | | | | 1,106 |
| Amortization of deferred stock-based compensation | | | | | | 3,083 | | | 3,083 |
| **Balances, December 31, 2004** | **57,458,246** | **$ 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, $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** |

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

F-4

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

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Comprehensive income, net of tax: | | | | | | | | | |
| Net income | | | | | | | 190,015 | | 190,015 |
| Change in derivative instrument fair value | | | | | | | | 87,107 | 87,107 |
| Reclassification to earnings | | | | | | | | (18,129) | (18,129) |
| Minimum pension liability adjustment | | | | | | | | (180) | (180) |
| Total comprehensive income | | | | | | | | | 258,813 |
| SFAS No. 158 transition amount | | | | | | | | (1,270) | (1,270) |
| Cash dividends, $0.10 per share | | | | | | | (5,603) | | (5,603) |
| Treasury stock purchases | | | | (3,319,300) | (123,108) | | | | (123,108) |
| Retirement of treasury stock | (3,275,689) | (33) | (122,598) | 3,275,689 | 122,631 | | | | |
| Issuance of Directors shares from treasury | | | | 29,827 | 851 | | | | 851 |
| Issuance of common stock under Employee Stock Purchase Plan | 26,046 | | 814 | | | | | | 814 |
| Sale of common stock, including income tax benefit of stock option exercises | 1,489,636 | 16 | 32,970 | | | | | | 32,986 |
| Adoption of Statement of Financial Accounting Standards No. 123R | | | (5,593) | | | 5,593 | | | |
| Stock-based compensation expense | | | 10,069 | 13,784 | 502 | | | | 10,571 |
| **Balances, December 31, 2006** | **55,251,733** | **$ 553** | **$ 38,940** | **(250,000)** | **$ (4,272)** | **$** | $ 695,224 | **$ 12,929** | **$ 743,374** |

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

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

| | For the Years Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| Reconciliation of net income to net cash provided by operating activities: | | | |
| Net income | $ 190,015 | $ 151,936 | $ 92,479 |
| Adjustments to reconcile net income to net cashprovided by operating activities: | | | |
| Gain on sale of proved properties | (6,910) | (222) | (1,803) |
| Depletion, depreciation, amortization, and abandonment liability accretion | 154,522 | 132,758 | 92,223 |
| Exploratory dry hole expense | 10,191 | 8,104 | 4,162 |
| Impairment of proved properties | 7,232 | | 494 |
| Abandonment and impairment of unproved properties | 4,301 | 5,780 | 1,420 |
| Unrealized derivative loss | 7,094 | 1,615 | 260 |
| Change in Net Profits Plan liability | 23,759 | 106,263 | 24,398 |
| Stock-based compensation expense | 11,422 | 7,165 | 4,189 |
| Deferred income taxes | 74,832 | 5,547 | 31,217 |
| Other | (2,479) | 281 | (1,948) |
| Changes in current assets and liabilities: | | | |
| Accounts receivable | 22,476 | (57,113) | (39,880) |
| Prepaid expenses and other | (17,886) | (1,210) | 157 |
| Accounts payable and accrued expenses | 5,215 | 42,438 | 25,978 |
| Income tax benefit from the exercise of stock options* | (16,084) | 6,037 | 3,816 |
| **Net cash provided by operating activities** | **467,700** | **409,379** | **237,162** |
| Cash flows from investing activities: | | | |
| Proceeds from sale of oil and gas properties | 860 | 1,213 | 2,829 |
| Capital expenditures | (455,056) | (270,881) | (199,385) |
| Acquisition of oil and gas properties | (270,639) | (73,905) | (68,805) |
| Deposits to short-term investments available-for-sale | | (1,502) | (1,470) |
| Receipts from short-term investments available-for-sale | 25 | 1,427 | 12,500 |
| Receipts from restricted cash | | | 10,353 |
| Other | 91 | 3,869 | (3,028) |
| **Net cash used in investing activities** | **(724,719)** | **(339,779)** | **(247,006)** |
| Cash flows from financing activities: | | | |
| Proceeds from credit facility | 935,137 | 284,090 | 181,500 |
| Repayment of credit facility | (601,137) | (321,090) | (155,500) |
| Proceeds from short-term note payable | 4,469 | | |
| Income tax benefit from the exercise of stock options* | 16,084 | | |
| Proceeds from sale of common stock | 17,716 | 11,193 | 14,030 |
| Repurchase of common stock | (123,108) | (28,902) | (35,743) |
| Dividends paid | (5,603) | (5,691) | (2,849) |
| Other | | (693) | (3) |
| **Net cash provided by (used in) financing activities** | **243,558** | **(61,093)** | **1,435** |
| Net change in cash and cash equivalents | (13,461) | 8,507 | (8,409) |
| Cash and cash equivalents at beginning of period | 14,925 | 6,418 | 14,827 |
| **Cash and cash equivalents at end of period** | **$ 1,464** | **$ 14,925** | **$ 6,418** |

* 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 (Continued)**

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

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | (in thousands) | | |
| Cash paid for interest, net of capitalized interest | $ 9,826 | $ 8,458 | $ 6,884 |
| Cash paid for income taxes | $ 25,505 | $ 65,752 | $ 14,787 |

As of December 31, 2006 and 2005, $73.5 million and $51.0 million, respectively, are included as additions to oil and gas properties and as increases to accounts payable and accrued expenses. These oil and gas property additions are reflected in cash used in investing activities in the periods that the payables are settled.

In February 2006, March 2005, and June 2004, the Company issued 484,351, 195,312, and 465,722 restricted stock units, respectively, pursuant to the Company s restricted stock plan. The total value of the issuances were $16.4 million, $4.5 million and $8.3 million, respectively.

In July 2006, May 2006, May 2005, May 2004, and January 2004 the Company issued 3,751, 26,076, 13,926, 16,800, and 8,400 shares, respectively, of common stock from treasury to its non-employee directors pursuant to the Company s non-employee director stock compensation plan. The Company recorded compensation expense related to these issuances of $976,000, $178,000 and $342,000 for the years ended December 31, 2006, 2005, and 2004, respectively.

In May 2006 the Company closed a transaction whereby it exchanged non-core oil and gas properties 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 August 2004 the Company closed a transaction whereby it exchanged oil and gas properties valued at $1.4 million together with $769,000 of cash for oil and gas properties valued at $2.2 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 $728,000. The new senior executive can earn up to 15,000 additional shares based on achieving certain performance levels. Approximately $27,000 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**
**DECEMBER 31, 2006**

**Note 1 Summary of Significant Accounting Policies**

*Description of Operations*

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.

*Basis of Presentation*

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. Subsidiaries that are not wholly-owned are accounted for using full consolidation with minority interest or by the equity or cost method as appropriate. Equity method investments are included in other noncurrent assets, and minority interest is included in other noncurrent liabilities in the accompanying consolidated balance sheets. All significant intercompany accounts and transactions have been eliminated.

Common stock and additional paid-in capital amounts have been reclassified for all periods presented to reflect a stock dividend distributed in March 2005.

*Use of Estimates in the Preparation of Financial Statements*

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Estimates of oil and gas reserve quantities provide the basis for calculations of depletion, depreciation, and amortization ( DD&A ), impairment, goodwill, and the Net Profits Interest Bonus Plan (the Net Profits Plan ) liability, each of which represents a significant component of the consolidated financial statements.

*Revenue Recognition*

The Company derives revenue primarily from the sale of produced natural gas and crude oil. The Company reports revenue as the gross amount received before taking into account production taxes and transportation costs, which are reported as separate expenses. Revenue is recorded in the month the Company s production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to a purchaser. At the end of each month the Company estimates the amount of production delivered to the purchaser and the price the Company will receive. The Company uses its knowledge of properties, their historical performance, the anticipated effect of weather conditions during the month of production, NYMEX and local spot market prices, and other factors as the basis for these estimates.

*Cash and Cash Equivalents*

The Company considers all liquid investments purchased with an initial maturity of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short-term nature of these instruments.

*Short-term Investments*

The Company s short-term investments consist of investment-grade marketable debt that is classified as held-to-maturity or available-for-sale. Securities categorized as held-to-maturity are stated at amortized cost whereas available-for-sale securities are marked-to-market. As of December 31, 2006 and 2005, the Company held $1.5 million of short-term investments.

*Concentration of Credit Risk*

Substantially all of the Company s receivables are within the oil and gas industry, primarily from purchasers of oil and gas and from joint interest owners. Although diversified among many companies, collectability is dependent upon the financial wherewithal of each individual company as well as the general economic conditions of the industry. The receivables are not collateralized. To date the Company has had minimal bad debts.

The Company has accounts with separate banks in Denver, Colorado; Shreveport, Louisiana; Tulsa, Oklahoma; Houston, Texas; and Billings, Montana. At December 31, 2006, 2005, and 2004, the Company had $1.6 million, $36.8 million, and $22.2 million respectively, invested in money market funds, corporate commercial paper, repurchase agreements, and U.S. Treasury obligations. The difference between the investment amount and the cash and cash equivalents amount on the consolidated balance sheets represents uncleared disbursements and non-interest bearing checking accounts. The Company s policy is to invest in highly-rated instruments and to limit the amount of credit exposure at each individual institution.

The Company currently uses ten separate counterparties for its oil and gas commodity and interest rate derivatives. The counterparties to the Company s derivative instruments are all highly-rated entities.

*Oil and Gas Producing Activities*

The Company follows the successful efforts method of accounting for its oil and gas properties. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense. Exploratory dry hole costs are included in cash flows from investing activities as part of capital expenditures within the consolidated statements of cash flows. The costs of development wells are capitalized whether or not proved reserves are found.

Geological and geophysical costs and the costs of carrying and retaining unproved properties are expensed as incurred. DD&A of capitalized costs related to proved oil and gas properties is calculated on a field-by-field basis using the units-of-production method based upon proved reserves. The computation of DD&A takes into consideration restoration, dismantlement, and abandonment costs and the anticipated proceeds from salvaging equipment. As of December 31, 2006, the Company s capitalized proved oil and gas properties included $92.7 million of estimated salvage value, which is excluded from the depletable property costs when calculating DD&A.

In 2005, the Company adopted Statement of Financial Accounting Standards Staff Position No. FAS 19-1, Accounting for Suspended Well Costs, ( FSP FAS 19-1 ). Upon adoption of FSP FAS 19-1 the Company evaluated all existing capitalized exploratory well costs under the provisions of FSP FAS 19-1. As a result, the Company determined that no suspended well costs should be impaired. For additional discussion, please see Note 12 Disclosures about Oil and Gas Producing Activities under the heading *Suspended Well Costs*.

The Company reviews its long-lived assets for impairments when events or changes in circumstances indicate that an impairment may have occurred. The impairment test for proved properties compares the expected undiscounted future net cash flows on a field-by-field basis with the related net capitalized costs, including costs associated with asset retirement obligations, at the end of each period. Expected future cash flows are calculated on all proved reserves using a discount rate and price forecasts selected by the Company s management. The discount rate is a rate that management believes is representative of current market conditions. The price forecast is based on NYMEX strip pricing for the first three years and is then escalated to and capped at specified maximum prices. Operating costs are also adjusted as deemed appropriate for these estimates. When the net capitalized costs exceed the undiscounted future net revenues of a field, the cost of the field is reduced to fair value, which is determined using discounted future net revenues. An impairment allowance is provided on unproved property when the Company determines the property will not be developed or the carrying value is not realizable.

*Sales of Proved and Unproved Properties*

The sale of a partial interest in a proved oil and gas property is accounted for as normal retirement, and no gain or loss is recognized as long as this treatment does not significantly affect the units-of-production depletion rate. A gain or loss is recognized for all other sales of producing properties and is included in the results of operations.

The sale of a partial interest in an unproved property is accounted for as a recovery of cost when substantial uncertainty exists as to recovery of the cost applicable to the interest retained. A gain on the sale is recognized to the extent the sales price exceeds the carrying amount of the unproved property. A gain or loss is recognized for all other sales of nonproducing properties and is included in the results of operations.

*Other Property and Equipment*

Other property and equipment such as office furniture and equipment, automobiles, and computer hardware and software are recorded at cost. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs are expensed when incurred. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets from three to eight years. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts.

*Gas Balancing*

The Company uses the sales method of accounting for gas revenue whereby sales revenue is recognized on all gas sold to purchasers, regardless of whether the sales are proportionate to the Company s ownership in the property. An asset or a liability is recognized to the extent that there is an imbalance in excess of the remaining gas reserves on the underlying properties. The Company s gas imbalance position at December 31, 2006 and 2005 resulted in the recording of $1.4 million and $1.6 million, respectively, to receivables, and $791,000 and $869,000, respectively, to payables.

*Derivative* Financial Instruments

The Company seeks to protect its rate of return on acquisitions of producing properties and other production by hedging cash flows. The Company intends for derivative instruments used for this purpose to be designated as, and to qualify as cash flow hedging instruments under Statement of Financial

Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, ( SFAS No. 133 ) and related pronouncements. The Company seeks to minimize basis risk and indexes the majority of its oil hedges to NYMEX prices and the majority of its gas hedges to various regional index prices associated with pipelines in proximity to the Company s areas of gas production. For additional discussion of derivatives, please see Note 10 Derivative Financial Instruments.

*Fair Value of Financial Instruments*

The Company s financial instruments including cash and cash equivalents, accounts receivable, and accounts payable are carried at cost, which approximates fair value due to the short-term maturity of these instruments. The recorded value of the Company s credit facility approximates its fair value as it bears interest at a floating rate. The Company had $334.0 million in loans outstanding under its revolving credit agreement as of December 31, 2006. No amounts under its revolving credit agreement were outstanding as of December 31, 2005. The Company s interest rate swaps are recorded at fair value as discussed in Note 10 Derivative Financial Instruments. The Company s 5.75% Senior Convertible Notes due 2022 (the Convertible Notes ) are recorded at cost, and the fair value is disclosed in Note 5 Long-Term Debt. The Company has other financial instruments and investments in available-for-sale securities that are marked-to-market with changes in fair value being recorded in accumulated other comprehensive income. Since considerable judgment is required to develop estimates of fair value, the estimates provided are not necessarily indicative of the amounts the Company could realize upon the sale or refinancing of such instruments.

*Net Profits Plan*

The Company records the estimated liability of future payments for its Net Profits Plan. The estimated liability is a discounted calculation and has underlying assumptions, including estimates of oil and gas reserves, recurring and workover lease operating expense, production and ad valorem tax rates, present value discount factors, and pricing assumptions. The estimates the Company uses in calculating the liability are adjusted from period-to-period based on the most current information attributable to the underlying assumptions. Changes in the estimated liability of future payments associated with the Net Profits Plan are recorded as increases or decreases to expense in the current period as a separate line item in the consolidated statements of operations as these changes are considered changes in estimates. The estimated Net Profits Plan liability is recorded separately as a noncurrent liability in the accompanying consolidated balance sheets.

The amounts due to participants and payable in each period under the Net Profits Plan as cash compensation related to periodic operations are recognized as compensation expense and are included within general and administrative expense and exploration expense. The corresponding current liability is included in accounts payable and accrued expenses in the accompanying consolidated balance sheets. This treatment provides for a consistent matching of cash expense with net cash flows from the oil and gas properties in each respective pool of the Net Profits Plan. For additional discussion, please see Note 7 Compensation Plans under the heading *Net Profits Plan.*

*Income Taxes*

Deferred income taxes are provided on the difference between the tax basis of an asset or liability and its carrying amount in the financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively.

*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 of common shares outstanding during each period.

Diluted net income per common share of stock is calculated by dividing adjusted net income by the weighted-average of common shares outstanding, including the effect of other dilutive securities. Adjusted net income is used for the if-converted method and is derived by adding interest expense recognized on the Convertible Notes back to net income and then adjusting for nondiscretionary items that are based on income and that would have changed had the Convertible Notes been converted at the beginning of the period. The Company s potentially dilutive securities 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 under the Restricted Stock Plan 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 therefore included in the issued and outstanding share count.

The treasury stock method is used to measure the dilutive impact of stock options. The following table details the weighted-average dilutive and anti-dilutive securities related to stock options and restricted stock units ( RSUs ) for the periods presented:

| | **For the Years Ended December 31,** | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| Dilutive | 1,978,577 | 2,293,768 | 1,499,288 |
| Anti-dilutive | | | 186 |

The dilutive effect of stock options and restricted stock units is considered in the detailed calculations below. There were no anti-dilutive securities related to RSUs 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. A total of 7,692,300 potentially dilutive shares related to the Convertible Notes were included in the calculation of diluted net income per common share for the years ended December 31, 2006, 2005, and, 2004. The Convertible Notes were issued in March 2002. The Company has called these Convertible Notes for redemption on March 20, 2007. The note holders have the ability to convert the notes to common stock utilizing a conversion price of $13 per share. It is expected that all note holders will elect to convert their notes into common shares as the Company s current share price is in excess of the $13 conversion price. The Company s closing stock price on February 16, 2007, was $37.32.

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

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | (In thousands, except per share amounts) | | |
| Net income | $ 190,015 | $ 151,936 | $ 92,479 |
| Adjustments to net income for dilution: | | | |
| Add: interest expense avoided if Convertible Notes were converted to equity | 6,337 | 6,337 | 6,354 |
| Less: other adjustments | (63) | (64) | (64) |
| Less: income tax effect of dilutive items | (2,237) | (2,275) | (2,312) |
| Net income adjusted for the effect of dilution | $ 194,052 | $ 155,934 | $ 96,457 |
| Basic weighted-average common shares outstanding | 56,291 | 56,907 | 57,702 |
| Add: dilutive effect of stock options and RSUs | 1,979 | 2,295 | 1,500 |
| Add: dilutive effect of Convertible Notes using the if-converted method | 7,692 | 7,692 | 7,692 |
| Diluted weighted-average common shares outstanding | 65,962 | 66,894 | 66,894 |
| Basic earnings per common share: | $ 3.38 | $ 2.67 | $ 1.60 |
| Diluted earnings per common share: | $ 2.94 | $ 2.33 | $ 1.44 |

*Stock-Based Compensation*

At December 31, 2006, the Company had stock-based employee compensation plans that included RSUs and stock options issued to employees and non-employee directors as more fully described in Note 7 Compensation Plans. Stock options were last issued in December 2004. Prior to 2006, the Company had accounted for stock-based compensation using the intrinsic value recognition and measurement principles detailed in Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees and related interpretations. No stock-based employee compensation expense relating to stock options has been reflected in the Company s consolidated statements of operations for any period presented prior to 2006, since all options granted under the plans had an exercise price equal to the market value of the underlying common stock on the date of grant. The Company used the Black-Scholes option valuation model to calculate the disclosures required under Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation ( SFAS No. 123 ). Beginning January 1, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards No. 123(R), Share-Based Payment ( SFAS No. 123(R) ). This statement requires the Company to record expense associated with the fair value of stock-based compensation. The total compensation expense associated with unvested stock options at the date of adoption of this standard totaled $2.4 million. The Company elected to use the modified-prospective adoption method for the standard and has consequently recognized additional compensation expense of $1.9 in 2006 and expects to recognize expense of $443,000 in 2007 and $17,000 in 2008. The Company has recorded compensation expense associated with the issuance of restricted stock units since the plan was adopted in 2004 and units were first granted. The Company recognizes costs associated with these grants based on the estimated fair value of the restricted stock units as determined at the time of the grant.

The following table illustrates the pro forma effect on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS No. 123 to stock-based employee compensation:

| | For the Years Ended December 31, 2005 | 2004 |
|---|---|---|
| | (In thousands, except per share amounts) | |
| Net income | | |
| As reported: | $ 151,936 | $ 92,479 |
| Add: stock-based employee compensation expense included in reported net income, net of related tax effects | 4,453 | 2,650 |
| Less: stock-based employee compensation expense determined under fair value method for all awards, net of related income tax effects | (6,282 ) | (5,839 ) |
| Pro forma | $ 150,107 | $ 89,290 |
| Pro forma basic earnings per share | $ 2.64 | $ 1.54 |
| Pro forma diluted earnings per share | $ 2.30 | $ 1.39 |

For purposes of pro forma disclosures, the estimated fair values of the options and employee stock purchase plan ( ESPP ) grants are amortized to expense over the options vesting periods. The effects of applying SFAS No. 123 in the pro forma disclosure are not necessarily indicative of actual future amounts, particularly since the future amortization expense is less than was recorded in 2006, as described above.

*Recent Issued Accounting Standards*

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 the Company s 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 is 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 the Company s evaluation as of December 31, 2006, the Company s historical financial statements were not affected by the adoption of this standard.

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.

*Comprehensive Income*

Comprehensive income consists of net income, the deferred gain or loss for the effective portion of derivative instruments classified as cash flow hedges, and accrued pension benefit obligation in excess of plan assets. Comprehensive income is presented net of income taxes in the consolidated statements of stockholders equity and comprehensive income.

The changes in the balances of components comprising other comprehensive income and loss are presented in the following table:

| | Derivative Instruments | Minimum Pension Liability | Other Comprehensive Income (Loss) |
|---|---|---|---|
| For the period ending December 31, 2005 | | | |
| Before tax amount | $ (92,097) | $ 455 | $ (91,642) |
| Tax (expense) benefit | 34,941 | (172) | 34,769 |
| After tax amount | $ (57,156) | $ 283 | $ (56,873) |
| For the period ending December 31, 2006 | | | |
| Before tax amount | $ 111,437 | $ (290) | $ 111,147 |
| Tax (expense) benefit | (42,459) | 110 | (42,349) |
| After tax amount | $ 68,978 | $ (180) | $ 68,798 |

*Major Customers*

During 2006 no customer individually accounted for 10 percent of the Company s total oil and gas production revenue. During 2005 one customer individually accounted for 13 percent of the Company s total oil and gas production revenue. During 2004 one customer individually accounted for 20 percent of the Company s total oil and gas production revenue.

*Industry Segment and Geographic Information*

The Company operates in one industry segment, which is the exploration, exploitation, development, acquisition, and production of natural gas and crude oil. All of the Company s operations are conducted in the Continental United States and the Gulf of Mexico. Consequently, the Company currently reports as a single industry segment. The gas marketing department provides mostly internal service, acting as a first purchaser of natural gas and natural gas liquids produced by the Company and as such the majority of activity is eliminated in consolidation. The small amount of third-party income these operations generate is not material to the Company s financial position and segmentation of such net income would not provide a better understanding of the Company s performance, however, gross revenue and expense related to gas marketing operations are presented discreetly in the consolidated statements of operations.

*Stock Dividend*

In March 2005 the Company s Board of Directors approved a two-for-one stock split in the form of a stock dividend whereby one additional share of common stock was distributed for each common share outstanding. The stock dividend was distributed on March 31, 2005, to shareholders of record as of the close of business on March 21, 2005. All share and per share amounts for all prior periods presented herein have been reclassified to reflect this stock split.

*Intangible Asset*

As of December 31, 2006, and 2005, the Company s consolidated balance sheets include $3.4 million and $736,000, respectively, of intangible assets. These assets arise from acquired oil and gas sale contracts with favorable pricing terms. They do not qualify as derivatives or hedges under SFAS 133. Intangible assets of the Company are amortized using the units-of-production method and are periodically evaluated for impairment. Intangible assets are included in the Other Noncurrent Assets line of the Company s consolidated balance sheets.

*Goodwill*

Goodwill is measured as the excess of the acquisition costs over the sum of the amounts assigned to the identifiable assets acquired less liabilities assumed. Goodwill was recorded as a result of the acquisition of Agate Petroleum, Inc. in January 2005. Goodwill is reviewed for impairment annually or more frequently if impairment indicators arise. The goodwill review is conducted at the reporting unit level. A reporting unit is defined as the oil and gas properties in a region.

*Off Balance Sheet Arrangements*

As part of its ongoing business, the Company has not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities ( SPEs ), which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. As of and up to December 31, 2006, the Company has not been involved in any unconsolidated SPE transactions.

**Note 2 Accounts Receivable and Accounts Payable and Accrued Expenses**

Accounts receivable are comprised of the following:

| | As of December 31, 2006 | 2005 |
|---|---|---|
| | (In thousands) | |
| Accrued oil and gas sales | $ 95,036 | $ 138,521 |
| Due from joint interest owners | 33,309 | 21,696 |
| Other | 14,376 | 4,980 |
| Total accounts receivable | $ 142,721 | $ 165,197 |

Accounts payable and accrued expenses are comprised of the following:

| | As of December 31, 2006 | 2005 |
|---|---|---|
| | (In thousands) | |
| Accrued drilling costs | $ 68,326 | $ 40,071 |
| Revenue payable | 27,591 | 61,924 |
| Accrued lease operating expense | 11,153 | 8,789 |
| Accrued taxes | 2,358 | 6,550 |
| Accrued interest | 2,846 | 1,861 |
| Joint owner advances | 958 | 2,954 |
| Accrued compensation | 10,323 | 16,618 |
| Trade payables | 37,152 | 15,214 |
| Oil hedge accrual | 665 | 1,000 |
| Other | 10,462 | 9,976 |
| Total account payable and accrued expenses | $ 171,834 | $ 164,957 |

**Note 3 Acquisitions and Divestitures**

*Permian Basin, Texas Acquisition*

On December 14, 2006, the Company acquired oil and gas properties in the Permian Basin in West Texas from private parties in exchange for $247.6 million. Of the total purchase price amount, $244.1 million was allocated to proved and unproved oil and gas properties and $3.0 million was allocated to intangible assets. The company allocated the purchase price based on the estimated fair value of the assets and liabilities acquired. The final purchase accounting allocation is expected to be completed in the first half of 2007.

*Supplemental Pro Forma Information*

The following table presents unaudited supplemental pro forma information regarding the results of operations for the Company for the fiscal years ended December 31, 2006, and 2005, as if the acquisition of the Permian Basin properties had been consummated as of January 1, 2005. The supplemental pro forma information regarding the results of operations is provided for comparative purposes only and does not necessarily reflect the results that would have occurred had the acquisition occurred at the beginning of the periods presented or the results that may occur in the future.

| | As of December 31, | | | |
|---|---|---|---|---|
| | **2006** | | **2005** | |
| | **(In thousands except, per share amounts)** | | | |
| Total operating revenues | $ | 835,778 | $ | 752,702 |
| Net income | $ | 208,352 | $ | 155,904 |
| Basic net income per common share | $ | 3.71 | $ | 2.74 |
| Diluted net income per common share | $ | 3.22 | $ | 2.39 |

*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 was accounted for at estimated fair value.

*Agate Acquisition*

On January 5, 2005, the Company acquired Agate Petroleum, Inc. 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.

*Wold Acquisition*

On August 1, 2005, the Company acquired oil and gas properties from Wold Oil Properties, Inc. 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.

*Sales of Properties*

The Uinta Basin exchange described above is considered a non-monetary exchange and therefore was accounted for using estimated fair value. In this transaction, the Company disposed of properties with a cost of $4.2 million and received properties with an estimated fair market value of $11.5 million, recognizing a $7.3 million gain. Throughout 2005, the Company sold interests in certain properties that were subject to existing preferential rights. The Company received cash proceeds of $1.2 million and recognized a gain of approximately $222,000 from these sales. Throughout 2004, the Company sold interests in certain non-core properties. The Company received $2.8 million in net proceeds and recognized a gain of approximately $1.8 million from these sales.

**Note 4 Income Taxes**

The provision for income taxes consists of the following:

| | For the Years Ended December 31, 2006 (In thousands) | 2005 | 2004 |
|---|---|---|---|
| Current taxes: | | | |
| Federal | $ 28,557 | $ 75,848 | $ 21,143 |
| State | 1,917 | 4,906 | 1,389 |
| Deferred taxes | 74,832 | 5,547 | 31,217 |
| Total income tax expense | $ 105,306 | $ 86,301 | $ 53,749 |

As a result of the exercise of stock options, the Company was able to reduce its income tax payable in each year presented. The tax benefit to the Company of stock option exercises was $16.1 million in 2006, $6.0 million in 2005, and $3.8 million in 2004. The components of the net deferred tax liability are as follows:

| | December 31, 2006 (In thousands) | 2005 |
|---|---|---|
| Deferred tax liabilities: | | |
| Oil and gas properties | $ 299,082 | $ 204,745 |
| Unrealized derivative gain included in accumulated other comprehensive income | 17,184 | |
| Interest on Convertible Notes | 6,925 | 5,600 |
| Other | 59 | 2,750 |
| Total deferred tax liabilities | 323,250 | 213,095 |
| Deferred tax assets: | | |
| Net Profits Plan liability | 59,537 | 51,712 |
| Unrealized derivative loss included in accumulated other comprehensive income | 8,174 | 33,441 |
| Stock compensation | 8,104 | 4,585 |
| State tax net operating loss carryforward or carryback | 4,589 | 2,928 |
| State and federal income tax benefit | 2,285 | 1,587 |
| Other long-term liabilities | 2,026 | |
| Employee benefits and other | 1,391 | 609 |
| Deferred capital loss | 619 | 761 |
| Total deferred tax assets | 86,725 | 95,623 |
| Valuation allowance | (2,660) | (2,572) |
| Net deferred tax assets | 84,065 | 93,051 |
| Total net deferred tax liabilities | 239,185 | 120,044 |
| Less: current deferred income tax liabilities | (17,188) | (1,328) |
| Add: current deferred income tax assets | 2,521 | 9,580 |
| Non-current net deferred tax liabilities | $ 224,518 | $ 128,296 |
| Current federal refundable income tax | $ 7,293 | $ |
| Current federal income tax payable | $ | $ 3,346 |
| Current state refundable income tax | $ 391 | $ |
| Current state income tax payable | $ | $ 2,856 |

At December 31, 2006, the Company had estimated state net operating loss carryforwards of approximately $110.7 million that expire between 2007 and 2026 and state tax credits of $114,000, which expire between 2007 and 2016. A portion of the Company s valuation allowance relates to state net operating loss carryforwards, state tax credits, and state and federal income tax benefit amounts that the Company anticipates will expire before they can be utilized. The Company has concluded that permanent items included in the calculation of income tax for certain states may impact its ability to deduct net operating losses and realize federal income tax deduction benefits of those states and has adjusted its valuation allowances accordingly. The remaining portion of the valuation allowance relates to the Net Profits Plan liability and reflects an estimate of future executive compensation that may not be deductible for income tax purposes when future cash payments occur under the plan.

Federal income tax expense and benefit differ from the amount that would be provided by applying the statutory U.S. Federal income tax rate to income before income taxes for the following reasons:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | (In thousands) | | |
| Federal statutory taxes | $ 103,504 | $ 83,307 | $ 51,180 |
| Increase (reduction) in taxes resulting from: | | | |
| State taxes (net of federal benefit) | 2,081 | 4,185 | 2,586 |
| Domestic production activities deduction | (287) | (1,717) | |
| Statutory depletion | (315) | (224) | (224) |
| Other | 235 | (108) | (665) |
| Change in valuation allowance | 88 | 858 | 872 |
| Income tax expense from operations | $ 105,306 | $ 86,301 | $ 53,749 |

Acquisitions, drilling, and basis differentials impacting the prices received for crude oil and natural gas affect the apportionment of taxable income to the states where the Company owns properties. As these factors change, the Company s blended state income tax rate changes. This change applied to the Company s total temporary differences will impact the total income tax reported in the current year and is reflected in state taxes in the table above. Items affecting state apportionment factors are evaluated upon completion of the prior year income tax return and after significant acquisitions are closed during the current year.

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 of tax positions. FIN 48 will require the Company to recognize the impact of a tax position in its financial statements only if the technical merits of that position indicate that the position is more likely than not of being sustained upon audit. The Company has evaluated the impact of FIN 48 as of the January 1, 2007 adoption date and determined there will be no impact to its financial statements.

**Note 5 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 redeterminations. The borrowing base redetermination process considers the value of St. Mary s oil and gas properties as determined by the bank syndicate. The Company has elected an aggregate commitment amount of $500 million under the credit facility. 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 $334.0 million and $350.0 million in outstanding loans under its revolving credit agreement on December 31, 2006 and February 16, 2007, respectively.

*5.75% Senior Convertible Notes Due 2022*

As of December 31, 2006, the Company also had $100.0 million in outstanding borrowings in the form of 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 Convertible Notes market 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 all of 2006. 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 Convertible Notes are general unsecured obligations and rank on parity in right of payment with all existing and future unsecured senior indebtedness and other general unsecured obligations. They are senior in right of payment to all future subordinated indebtedness. The Convertible Notes are convertible at any time into the Company s common stock at a conversion price of $13 per share, subject to adjustment. The Company can redeem the Convertible Notes with cash in whole or in part at a repurchase price of 100 percent of the principal amount plus accrued and unpaid interest (including contingent interest) beginning on March 20, 2007. The Company has given notice that it intends to call the Convertible Notes on March 20, 2007. The Company expects the note holders to elect conversion of the Convertible Notes to common stock since the conversion price of $13 per share is considerably lower than the Company s current stock price. The Company expects to issue 7,692,300 shares of commons stock, which as of February 16, 2007, is approximately 14 percent of the Company s outstanding common stock balance, to settle the conversion of the Convertible Notes. The note holders have the option to require the Company to repurchase the Convertible Notes for cash at 100 percent of the principal amount plus accrued and unpaid interest (including contingent interest) upon either (1) a change in control of St. Mary or (2) on March 20, 2007, March 15, 2012, and March 15, 2017. If the note holders require repurchase on March 20, 2007, the Company may elect to pay the repurchase price with cash, shares of its common stock valued at a discount at the time of repurchase, or any combination of cash and its discounted common stock. The shares of common stock used in any repurchase will be discounted at 95 percent of market price if 33 percent or less of the repurchase price is in shares of the Company s common stock; otherwise, the stock will be discounted at 93 percent of market value. St. Mary is not restricted from paying dividends, incurring debt, or issuing or repurchasing its securities under the indenture for the Convertible Notes. There are no financial covenants in the indenture. Based on the market price of the Convertible Notes, the estimated fair value of the Convertible Notes was approximately $284 million as of December 31, 2006, and approximately $286 million as of December 31, 2005.

*Weighted-Average Interest Rate Paid and Capitalized Interest*

The weighted-average interest rate paid in 2006, 2005, and 2004 was 7.6 percent, 7.1 percent, and 7.1 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, and the effect of interest rate swaps. The impact of these items over a higher average outstanding loan balance in 2006 results in a higher weighted-average interest rate. The Company capitalized interest costs of $3.5 million, $1.9 million, and $1.4 million for the years ended December 31, 2006, 2005, and 2004, respectively.

**Note 6 Commitments and Contingencies**

The Company leases office space under various operating leases with terms extending as far as May 31, 2014. Rent expense, net of sublease income, was $1.5 million, $1.3 million, and $1.5 million in 2006, 2005, and 2004, respectively. The Company also leases office equipment under various operating leases. The Company has a non-cancelable sublease, through May 2012, of approximately $997,000, $184,000 per year through 2011 and $84,000 in 2012. The annual minimum lease payments for the next five years and thereafter are presented below:

| **Years Ending December 31,** | **(In thousands)** |
|---|---|
| 2007 | $ 2,957 |
| 2008 | 2,560 |
| 2009 | 2,456 |
| 2010 | 2,399 |
| 2011 | 2,208 |
| Thereafter | 1,436 |
| Total | $ 14,016 |

The Company is subject to litigation and claims that have arisen in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of such litigation and claims will not have a material effect on the results of operations or the financial position of the Company. Management believes it has sufficiently provided for such items to the extent necessary in the consolidated balance sheets.

**Note 7 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 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. Included in the general and administrative and exploration line items in the consolidated statements of operations are $1.9 million, $7.4 million, and $2.0 million of cash bonus expense for the years ended December 31, 2006, 2005, and 2004, respectively.

*Net Profits Plan*

Under the Company s 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 payments under the Net Profit Plan 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 formulated by applying a price that is derived from a rolling 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 adjusted to include 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.

| | **As of December 31,** | |
|---|---|---|
| | **2006** | **2005** |
| | **(In thousands)** | |
| Liability balance for Net Profits Plan as of the beginning of the period | $ 136,824 | $ 30,561 |
| Increase in liability | 49,900 | 127,064 |
| Reduction in liability for cash payments made or accrued and recognized as compensation expense | (26,141) | (20,801) |
| Liability balance for Net Profits Plan as of the end of the period | $ 160,583 | $ 136,824 |

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 used in the calculation changed by five percent, the liability recorded at December 31, 2006, would differ by approximately $14 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 as an expense or benefit associated with the change in the estimated liability is not allocated to general and administrative costs or exploration costs because it 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 Years Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | (In thousands) | | |
| General and administrative expense | $ 10,342 | $ 51,419 | $ 14,609 |
| Exploration expense | 13,417 | 54,844 | 9,789 |
| Total | $ 23,759 | $ 106,263 | $ 24,398 |

*401(k) Plan*

The Company has a defined contribution pension plan (the 401(k) Plan ) that is subject to the Employee Retirement Income Security Act of 1974. The 401(k) Plan allows eligible employees to contribute up to 60 percent of their base salaries. The Company matches each employee s contributions up to six percent of the employee s base salary and may make additional contributions at its discretion. The Company s contributions to the 401(k) Plan were $1.2 million, $966,000, and $834,000 for the years ended December 31, 2006, 2005, and 2004, respectively. No discretionary contributions were made by the Company to the 401(k) Plan in any of these years.

*Employee Stock Purchase Plan*

Under the St. Mary Land & Exploration Company Employee Stock Purchase Plan ( the ESPP ), eligible employees may purchase shares of the Company s common stock through payroll deductions of up to 15 percent of eligible compensation. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on the first or last day of the purchase period, and shares issued under the ESPP are restricted for a period of 18 months from the date issued. The ESPP is intended to qualify under Section 423 of the Internal Revenue Code. The Company has set aside 2,000,000 shares of its common stock to be available for issuance under the ESPP, of which 1,629,345 shares are available for issuance as of December 2006. Shares issued under the ESPP totaled 26,046 in 2006, 28,447 in 2005, and 27,748 in 2004. Total proceeds to the Company for the issuance of these shares were $815,275 in 2006, $601,000 in 2005, and $375,000 in 2004.

The fair value of employee stock purchase plan shares was measured at the date of grant using the Black-Scholes option-pricing model. The fair values of employee stock purchase plan shares issued were estimated using the following weighted-average assumptions:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| Risk free interest rate | 5.1 % | 2.5 % | 3.1 % |
| Dividend yield | 0.3 % | 0.4 % | 0.3 % |
| Volatility factor of the expected market price of the Company s common stock | 36.7 % | 36.3 % | 23.8 % |
| Expected life (in years) | 0.5 | 0.5 | 0.5 |

For the ESPP offering periods during 2006, the Company has expensed $243,311 based on the estimated fair value on the respective grant dates.

F-23

*Equity Incentive Compensation Plan*

There are several components to the equity compensation plan that are described in this section. The various types of equity awards were granted by the Company in different periods. For example, the Company ceased issuing stock options in 2004 and began issuing restricted stock or restricted stock units to employees and directors. These 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 Equity 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 Equity 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 Equity Plan, and no further grants will be made under the Predecessor Plans. Each outstanding award under a Predecessor Plan prior to the effective date of the 2006 Equity 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 No. 123(R) using the modified-prospective transition method. Under that transition method, compensation expense recognized in 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. 123(R).

As of December 31, 2006, 2.7 million shares of common stock remained available for grant under the 2006 Equity 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 Equity 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 Equity Plan.

St. Mary anticipates granting restricted stock and restricted stock units under the 2006 Equity 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 December 31, 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 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 $4.9 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. Vested shares of common stock underlying the RSU grants will be issued on the third anniversary of the grant, at which time the shares carry no further restrictions. For grants made beginning with the 2006 grant period, the Company is using the accelerated amortization method as described in FASB Interpretation No. 28, Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans an interpretation of APB Opinions No. 15 and 25, whereby approximately 48 percent of the total estimated compensation expense is recognized in the first year of the vesting period. Expense for grants made for plan years prior to 2006 are being amortized under the straight-line method since this method was allowed prior to the adoption of SFAS No. 123(R). As of December 31, 2006, there was a total of 1,061,223 RSUs outstanding, of which 555,062 were vested. Total compensation expense related to the RSUs for the year ended December 31, 2006 was $8.5 million. This amount includes $1.2 million of compensation expense related to the 2006 Equity Plan year for vesting of the estimated value of grants expected to be issued in 2007.

In measuring compensation expense from the grant of RSUs, SFAS No. 123(R) requires companies to estimate the fair value of the award on the grant date. The fair value of the RSUs is inherently less than the market value of an unrestricted security. The fair value of RSUs has been measured using the Black-Scholes option-pricing model. 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 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 Years Ended December 31,** | | | |
|---|---|---|---|---|
| | **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. 123(R), 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. 123(R) requires expense recognized subsequent to the adoption date to be based on fair value.

*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 that vested immediately upon commencement of employment. Approximately $728,000 of compensation expense was recorded related to this award in 2006. In addition to this award, the employee may earn an additional 5,000 shares over a four-year period and an additional 15,000 shares contingent on the Company meeting certain net asset growth performance conditions over a four-year period. The fair value of this award will be recorded to compensation expense over the vesting period. As of December 31, 2006, approximately $27,000 of compensation expense had been recorded related to the contingent award.

A summary of the status and activity of non-vested stock awards and RSUs for year ended December 31, 2006, is presented below:

| | **Shares** | **Weighted-Average Grant-Date Fair Value** |
|---|---|---|
| Non-vested, at December 31, 2005 | 356,099 | $ 18.91 |
| Granted | 517,851 | $ 33.94 |
| Vested | (298,352 ) | $ 25.95 |
| Forfeited | (69,437 ) | $ 27.84 |
| Non-vested, at December 31, 2006 | 506,161 | $ 28.92 |

*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 underlying 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 year ended December 31, 2006, the Company recognized stock-based compensation expense of approximately $1.9 million related to stock options that were outstanding and unvested as of January 1, 2006. There was no cumulative effect adjustment from the adoption of SFAS No. 123(R).

Prior to adopting SFAS No. 123(R), 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. 123(R) 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. 123(R), $16.1 million of excess tax benefit for the year ended December 31, 2006, has been classified as a financing cash inflow. Cash received from option exercises under all share-based payment arrangements for the years ended December 31, 2006, 2005, and 2004 was $16.9 million, $10.6 million, and $14.0 million, respectively.

A summary of activity associated with the Company s Stock Option Plans during the last three years follows:

| | Shares | Weighted-Average Exercise Price | Aggregate Intrinsic Value |
|---|---|---|---|
| For the period ending December 31, 2004 | | | |
| Outstanding, start of year | 7,050,256 | $ 11.55 | |
| Granted | 117,356 | 18.90 | |
| Exercised | (1,399,052) | 10.03 | |
| Forfeited | (117,210) | 12.50 | |
| Outstanding, end of year | 5,651,350 | 12.06 | $ 49,784,879 |
| Vested or expected to vest, end of year | 5,651,350 | | $ 49,784,879 |
| Exercisable, end of year | 4,441,362 | 11.76 | $ 40,445,153 |
| For the period ending December 31, 2005 | | | |
| Outstanding, start of year | 5,651,350 | 12.06 | |
| Granted | | | |
| Exercised | (936,403) | 11.31 | |
| Forfeited | (16,704) | 13.24 | |
| Outstanding, end of year | 4,698,243 | 12.21 | $ 115,595,735 |
| Vested or expected to vest, end of year | 4,698,243 | | $ 115,595,735 |
| Exercisable, end of year | 4,121,424 | 12.07 | $ 101,972,732 |
| For the period ending December 31, 2006 | | | |
| Outstanding, start of year | 4,698,243 | 12.21 | |
| Granted | | | |
| Exercised | (1,489,636) | 11.35 | |
| Forfeited | (87,005) | 14.33 | |
| Outstanding, end of year | 3,121,602 | 12.56 | $ 75,800,322 |
| Vested or expected to vest, end of year | 3,121,602 | | $ 75,800,322 |
| Exercisable, end of year | 2,966,944 | $ 12.56 | $ 72,049,258 |

There were no options granted for the years ended December 31, 2006 and 2005. For the year ended December 31, 2004, the weighted-average fair value of options granted during the year was $8.44.

A summary of additional information related to options outstanding as of December 31, 2006, follows:

| | Options Outstanding | | | Options Exercisable | |
|---|---|---|---|---|---|
| Range of Exercise Prices | Number Outstanding | Weighted-Average Remaining Contractual Life | Weighted-Average Exercise Price | Number Exercisable | Weighted-Average Exercise Price |
| $ 4.62 8.75 | 448,948 | 3.1 years | $ 6.61 | 448,948 | $ 6.61 |
| 10.60 11.58 | 487,062 | 5.2 years | 11.01 | 362,062 | 10.81 |
| 11.95 12.50 | 581,882 | 5.8 years | 12.19 | 581,882 | 12.19 |
| 12.53 13.39 | 478,976 | 6.6 years | 12.73 | 463,976 | 12.72 |
| 13.65 14.25 | 506,220 | 6.8 years | 14.00 | 506,220 | 14.00 |
| 16.66 16.66 | 550,110 | 4.0 years | 16.66 | 550,110 | 16.66 |
| 20.87 20.87 | 68,404 | 8.0 years | 20.87 | 53,746 | 20.87 |
| Total | 3,121,602 | | | 2,966,944 | |

The fair value of options was measured at the date of grant using the Black-Scholes option-pricing model. There were no stock options granted in 2006 or 2005. The fair values of options granted were estimated using the following weighted-average assumptions:

| | For the Year Ended December 31, 2004 |
|---|---|
| Risk free interest rate: | 4.10 % |
| Dividend yield: | 0.30 % |
| Volatility factor of the expected market price of the Company s common stock: | 35.90 % |
| Expected life of the options (in years) | 9 |

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 8 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 Nonqualified Pension Plan ).

On December 31, 2006, the Company adopted the recognition and disclosure provisions of SFAS 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 ). This standard requires the Company to recognize the funded status (i.e., the difference between the fair value of plan assets and the projected benefit obligation) of its pension plan in the December 31, 2006, consolidated balance sheets as either an asset or a liability, with a corresponding adjustment to accumulated other comprehensive income, net of tax. The adjustment to accumulated other comprehensive income at adoption represents the net unrecognized actuarial losses and unrecognized prior service costs, both of which were previously netted against the plan s funded status in the Company s consolidated balance sheets pursuant to the provisions of SFAS No. 87, Employers Accounting for Pensions ( SFAS No. 87 ). These amounts will be subsequently recognized as net periodic pension cost pursuant to the Company s accounting policy for amortizing such amounts. Further actuarial gains and losses that arise in subsequent periods and are not recognized as net periodic pension cost in the same periods will be recognized as a component of other comprehensive income. Those amounts will be subsequently recognized as a component of net periodic pension cost on the same basis as the amounts recognized in accumulated other comprehensive income at adoption of SFAS No. 158.

The incremental effects of adopting the provisions of SFAS No. 158 on the Company s statement of financial position at December 31, 2006, are presented in the following table. The adoption of SFAS No. 158 had no effect on the Company s consolidated statements of operations for the year ended December 31, 2006, or for any prior period presented, and it will not effect the Company s operating results in future periods. Had the Company not been required to adopt SFAS No. 158 at December 31, 2006, it would have recognized an additional minimum liability pursuant to the provisions of SFAS No. 87.

The effect of recognizing this additional minimum liability is included in the table below in the column labeled Prior to Adopting SFAS No. 158.

| | At December 31, 2006 | | |
|---|---|---|---|
| | Prior to Adopting SFAS No. 158 (In thousands) | Effect of Adopting SFAS No. 158 | As Reported |
| Accrued pension liability | $ 3,355 | $ 2,619 | $ 5,974 |
| Deferred income taxes | $ (932 ) | $ (990 ) | $ (1,922 ) |
| Accumulated other comprehensive income | $ | $ 2,619 | $ 2,619 |

Actuarial gains and losses are comprised of experience changes and effects of changes in actuarial assumptions. Experience changes are the effects of differences between previous actuarial assumptions and what actually occurred. Included in accumulated other comprehensive income at December 31, 2006 are the following amounts that have not yet been recognized in net periodic pension cost:

| | As of December 31, 2006 |
|---|---|
| Unrecognized actuarial losses | $ 2,619 |
| Unrecognized prior service costs | |
| Accumulated other comprehensive income | $ 2,619 |

The estimated net loss for the defined benefit pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year is $130,000.

*Obligations and Funded Status for Both Pension Plans*

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2006 (In thousands) | 2005 | 2004 |
| Change in benefit obligations: | | | |
| Projected benefit obligation at beginning of year | $ 11,900 | $ 10,174 | $ 8,048 |
| Service cost | 1,684 | 1,385 | 1,139 |
| Interest cost | 652 | 535 | 489 |
| Actuarial (gain) loss | 7 | (4 ) | 1,236 |
| Benefits paid | (480 ) | (190 ) | (738 ) |
| Projected benefit obligation at end of year | $ 13,763 | $ 11,900 | $ 10,174 |
| Change in plan assets: | | | |
| Fair value of plan assets at beginning of year | $ 5,955 | $ 4,675 | $ 3,694 |
| Actual return on plan assets | 968 | 412 | 434 |
| Employer contribution | 1,346 | 1,058 | 1,285 |
| Benefits paid | (480 ) | (190 ) | (738 ) |
| Fair value of plan assets at end of year | $ 7,789 | $ 5,955 | $ 4,675 |
| Funded status: | $ (5,974 ) | $ (5,945 ) | $ (5,499 ) |
| Accumulated Benefit Obligation | $ 9,922 | $ 8,429 | $ 7,143 |

The underfunded status of the plan of $6.0 million at December 31, 2006 is recognized in the accompanying statement of financial position as long-term accrued pension liability. No plan assets are expected to be returned to the Company during the fiscal year-ended December 31, 2007.

*Information for Pension Plans with an Accumulated Benefit Obligation in Excess of Plan Assets for Both Plans*

| | As of December 31, 2006 | 2005 |
|---|---|---|
| | (In thousands) | |
| Projected benefit obligation | $ 13,763 | $ 11,900 |
| Accumulated benefit obligation | $ 9,922 | $ 8,429 |
| Fair value of plan assets | $ 7,789 | $ 5,955 |

*Components of Net Periodic Benefit Cost for Both Pension Plans*

| | For the Years Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| | (In thousands) | | |
| Components of net periodic benefit cost: | | | |
| Service cost | $ 1,684 | $ 1,385 | $ 1,139 |
| Interest cost | 652 | 535 | 489 |
| Expected return on plan assets that reduces periodic pension cost | (427 ) | (354 ) | (295 ) |
| Amortization of prior service cost | | | (16 ) |
| Amortization of net actuarial loss | 296 | 241 | 218 |
| Net periodic benefit cost | $ 2,205 | $ 1,807 | $ 1,535 |

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

*Assumptions*

Weighted-average assumptions to measure the Company s projected benefit obligation and net periodic benefit cost are as follows:

| | As of December 31, 2006 | 2005 |
|---|---|---|
| Projected benefit obligation | | |
| Discount rate | 5.90 % | 5.50 % |
| Rate of compensation increase | 6.18 % | 5.93 % |
| Net periodic benefit cost | | |
| Discount rate | 5.50 % | 5.75 % |
| Expected return on plan assets | 7.50 % | 7.50 % |
| Rate of compensation increase | 6.18 % | 5.93 % |

F-30

*Plan Assets*

The Company s weighted-average asset allocation for the Qualified Plan is as follows:

| Asset Category | Target 2007 | As of December 31, 2006 | 2005 |
|---|---|---|---|
| Equity securities | 60.0 % | 64.8 % | 61.6 % |
| Debt securities | 40.0 % | 35.2 % | 38.2 % |
| Other | | | 0.2 % |
| Total | 100.0 % | 100.0 % | 100.0 % |

Equity securities do not include any shares of the Company s common stock for any period presented. There is no asset allocation for the Nonqualified Pension Plan since that plan does not have its own assets. An expected return on plan assets of 7.5 percent was used to calculate the Company s obligation under the Qualified Plan. Factors considered in determining the expected return include the 60 percent equity and 40 percent debt securities mix of investment for plan assets and the long-term historical rate of return provided by the equity and debt securities markets. The estimated rate of return on plan assets was 7.5 percent for 2006 and 2005. The difference in investment income using the projected rate of return compared to the actual rates of return for the past two years was not material and will not have a material effect on the statements of operation or on cash flows from operating activities in future years.

*Contributions*

The Company contributed $1.3 million, $1.1 million, and $1.3 million, to the pension plans in the years ended December 31, 2006, 2005, and 2004, respectively. St. Mary expects to contribute approximately $2.8 million to the pension plans in 2007.

*Benefit Payments*

The Plans made actual benefit payments of $480,000, $190,000, and $738,000 in the years ended December 31, 2006, 2005, and 2004, respectively. Expected benefit payments over the next ten years follows:

| Years Ended December 31, | (in thousands) |
|---|---|
| 2007 | $ 1,399 |
| 2008 | 502 |
| 2009 | 553 |
| 2010 | 726 |
| 2011 | 1,400 |
| 2012 through 2016 | $ 12,025 |

**Note 9 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 are due to increases in estimated abandonment costs and changes in 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:

| | As of December 31, | |
|---|---|---|
| | 2006 | 2005 |
| | (In thousands) | |
| Beginning asset retirement obligation | $ 66,078 | $ 40,911 |
| Liabilities incurred | 7,555 | 13,188 |
| Liabilities settled | (1,484 ) | (955 ) |
| Accretion expense | 4,926 | 3,279 |
| Revision to estimated cash flows | 167 | 9,655 |
| Ending asset retirement obligation | $ 77,242 | $ 66,078 |

**Note 10 Derivative Financial Instruments**

The Company realized a net gain of $20.5 million, a net loss of $24.4 million, and a net loss of $49.8 million from its derivative contracts for the years ended December 31, 2006, 2005, and 2004, respectively.

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

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | (In thousands) | | |
| Derivative contract settlements included in oil and gas hedge gain (loss) | $ 28,176 | $ (22,539 ) | $ (50,299 ) |
| Ineffective portion of hedges qualifying for hedge accounting included in derivative gain (loss) | (8,087 ) | (1,754 ) | 113 |
| Non-qualified derivative contracts included in derivative gain (loss) | 993 | 139 | (373 ) |
| Interest rate derivative contract settlements | (550 ) | (247 ) | 795 |
| Total gain (loss) | $ 20,532 | $ (24,401 ) | $ (49,764 ) |

*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, natural gas, and natural gas liquids. 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 December 31, 2006, the Company has hedge contracts in place through 2011 for a total of approximately 15.0 million Bbls, 79.0 million MMBTU, and 33.5 million gallons of anticipated production.

The Company attempts to qualify its oil and natural gas derivative instruments as cash flow hedges for accounting purposes. The Company formally documents all relationships between the derivative instruments and the hedged production, as well as the Company s risk management objective and strategy for the particular derivative contracts. This process includes linking all derivatives that are designated as cash flow hedges to the specific forecasted sale of oil or gas at its physical location. The Company also formally assesses (both at the derivative s inception and on an ongoing basis) whether the derivatives being utilized have been highly effective at offsetting changes in the cash flows of hedged production and whether those derivative may be expected to remain highly effective in future periods. If it is determined that a derivative has ceased to be highly effective as a hedge, the Company will discontinue hedge accounting prospectively. If hedge accounting is discontinued and the derivative remains outstanding, the Company will recognize all subsequent changes in its fair value on the Company s consolidated statement of operations for the period in which the change occurs. As of December 31, 2006, all oil and natural gas derivative instruments qualified as cash flow hedges for accounting purposes. The Company anticipates that all forecasted transactions will occur by the end of their originally specified periods. All contracts are entered into for other than trading purposes.

The fair value of the derivative instruments is included in the balance sheets as assets or liabilities. The estimated fair value of oil and natural gas derivative contracts designated and qualifying as cash flow hedges under SFAS No. 133 was a net asset of $13.7 million at December 31, 2006.

After-tax changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings upon sale of the hedged production. As of December 31, 2006, the amount of unrealized gain 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 $28.6 million.

Any change in fair value resulting from ineffectiveness is recognized currently in unrealized derivative gain (loss) in the consolidated statement of operations. Derivative gain or loss for the years ended December 31, 2006, 2005, and 2004, includes a net loss of $8.1 million, a net loss of $1.8 million, and a net gain of $113,000, respectively, from ineffectiveness related to oil and natural gas derivative contracts.

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.

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.

*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 at December 31, 2006, and 2005 was a liability of $121,000 and $646,000, respectively. The Company recorded net derivative gain in the consolidated statements of operations of $525,000 and net derivative losses of $213,000 and $328,000 for the years ended December 31, 2006, 2005, and 2004, respectively, from mark-to-market adjustments for these derivatives. These derivatives do not qualify for fair value hedge treatment under SFAS No. 133 and related pronouncements.

During the year ended December 31, 2006, the Company made payments of $550,000, and during the year ended December 31, 2005, the Company made payments of $247,000 under the swap arrangements. These payments are included in the Company s interest expense.

*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 year presented includes $95,000 of amortization for this derivative. The unrealized derivative loss (gain) line in the consolidated statements of operations for the years ended December 31, 2006, 2005, and 2004, includes net gains of $468,000 and $352,000 and a net loss of $45,000, respectively, from mark-to-market adjustments for this derivative. There was no fair value for this derivative at December 31, 2006 and there was a liability of $468,000 at December 31, 2005.

**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 in 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. The Company repurchased 3,319,300, 1,175,282, and 978,600 shares in 2006, 2005, and 2004, respectively. The Company retired 3,275,689, 1,411,356, and 2,458,800 shares in 2006, 2005, and 2004, respectively.

*Repurchase of St. Mary Common Stock from Flying J*

In February 2004 the Company repurchased 6,671,636 restricted shares of its common stock from Flying J Oil & Gas Inc. and Big West Oil & Gas Inc. (collectively Flying J ) for a total of $91.0 million. St. Mary originally issued these shares to Flying J on January 29, 2003, in connection with St. Mary s acquisition of certain oil and gas properties. In addition to issuing the shares in the acquisition, St. Mary loaned Flying J $71.6 million. Flying J used the proceeds of the stock repurchase to repay their outstanding loan balance of $71.6 million. Accrued interest, which had not been recorded by the Company for financial reporting purposes due to the non-recourse nature of the loan, was forgiven. The net $19.4 million cash outlay for the repurchase was funded from the Company s existing cash balances and borrowings under its bank credit facility.

**Note 12 Disclosures about Oil and Gas Producing Activities**

*Costs Incurred in Oil and Gas Producing Activities:*

Costs incurred in oil and gas property acquisition, exploration and development activities, whether capitalized or expensed, are summarized as follows. The 2006, 2005, and 2004 amounts include $7.8 million, $22.8 million, and $14.1 million, respectively, of capitalized costs associated with asset retirement obligations.

| | For the Years Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| | (In thousands) | | |
| Development costs | $ 367,546 | $ 249,518 | $ 190,829 |
| Exploration | 126,220 | 69,817 | 37,977 |
| Acquisitions: | | | |
| Proved | 238,400 | 84,981 | 69,054 |
| Unproved | 44,472 | 2,853 | 7,646 |
| Leasing activity | 28,816 | 14,330 | 7,877 |
| Total | $ 805,454 | $ 421,499 | $ 313,383 |

*Suspended Well Costs:*

The following table reflects the net changes in capitalized exploratory well costs during 2006, 2005, and 2004, and does not include amounts that were capitalized and either subsequently expensed or reclassified to producing well costs in the same period.

| | For the Years Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| | (In thousands) | | |
| Beginning balance at January 1, | $ 7,994 | $ 189 | $ 544 |
| Capitalized exploratory well costs charged to expense upon the adoption of FSP FAS 19-1 | | | |
| Additions to capitalized exploratory well costs pending the determination of proved reserves | 17,693 | 7,994 | 189 |
| Reclassifications to wells, facilities, and equipment based on the determination of proved reserves | (2,888 ) | (189 ) | |
| Capitalized exploratory well costs charged to expense | | | (544 ) |
| Ending balance at December 31, | $ 22,799 | $ 7,994 | $ 189 |

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed and the number of projects for which exploratory well costs have been capitalized since the completion of drilling.

| | For the Years Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| | (In thousands) | | |
| Exploratory well costs capitalized for one year or less | $ 17,693 | $ 7,994 | $ 189 |
| Exploratory well costs capitalized for more than one year | 5,106 | | |
| Ending balance at December 31, | $ 22,799 | $ 7,994 | $ 189 |
| Number of projects with exploratory well costs that have been capitalized more than a year | 1 | | |

The $5.1 million of exploratory well costs capitalized for more than one year is for a well located offshore in the Gulf of Mexico. A Reserve Analysis and Reservoir Simulation Study has been completed for this well. Project economics are still supported and in 2007 construction of long lead-time infrastructure will begin. Production from this well is expected to commence in 2009. The operational plan is to build the connection and process facilities in support of the already recognized costs. These costs are believed to be realizable.

*Oil and Gas Reserve Quantities (Unaudited):*

For all years presented, Netherland, Sewell and Associates, Inc. ( NSAI ) prepared the reserve information for the Company s coalbed methane projects at Hanging Woman Basin in the northern Powder River Basin as well as the Company s non-operated coalbed methane interest in the Green River Basin. The Company engaged Ryder Scott Company to review the Company s internal engineering estimates for 80 percent of the PV-10 value of its proven conventional oil and gas reserves in 2006. In 2005 and 2004, Ryder Scott prepared the reserve estimates for at least 80 percent of the PV-10 value of the Company s conventional oil and gas assets. St. Mary personnel prepared the reserve estimates for the remainder of all properties. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. All of the Company s proved reserves are located in the continental United States and Gulf of Mexico.

Presented below is a summary of the changes in estimated reserves of the Company:

| | **For the Years Ended December 31,** | | | | | |
|---|---|---|---|---|---|---|
| | **2006** | | **2005** | | **2004** | |
| | **Oil or Condensate (MBbl)** | **Gas (MMcf)** | **Oil or Condensate (MBbl)** | **Gas (MMcf)** | **Oil or Condensate (MBbl)** | **Gas (MMcf)** |
| Developed and undeveloped: | | | | | | |
| Beginning of year | 62,903 | 417,075 | 56,574 | 319,196 | 47,787 | 307,024 |
| Revisions of previous estimate | 524 | 10,946 | 1,593 | 24,354 | 1,994 | (21,885) |
| Discoveries and extensions | 857 | 36,723 | 2,553 | 21,998 | 1,543 | 26,925 |
| Infill reserves in an existing proved field | 4,131 | 49,107 | 3,286 | 83,093 | 4,763 | 36,260 |
| Purchases of minerals in place | 11,857 | 28,030 | 4,831 | 20,823 | 5,773 | 17,635 |
| Sales of reserves | (20) | (2,958) | (7) | (588) | (487) | (165) |
| Production | (6,057) | (56,448) | (5,927) | (51,801) | (4,799) | (46,598) |
| End of year(a) | 74,195 | 482,475 | 62,903 | 417,075 | 56,574 | 319,196 |
| Proved developed reserves: | | | | | | |
| Beginning of year | 55,971 | 313,125 | 47,992 | 272,295 | 43,693 | 264,140 |
| End of year | 61,519 | 358,477 | 55,971 | 313,125 | 47,992 | 272,295 |

(a) At December 31, 2006, 2005, and 2004 amounts include approximately 610, 829, and 786 MMcf, respectively, representing the Company s net underproduced gas balancing position.

*Standardized Measure of Discounted Future Net Cash Flows (Unaudited):*

SFAS No. 69, Disclosures about Oil and Gas Producing Activities ( SFAS No. 69 ) prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Company has followed these guidelines, which are briefly discussed below.

Future cash inflows and future production and development costs are determined by applying benchmark prices and costs, including transportation, quality, and basis differentials, in effect at year-end to the year-end estimated quantities of oil and gas to be produced in the future. Each property the Company operates is also charged with field-level overhead in the estimated reserve calculation. Estimated future income taxes are computed using current statutory income tax rates, including consideration for estimated future statutory depletion. The resulting future net cash flows are reduced to present value amounts by applying a ten percent annual discount factor.

Future operating costs are determined based on estimates of expenditures to be incurred in developing and producing the proved oil and gas reserves in place at the end of the period, using year-end costs and assuming continuation of existing economic conditions, plus Company overhead incurred by the central administrative office attributable to operating activities.

The assumptions used to compute the standardized measure are those prescribed by the FASB and the Securities and Exchange Commission. These assumptions do not necessarily reflect the Company s expectations of actual revenues to be derived from those reserves, nor their present value. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates are the basis for the valuation process. The following prices as adjusted for transportation, quality, and basis differentials, were used in the calculation of the standardized measure:

| | **2006** | **2005** | **2004** |
|---|---|---|---|
| Gas (per Mcf) | $ 5.54 | $ 8.34 | $ 5.80 |
| Oil (per Bbl) | $ 53.65 | $ 55.63 | $ 40.06 |

The following summary sets forth the Company s future net cash flows relating to proved oil and gas reserves based on the standardized measure prescribed in SFAS No. 69:

| | **As of December 31, 2006 (In thousands)** | **2005** | **2004** |
|---|---|---|---|
| Future cash inflows | $ 6,653,455 | $ 6,979,279 | $ 4,118,188 |
| Future production costs | (2,283,452 ) | (2,146,590 ) | (1,349,380 ) |
| Future development costs | (429,303 ) | (385,379 ) | (164,797 ) |
| Future income taxes | (1,125,955 ) | (1,448,444 ) | (827,368 ) |
| Future net cash flows | 2,814,745 | 2,998,866 | 1,776,643 |
| 10 percent annual discount | (1,238,308 ) | (1,286,568 ) | (742,705 ) |
| Standardized measure of discounted future net cash flows | $ 1,576,437 | $ 1,712,298 | $ 1,033,938 |

The principle sources of change in the standardized measure of discounted future net cash flows are:

| | For the Years Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| | (In thousands) | | |
| Standard measure, beginning of year | $ 1,712,298 | $ 1,033,938 | $ 859,956 |
| Sales of oil and gas produced, net of production costs | (554,147) | (590,671) | (368,099) |
| Net changes in prices and production costs | (661,074) | 725,154 | 166,826 |
| Extensions, discoveries and other including infill reserves in an existing proved field, net of production costs | 280,822 | 422,481 | 279,763 |
| Purchase of minerals in place | 263,762 | 132,185 | 73,875 |
| Development costs incurred during the year | 67,864 | 55,324 | 46,156 |
| Changes in estimated future development costs | 114,007 | (42,710) | (17,489) |
| Revisions of previous quantity estimates | 34,940 | 117,763 | (24,271) |
| Accretion of discount | 249,417 | 150,112 | 125,175 |
| Sales of reserves in place | (8,991) | (1,000) | (3,906) |
| Net change in income taxes | 200,858 | (314,685) | (75,389) |
| Changes in timing and other | (123,319) | 24,407 | (28,659) |
| Standardized measure, end of year | $ 1,576,437 | $ 1,712,298 | $ 1,033,938 |

**Note 13 Quarterly Financial Information (Unaudited)**

The Company s quarterly financial information for fiscal 2006 and 2005 is as follows (in thousands, except per share amounts):

| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter |
|---|---|---|---|---|
| **Year Ended December 31, 2006** | | | | |
| Total revenue | $ 193,588 | $ 193,381 | $ 198,040 | $ 202,692 |
| Less: costs and expenses | 112,902 | 128,296 | 110,818 | 133,419 |
| Income from operations | $ 80,686 | $ 65,085 | $ 87,222 | $ 69,273 |
| Income before income taxes | $ 80,131 | $ 64,076 | $ 85,142 | $ 65,972 |
| Net income | $ 50,526 | $ 40,080 | $ 55,877 | $ 43,532 |
| Basic net income per common share | $ 0.88 | $ 0.70 | $ 1.01 | $ 0.78 |
| Diluted net income per common share | $ 0.76 | $ 0.61 | $ 0.88 | $ 0.69 |
| Dividends declared per common share | $ 0.05 | $ | $ 0.05 | $ |
| **Year Ended December 31, 2005** | | | | |
| Total revenue | $ 143,818 | $ 164,574 | $ 203,304 | $ 227,894 |
| Less: costs and expenses | 86,161 | 101,820 | 158,721 | 146,894 |
| Income from operations | $ 57,657 | $ 62,754 | $ 44,583 | $ 81,000 |
| Income before income taxes | $ 55,795 | $ 60,578 | $ 42,322 | $ 79,542 |
| Net income | $ 35,103 | $ 38,261 | $ 27,334 | $ 51,238 |
| Basic net income per common share | $ 0.61 | $ 0.67 | $ 0.48 | $ 0.91 |
| Diluted net income per common share | $ 0.54 | $ 0.59 | $ 0.42 | $ 0.78 |
| Dividends declared per common share | $ 0.05 | $ | $ 0.05 | $ |

**SIGNATURES**

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

| | | |
|---|---|---|
| | ST. MARY LAND & EXPLORATION COMPANY<br>(Registrant) | |
| Date: February 22, 2007 | By: | /s/ MARK A. HELLERSTEIN<br>Mark A. Hellerstein<br>Chairman of the Board of Directors<br>and Chief Executive Officer |

**GENERAL POWER OF ATTORNEY**

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints each of Mark A. Hellerstein and David W. Honeyfield his or her true and lawful attorney-in-fact and agent with full power of substitution and resubstitution, and each with full power to act alone, for the undersigned and in his or her name, place and stead, in any and all capacities, to sign any amendments to this Annual Report on Form 10-K for the fiscal year ended December 31, 2006, and to file the same, with exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, hereby ratifying and confirming all that each of said attorney-in-fact, or his substitute or substitutes, may do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

| Signature | Title | Date |
|---|---|---|
| /s/ MARK A. HELLERSTEIN<br>Mark A. Hellerstein | Chairman of the Board of Directors<br>and Chief Executive Officer | February 22, 2007 |
| /s/ DAVID W. HONEYFIELD<br>David W. Honeyfield | Vice President-Chief Financial Officer,<br>Secretary and Treasurer | February 22, 2007 |
| /s/ MARK T. SOLOMON<br>Mark T. Solomon | Controller | February 22, 2007 |
| /s/ BARBARA M. BAUMANN<br>Barbara M. Baumann | Director | February 22, 2007 |
| /s/ LARRY W. BICKLE<br>Larry W. Bickle | Director | February 22, 2007 |
| /s/ THOMAS E. CONGDON<br>Thomas E. Congdon | Director | February 22, 2007 |
| /s/ WILLIAM J. GARDINER<br>William J. Gardiner | Director | February 22, 2007 |

| | | |
|---|---|---|
| /s/ JULIO M. QUINTANA<br>Julio M. Quintana | Director | February 22, 2007 |
| /s/ WILLIAM D. SULLIVAN<br>William D. Sullivan | Director | February 22, 2007 |
| /s/ JOHN M. SEIDL<br>John M. Seidl | Director | February 22, 2007 |