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

FORM 10-K/A

☒ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2006

or

☐ **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

Commission file number 001-31539

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

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

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

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

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
Common Stock, $.01 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

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

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

The aggregate market value of 53,716,420 shares of voting stock held by non-affiliates of the registrant, based upon the closing sale price of the common stock on June 30, 2006, the last business day of the registrant's most recently completed second fiscal quarter, of $40.25 per share as reported on the New York Stock Exchange was $2,162,085,905. Shares of common stock held by each director and executive officer and by each person who owns 10 percent or more of the outstanding common stock or who is otherwise believed by the Company to be in a control position have been excluded. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of February 16, 2007, the registrant had 55,004,399 shares of common stock outstanding, net of 250,000 treasury shares held by the Company.

DOCUMENTS INCORPORATED BY REFERENCE

Certain information required by Items 10, 11, 12, 13 and 14 of Part III is incorporated by reference from portions of the registrant's definitive proxy statement relating to its 2007 annual meeting of stockholders to be filed within 120 days after December 31, 2006.

EXPLANATORY NOTE:

This Amendment on Form 10-K/A to the Annual Report on Form 10-K for the fiscal year ended December 31, 2006, by St. Mary Land & Exploration Company (the "Company") is being filed to correct certain disclosures appearing under Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, on pages 48, 51 and 52, and a disclosure appearing under Item 8, Financial Statements and Supplementary Data, in the Notes to Consolidated Financial Statements on page F-20.

Page 48 of the original filing incorrectly indicated that the number of shares of common stock issued by the Company in 2004 as a result of stock option exercises was 27,748 shares, whereas the correct amount was 1,399,052 shares. Page 51 of the original filing incorrectly indicated that the cash received from oil and gas sales, net of realized effects of hedging, increased $47.9 million to $758.9 million for the year ended December 31, 2006, whereas the correct amounts were $152.5 million and $802.1 million, respectively. Page 51 of the original filing also incorrectly indicated that the cash received from oil and gas sales, net of realized effects of hedging, increased $268.6 million to $651.6 million for the year ended December 31, 2005, whereas the correct amounts were $265.0 million and $649.6 million, respectively. Page 51 of the original filing further incorrectly indicated that the year ended December 31, 2004, reflected $20.7 million net cash received from short-term investments and from the expiration of the restriction period for funds held for tax-deferred exchange of oil and gas properties, whereas the correct amount was $21.4 million. Page 52 of the original filing incorrectly indicated that the 2006 increase in costs incurred for capital and exploration activities was a result of planned increases in drilling activity and a $196.2 million increase in acquisitions, whereas the correct amount was $195.0 million. Page F-20 of the original filing incorrectly indicated that the Company's interest rate for ABR loans when its borrowing base utilization percentage is greater than or equal to 50% but less than 75% is equal to prime plus 0.250%, whereas the correct interest rate is prime plus 0.000%.

Pursuant to the rules of the SEC, Item 15 of the original filing has been amended to contain currently dated certifications of the Company's Chief Executive Officer and Chief Financial Officer, as required by Sections 302 and 906 of the Sarbanes-Oxley Act of 2002.

The correct amounts as described above are reflected in the corrected disclosures in this Form 10-K/A.All other information contained in the original Form 10-K remains unchanged, and the entire report with all Items is included in this Form 10-K/A for the convenience of the reader. The Company has not updated the disclosures contained herein to reflect events that occurred after the date of the original filing.

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PART I

When we use the terms "St. Mary," "the Company," "we," "us," or "our," we are referring to St. Mary Land & Exploration Company and its subsidiaries, unless the context otherwise requires. We have included technical terms important to an understanding of our business under "Glossary". Throughout this document we make statements that are classified as "forward-looking". Please refer to the "Cautionary Information about Forward-Looking Statements" section of this document for an explanation of these types of statements.

ITEM 1. BUSINESS

Background and Strategy

We are an independent oil and gas company engaged in the exploration, exploitation, development, acquisition and production of natural gas and crude oil. We were founded in 1908 and incorporated in Delaware in 1915. Our principal offices are located at 1776 Lincoln Street, Suite 700, Denver, Colorado 80203, and our telephone number is (303) 861-8140.

Our objective is to build stockholder value through consistent economic growth in reserves and production that increases net asset value per share. We seek to invest in oil and gas producing assets that result in a superior return on equity while preserving underlying capital, resulting in a return on equity to stockholders that reflects capital appreciation as well as the payment of cash dividends.

Our operations are focused in the following five core operating areas in the United States:

- The Rocky Mountain region is managed from our office in Billings, Montana. The oil and gas assets are located in the Williston Basin in eastern Montana and western North Dakota as well as the major producing basins in Wyoming. Recent activity in the northern Rockies includes drilling in the Middle Bakken formation, continued development in the Red River formation, and drilling horizontal prospects in the Mississippian formations of the Williston Basin, principally the Mission Canyon and Ratcliffe. As a follow-on to acquisitions made in the last several years, the Company has increased its activity in Wyoming, including development of legacy oil fields in the Big Horn and Wind River basins and gas development in the Greater Green River Basin. Our Rocky Mountain region also includes the development of coalbed methane reserves in the Hanging Woman Basin which is located in the northern Powder River Basin;
- The Mid-Continent region is comprised of properties in Oklahoma and northern Texas, primarily in the Anadarko and Arkoma basins. The most significant activity is in the Mayfield development area in Roger Mills and Beckham Counties in western Oklahoma and the horizontal Arkoma program in eastern Oklahoma, where we are pursuing a horizontal drilling program targeting the Wapanucka limestone, Cromwell sandstone, and Woodford shale formations. The Mid-Continent region is managed from our office in Tulsa, Oklahoma. Due to the specific technical expertise of the Mid-Continent team, the Company's assets in Constitution Field in Jefferson County, Texas are also managed within this region;
- The ArkLaTex region spans northern Louisiana, southern Arkansas, Mississippi, and eastern Texas and is managed by our Shreveport, Louisiana office. Recent activity includes the horizontal limestone program targeting resources in the James and Glen Rose formations throughout the region. The ArkLaTex region also manages our interests in a significant vertical well development effort at the Elm Grove Field. Elm Grove continues to be a strong producing asset with recent incremental success in the field from Hosston formation recompletions. This region also oversees our interest in the Terryville Field where we plan to increase activity in 2007;

- The Permian Basin region in western Texas and eastern New Mexico includes our recently acquired interests in the Sweetie Peck Field in the Midland Basin. Our activities in this field target the producing formations of the Spraberry interval—including the Spraberry, Leonard, and Wolfcamp formations. Our legacy assets in the Permian include our waterflood projects at Parkway Delaware Unit and East Shugart Delaware Unit in New Mexico. We opened an office in Midland, Texas in February 2007 to manage our Permian assets; and
- The Gulf Coast region consists of onshore Texas and Louisiana properties and includes the Judge Digby Field in Pointe Coupee Parish, Louisiana, our fee property in St. Mary Parish, Louisiana, and a presence in the offshore Gulf of Mexico. The region is managed from our Houston, Texas office. This office has expertise in the utilization of 3-D seismic to identify direct hydrocarbon indicators (DHI) along the Gulf Coast and in the Gulf of Mexico.

As of December 31, 2006, we had estimated proved reserves of 74.2 MMBbl of oil and 482.5 Bcf of natural gas, for a total of 927.6 BCFE. This represents an increase in reserve volumes of 17 percent from the end of 2005. The increase in reserves results from our drilling program whereby we added 115.8 BCFE and from acquisitions that added 99.2 BCFE. We had net upward revisions of 14.1 BCFE, which was comprised of an upward performance revision of 66.3 BCFE and a downward price revision of 52.2 BCFE. These proved oil and gas reserves have a PV-10 value of $2.2 billion and a standardized measure value, including the effect of income taxes of $1.6 billion. The percentage of proved developed reserves is 78 percent. The mix of natural gas reserves to oil reserves is 52 percent natural gas and 48 percent oil. Prices used to estimate oil and gas reserves were essentially flat for oil from a year earlier and down 44 percent year over year for natural gas, resulting in a decrease in PV-10 of 13 percent compared to last year. For the year ended December 31, 2006, we produced 92.8 BCFE, of which 61 percent was natural gas. This total production represents an average daily production of 254.2 MMCFE, a six percent increase from 2005.

Our reserve replacement percentage for 2006, including the effect of 3.1 BCFE of asset sales, was 244 percent of production. The reserve replacement percentage was 247 percent when the effect of divestitures is excluded. We acquired 99.2 BCFE through acquisitions in 2006, the majority of which came through our Sweetie Peck acquisition that closed in December 2006. Excluding acquisitions and divestitures, our reserve replacement percentage was 140 percent. The percentage of proved undeveloped reserves increased from 18 percent at the end of 2005 to 22 percent at December 31, 2006. This increase is directly related to the acquisition of proved undeveloped reserves associated with our Sweetie Peck acquisition, as well as recognition of increased per well proved undeveloped reserves in the ArkLaTex region due to continued success at Elm Grove. The increases were partially offset by the loss of proved undeveloped reserves in the Mid-Continent region attributable to the downward pricing revision referenced earlier. We believe the use of the term "reserve replacement percentage" is widely understood and utilized by those who make investment decisions related to the oil and gas exploration and production industry. Therefore, we believe this measure provides a useful basis of comparison to other companies and provides a measure of the growth of the Company.

In executing our business plan, we attempt to focus our resources in selected domestic basins where we believe our expertise in geology, geophysics, and drilling and completion techniques provide us with competitive advantages. In 2006, we spent $493.8 million in capital expenditures related to drilling activities, up 55 percent from the

$319.3 million spent in 2005. This increase was due to a combination of increased activity throughout the Company and cost escalations throughout the year for drilling and field services. Additionally, we spent $28.8 million on leasehold interests during 2006, which is double that of the prior year. Our acquisition spending in 2006 was $282.9 million, which was a significant increase from the $87.8 million spent in 2005. The primary driver of the increase in acquisition spending was the $247.6 million Sweetie Peck acquisition in the Permian Basin which closed in December 2006.

Our total capital budget for 2007 is $821 million, which includes $721 million of exploration and development activities and $100 million for acquisitions. We continue to believe that acquisitions play a key role in our future growth and we will evaluate properties for acquisition that are in our core areas of operations or in new basins where we believe we have operating expertise and can effectively execute operations. In the past few years we have placed a greater emphasis on growth through the drill bit and growing our inventory of drilling prospects. This shift has been partially an evolution of strategy and partially a reflection of the very competitive nature of the acquisition market in recent years. Our ability to make a significant acquisition in 2006 was a result of having strong relationships within the industry, a detailed understanding of the underlying geology, operations, and leasehold situation related to the acquisition, and the ability to transact the acquisition in a negotiated manner rather than through a broad auction process.

The increase in budgeted exploration and development spending for 2007 represents a roughly $200 million or 41 percent increase over 2006. In our budgetary decisions, we measure and rank our projects based on their risk-adjusted estimated internal rate of return and return on investment. Balanced against this is the reality of lease term expirations, lease commitments, rig availability, permitting considerations and other operating aspects of managing an oil and gas company. Unlike the previous year, this year's budget includes minimal cost escalations for drilling and field services. We believe we have begun to see a flattening of drilling and field service costs in our regions. The increase in our 2007 exploration and development budget is driven primarily by three factors. The first is an increase in Permian Basin spending that results from our planned execution of the drilling program associated with our Sweetie Peck acquisition. The second is an escalation of activity in our ArkLaTex region related to increased drilling and recompletion work in the Elm Grove Field together with an expansion of our horizontal limestone program in the James Lime formation. The third is an acceleration of the drilling program at our coalbed methane project at Hanging Woman Basin. Our base drilling program is a balanced program of low-to-medium-risk development and exploitation projects that provide a foundation for steady growth. We believe that the development of multi-year drilling programs in the Atoka/Granite Wash formations at Northeast Mayfield, the horizontal Arkoma Basin program targeting formations in the Wapanucka limestone, Cromwell sandstone, and Woodford shale, the Cotton Valley and Hosston plays at Elm Grove Field, our coalbed methane project in the Hanging Woman Basin, and the producing horizons of the Spraberry interval at the Sweetie Peck Field in the Permian Basin all help provide us with a core inventory of prospects for future development. We continue to work on developing or acquiring additional multi-year drilling programs in each of our regions.

As of December 31, 2006, we operated 67 percent of our properties on a reserve volume basis and 69 percent on a PV-10 value basis. We plan to operate 72 percent of our exploration and development budget in 2007. We believe it is important to operate a significant amount of our asset base as it allows us to control geologic and operational decisions as well as the timing of those decisions. We began 2007 with 12 operated drilling rigs running and plan to increase the operated rig count to 18 rigs by year-end.

Our 2007 acquisition budget is lower on a percentage basis than in prior years, although we will continue to seek acquisitions of oil and gas properties that complement our existing operations, offer economies of scale and provide further development, exploitation, and exploration opportunities. We will focus on areas where we have specialized knowledge or operating expertise that enable us to acquire attractively priced properties. In 2006, we acquired $282.9 million of oil and gas properties, most of which were purchased with cash from operations or with proceeds from our revolving credit facility. In 2006, we also closed a tax-deferred exchange of non-core assets in the Uinta Basin in Utah for oil and gas properties in Richland County, Montana. In addition to asset transactions, we have and will pursue corporate acquisitions that we believe are accretive to net asset value per share and that we are capable of integrating. In 2005, we acquired the stock of Agate Petroleum, Inc. for cash. Other examples of corporate acquisitions include the acquisition of Goldmark Engineering in 2004 for cash and the acquisitions of

Nance Petroleum Corporation and King Ranch Energy, Inc. in 1999, both of which were accomplished with the issuance of our common stock. The Flying J Oil & Gas Inc. property acquisition transaction completed in 2003 was not a corporate acquisition, yet we used a combination of restricted stock, a loan to Flying J, and options on our common stock for this transaction. When we consider the issuance of common stock for the acquisition of properties or a corporate entity, we base our investment decision primarily on the impact to net asset value per share.

We divest selected non-core assets when market conditions and prices are attractive. We will continue to evaluate such opportunities in the future when we believe it to be appropriate. During 2006, we sold properties with estimated proved reserves of 3.1 BCFE, or less than four-tenths of one percent of our reserves as of the beginning of the year.

In growing the Company, we seek to develop our existing property base and acquire acreage with additional potential in our core areas. From January 1, 2004 through December 31, 2006, we participated in the drilling of 1,493 gross wells with a success rate of 92 percent. During this three-year period we added estimated proved reserves of 596.3 BCFE at an average finding cost of $2.61 per MCFE. Not including the effect of divestitures, these results represent a three-year average reserve replacement percentage of 233 percent. Production has grown from an average daily rate of 206.0 MMCFE per day in 2004 to 254.2 MMCFE per day in 2006.

As of December 31, 2006, we had an acreage position of 2,244,488 gross (1,169,982 net) acres of which 1,272,789 gross (743,120 net) acres were undeveloped. Our percentage of undeveloped acreage on a gross and net basis is 57 percent and 64 percent, respectively. Our current leasehold position represents a seven percent increase on a gross acre basis and a six percent increase on a net acre basis from 2005. This growth in acreage is fundamental to our increasing emphasis on development of resource plays. In addition to our leased acreage position, we own 24,914 acres of fee properties in St. Mary Parish, Louisiana, of which 57 percent is undeveloped. Lastly, we have mineral servitudes representing 14,663 gross (9,868 net) acres in other portions of Louisiana, the majority of which is developed. We do not believe there are any substantial issues with respect to leasehold terms or expirations on our overall acreage holdings. We believe that our lease position provides a competitive advantage in certain locations and is a strategic asset for the Company.

Our senior technical managers in each region possess between 15 and 40 years of industry experience and lead fully-staffed regional technical offices that are supported by centralized administration from our corporate office in Denver. We use our comprehensive base of geological, geophysical, land, engineering, and production experience in each of our core operating areas to source prospects for our ongoing low-to-medium-risk development and exploitation programs. We conduct detailed geologic studies and use an array of technologies and tools including 2-D and 3-D seismic imaging, hydraulic fracturing and other reservoir stimulation techniques, horizontal drilling, secondary recovery, and specialized logging tools to enhance the potential of our existing properties.

Conservative use of financial leverage has long been a critical element of our strategy. We believe that maintaining a strong balance sheet is a significant competitive advantage that enables us to pursue acquisition and other opportunities, especially in weaker price environments. It also provides us with the financial resources to weather periods of volatile commodity prices or escalating costs. Our debt to book capitalization ratio was 37 percent at the end of December 2006. Included in our outstanding debt as of year-end is $100.0 million of Senior Convertible Notes which are callable in March 2007. We have called these Convertible Notes for redemption. The date of redemption will be March 20, 2007. As the conversion price of the Convertible Notes is $13.00 per share, we fully expect that the note holders will force conversion of the Convertible Notes into approximately 7.7 million shares of common stock. The contemplated conversion of these Convertible Notes to equity would give us a pro forma debt to book capitalization ratio of 29 percent at December 31, 2006.

In summary, we believe that our dedication to making investment decisions based on net asset value per share, our long-standing geologic and engineering experience in the regions in which we operate, our appropriate application of technology, our established networks of local industry relationships, and our acreage holdings in our core operating areas all provide us with competitive advantages that we can use to continue growing the Company.

Significant Developments since December 31, 2005

- *Senior Management Transition.* During 2006, the Company underwent or announced personnel changes in the chief operating officer and chief executive officer roles. Doug York, our previous Chief Operating Officer, left the company in early 2006 to pursue other professional interests. Mark Hellerstein, our long-serving President and Chief Executive Officer, announced in mid-2006 his intention to retire from day-to-day management upon the successful transition of his duties to a successor. Tony Best, an executive with 28 years of experience in the oil and gas industry, joined the Company in June 2006 as President and Chief Operating Officer. Mr. Hellerstein and Mr. Best worked together through the second half of 2006 to develop a succession plan whereby Mr. Best would succeed Mr. Hellerstein as Chief Executive Officer in February 2007. Mr. Hellerstein will continue to serve as the Chairman of the Board. With Mr. Best taking over the role of CEO, the Company hired Jay Ottoson in December 2006 as Executive Vice President and Chief Operating Officer. Mr. Ottoson has 22 years of operational and management experience in the oil and gas industry.
- *2006 Acquisition of Oil and Gas Properties.* Our acquisitions of proved and unproved oil and gas properties in 2006 totaled $282.9 million. The most significant transaction was the purchase of oil and gas properties in the Sweetie Peck Field in the Permian Basin of west Texas for $247.6 million in December 2006. This acquisition represents the largest acquisition in our history and added 78.0 BCFE of proved oil and gas reserves. The acquisition led to the opening of a new office in Midland, Texas in February 2007 and the hiring of personnel charged with managing these assets. The Company also had several smaller niche transactions throughout the year in the Mid-Continent, ArkLaTex, and Rocky Mountain regions.
- *Significant Volatility in Commodity Prices.* During 2006, the exploration and production sector was impacted by volatility in the prices for crude oil and natural gas. Our operations and financial condition are significantly impacted by these prices. We sell the majority of our natural gas on contracts which use first of the month (also frequently referred to as bid week) index pricing. The Inside FERC contract price for January 2006 was $11.45 per MMBtu but declined to $4.20 per MMBtu by October 2006, spending much of the period in the $6 to $7 per MMBtu range during the year. The average NYMEX price for natural gas was $7.26 per MMBtu for 2006. Our crude oil is sold on contracts that pay us the average of posted prices for the period in which the crude oil is sold. NYMEX crude oil began 2006 with an average January price of $65.54 per barrel and reached a high average price for the year of $74.46 per barrel in July as tensions in the Middle East escalated. The average NYMEX price for the year was $66.22 per barrel. We hedge a portion of our oil and gas production using swaps and collars. A gain of $44.7 million was realized on our natural gas hedges for the year and a loss of $16.5 million was realized on our oil hedges for the year.
- *Repurchase of Common Stock.* The Company evaluates the market price of our common stock relative to our internal assessment of net asset value per share. To the extent that the market price per share is below what we believe to be the net asset value per share, we will repurchase shares under the program. In April and May of 2006, we repurchased 3.3 million shares of our common stock in the open market for a weighted-average price of $37.09, per share including commissions. These shares were purchased under a share repurchase program approved by the Board. At the time we repurchased our shares, we entered into hedges for a commensurate amount of our

production that was represented by the share repurchase in order to lock in the discounted price at which our shares were trading. In the third quarter, the Board authorized a refresh to the number of shares available for repurchase to a total of six million shares. This six million share authorization to repurchase common stock remains available as of the date of this filing.

- *Increase in 2006 Year-End Reserves.* Proved reserves increased 17 percent to 927.6 BCFE at December 31, 2006, from 794.5 BCFE at December 31, 2005. We added 115.8 BCFE from our drilling program and 99.2 BCFE from acquisitions. We had a 66.3 BCFE upward performance revision and a downward revision due to prices of 52.2 BCFE due to the decreased gas price at the end of 2006. We sold properties with reserves of 3.1 BCFE in 2006.
- *Drilling Results.* Reserve additions were driven principally from drilling results in the Rockies, Mid-Continent and ArkLaTex regions, with each region contributing approximately a quarter of the total reserve additions through drilling activities. The Gulf Coast realized reserve additions of 11.9 BCFE through the successful execution of its DHI program, which resulted in six successful wells out of eight attempts during 2006. The 34.5 BCFE increase in the Rockies can be attributed primarily to continued development of the Hanging Woman Basin coalbed methane project, as well as activities in the Bakken formation, various Mississippian formations, and the Red River formation. The Red River activity continues to provide reserve additions in the Rockies as we take advantage of 3-D seismic to identify structures. Our Mid-Continent reserve additions of 25.2 BCFE were primarily from continued development of theNortheast Mayfield area and the horizontal Arkoma program targeting the Wapanucka limestone, Cromwell Sandstone, and the Woodford shale. The ArkLaTex region grew from total proved reserves of 111.3 BCFE at the end of 2005 to 159.5 BCFE this yearend. This is the second year in a row where reserves in this region grew in excess of 40 percent from the prior year. This growth is a reflection of the value we are deriving from the Elm Grove Field development through both initial completions into the Lower Cotton Valley formation and subsequent recompletions using coiled tubing assisted fracturing in the Hosston. Additionally, we had a successful year in our horizontal limestone program in east Texas and western Louisiana.
- *Hedging of Oil and Natural Gas through 2011.* Beginning in October 2005, we entered into financial derivative transactions to hedge oil and gas prices on a significant portion of our proved developed producing assets. These hedges have been placed in the form of zero-cost collars. We have also hedged specific production related to acquisitions made in 2006 as well as the forecasted production for our 2007 Northeast Mayfield development program using swap contracts.

Major Customers

During 2006, no customer individually accounted for 10 percent of the Company's total oil and gas production revenue. During 2005, sales to Tesoro Refining and Marketing individually accounted for 13 percent of the Company's total oil and gas production revenue. During 2004 sales to Tesoro Refining and Marketing individually accounted for 20 percent of the Company's total oil and gas production revenue.

Employees and Office Space

As of February 16, 2007, we had 359 full-time employees. None of our employees are subject to a collective bargaining agreement, and we consider our relations with our employees to be good. We lease approximately 56,900 square feet of office space in Denver, Colorado for our executive and administrative offices, of which 9,500 square feet is subleased. We lease approximately 20,900 square feet of office space in Tulsa, Oklahoma; approximately 12,600 square feet in Shreveport, Louisiana; approximately 16,600 square feet in Houston, Texas; approximately 6,900 square feet in Midland, Texas; approximately 34,400 square feet in Billings, Montana; and approximately 2,000 square feet in Casper, Wyoming.

Title to Properties

Substantially all of our working interests are held pursuant to leases from third parties. A title opinion is usually obtained prior to the commencement of drilling operations. We have obtained title opinions or have conducted a thorough title review on substantially all of our producing properties and believe that we have satisfactory title to such properties in accordance with standards generally accepted in the oil and gas industry. The majority of the value of our properties is subject to a mortgage under our credit facility, customary royalty interests, liens for current taxes, and other burdens that we believe do not materially interfere with the use of or affect the value of such properties. We perform only a minimal title investigation before acquiring undeveloped leasehold.

Seasonality

Generally, but not always, the demand and price levels for natural gas increase during the colder winter months and decrease during the warmer summer months. To lessen seasonal demand fluctuations, pipelines, utilities, local distribution companies, and industrial users utilize natural gas storage facilities and forward purchase some of their anticipated winter requirements during the summer. However, increased summertime demand for electricity is beginning to place an increasing demand on storage volumes. Crude oil and the demand for heating oil are also impacted by generally higher prices in the winter. Seasonal anomalies such as mild winters sometimes lessen these fluctuations. The impact of seasonality has somewhat been exacerbated by the overall supply and demand economics related to crude oil because there is a narrow margin of production capacity in excess of existing worldwide demand.

Competition

The oil and gas industry is intensely competitive. This is particularly true in the acquisition of prospective oil and natural gas properties and oil and gas reserves. We believe that our leasehold position provides a sound foundation for a robust drilling program. Our competitive position also depends on our geological, geophysical, and engineering expertise, and our financial resources. We believe that the location of our leasehold acreage, our exploration, drilling, and production expertise, and the experience and knowledge of our management and industry partners enable us to compete effectively in our core operating areas. Notwithstanding our talents and assets, we still face stiff competition from a substantial number of major and independent oil and gas companies that have larger technical staffs and greater financial and operational resources than we do. Many of these companies not only engage in the acquisition, exploration, development, and production of oil and natural gas reserves, but also have refining operations, market refined products, own drilling rigs, and generate electricity. We also compete with other oil and natural gas companies in attempting to secure drilling rigs and other equipment necessary for the drilling and completion of wells. Consequently, drilling equipment may be in short supply from time to time. Currently, access to incremental drilling equipment in certain regions is difficult but is not, at this time, anticipated to have any material negative impact on our ability to deploy our drilling capital budget for 2007. We are seeing signs of loosening rig availability, although it is quite specific by region. Finally, we also compete for people. As drilling activities have accelerated, the need for talented people has grown at a time when the number of people available is constrained.

Government Regulations

Our business is subject to various federal, state, and local laws and governmental regulations that may be changed from time to time in response to economic or political conditions. Matters subject to regulation include the issuance of drilling permits, discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties, taxation, and environmental protection. From time to time, regulatory agencies have imposed price controls and

limitations on production by restricting the rate of flow of oil and gas wells below actual production capacity in order to conserve supplies of oil and gas.

Energy Regulations. Our sales of natural gas are affected by the availability, terms, and cost of transportation. The price and terms of access to pipeline transportation are subject to extensive federal and state regulation. While the rules and regulations of the Federal Energy Regulatory Commission (FERC) have in the past greatly affected the production and sale of natural gas, the direct impact on the upstream exploration and production segment of the energy industry has greatly diminished in favor of allowing market forces to set the price paid for natural gas production. FERC regulations continue to affect the midstream and transportation segments of the industry and thus can have an indirect impact of the sales price we receive for natural gas production. There is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue. We do not believe that we will be more materially affected by any action taken by the FERC or Congress than other natural gas producers and marketers with whom we compete.

Certain operations we conduct involve federal minerals administered by the Minerals Management Service. The MMS issues leases covering such lands through competitive bidding. These leases contain relatively standardized terms and require compliance with federal laws and detailed MMS regulations. For offshore operations, lessees must obtain MMS approval for exploration plans and development and production plans prior to the commencement of such operations. In addition to permits required from other agencies such as the Coast Guard, the Army Corps of Engineers, and the Environmental Protection Agency, lessees must obtain a permit from the MMS prior to the commencement of drilling. Lessees must also comply with detailed MMS regulations governing, among other things:

- Engineering and construction specifications for offshore production facilities;
- safety procedures;
- flaring of production;
- plugging and abandonment of Outer Continental Shelf (OCS) wells;
- calculation of royalty payments and the valuation of production for this purpose; and
- removal of facilities.

To cover the various obligations of lessees on the OCS, the MMS generally requires that lessees post substantial bonds or other acceptable assurances that such obligations will be met. The cost of such bonds or other surety can be substantial, and we may not be able to continue to obtain bonds or other surety in all cases. Under certain circumstances the MMS may require our operations on federal leases to be suspended or terminated.

Many of the states in which we conduct our oil and gas drilling and production activities regulate such activities by requiring, among other things, drilling permits and bonds and reports concerning operations. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing of waste material, plugging and abandonment of wells, restoration requirements, unitization, pooling of natural gas and oil properties, and establishment of maximum rates of production from natural gas and oil wells. States generally have the ability to prorate production to the market demand for oil and natural gas; however, this is not currently occurring.

Environmental Regulations. Our operations are subject to numerous existing federal, state, and local laws and regulations governing environmental quality and pollution control. These laws and regulations may require that permits be obtained before drilling commences, restrict the types, quantities, and concentration of various substances that can be released into the environment in connection with drilling and production activities, and limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, and other protected areas, including areas containing endangered animal species. As a result, these laws and regulations may substantially increase the costs of exploring, developing, or producing oil and gas and may prevent or delay the commencement or continuation of a project. In addition, these laws and regulations may impose substantial clean-up, remediation, and other obligations in the event of any discharges or emissions in violation of such laws and regulations.

Our coalbed methane gas production from the Hanging Woman Basin is similar to our traditional natural gas production as to the physical producing facilities and the product produced. However, the subsurface mechanisms that allow the gas to move to the wellbore and the producing characteristics of coalbed methane wells are very different from traditional natural gas production. Unlike conventional gas wells, which require a porous and permeable reservoir, hydrocarbon migration, and a natural structural and/or stratigraphic trap, coalbed methane gas is trapped in the molecular structure of the coal itself until released by pressure changes resulting from the removal of *in situ* water. Frequently, coalbeds are partly or completely saturated with water. As the water is removed, internal pressures on the coal are decreased, allowing the gas to desorb from the coal and flow to the wellbore. Unlike traditional gas wells, new coalbed methane wells often produce water for several months and then, as the water production decreases, natural gas production increases.

Coalbed methane gas production in the Hanging Woman Basin requires state permits for the use of well-site pits and evaporation ponds for the disposal of produced water. Groundwater produced from the coal seams can generally be discharged into arroyos, surface waters, well-site pits, and evaporation ponds without a permit if it does not exceed surface discharge permit levels, and meets state and federal primary drinking water standards. All of these disposal options require an extensive third-party water sampling and laboratory analysis program to ensure compliance with state permit standards. Where water of lesser quality is involved or the wells produce water in excess of the applicable volumetric permit limits, additional disposal wells may have to be drilled to re-inject the produced water back into deep underground rock formations.

A portion of our acreage at Hanging Woman Basin is on federal lands, and a segment of these federal lands are in Montana. We are subject to delays in permitting associated with the completion of a supplemental Environmental Impact Statement covering the contemplation of phased development on Federal leases in Montana. We are also affected by considerations for sage grouse that are native to the area. Each of these issues has the potential to impact the timing of our permitting and drilling operations associated with development of our reserves at Hanging Woman Basin.

To date we have not experienced any material adverse effect on our operations from obligations under environmental laws and regulations. We believe that we are in substantial compliance with currently applicable environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse impact on us.

Cautionary Information about Forward-Looking Statements

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

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

· the drilling of wells and other exploration and development plans, as well as possible future acquisitions;

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

· future oil and gas production estimates;

· our outlook on future oil and gas prices;

· cash flows, anticipated liquidity, and the future repayment of debt;

· business strategies and other plans and objectives for future operations, including plans for expansion and growth of operations and our outlook on future financial condition or results of operations; and

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

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

· The volatility and level of realized oil and natural gas prices;

· unexpected drilling conditions and results;

· unsuccessful exploration and development drilling;

· the availability and risks of economically attractive exploration, development, and property acquisition opportunities and any necessary financing;

· the risks of hedging strategies;

· lower prices realized on oil and gas sales resulting from our commodity price risk management activities;

· the uncertain nature of the expected benefits from the acquisition of oil and gas properties;

· production rates and reserve replacement;

· the imprecise nature of oil and gas reserve estimates;

· uncertainties inherent in projecting future rates of production from drilling activities and acquisitions;

· drilling and operating service availability;

· uncertainties in cash flow;

· the financial strength of hedge contract counterparties;

· the negative impact that lower oil and natural gas prices could have on our ability to borrow;

· our ability to compete effectively against other independent and major oil and gas companies; and

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

We caution you that forward-looking statements are not guarantees of future performance and that actual results or developments may differ materially from those expressed or implied in the forward-looking statements. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by securities laws.

Available Information

Our Internet website address is www.stmaryland.com. Within our website's financial information section we make available free of charge our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC under applicable securities laws. These materials are made available as soon as reasonably practical after we electronically file such materials with or furnish such materials to the SEC.

We also make available through our website's corporate governance section our Corporate Governance Guidelines, Code of Business Conduct and Ethics, and the Charters for our Board of Directors' Audit Committee, Compensation Committee, Executive Committee, and Nominating and Corporate Governance Committee. These documents are also available in print to any stockholder who requests them. Requests for these documents may be submitted to:

St. Mary Land & Exploration Company
Investor Relations
1776 Lincoln Street, Suite 700
Denver, Colorado 80203
Telephone: (303) 863-4322
http://www.stmaryland.com/investors/index.htm

Information on our website is not incorporated by reference into this Form 10-K and should not be considered part of this document.

Glossary

The terms defined in this section are used throughout this Form 10-K.

2-D seismic or 2-D data. Seismic data that is acquired and processed to yield a two-dimensional cross-section of the subsurface.

3-D seismic or 3-D data. Seismic data that is acquired and processed to yield a three-dimensional picture of the subsurface.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf. Billion cubic feet, used in reference to natural gas.

BCFE. Billion cubic feet of gas equivalent. Gas equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

BOE. Barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing either oil or gas in sufficient commercial quantities to justify completion as an oil or gas well.

Exploratory well. A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir beyond its known horizon.

Farmout. An assignment of an interest in a drilling location and related acreage conditioned upon the drilling of a well on that location.

Fee land. The most extensive interest that can be owned in land, including surface and mineral (including oil and gas) rights.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

Finding cost. Expressed in dollars per BOE or MCFE. Finding costs are calculated by dividing the amount of total capital expenditures for oil and gas activities, including the effect of asset retirement obligations, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, acquisitions, and revisions of previous estimates during the same period. The information for this calculation is included in the note regarding disclosures about oil and gas producing activities contained in the Notes to Consolidated Financial Statements included in this Form 10-K.

Formation. A succession of sedimentary beds that were deposited under the same general geologic conditions.

Gross acre. An acre in which a working interest is owned.

Gross well. A well in which a working interest is owned.

Horizontal wells. Wells which are drilled at angles greater than 70 degrees from vertical.

Hydraulic fracturing. A procedure to stimulate production by forcing a mixture of fluid and proppant (usually sand) into the formation under high pressure. This creates artificial fractures in the reservoir rock, which increases permeability and porosity.

MBbl. One thousand barrels of oil or other liquid hydrocarbons.

MMBbl. One million barrels of oil or other liquid hydrocarbons.

MBOE. One thousand barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

MMBOE. One million barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

Mcf. One thousand cubic feet, used in reference to natural gas.

MCFE. One thousand cubic feet of gas equivalent. Gas equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

MMcf. One million cubic feet, used in reference to natural gas.

MMCFE. One million cubic feet of gas equivalent. Gas equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

MMBtu. One million British Thermal Units. A British Thermal Unit is the amount of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

Net acres or net wells. The sum of our fractional working interests owned in gross acres or gross wells.

Net asset value per share. The result of the fair market value of total assets less total liabilities, divided by the total number of outstanding shares of common stock.

NYMEX. New York Mercantile Exchange.

OCS. Outer Continental Shelf in the Gulf of Mexico.

PV-10 value. The present value of estimated future gross revenue to be generated from the production of estimated net proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date indicated (unless such prices or costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion, and amortization, discounted using an annual discount rate of 10 percent. While this measure does not include the effect of income taxes as it would in the use of the standardized measure calculation, it does provide an indicative representation of the relative value of the Company on a comparative basis to other companies and from period to period.

Productive well. A well that is producing oil or gas or that is capable of commercial production.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves. The estimated quantities of oil, gas and gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped reserves. Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Recompletion. The completion in an existing wellbore in a formation other than that in which the well has previously been completed.

Reserve life. Expressed in years, represents the estimated net proved reserves at a specified date divided by actual production for the preceding 12-month period.

Reserve replacement percentage—excluding sales. The sum of reserve extensions and discoveries, reserve acquisitions, and reserve revisions of previous estimates for a specified period of time divided by production for that same period of time. This is believed to be a useful non-GAAP measure that is widely utilized within the exploration and production industry as well as by investors. It is an easily calculable number and is representative of the relative success a company is having in replacing its production from its declining asset base as well as its ability to grow the overall company.

Reserve replacement percentage—including sales. The sum of sales of reserves, reserve extensions and discoveries, reserve acquisitions, and reserve revisions of previous estimates for a specified period of time divided by production for that same period of time. This is believed to be a useful non-GAAP measure that is widely utilized within the exploration and production industry as well as by investors. It is an easily calculable number and is representative of the relative success a company is having in replacing its production from its declining asset base as well as its ability to grow the overall company.

Royalty. The share paid to the owner of mineral rights, expressed as a percentage of gross income from oil and gas produced and sold unencumbered by expenses relating to the drilling, completing, and operating of the affected well.

Royalty interest. An interest in an oil and gas property entitling the owner to shares of oil and gas production free of costs of exploration, development, and production operations.

Standardized measure of discounted future net cash flows. The discounted future net cash flows relating to proved reserves based on year-end prices, costs and statutory tax rates, and a 10 percent annual discount rate. The information for this calculation is included in the note regarding disclosures about oil and gas

producing activities contained in the Notes to Consolidated Financial Statements included in this Form 10-K.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether such acreage contains estimated net proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce, and conduct operating activities on the property and to share in the production, sales, and costs.

ITEM 1A. RISK FACTORS

In addition to the other information included in this Form 10-K, the following risk factors should be carefully considered when evaluating St. Mary.

Risks Related to Our Business

Oil and natural gas prices are volatile, and a decline in prices could hurt our profitability, financial condition, and ability to grow.

Our revenues, operating results, profitability, future rate of growth, and the carrying value of our oil and gas properties depend heavily on the prices we receive for oil and natural gas sales. Oil and gas prices also affect our cash flows and borrowing capacity, as well as the amount and value of our oil and gas reserves.

Historically, the markets for oil and gas have been volatile and they are likely to continue to be volatile. Wide fluctuations in oil and gas prices may result from relatively minor changes in the supply of and demand for oil and gas, market uncertainty, and other factors that are beyond our control, including:

- Worldwide and domestic supplies of oil and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain production quotas;
- pipeline, transportation, or refining capacity constraints in a regional or localized area may put downward pressure on the realized price for oil or natural gas;
- political instability or armed conflict in oil or gas producing regions;
- worldwide and domestic economic conditions;
- the level of consumer demand;
- productive capacity of the industry as a whole;
- the availability of transportation facilities;
- weather conditions;
- the price and availability of alternative fuels; and

· governmental regulations and taxes.

These factors and the volatility of oil and gas markets make it very difficult to predict future oil and gas price movements with any certainty. Declines in oil or gas prices would reduce our revenues and could also reduce the amount of oil and gas that we can produce economically, which could have a material adverse effect on us.

If we are not able to replace reserves, we will not be able to sustain production.

Our future operations depend on our ability to find, develop, and acquire oil and gas reserves that are economically recoverable. Our properties produce oil and gas at a declining rate over time. In order to maintain current production rates we must locate and develop or acquire new oil and gas reserves to replace those being depleted by production. We may do this even during periods of low oil and gas prices. In addition, competition for the acquisition of producing oil and gas properties is intense and many of our competitors have financial and other resources for acquisitions that are substantially greater than those available to us. Therefore, we may not be able to acquire oil and gas properties that contain economically recoverable reserves, or we may not be able to acquire such properties at prices acceptable to us. Without successful drilling or acquisition activities, our reserves, production, and revenues will decline over time.

Competition in our industry is intense, and many of our competitors have greater financial and technical resources than we do.

We face intense competition from major oil companies, independent oil and gas exploration and production companies, financial buyers, and institutional and individual investors who are actively seeking oil and gas properties throughout the world, along with the equipment, expertise, labor, and materials required to operate oil and gas properties. Many of our competitors have financial and technical resources vastly exceeding those available to us, and many oil and gas properties are sold in a competitive bidding process in which our competitors may be able to pay more for development prospects and productive properties or in which our competitors have technological information or expertise that is not available to us to evaluate and successfully bid for the properties. In addition, shortages of equipment, labor, or materials as a result of intense competition may result in increased costs or the inability to obtain those resources as needed. We may not be successful in acquiring and developing profitable properties in the face of this competition.

We also compete for people. As drilling activities have accelerated, the need for talented people has grown at a time when the number of people available is constrained.

The actual quantities and present values of our proved oil and gas reserves may be less than we have estimated.

This Form 10-K and other SEC filings by us contain estimates of our proved oil and gas reserves and the estimated future net revenues from those reserves. Reserve estimates are based on various assumptions, including assumptions required by the SEC relating to oil and gas prices, drilling and operating expenses, capital expenditures, taxes, timing of operations, and availability of funds. The process of estimating reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering, and economic data for each reservoir. These estimates are dependent on many variables and therefore changes often occur as these variables evolve and commodity prices fluctuate. Therefore, these estimates are inherently imprecise.

Actual future production, oil and gas prices, revenues, production taxes, development expenditures, operating expenses, and quantities of recoverable oil and gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present values of proved reserves disclosed by us, and the actual quantities and present values may be less than we have previously estimated. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices, and other factors, many of which are beyond our control. Our properties may also be susceptible to hydrocarbon drainage from production by operators on adjacent properties.

As of December 31, 2006, approximately 22 percent, or 200.1 BCFE, of our estimated proved reserves were proved undeveloped and approximately 11 percent or 100.1 BCFE, were proved developed non-producing. Estimates of proved undeveloped reserves and proved developed non-producing reserves are

nearly always based on volumetric calculations rather than the performance data used to estimate producing reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Production revenues from proved developed non-producing reserves will not be realized until some time in the future. Our estimates of proved undeveloped reserves assume that we will make significant capital expenditures to develop these reserves, including an estimated $185 million in 2007. Although we have estimated our reserves and the costs associated with these reserves in accordance with industry standards, estimated costs may not be accurate, development may not occur as scheduled, and actual results may not occur as estimated.

You should not assume that the PV-10 values included in this Form 10-K represent the current market value of our estimated oil and natural gas reserves. Management has based the estimated discounted future net cash flows from proved reserves on prices and costs as of the date of the estimate, in accordance with SEC requirements, whereas actual future prices and costs may be materially higher or lower. For example, values of our reserves as of December 31, 2006, were estimated using a calculated weighted-average sales price of $5.64 per Mcf of gas (Gulf Coast spot price) and $61.05 per Bbl of oil (NYMEX). We ensure that we consider basis and location differentials as of that date in estimating our reserves. During 2006 our monthly average realized gas prices, excluding the effect of hedging, were as high as $8.65 per Mcf and as low as $4.97 per Mcf. For the same period our monthly average realized oil prices were as high as $69.58 per Bbl and as low as $50.61 per Bbl. Many other factors will affect actual future net cash flows, including:

· The amount and timing of actual production;

· supply and demand for oil and natural gas;

· curtailments or increases in consumption by oil purchasers and natural gas pipelines; and

· changes in governmental regulations or taxes.

The timing of production from oil and natural gas properties and of related expenses affects the timing of actual future net cash flows from proved reserves and thus their actual present value. Our actual future net cash flows could be less than the estimated future net cash flows for purposes of computing PV-10 values. In addition, the ten percent discount factor required by the SEC to be used to calculate PV-10 values for reporting purposes is not necessarily the most appropriate discount factor given actual interest rates and risks to which our business and the oil and natural gas industry in general are subject.

Our producing property acquisitions may not be worth what we paid due to uncertainties in evaluating recoverable reserves and other expected benefits, as well as potential liabilities.

Successful property acquisitions require an assessment of a number of factors beyond our control. These factors include exploration potential, future oil and gas prices, operating costs, and potential environmental and other liabilities. These assessments are not precise and their accuracy is inherently uncertain.

In connection with our acquisitions, we perform a customary review of the acquired properties that will not necessarily reveal all existing or potential problems. In addition, our review may not allow us to fully assess the potential deficiencies of the properties. We do not inspect every well, and even when we inspect a well we may not discover structural, subsurface, or environmental problems that may exist or arise. We may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an “as is” basis with limited remedies for breaches of representations and warranties.

In addition, significant acquisitions can change the nature of our operations and business if the acquired properties have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such acquisitions may be limited.

Integrating acquired properties and businesses involves a number of other special risks, including the risk that management may be distracted from normal business concerns by the need to integrate operations and systems as well as retain and assimilate additional employees. Therefore, we may not be able to realize all of the anticipated benefits of our acquisitions.

Exploration and development drilling may not result in commercially productive reserves.

Oil and gas drilling and production activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas will be found. The cost of drilling and completing wells is often uncertain, and oil and gas drilling and production activities may be shortened, delayed, or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- Unexpected drilling conditions;
- title problems;
- pressure or geologic irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental requirements;
- shortages or delays in the availability of or increases in the cost of drilling rigs, fracture stimulation crews and equipment, chemicals and supplies, and
- shortages in availability of experienced drilling crews.

The prevailing prices of oil and gas also affect the cost of and the demand for drilling rigs, production equipment, and related services. The availability of drilling rigs can vary significantly from region to region at any particular time. Although land drilling rigs can be moved from one region to another in response to changes in levels of demand, an undersupply of rigs in any region may result in drilling delays and higher drilling costs for the rigs that are available in that region.

Another significant risk inherent in our drilling plans is the need to obtain drilling permits from state, local, and other governmental authorities. Delays in obtaining regulatory approvals and drilling permits, including delays which jeopardize our ability to realize the potential benefits from leased properties within the applicable lease periods, the failure to obtain a drilling permit for a well, or the receipt of a permit with unreasonable conditions or costs could have a materially adverse effect on our ability to explore on or develop our properties.

The wells we drill may not be productive and we may not recover all or any portion of our investment in such wells. The seismic data and other technologies that we use do not allow us to know conclusively prior to drilling a well that oil or gas is present, or whether it can be produced economically. The cost of drilling, completing, and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Drilling activities can result in dry wells or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover initial drilling and completion costs.

Our future drilling activities may not be successful. Our overall drilling success rate or our drilling success rate for activity within a particular area may decline. In addition, we may not be able to obtain any options or lease rights in potential drilling locations that we identify. Although we have identified numerous potential drilling locations, we may not be able to economically produce oil or natural gas from all of them.

Our hedging transactions may limit the prices that we receive for oil and gas sales and involve other risks.

To manage our exposure to price risks in the sale of our oil and natural gas, we enter into commodity price risk management arrangements from time to time with respect to a portion of our current or future production. We have hedged a significant portion of anticipated future production from our currently producing properties using zero-cost collars and swaps. Commodity price hedging may limit the prices that we receive for our oil and gas sales if oil or natural gas prices rise substantially over the price established by the hedge. In addition, these transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- Our production is less than expected;
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement; or
- the counterparties to our hedge contracts fail to perform under the contracts.

Some of our hedging agreements may also require us to furnish cash collateral, letters of credit, or other forms of performance assurance in the event that mark-to-market calculations result in settlement obligations by us to the counterparties, which would impact our liquidity and capital resources. In addition, some of our hedging transactions use derivative instruments that may involve basis risk. Basis risk in a hedging contract occurs when the index upon which the contract is based is more or less variable than the index upon which the hedged asset is based, thereby making the hedge less effective. For example, a NYMEX index used for hedging certain volumes of production may have more or less variability than the regional price index used for the sale of that production.

Future oil and gas price declines or unsuccessful exploration efforts may result in write-downs of our asset carrying values.

We follow the successful efforts method of accounting for our oil and gas properties. All property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending the determination of whether proved reserves have been discovered. If proved reserves are not discovered with an exploratory well, the costs of drilling the well are expensed.

The capitalized costs of our oil and gas properties, on a field basis, cannot exceed the estimated future net cash flows of that field. If net capitalized costs exceed future net revenues, we must write down the costs of each such field to our estimate of fair market value. Unproved properties are evaluated at the lower of cost or fair market value. Accordingly, a significant decline in oil or gas prices or unsuccessful exploration efforts could cause a future write-down of capitalized costs.

We review the carrying value of our properties quarterly based on prices in effect as of the end of each quarter or as of the time of reporting our results. Once incurred, a write-down of oil and gas properties cannot be reversed at a later date even if oil or gas prices increase.

Substantial capital is required to replace our reserves.

We need to make substantial capital expenditures to find, acquire, develop, and produce oil and natural gas reserves. Future cash flows and the availability of financing are subject to a number of factors, such as the level of production from existing wells, our success in locating and acquiring new reserves, and prices paid for oil and natural gas. If oil or gas prices decrease or we encounter operating difficulties that result in our cash flows from operations being less than expected, we may have to reduce our capital expenditures unless we can raise additional funds through debt or equity financing. Debt or equity financing may not always be available to us in sufficient amounts or on acceptable terms.

If our revenues were to decrease due to lower oil or gas prices, decreased production, or other reasons, and if we could not obtain capital through our credit facility or other acceptable debt or equity financing arrangements, our ability to execute our development plans, replace our reserves, or maintain production levels could be greatly limited.

A decrease in oil or gas prices could limit our ability to borrow under our credit facility.

Our credit facility has a maximum loan amount of $500 million, subject to a borrowing base that the lenders periodically redetermine based on the value of our oil and gas properties, which in turn is based in part on oil and gas prices. Lower oil or gas prices in the future could limit our borrowing base and reduce our ability to borrow under the credit facility.

We could incur substantial additional debt, which could limit our financial flexibility.

As of December 31, 2006, we had $334.0 million in outstanding borrowings under our bank credit facility and $100.0 million in outstanding long-term debt under our 5.75 % Senior Convertible Notes due 2022. We also had a current note payable due to an individual that sold certain oil and gas properties to us in 2006. This note amount was $4.5 million at December 31, 2006, and was paid subsequent to year end. Our long-term debt represented 37 percent of our total book capitalization as of December 31, 2006. The contemplated conversion of these Convertible Notes to equity would give us a pro forma debt to book capitalization ratio of 29 percent at December 31, 2006. Our credit facility has a maximum loan amount of $500 million, a current borrowing base of $900 million, and we have elected a current commitment amount of $500 million.

Our level of debt could have important consequences for our operations, including:

- Requiring us to dedicate a substantial portion of our cash flows from operations to make required payments on debt, thereby reducing the availability of cash flows for working capital, capital expenditures, and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, and other general business activities, or increasing the costs for such additional financing;
- limiting our flexibility in planning for, or reacting to, changes in our business and our industry; and
- increasing our vulnerability to adverse effects from a downturn in our business or the general economy.

We may incur additional debt, including secured debt under our credit facility or otherwise, in order to make future acquisitions or to develop our properties. An increased level of debt increases the risk that we may default on our debt obligations. We may not be able to generate sufficient cash flow from operations or be able to make other arrangements for the repayment or refinancing of the debt.

In addition, our credit facility is subject to periodic borrowing base redeterminations. We could be forced to repay a portion of our bank borrowings in the event of a downward redetermination of our borrowing base, and we may not have sufficient funds to make such repayment at that time. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowing or arrange new financing, we may be forced to sell significant assets.

We are subject to operating and environmental risks and hazards that could result in substantial losses.

Oil and gas operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, adverse weather such as hurricanes in the Gulf Coast region, freezing conditions, formations with abnormal pressures, pipeline ruptures or spills, pollution, releases of toxic gas, and other environmental risks and hazards. If any of these types of events occurs, we could sustain substantial losses.

Under certain limited circumstances we may be liable for environmental damage caused by previous owners or operators of properties that we own, lease, or operate. As a result, we may incur substantial liabilities to third parties or governmental entities, which could reduce or eliminate funds available for exploration, development, or acquisitions or cause us to incur losses.

We maintain insurance against some, but not all, of these potential risks and losses. We have significant but limited coverage for sudden environmental damages.We do not believe that insurance coverage for the full potential liability that could be caused by sudden environmental damages or insurance coverage for environmental damage that occurs over time is available at a reasonable cost. In addition, pollution and environmental risks generally are not fully insurable. Further, we may elect not to obtain other insurance coverage under circumstances where we believe that the cost of available insurance is excessive relative to the risks presented. Accordingly, we may be subject to liability or may lose substantial portions of certain properties in the event of environmental or other damages. If a significant accident or other event occurs and is not fully covered by insurance, we could suffer a material loss.

Following the hurricanes in 2004 and 2005, the insurance markets have suffered significant losses. As a result, the availability of coverage and the cost at which such coverage will be available in the future is uncertain and as evidenced in 2006, was substantially more expensive than in prior years.

Our operations are subject to complex laws and regulations, including environmental regulations that result in substantial costs and other risks.

Federal, state, and local authorities extensively regulate the oil and gas industry. Legislation and regulations affecting the industry are under constant review for amendment or expansion, raising the possibility of changes that may affect, among other things, the pricing or marketing of oil and gas production. Noncompliance with statutes and regulations may lead to substantial penalties, and the overall regulatory burden on the industry increases the cost of doing business and, in turn, decreases profitability.

Governmental authorities regulate various aspects of oil and gas drilling and production, including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of oil and gas properties, environmental matters, safety standards, the sharing of markets, production limitations, plugging and abandonment, and restoration. To cover the various obligations of leaseholders in federal waters, federal authorities generally require that leaseholders have substantial net worth or post bonds or other acceptable assurances that such obligations will be met. The cost of these bonds or other assurances can be substantial, and we may not be able to obtain bonds or other assurances in all cases. Under limited circumstances, federal authorities may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could have a material adverse effect on our operations. Our development at Hanging Woman Basin is particularly affected, as a portion of our acreage is on federal lands.

Our operations are also subject to complex and constantly changing environmental laws and regulations adopted by federal, state, and local governmental authorities in jurisdictions where we are engaged in exploration or production operations. New laws or regulations, or changes to current requirements, could result in material costs or claims with respect to properties we own or have owned. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between state and federal agencies. We could face significant liabilities to governmental authorities and third parties for discharges of oil, natural gas, or other pollutants into the air, soil, or water, and we could be required to spend substantial amounts on investigations, litigation, and remediation. Existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced, or altered in the future, may have a materially adverse effect on us.

In addition, in response to studies suggesting that emissions of certain gases may be contributing to warming of the Earth's atmosphere, many states are beginning to consider initiatives to track and record these gases, generally referred to as "greenhouse gases," with several states having already adopted regulatory initiatives and one state, California, having adopted legislation aimed at reducing emissions of greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of refined oil products and natural gas, are included among the types of gases targeted by greenhouse gas initiatives and laws. This movement is in its infancy but regulatory initiatives or legislation placing restrictions on emissions of methane or carbon dioxide that may be imposed at the federal, state and local level could adversely affect our operations and the demand for our products.

We depend on transportation facilities owned by others.

The marketability of our oil and gas production depends in part on the availability, proximity, and capacity of pipeline transportation systems owned by third parties. The lack of available transportation capacity on these systems and facilities could result in the shutting-in of producing wells, the delay or discontinuance of development plans for properties, or lower price realizations. Although we have some contractual control over the transportation of our production, material changes in these business relationships could materially affect our operations. Federal and state regulation of oil and gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines, and general economic conditions could adversely affect our ability to produce, gather, and transport oil and natural gas.

Risks Related to Our Common Stock

The price of our common stock may fluctuate significantly, which may result in losses forinvestors.

From January 1, 2005, to February 16, 2007, the last daily sale price of our common stock as reported by the New York Stock Exchange ranged from a low of $19.45 per share to a high of $45.28 per share, as adjusted to reflect our 2-for-1 stock split effected in the form of a stock dividend on March 31, 2005. We expect our stock to continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These factors include:

- Changes in oil or natural gas prices;
- variations in quarterly drilling, recompletions, acquisitions, and operating results;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;
- additions or departures of key personnel; and
- future sales of our common stock.

We may fail to meet expectations of our stockholders and/or of securities analysts at some time in the future, and our stock price could decline as a result.

Our certificate of incorporation and bylaws have provisions that discourage corporate takeovers and could prevent stockholders from receiving a takeover premium on their investment.

Our certificate of incorporation and bylaws contain provisions that may have the effect of delaying or preventing a change of control. These provisions, among other things, provide for non-cumulative voting in the election of the Board of Directors and impose procedural requirements on stockholders who wish to make nominations for the election of Directors or propose other actions at stockholder meetings. These provisions, alone or in combination with each other and with the shareholder rights plan described below, may discourage transactions involving actual or potential changes of control, including transactions that otherwise could involve payment of a premium over prevailing market prices to stockholders for their common stock.

Under our shareholder rights plan, if the Board of Directors determines that the terms of a potential acquisition do not reflect the long-term value of St. Mary, the Board of Directors could allow the holder of each outstanding share of our common stock other than those held by the potential acquirer to purchase one additional share of our common stock with a market value of twice the exercise price. This prospective dilution to a potential acquirer would make the acquisition impracticable unless the terms were improved to the satisfaction of the Board of Directors. The existence of the plan may impede a takeover not supported by our Board even though such takeover may be desired by a majority of our stockholders or may involve a premium over the prevailing stock price.

Our shares that are eligible for future sale may have an adverse effect on the price of our common stock.

As of February 16, 2007, we had 55,004,399 shares of common stock outstanding, net of 250,000 shares held in treasury. Of the net shares outstanding, 54,909,904 shares were freely tradable without substantial restriction or the requirement of future registration under the Securities Act of 1933. Also as of that date, options to purchase 3,118,936 shares of our common stock were outstanding, of which 2,964,278 were exercisable. These options are exercisable at prices ranging from $4.62 to $20.87 per share. In addition, restricted stock units providing for the issuance of up to a total of 1,061,223 shares of our common stock were outstanding. Further, we expect to issue approximately 7,692,300 shares of common stock upon conversion of the $100 million of our Senior Convertible Notes. The number of shares is based on the conversion price of $13.00 per share. Conversion is expected as an outcome of our recent announcement to call the notes for redemption on March 20, 2007. Sales of substantial amounts of common stock, or a perception that such sales could occur, and the existence of options and restricted stock units to issue shares of common stock at prices that may be below the then-current market price of the common stock could adversely affect the market price of the common stock and could impair our ability to raise capital through the sale of our equity securities.

We may not always pay dividends on our common stock.

The payment of future dividends remains in the discretion of the Board of Directors and will continue to depend on our earnings, capital requirements, financial condition, and other factors. In addition, the payment of dividends is subject to covenants in our credit facility, including a covenant regarding the level of our current ratio of current assets to current liabilities and a limit on the annual dividend rate that we may pay to no more than $0.25 per share. The Board of Directors may determine in the future to reduce the current semi-annual dividend rate of $0.05 per share or discontinue the payment of dividends altogether.

A director and his extended family may be able to exert influence over us.

Thomas E. Congdon, a director and our former Chairman of the Board, and members of his extended family are estimated to own between one and five percent of the outstanding shares of our common stock as of February 16, 2007. While no formal arrangements exist, these extended family members could be inclined to act in concert with Mr. Congdon on matters related to control of St. Mary, including for example the election of directors or in response to an unsolicited proposal to acquire St. Mary. Accordingly, Mr. Congdon and his family may be able to influence matters presented to our Board of Directors and stockholders.

ITEM 1B. UNRESOLVED STAFF COMMENTS

St. Mary has no unresolved comments from the SEC staff regarding its periodic or current reports under the Securities Exchange Act of 1934.

ITEM 2. PROPERTIES

Operations

St. Mary's exploration, development, and acquisition activities and oil and gas properties are focused in five core operating areas: the Rocky Mountain region; the Mid-Continent region; the ArkLaTex region; the Permian Basin region; and the Gulf Coast region. Our Hanging Woman Basin project is within our Rocky Mountain region and is managed by personnel from our Billings, Montana office. Information concerning each of our major areas of operations is shown below with the summary of our estimated proved reserves as of December 31, 2006.

	Estimated Proved Reserves					
	Oil	Gas	MMCFE		PV-10 Value	
	(MBbl)	(MMcf)	Amount	Percent	(In thousands)	Percent
Rocky Mountain	52,285	75,845	389,556	42.0	$ 948,413	44.0
Hanging Woman Basin	—	33,385	33,385	3.6	40,047	1.8
Total Rocky Mountain	52,285	109,230	422,941	45.6	988,460	45.8
Mid-Continent	1,503	161,693	170,714	18.4	412,050	19.1
ArkLaTex	1,142	152,686	159,535	17.2	264,827	12.3
Permian Basin	18,903	28,828	142,247	15.3	393,036	18.2
Gulf Coast	362	30,038	32,210	3.5	99,076	4.6
Total	74,195	482,475	927,647	100.0	$ 2,157,449	100.0

Rocky Mountain Region. Nance Petroleum Corporation, a wholly-owned subsidiary of St. Mary, has conducted operations on behalf of the Company in the Williston Basin in eastern Montana and western North Dakota since 1991. Our office in Billings, Montana has a full-time staff of 112 people. We have expanded our operations into the Greater Green River, Powder River, Big Horn, and Wind River basins of Wyoming over the past several years as a result of acquisitions. The largest growth in the region came in late 2002 and early 2003 with significant property acquisitions from Choctaw, Burlington Resources, and Flying J. These transactions brought with them a tremendous acreage position that has precipitated additional growth in this region.

St. Mary spent $161.3 million in 2006 on exploration, development, and acquisitions in the Rocky Mountain region including Hanging Woman Basin, with $146.4 million directed towards drilling and leasing activities. In 2005, $197.0 million was spent in the Rockies, including $22.9 million at Hanging Woman Basin. The relative decrease in total capital from the prior year reflects the Agate and Wold acquisitions that occurred in 2005. In recent years, our conventional Rockies program has focused on the horizontal Bakken play, although the level of activity is decreasing in 2007. We continue to develop the Red River formation using smaller 3-D seismic surveys. We have successfully used 3-D seismic imaging to delineate structure and porosity development in this formation. As a result of transactions in 2004 and 2005, including Goldmark, Agate, and Wold, we have acquired a position in a number of legacy oil fields in

the Big Horn and Wind River basins, as well as a presence in the Greater Green River Basin. Production in 2006 from conventional oil and gas in the Rockies was 37.5 BCFE, 79 percent of which was oil. This represents an increase of one percent from production of 37.2 BCFE for 2005. Proved reserves for conventional Rockies assets in 2006 were 389.6 BCFE, 92 percent of which were proved developed and 81 percent of which were oil. This represents a decline of three percent from 2005 year-end proved reserves. Reserves declined in 2006 as our production was not replaced by our drilling or acquisition activity. Our drilling, while successful overall, resulted in more marginally productive wells in the Bakken formation during 2006 as we near the end of that specific drilling program. Additionally, reserves and production were negatively impacted by our inability to secure a drilling rig in the southern Rockies for most of the year.

The Elm Coulee Field in the Rockies is the highest value field in the region at year-end 2006, with proved reserves of 43.8 BCFE and a PV-10 value of $143.0 million. The reserves in this field are predominately oil and the Bakken is the formation of primary interest. This field comprises approximately seven percent of the entire Company's PV-10 value of $2.2 billion and is represented by interest in 89 gross wells with an average working interest of 54 percent.

Another significant drilling program in the Rockies is at our Hanging Woman Basin coalbed methane development in the northern Powder River Basin. In 2006, we spent a total of $30.4 million developing this program. We participated in 138 wells, 132 of which were operated, as well as the build out of the necessary infrastructure to operate in the area. Production from Hanging Woman Basin began in mid-December 2004, was 0.5 Bcf in 2005, and quadrupled to 2.0 Bcf in 2006. Due to regulatory and permitting delays, significant dewatering time, and low production rates per well, it will take a number of years to develop the field to the point of having production volumes that are meaningful to our total production profile. Even so, we expect to see significant percentage increases in annual production for several years. Proved reserves at December 31, 2006, were 33.4 Bcf, 91 percent of which were proved developed. This represents a 32 percent increase in proved reserves year-over-year. All of these reserves are located on our acreage in Wyoming.

Our capital budget for the Rocky Mountain region represents the largest portion of our 2007 drilling budget at approximately $213 million for 2007, with $155 million budgeted for the conventional Rockies program and $58 million budgeted for activities at Hanging Woman Basin. In the conventional Rockies program, we plan to drill or participate in 178 gross wells in 2007. We will operate 81 percent of the planned capital expenditures forecasted for the conventional Rockies. Our operated activities are focused on expanding a horizontal re-entry program targeting the Madison and Mission Canyon formations, drilling and re-entering wells in the legacy Murphy Dome oil field, and targeting the Lewis and Almond formations in the Greater Green River Basin. Fewer operated wells are planned for the Bakken program in 2007 as this successful grass roots program is nearing the end of primary development. However, we do plan to attempt a handful of horizontal re-entry wells targeting this formation. We will continue to exploit what we believe to be a competitive advantage in the Red River formation in 2007. The plans of our non-operated partners in 2007 are dominated by horizontal Bakken, Madison, and Mission Canyon wells, as well as a significant number of wells at the Atlantic Rim coalbed methane development in Wyoming. At Hanging Woman Basin, our plan is to drill or participate in 258 wells in 2007. All of the activity in the Hanging Woman Basin this year is scheduled to occur in Wyoming. We will operate 84 percent of the gross well activity and 87 percent of the planned capital expenditures. Our operated drilling program anticipates growing to a four rig program during the year. The majority of our operated activity will focus on the shallow and intermediate coal benches. Additional horizontal wells are planned for the deep coal package during 2007, and we will continue to monitor the results of the four deep horizontal wells that were drilled in late 2006. We do not expect to have enough information to make an assessment of the horizontal program until late 2007 or early 2008.

Mid-Continent Region. St. Mary has been active in the Mid-Continent region since 1973. Operations for the region are managed by our 50 full-time employees in Tulsa, Oklahoma. We have been active in the Anadarko Basin of western Oklahoma since our entry into the region and have begun operating in the Arkoma Basin in eastern Oklahoma in recent years. Our long history of operations and proprietary geologic knowledge enables us to sustain economic development and exploration programs despite periods of adverse industry conditions. We apply current technology through the use of hydraulic fracturing, innovative well completion techniques, and horizontal drilling to accelerate production and associated cash flow from the region's tight gas reservoirs and developing plays.

In 2006, we spent $214.3 million in the Mid-Continent region on exploration, development, and acquisition activity, which is 58 percent more than the $135.6 million spent in 2005. The increase in 2006 is the result of drilling and service cost inflation and additional activity in our horizontal Arkoma program targeting the Wapanucka limestone, Cromwell sandstone, and Woodford shale formations, as well as a moderate ramp up of activity in the Constitution field and throughout the Anadarko Basin. We were also much more active in the leasing aspect of our business in 2006, spending $17.7 million, which is almost four times the amount spent on leasing in 2005. Mid-Continent production in 2006 was 29.8 BCFE, 92 percent of which was natural gas. This is an increase of 13 percent from the 26.5 BCFE produced in 2005. Proved reserves at the end of 2006 were 170.7 BCFE, 94 percent of which were proved developed and 95 percent of which were natural gas. Year over year, proved reserves dropped three percent from 175.4 BCFE at December 31, 2005. The Mid-Continent decrease was primarily caused by a downward price revision of 28.9 BCFE in 2006, as natural gas prices used to calculate SEC proved reserves declined 44 percent year-over-year to $5.64 per MMBtu. While we are subject to the volatility of commodity prices with respect to the calculation of year-end SEC proved reserves, we believe our active hedging program protects our economics despite periodic swings in commodity prices that can result in negative reserve revisions due to price reductions. Although we may be helped by the financial protection offered by our derivative contracts, our individual well economics must also meet acceptable return criteria in order to proceed with drilling activity.

The Paggi Broussard #1 well operated by our Mid-Continent region is the highest single value property in the Company, with 8.5 BCFE of proved reserves and a PV-10 value of $47.4 million as of December 31, 2006. This single well represents two percent of our entire PV-10 value of $2.2 billion. The well was drilled in late 2004 and has shown remarkably little decline in the time since it was placed online. The Paggi Broussard #2 was drilled and placed online in mid-2006 and is the second highest value well and fifth largest value entity in the Company with proved reserves of 3.2 BCFE and a PV-10 value of $17.2 million as of December 31, 2006. The largest value field in the Mid-Continent is Northeast Mayfield which produces primarily from the Morrow and Atoka/Granite Wash formations. At the end of 2006 the proved reserves at Northeast Mayfield were 37.3 BCFE and the PV-10 value was $88.1 million.

The 2007 capital expenditure budget for the Mid-Continent region is $206 million, 82 percent of which will be operated by the Company. The largest component of the budget is our program in the Arkoma basin, where 17 operated wells are planned. The majority of these will be horizontal wells targeting the Woodford shale formation. Activity in the horizontal Arkoma program is currently focused on the Woodford shale as it is the deepest of the three zones of interest, and by drilling to the Woodford we will hold the acreage through that depth. We continue to evaluate our drilling and completion efforts in the horizontal Arkoma program to ensure we are improving and maximizing the potential of this program. The next most significant program is the Atoka/Granite Wash program in the Mayfield development area where we will drill or participate in 30 gross wells in 2007, 18 of which will be operated by the Company. The production profile of Atoka/Granite Wash wells is such that approximately 50 percent of the expected total production is recovered within the first year, and therefore these wells can be more economically sensitive to commodity price volatility. As a result, we have hedged the anticipated production from the planned 2007 Atoka/Granite Wash program for the next two years to ensure that our economic thresholds

are being met. We evaluate the commodity price and cost environment prior to drilling each well to ensure the well project meets our economic standards. However, our hedging program provides us the flexibility to continue drilling should operational or leasehold issues dictate moving forward with the program when the current economics for individual wells may be currently unfavorable. The Company has also budgeted capital for wells targeting the Springer and Britt formations in 2007.

ArkLaTex Region. Our 24 full-time employees in Shreveport, Louisiana manage St. Mary's operations in the ArkLaTex region. The ArkLaTex region was the first operating office for the Company, originating from the acquisition of oil and gas assets from T.L. James & Company in 1992. For years the activities of this region focused on the tight sandstone Cotton Valley and Travis Peak formations in the region. In recent years, we have added development of limestone carbonates in the ArkLaTex, including the James, Glen Rose, Rodessa, and Pettit formations.

The ArkLaTex region spent $88.0 million in 2006 on exploration, development, and acquisition activities, which is double the $44.0 million spent in 2005. The primary drivers of this increase in capital were an increase in activity at Elm Grove and an escalation of cost in our horizontal limestone program related to a new completion technique. Our non-operated interests in the Elm Grove Field were purchased in late 2004, and since that time the ownership in the field has consolidated considerably. This consolidation has allowed the remaining owners to accelerate development of the Lower Cotton Valley formation which has historically been the target interval in this field. The increase in activity has occurred in areas of the field where we have relatively higher working interests, thereby increasing our capital expenditures in the field. In the horizontal limestone program, we began using a new completion technique in 2006 that allows us to isolate sections of the horizontal wellbore. By isolating different sections we can complete and stimulate each isolated section in a manner that is optimal for that particular segment of the formation. While this technique increased our costs significantly, it also increased our production and reserves per well, thereby economically justifying the additional expenditure. The region's 2006 production was down two percent to 10.5 BCFE. The production in the region is 92 percent gas. We experienced a number of operational and timing issues during 2006, primarily associated with compression, which contributed to the decline in production. Our proved reserves at year-end 2006 were 159.5 BCFE, 44 percent of which were proved developed and 96 percent of which were natural gas. This is a 43 percent increase over 2005 year-end proved reserves of 111.3 BCFE.

The Elm Grove Field is the highest value field in the ArkLaTex region at year-end 2006, with proved reserves of 79.5 BCFE and a PV-10 value of $107.8 million. Elm Grove comprises approximately five percent of the entire Company's PV-10 value. We own interests in 320 wells in the field and our working interest ranges from 0.2 percent to 37.3 percent, with the higher working interests in the southern portion of our acreage. The reserves in this field are comprised of natural gas. The Lower Cotton Valley and Hosston formations are the major reserve contributors in this field.

Our capital budget for the ArkLaTex in 2007 is $131 million, 57 percent of which will be operated by us. The largest part of this year's budget relates to our horizontal limestone program where 22 wells are planned for 2007. In 2006, the Company increased its acreage position targeting these limestone formations by 63 percent to approximately 43,000 net acres. We plan to dedicate two rigs to this horizontal program throughout the year. Elm Grove also represents a significant portion of the region's capital budget as development in this field continues to move forward at an aggressive pace. A total of 87 grass roots wells are planned in the field this year, which is a substantial increase from the prior year. In addition to the continued pursuit of the traditional Lower Cotton Valley target, recompletions using coiled tubing assisted fracturing that target the Hosston formation proved to be very successful in 2006. 20 such Hosston recompletions are budgeted for 2007.

Permian Basin Region. The Permian Basin area covers a significant portion of western Texas and eastern New Mexico and is one of the major producing basins in the United States. Our holdings in the

Permian Basin resulted from a series of property acquisitions beginning in 1996. In December 2006, we acquired oil and natural gas assets in the Sweetie Peck Field in the Midland Basin in the largest acquisition in our history. To manage the significant increase in operated properties associated with the Sweetie Peck acquisition, we opened a regional office in Midland, Texas in early February 2007. Our office in Midland currently has five full-time employees.

In 2006, we spent $275.2 million on capital expenditures in the Permian basin, compared to $7.7 million in the prior year. The substantive majority of this increase related to the acquisition of oil and gas properties in the Sweetie Peck Field. The productive targets for this field are the producing formations of the Spraberry interval including the Spraberry, Leonard, and Wolfcamp formations. We also spent capital in 2006 on our successful waterflood projects in the Delaware Basin of southeastern New Mexico as well as at HJSA Field. Production from the Permian region was 3.2 BCFE in 2006 and 80 percent of the production was oil. Production increased eight percent over the prior year. Year-end 2006 proved reserves were 142.2 BCFE, 58 percent of which were proved developed and 80 percent of which were oil. This represents an increase of 185 percent from 2005 year-end reserves of 49.9 BCFE.

The Sweetie Peck Field comprises eight percent of our total proved reserves and represents the largest value field in the Company, with proved reserves at year-end 2006 of 78.0 BCFE. Currently there are 73 proved developed producing wells and our working interest in each of these wells is either 95 or 100 percent. The PV-10 value for proved developed wells in the field is $219.5 million, which equates to approximately ten percent of our entire PV-10 value.

The capital budget for 2007 in the region is $111 million, of which 80 percent will be operated by the Company. The majority of the increase relates to anticipated drilling at Sweetie Peck and certain non-operated activity in the basin. Fifty-four wells are planned in the Sweetie Peck Field for 2007, all of which will be operated by us. Other projects contemplated in this year's budget include continued development at HJSA and infill and optimization projects at the East Shugart Delaware Unit and Parkway Delaware Unit waterflood projects.

Gulf Coast Region. St. Mary's presence in south Louisiana dates to the early 1900s when our founders acquired our namesake property in St. Mary Parish, Louisiana abutting the Gulf of Mexico. These 24,914 acres of fee lands yielded $5.0 million of gross oil and gas royalty revenue in 2006. Our Gulf Coast regional presence expanded as a result of the acquisition of King Ranch Energy, Inc. in 1999. In recent years, our team in Houston, Texas has developed an expertise applying DHI technology. This group of 19 full-time employees manages St. Mary's diverse activities in our Gulf Coast and Permian Basin regions.

Our 2006 capital expenditures in the Gulf Coast region totaled $65.5 million, which is 78 percent higher than the $36.8 million spent in 2005. The increase was due to a ramp up in activity for our DHI program as well as our participation as non-operator in an intermediate deep water project. We were successful in six out of eight tests in our DHI program in 2006. We had meaningful operated exploratory successes with the Clyde Leger 1 well at the Duson prospect and with the State Tract 345-1 at the Holly prospect. We also participated in two successful new drills and two successful recompletions in the Judge Digby Field located in Point Coupee Parish outside of Baton Rouge, Louisiana. Offshore, the Company had a non-operated exploration success with the Vermillion 101 well, which began flowing to sales in December 2006. Also, in our intermediate deep water program we had an initial discovery with our operating partner at the Zloty prospect where initial production is expected in mid-2008. Production for 2006 in the Gulf Coast region was 9.7 BCFE, 90 percent of which was natural gas. This is a four percent increase in production from the 9.3 BCFE produced in 2005. The increase in production was a result of the successes mentioned above that were brought online in 2006, as well as contribution from a significant royalty well on our fee acreage that produced for a portion of the year. Proved reserves as of year-end 2006, including those related to the fee properties, were 32.2 BCFE, of which 80 percent were proved developed and 93 percent were natural gas. This is a seven percent increase in proved reserves from 30.0 BCFE as of year-end 2005.

The most significant field in the Gulf Coast region is the Judge Digby Field. As of the end of December 2006, this field had a PV-10 value of $34.3 million with 9.7 BCFE of proved reserves. This accounts for less than two percent of the Company's PV-10 value.

Our exploration and development budget in the Gulf Coast region for 2007 is $60million, which consists of activity for both onshore and offshore projects in Texas and Louisiana as well as low to moderate risk DHI prospects in state and federal waters of the Gulf of Mexico. There is also capital budgeted in 2007 related to intermediate deep water projects for both new prospects as well as commitments resulting from our 2005 and 2006 successes. The majority of this activity will be operated by others as we plan to operate approximately 14 percent of the 2007 forecasted drilling projects.

Acquisitions and Divestitures

We spent a total of $282.9 million on acquisitions of proved and unproved oil and gas properties in 2006. Proved reserves contributed from our acquisitions were 99.2 BCFE, of which 49 percent were proved developed and 72 percent were oil. The most significant acquisition this year was that of the oil and gas properties in the Sweetie Peck Field in the Permian Basin from several private parties in December 2006. The adjusted purchase price for these assets was $247.6 million, which is subject to regular and customary post-closing adjustments. At year-end 2006 there were 78.0 BCFE of proved reserves related to this transaction, 48 percent of which were proved developed and 78 percent of which were oil. Our other acquisitions where smaller, niche transactions and related primarily to the Rockies and Mid-Continent regions. In 2006, we also divested properties with 3.1 BCFE of proved reserves, the majority of which related to a tax-deferred exchange in which we exchanged non-core properties in the Uinta Basin of Utah for properties in Richland County, Montana.

Significant acquisitions prior to 2006 include the 2005 acquisitions of Agate Petroleum, Inc. and properties from Wold Oil Properties, Inc. In 2004, we acquired oil and gas properties from Goldmark Engineering, Inc., in the Rocky Mountain region and the Elm Grove Field from Border Company in the ArkLaTex region.

Reserves

The following table presents summary information with respect to the estimates of our proved oil and gas reserves for each of the years in the three-year period ended December 31, 2006. For all years presented Netherland, Sewell and Associates, Inc. ("NSAI") prepared the reserve information for the Company's coalbed natural gas projects at Hanging Woman Basin in the northern Powder River Basin as well as St. Mary's non-operated coalbed methane interest in the Green River Basin. We have engaged Ryder Scott Company to review internal engineering estimates for 80 percent of the PV-10 value of our 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 our 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 producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available. The PV-10 values shown in the following table are not intended to represent the current market value of the estimated proved oil and gas reserves owned by St. Mary. Neither prices nor costs have been escalated. You should read the following table along with the section entitled "Risk Factors—Risks Related to Our Business—Estimates of oil and gas reserves are not precise."

	As of December 31,		
Proved Reserves Data:	2006	2005	2004
Oil (MBbl)	74,195	62,903	56,574
Gas (MMcf)	482,475	417,075	319,196
MMCFE	927,647	794,493	658,638
PV-10 value (in thousands)	$ 2,157,449	$ 2,494,169	$ 1,501,123
Standardized measure of discounted future net cash flows (in thousands)	$ 1,576,437	$ 1,712,298	$ 1,033,938
Proved developed reserves	78%	82%	85%
Reserve replacement—including sales	244%	256%	186%

Reserve replacement—excluding sales	247%	256%	190%
Reserve life (years)(1)	10.0	9.1	8.7

(1) Reserve life represents the estimated proved reserves at the dates indicated divided by actual production for the preceding 12-month period.

Production

The following table summarizes the average volumes and realized prices, including and excluding the effects of hedging, of oil and gas produced from properties in which St. Mary held an interest during the periods indicated. Also presented is a production cost per MCFE summary for the Company.

	Years Ended December 31,		
	2006	2005	2004
Net production:			
Oil (MBbl)	6,057	5,927	4,799
Gas (MMcf)	56,448	51,801	46,598
MMCFE	92,788	87,363	75,393
Average net daily production:			
Oil (Bbl)	16,594	16,238	13,113
Gas (Mcf)	154,652	141,922	127,316
MCFE	254,214	239,352	205,992
Average realized sales price, excluding the effects of hedging:			
Oil (per Bbl)	$ 59.33	$ 53.18	$ 39.77
Gas (per Mcf)	$ 6.58	$ 8.08	$ 5.85
Per MCFE	$ 7.88	$ 8.40	$ 6.15
Average realized sales price, including the effects of hedging:			
Oil (per Bbl)	$ 56.60	$ 50.93	$ 32.53
Gas (per Mcf)	$ 7.37	$ 7.90	$ 5.52
Per MCFE	$ 8.18	$ 8.14	$ 5.48
Production costs per MCFE:			
Lease operating expense	$ 1.25	$ 0.99	$ 0.81
Transportation expense	$ 0.12	$ 0.09	$ 0.10
Production taxes	$ 0.54	$ 0.56	$ 0.36

Productive Wells

As of December 31, 2006, St. Mary had working interests in 2,234 gross (1,050 net) productive oil wells and 3,359 gross (895 net) productive gas wells. Productive wells are either producing wells or wells capable of commercial production although currently shut in. One or more completions in the same wellbore are counted as one well. A well is categorized under state reporting regulations as an oil well or a

gas well based upon the ratio of gas to oil produced when it first commenced production, and such designation may not be indicative of current production.

Drilling Activity

All of our drilling activities are conducted on a contract basis with independent drilling contractors. We do not own any drilling equipment. The following table sets forth the wells drilled and recompleted in which St. Mary participated during each of the three years indicated:

	Years Ended December 31,					
	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	81	35.32	83	38.09	50	18.08
Gas	446	178.97	379	152.69	180	53.23
Non-productive	31	10.65	29	9.12	36	14.29
	558	224.94	491	199.90	266	85.60
Exploratory:						
Oil	10	5.53	8	1.91	11	9.71
Gas	15	3.68	5	0.86	83	43.65
Non-productive	8	1.81	5	2.32	8	2.84
	33	11.02	18	5.09	102	56.20
Farmout or non-consent	2	—	18	—	5	—
Total(1)	593	235.96	527	204.99	373	141.80

(1) Does not include three, nine, and seven gross wells completed on St. Mary's fee lands during 2006, 2005 and 2004, respectively, in which we have only a royalty interest.

Acreage

The following table sets forth the gross and net acres of developed and undeveloped oil and gas leases, fee properties, mineral servitudes, and lease options held by St. Mary as of December 31, 2006. Undeveloped acreage includes leasehold interests that may already have been classified as containing proved undeveloped reserves.

	Developed Acres(1)		Undeveloped Acres(2)		Total	
	Gross	Net	Gross	Net	Gross	Net
Arkansas	2,917	407	207	68	3,124	475
Colorado	3,544	2,876	23,037	13,571	26,581	16,447
Louisiana	131,639	45,046	52,144	15,607	183,783	60,653
Mississippi	6,370	1,030	5,516	1,554	11,886	2,584

Montana	67,564	43,958	434,226	293,622	501,790	337,580
New Mexico	5,440	2,608	1,480	1,187	6,920	3,795
North Dakota	146,075	94,796	187,121	108,097	333,196	202,893
Oklahoma	295,195	89,867	97,285	51,345	392,480	141,212
Texas	160,244	45,123	81,346	41,102	241,590	86,225
Utah(3)	480	115	3,574	878	4,054	993
Wyoming	150,030	100,131	382,857	214,999	532,887	315,130
Other(4)	2,201	905	3,996	1,090	6,197	1,995
	971,699	426,862	1,272,789	743,120	2,244,488	1,169,982
Louisiana Fee Properties	10,818	10,818	14,096	14,096	24,914	24,914
Louisiana Mineral Servitudes	10,173	5,740	4,490	4,128	14,663	9,868
	20,991	16,558	18,586	18,224	39,577	34,782
Total	992,690	443,420	1,291,375	761,344	2,284,065	1,204,764

(1) Developed acreage is acreage assigned to producing wells for the spacing unit of the producing formation. Developed acreage in certain of St. Mary's properties that include multiple formations with different well spacing requirements may be considered undeveloped for certain formations, but have only been included as developed acreage in the presentation above.

(2) Undeveloped acreage is lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether such acreage contains estimated proved reserves.

(3) St. Mary holds an overriding royalty interest in an additional 36,021 gross acres in Utah.

(4) Includes interests in Alabama, Kansas, Nebraska and South Dakota.

ITEM 3. LEGAL PROCEEDINGS

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

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

There were no matters submitted to a vote of our security holders during the fourth quarter of 2006.

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth the names, ages and positions held by St. Mary's executive officers.The age of the executive officers is as of February 15, 2007.

Name	Age	Position
Mark A. Hellerstein	54	Chairman of the Board and Chief Executive Officer(1)
Anthony J. Best	57	President(1)
Javan D. Ottoson	48	Executive Vice President and Chief Operating Officer
Robert L. Nance	70	Senior Vice President, and President and Chief Executive Officer of Nance Petroleum Corporation, a wholly-owned subsidiary of St. Mary
Jerry R. Schuyler	51	Senior Vice President and Regional Manager
Paul M. Veatch	40	Senior Vice President and Regional Manager
David W. Honeyfield	40	Vice President—Chief Financial Officer, Treasurer, and Secretary
Milam Randolph Pharo	54	Vice President—Land and Legal and Assistant Secretary
Garry A. Wilkening	56	Vice President—Administration
William D. Hart	55	Vice President—General Manager, ArkLaTex
Mark T. Solomon	38	Controller

(1) Mr. Hellerstein will be retiring as Chief Executive Officer on February 23, 2007, at which time Mr. Best will be appointed to that position. Mr. Hellerstein will remain Chairman of the Board.

Each executive officer has held his respective position during the past five years, except as follows:

Mark A. Hellerstein was appointed Chairman of the Board in September 2002.

Anthony J. Best joined St. Mary in June 2006 as President and Chief Operating Officer. In December 2006, Mr. Best relinquished his position as Chief Operating Officer when Javan D. Ottoson was elected to that office. From 2003 to October 2005, Mr. Best was President and Chief Executive Officer of Pure Resources, Inc., a subsidiary of Unocal, where he managed all of Unocal's onshore U.S. assets. From 2000 to 2002, Mr. Best had an energy and leadership consulting practice working with oil and gas firms and non-profit organizations. From 1979 to 2000, Mr. Best was with ARCO in a variety of positions, including a period as President—ARCO Permian, President—ARCO Latin America, Field Manager for Prudhoe Bay, and VP—External Affairs for ARCO Alaska.

Javan D. Ottoson joined St. Mary in December 2006 as Executive Vice President and Chief Operating Officer. Mr. Ottoson has been in the oil and gas industry for 22 years, most recently as Senior Vice President—Drilling and Engineering at Energy Partners, Ltd. in New Orleans. Mr. Ottoson managed the Permian assets for Pure Resources, Inc., a Unocal subsidiary, and its successor owner, Chevron, from 2003 to 2006. Prior to that, Mr. Ottoson worked for ARCO in management and operational roles. These roles included President of ARCO China, Commercial Director of ARCO British, and Vice President of Operations and Development, ARCO Permian.

Jerry R. Schuyler joined St. Mary in December 2003 as Senior Vice President and Regional Manager of the Gulf Coast region. From November 2001 to July 2002, Mr. Schuyler was Senior Vice President and General Manager—Eastern Onshore Division for Dominion Exploration & Production, Inc., where he managed all operations and exploration for Dominion's Gulf Coast and eastern onshore U.S. regions. From March 2000 to November 2001, Mr. Schuyler was Senior Vice President and General Manager of Dominion's Onshore U.S. Division, where he managed all operations and exploration for all of Dominion's onshore U.S. regions.

Paul M. Veatch was appointed Senior Vice President and Regional Manager of the Mid-Continent region in March 2006. Mr. Veatch joined St. Mary in April 2001 as Regional A & D Engineer. He was

Manager of Engineering from April 2003 to August 2004 and Vice President—General Manager, ArkLaTex from August 2004 to March 2006.

David W. Honeyfield was appointed as Chief Financial Officer in May 2005. Mr. Honeyfield joined St. Mary in May 2003 as Vice President—Finance, Treasurer, and Secretary. Prior to joining St. Mary, Mr. Honeyfield was Controller and Chief Accounting Officer of Cimarex Energy Co. from September 2002 to May 2003. From April 2002 to September 2002, he was Controller and Chief Accounting Officer of Key Production Company, Inc., which was acquired by Cimarex in September 2002. Prior to joining Key Production Company, Mr. Honeyfield was a senior audit manager with Arthur Andersen LLP in Denver. Mr. Honeyfield had been with Arthur Andersen since January 1991.

Garry A. Wilkening relinquished his position as Controller in January 2007 when Mark T. Solomon was elected to that office. Mr. Wilkening continues to serve as Vice President—Administration. Mr. Wilkening was Vice President—Administration and Controller from 1999 to 2007.

William D. Hart was appointed Vice President—General Manager, ArkLaTex in May 2006. Mr. Hart joined the Company as Exploration Manager, Geologist, Shreveport in November 1992. Mr. Hart was Vice President, Geology, ArkLaTex from May 1996 to May 2006.

Mark T. Solomon was appointed Controller in January 2007. Mr. Solomon joined St. Mary in 1996. He served as Financial Reporting Manager from February 1999 to September 2002, Assistant Vice President—Financial Reporting from September 2002 to May 2006 and Assistant Vice President - Assistant Controller from May 2006 to January 2007. Prior to joining St. Mary, Mr. Solomon was an auditor with Ernst & Young LLP.

Executive officers generally are elected at the regular meeting of the Board immediately following the annual stockholders meeting, to serve for the ensuing year or until their successors are duly qualified and elected. The executive officers of St. Mary do not have fixed terms and serve at the discretion of the Board of Directors. Any officer elected or appointed by the Board may be removed by the Board with or without cause, subject to any contractual rights of the person so removed.

Mr. Hellerstein has an employment agreement with St. Mary. The agreement is in effect until June 30, 2007. Upon any termination of the employment of Mr. Hellerstein by St. Mary before June 30, 2007, for any reason other than death, disability or misconduct by Mr. Hellerstein, St. Mary is generally obligated to continue to pay his base salary, additional bonus and incentive compensation, and other fringe benefits until June 30, 2007.

Mr. Best also has an employment agreement with St. Mary. Upon any termination of the employment of Mr. Best by St. Mary for any reason other than death, disability, or misconduct by Mr. Best, St. Mary is generally obligated to continue to pay his base salary and insurance benefits for a period of two years after termination. In addition, upon commencement of employment, Mr. Best received a cash bonus and a special restricted stock award of 20,000 shares that are vested immediately and not subject to forfeiture. Over the next four years Mr. Best is also eligible to earn additional restricted shares in varying amounts, a portion of which are based on the Company's net asset value growth.

There are no family relationships between any executive officer and any other executive officer or director. There are no arrangements or understandings between any officer and any other person pursuant to which that officer was elected.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATEDSTOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

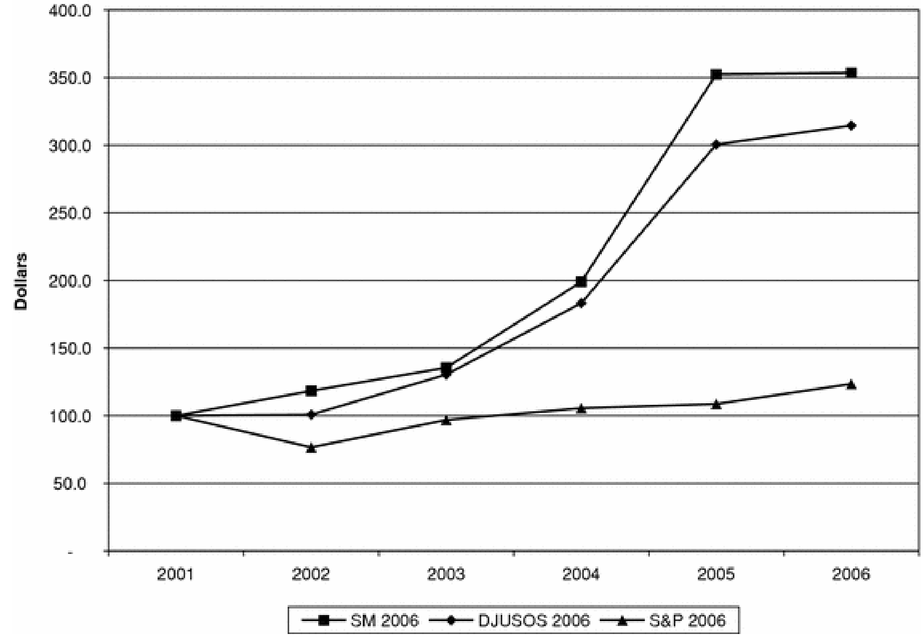
Market Information. St. Mary's common stock is currently traded on the New York Stock Exchange under the symbol SM. The range of high and low sales prices for the quarterly periods in 2006 and 2005, as reported by the New York Stock Exchange and adjusted for the two-for-one stock split effected in the form of a stock dividend which was distributed on March 31, 2005 to shareholders of record as of March 21, 2005, is set forth below:

Quarter Ended	High	Low
December 31, 2006	$ 40.85	$ 33.43
September 30, 2006	43.92	34.77
June 30, 2006	45.59	34.38
March 31, 2006	44.69	34.70
December 31, 2005	$ 41.14	$ 30.52
September 30, 2005	37.80	28.89
June 30, 2005	30.45	21.46
March 31, 2005	26.73	19.45

PERFORMANCE GRAPH

The following performance graph compares the cumulative total stockholder return on St. Mary's common stock for the period December 31, 2001 to December 31, 2006 with the cumulative total return of the Dow Jones U.S. Exploration and Production Broad Index, and the Standard & Poor's 500 Stock Index.

COMPARE 5-YEAR CUMULATIVE TOTAL RETURN
AMONG ST. MARY LAND & EXPLORATION COMPANY



The preceding information under the caption “Performance Graph” shall be deemed to be “furnished” but not “filed” with the Securities and Exchange Commission.

Holders. As of February 16, 2007, the number of record holders of St. Mary’s common stock was 122. Based on inquiry, management believes that the number of beneficial owners of our common stock is approximately 7,300.

Dividends. St. Mary has paid cash dividends to stockholders every year since 1940. Semi-annual dividends of $0.025 per share were paid in each of the years 1998 through 2004. Semi-annual dividends of $0.05 per share were paid in 2005 and 2006. We expect that our practice of paying dividends on our common stock will continue, although the payment of future dividends will continue to depend on our earnings, capital requirements, financial condition, and other factors. In addition, the payment of dividends is subject to covenants in our credit facility, including the requirement that we maintain certain levels of stockholders’ equity and the limitation of our annual dividend rate to no more than $0.25 per share per year. Dividends are currently paid on a semi-annual basis. Dividends paid totaled $5.6 million in 2006 and $5.7 million in 2005.

Restricted Shares. Aside from Rule 144 restrictions on shares for insiders, shares subject to transfer restrictions under the provisions of the Employee Stock Purchase Plan, restricted shares issued to directors under the Non-Employee Director Stock Compensation Plan, and restricted shares issued to directors under the 2006 Equity Incentive Compensation Plan (the “2006 Equity Plan”), St. Mary has no restricted shares outstanding as of December 31, 2006.

Issuer Purchases of Equity Securities. St. Mary did not repurchase any shares of its common stock during the fourth quarter of 2006.

Equity Compensation Plans. St. Mary has the 2006 Equity Plan under which options and shares of St. Mary common stock are authorized for grant or issuance as compensation to eligible employees, consultants, and members of the Board of Directors. Our stockholders have approved this plan. See Note 7—Compensation Plans in the Notes to Consolidated Financial Statements included in Part IV, Item 15 of this report for further information about the material terms of these plans. The following table is a summary of the shares of common stock authorized for issuance under our equity compensation plans as of December 31, 2006:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
2006 Equity Incentive Compensation Plan			
Stock Options and Incentive Stock Options	3,121,602	$ 12.56	—(1)
Restricted Stock Plan	1,061,226	N/A	2,699,468(1)
Employee Stock Purchase Plan	—	—	1,629,345(2)
Equity compensation plans not approved by security holders	—	—	—
Total	4,182,828	$ 12.56	4,328,813

(1) In May 2006 the stockholders approved 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 immediately 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.

(2) 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 their 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.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth supplemental selected financial and operating data for St. Mary as of the dates and for the periods indicated. The financial data for each of the five years presented were derived from the consolidated financial statements of St. Mary. The following data should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations," which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with St. Mary's consolidated financial statements included in this report.

	Years Ended December 31,				
	2006	2005	2004	2003	2002
	(In thousands, except per share data)				
Total operating revenues	$ 787,701	$ 739,590	$ 433,099	$ 393,708	$ 196,305
Income before cumulative effect of change in accounting principle	$ 190,015	$ 151,936	$ 92,479	$ 90,140	$ 27,560
Net income per share:					
Basic	$ 3.38	$ 2.67	$ 1.60	$ 1.53	$ 0.49
Diluted	$ 2.94	$ 2.33	$ 1.44	$ 1.40	$ 0.49
Total assets at year end	$ 1,899,097	$ 1,268,747	$ 945,460	$ 735,854	$ 537,139
Long-term obligations:					
Line of credit	$ 334,000	$ —	$ 37,000	$ 11,000	$ 14,000
Convertible Notes	$ 99,980	$ 99,885	$ 99,791	$ 99,696	$ 99,601
Cash dividends declared and paid per common share	$ 0.10	$ 0.10	$ 0.05	$ 0.05	$ 0.05

Supplemental Selected Financial and Operational Data:

	Years Ended December 31,				
	2006	2005	2004	2003	2002
	(In thousands, except per volume data)				
Balance Sheet Data:					
Total working capital	$ 22,870	$ 4,937	$ 12,035	$ 3,101	$ 2,050
Total stockholders' equity	$ 743,374	$ 569,320	$ 484,455	$ 390,653	$ 299,513
Weighted-average shares outstanding:					
Basic	56,291	56,907	57,702	62,467	55,713
Diluted	65,962	66,894	66,894	71,069	56,782
Reserves:					
Oil (Bbls)	74,195	62,903	56,574	47,787	36,119
Gas (Mcf)	482,475	417,075	319,196	307,024	274,172
MCFE	927,647	794,493	658,638	593,744	490,887
Production and Operational:					
Oil and gas production revenues, including hedging	$ 758,913	$ 711,005	$ 413,318	$ 365,114	$ 185,670
Oil and gas production expenses	$ 176,590	$ 142,873	$ 95,518	$ 88,509	$ 50,839
DD&A	$ 154,522	$ 132,758	$ 92,223	$ 81,960	$ 54,432
General and administrative	$ 38,873	$ 32,756	$ 22,004	$ 21,197	$ 13,683
Production Volumes:					
Oil (Bbls)	6,057	5,927	4,799	4,541	2,815
Gas (Mcf)	56,448	51,801	46,598	49,663	38,164
MCFE	92,788	87,363	75,393	76,909	55,055
Realized Price—pre hedging:					
Per Bbl	$ 59.33	$ 53.18	$ 39.77	$ 29.40	$ 24.67
Per Mcf	$ 6.58	$ 8.08	$ 5.85	$ 5.12	$ 3.10
Realized Price—net of hedging:					
Per Bbl	$ 56.60	$ 50.93	$ 32.53	$ 26.96	$ 25.34
Per Mcf	$ 7.37	$ 7.90	$ 5.52	$ 4.89	$ 3.00
Expense per MCFE:					
LOE	$ 1.25	$ 0.99	$ 0.81	$ 0.77	$ 0.66
Transportation	$ 0.12	$ 0.09	$ 0.10	$ 0.09	$ 0.06
Production taxes	$ 0.54	$ 0.56	$ 0.36	$ 0.29	$ 0.20
DD&A	$ 1.67	$ 1.52	$ 1.22	$ 1.07	$ 0.99
General and administrative	$ 0.42	$ 0.37	$ 0.29	$ 0.28	$ 0.25
Cash Flow:					
From operations	$ 467,700	$ 409,379	$ 237,162	$ 204,319	$ 141,709
Used in investing	$ (724,719)	$ (339,779)	$ (247,006)	$ (196,939)	$ (180,931)
From (used in) financing	$ 243,558	$ (61,093)	$ 1,435	$ (3,707)	$ 46,260

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This discussion includes forward-looking statements. Please refer to “Cautionary Information about Forward-Looking Statements” in Part I, Item 1 of this Form 10-K for important information about 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. We earn 93 percent of our revenues and generate our cash flows from operations primarily from the sale of produced natural gas and crude oil. Our oil and gas reserves and operations are concentrated primarily in various Rocky Mountain Basins, including the Williston, Big Horn, Wind River, Powder River and Greater Green River Basins; the Mid-Continent Anadarko and Arkoma Basins; the Permian Basin; the tight sandstone reservoirs of East Texas, South Texas, and North Louisiana; and the onshore Gulf Coast and offshore Gulf of Mexico. We have developed a balanced portfolio of proved reserves, development drilling opportunities, and non-conventional gas prospects.

As of December 31, 2006, we had estimated proved reserves of 74.2 MMBbls of oil and 482.5 Bcf of natural gas, or 927.6 BCFE with a PV-10 value of $2.2 billion. The after income tax value of $1.6 billion is represented by the standardized measure calculation as presented in Note 12 of Part IV, Item 15 of this report. Our reserves were 78 percent proved developed and 52 percent natural gas. The $2.2 billion PV-10 value for proved reserves is a 13 percent decrease over the prior year. While proved reserves increased 17 percent, adjusted natural gas reserve pricing declined 44 percent year-over-year to $5.64 per MMBtu which had a significant impact on the PV-10 value. Adjusted crude oil reserve pricing at $61.05 per barrel was essentially flat compared to 2005. We added 99.2 BCFE of proved reserves through acquisitions this year, 49 percent of which were proved developed and 72 percent of which were oil. The significant decrease in natural gas prices experienced in 2006 resulted in a downward price revision of 52.2 BCFE. This decline in reserves attributed to downward price revisions was offset by a 66.3 BCFE upward revision for performance. Total production of oil and natural gas increased by six percent in 2006 to 92.8 BCFE. Approximately 61 percent of our 2006 production volumes were derived from sales of natural gas.

Senior Management Transition

During 2006, we underwent or announced personnel changes in the chief operating officer and chief executive officer roles. Doug York, our previous Chief Operating Officer, left us in early 2006 to pursue other professional interests. Mark Hellerstein, our long-serving President and Chief Executive Officer announced in mid-2006 his intention to retire from day-to-day management once a successor could be found. Tony Best, an executive with 28 years of experience in the oil and gas industry, joined us in June 2006 as President and Chief Operating Officer. Mr. Hellerstein and Mr. Best worked together through the second half of 2006 to develop a succession plan whereby Mr. Best would succeed Mr. Hellerstein as chief executive officer in February 2007. Mr. Hellerstein will continue to serve as the Chairman of the Board. With Mr. Best taking over the role of CEO, we hired Jay Ottoson in December 2006 as Executive Vice President and Chief Operating Officer. Mr. Ottoson has 22 years of operational and management experience in the oil and gas industry.

2006 Acquisition of Permian Oil and Natural Gas Assets

On December 14, 2006 we closed on the acquisition of oil and gas properties in the Sweetie Peck Field in West Texas for $247.6 million. This purchase price will be subject to regular and customary post-closing

adjustments for capital, revenues and expenses between the effective and closing dates. The transaction was the largest acquisition in our history. The properties acquired are located in the Midland Basin within the Permian Basin and target the producing formations of the Spraberry interval, which include the Spraberry, Leonard, and Wolfcamp formations. Proved reserves from the acquisition were 78.0 BCFE, 78 percent of which was oil. We acquired 73 producing wells and significant proved undeveloped and unproved potential. Approximately 60 percent of the value was attributable to proved developed producing reserves. The gross daily production rate from this field at the time of acquisition and through the end of 2006 averaged 22.2 MMCFE as of December 31, 2006. We hedged the first five years of oil production related to the transaction using swaps with annual average prices ranging between $65.15 and $68.04 per barrel. The residual natural gas production was hedged over a five year period at a weighted-average equivalent price of roughly $7.70 per MMBtu. We also hedged three years of natural gas liquids production.

This transaction adds low risk properties to our portfolio and significantly increases our presence in the region. The properties are all operated by St. Mary with either a 95 or 100 percent working interest ownership. The acquisition also adds an attractive multi-year drilling program to our inventory. We assumed operations on February 1, 2007, and are currently running two drilling rigs in the field. Our plan is to increase the number of rigs running in the field to four by year end. We are beginning to see an increased availability of drilling rigs, in sharp contrast from the previous two years. The most recent rig utilization report as published by Baker Hughes shows flat to declining utilization in all regions of the lower 48 states with the exception of the Rockies area. This trend is viewed as very favorable to the exploration and production segment of the industry. It would seem that a natural extension of the increased rig availability would be a decreasing contract rate on drilling rigs. However, we have not experienced any significant decreases at the current time.

Reserve Replacement and Growth

Like all oil and gas exploration and production companies, we face the challenge of natural production declines of oil and natural gas resources. An oil and gas exploration and production company depletes part of its asset base with each unit of oil and gas it produces. Historically, we have been able to grow our production despite this natural decline by adding more reserves through acquisitions and drilling activities than we produce. Future growth will depend on our ability to economically continue adding reserves in excess of production.

We believe growth in net asset value per share drives appreciation in our stock price over the long term. Our challenge is to grow net asset value per share. To accomplish this, our goal is to replace at least 200 percent of annual production with new reserves and grow production by ten to 15 percent per year. In 2006, we replaced 244 percent of our production at an all-in finding cost of $3.56 per MCFE. Reserve replacement percentage and finding cost are defined in the glossary at the end of Part I, Item 1 of this report. Excluding acquisitions, we replaced 140 percent of our production at a cost of $4.02 per MCFE. Through acquisition activities, net of divestitures, we replaced 104 percent of production at an acquisition cost of $2.94 per MCFE. We sold reserves representing three percent of our proved reserves at the beginning of the year. We believe annual reserve replacement and finding cost amounts are important analytical measures that are widely used by investors and industry peers in evaluating the performance of oil and gas companies. While single year measurements have some meaning in terms of a trend, we believe that evaluating these items over an extended period of time is a better indication of performance. We note that aberrations, causing both relatively good and bad results, will occur over short intervals of time. Our three-year average reserve replacement percentage is 231 percent and our three-year average finding cost is $2.61 per MCFE. Our all-in finding cost was notably higher in 2006 than in 2005 due to several factors. First, we experienced a downward price revision related to a significant pullback in natural gas prices at the end of 2006. Excluding this price revision, our reserve replacement percentage would have been 300

percent with a finding cost of $2.88 per MCFE. Second, we continued to see price inflation in the drilling and service sector throughout most of the year. Third, several of our drilling programs were not as productive as we had expected for the amount of capital deployed. For example, the Bakken program in the Williston Basin has been a highly successful program over the last several years. However this year’s results were more marginal and not as productive as wells drilled earlier in the program as we were testing wells closer to the fringe of the play. At the Centrahoma Field in the Arkoma Basin, our first four horizontal Woodford shale wells were moderately economic. Realistically, we believe that there is a capital intensive learning phase at the beginning of every resource play and that we will accrue benefits on future wells in this program as a result of the work performed this year. We are not satisfied with our results in 2006 despite meeting several important internal metrics. We believe we have a program that is somewhat lower in risk and the expectations are that the costs to replace production will be lower in 2007.

Sustainability in our business is dependent on the ability to create new ideas and new value year-after-year. The challenges we face are increasingly more difficult each year as North American oil and gas production continues to decline and other exploration and production companies compete for available reserves. We believe we have a formula for meeting these challenges. We have placed talented geoscientists, engineers, and landmen in each of our regional offices where their experience and knowledge of the local area can be fully utilized. We provide a compensation package that aligns their goals with those of the Company. We support our personnel with a strong balance sheet and fiscal and operating discipline. Even so, we are subject to similar constraints as other companies in the exploration and production industry. Limitations to future growth will be based on overall availability of additional qualified personnel, the availability of drilling rigs to grow our drilling programs, and the generation of new ideas and the utilization of appropriate technology to improve the economics of our operations. We believe that we have sufficient capital resources, that we have the ability to grow our workforce, and that we have the necessary access to drilling rigs in order to execute our $721 million drilling budget for 2007 in a successful and profitable manner.

Oil and Gas Prices

Results of our operations and financial condition are significantly affected by oil and natural gas commodity prices, which fluctuate dramatically. In contrast to 2005 where oil and gas producers benefited from surging commodity prices, 2006 was more challenging as we saw significant volatility in crude oil prices and experienced a severe decline in natural gas prices. Oil price fluctuations are more closely related to global events as opposed to domestic events, although the inability to increase supply domestically continues to be a factor. The global conditions that affect the price of oil include a continuing increase in demand from the global economy, political instability in the Middle East, and a decrease in excess worldwide production capacity. Oil prices reached an all time high in mid-2006 as conflict erupted on the border between Israel and Lebanon and threatened to engulf multiple countries in the region. Tensions eventually cooled and crude oil prices retreated throughout most of the rest of the year, despite OPEC's announcement in late 2006 of its intentions to reduce production quotas. The decrease in natural gas prices reflects the return to production of assets impacted by Hurricanes Katrina and Rita in late 2005 as well as the lack of any disruptive hurricane activity in the Gulf of Mexico during the 2006 hurricane season. Mild weather in the 2005/2006 heating season left natural gas storage at high levels for most of the year, which further pressured natural gas prices downward.

Repurchase of Common Stock.

In the second quarter of 2006 we repurchased 3,319,300 shares of our common stock in the open market at a weighted-average price of $37.09 per share, including commissions. In conjunction with the share repurchases that occurred in the second quarter, we also hedged production volumes proportionate to the percentage of outstanding stock that was repurchased. These shares were purchased under a share

repurchase program approved by the Board. We routinely evaluate the market price of our common stock relative to our assessment of net asset value per share. To the extent that the market price per share is below what we believe to be the net asset value per share, we will repurchase shares under the program.

In the third quarter of 2006 the Board authorized an increase to the number of shares available for repurchase to a total of 6,000,000 shares to reload the program for repurchases that occurred in prior years. As of the end of the year we had 6,000,000 shares authorized for repurchase.

Hedging Activities

We have an active hedging program in which we hedge the first two to five years of an acquisition's risked production. We will also on occasion enter into derivative transactions to hedge a portion of our existing forecasted production. In October 2005, we hedged a significant portion of anticipated future production from our current producing properties using zero-cost collars. We also hedged a portion of specific forecasted natural gas production for 2006, 2007, and 2008 using swap contracts. Taking into account all oil and gas production hedge contracts in place through February 16, 2007, we have hedged anticipated future production of approximately 15 million Bbls of oil, 83 million MMBtu of natural gas, and 40 million gallons of natural gas liquids through the year 2011. We believe we have established an economic base for our future operations, and the spread between the price floors and ceilings on our collars allows us to continue to participate in a higher oil and gas price environment. Please see Note 10 of Part IV, Item 15 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 distributions from the Net Profits Plan have been expensed as compensation costs in the amount of $26.1 million, $20.8 million, and $8.0 million for the years ended December 31, 2006, 2005, and 2004, respectively. The 2006 payments are lower than originally budgeted due primarily to the unanticipated decrease in natural gas prices in 2006. The actual cash payments we make are dependent on actual production, realized prices, and operating and capital costs associated with the properties in each individual pool. Actual cash payments will be inherently different from the estimated liability amounts.

With respect to the accounting estimate of the liability associated with future estimated payments from our Net Profits Plan, we have recorded $23.8 million of net expense for the year ended December 31, 2006, thereby increasing the long term liability associated with this item. This increase is related to an increase in the estimated prices used to calculate the liability, the accretion of the discount used for the calculation, and the addition of the 2006 pool. While we have forecast that this liability will again increase in 2007, it is not possible to predict this with certainty due to the impact of commodity prices and reserve estimates on the valuation of this estimated liability.

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

percentage of forecasted hedged production in the relevant period. The calculation of the estimated liability for the Net Profits Plan is highly sensitive to our price estimates and discount rate assumptions. For example, if we changed the commodity prices in our calculation by five percent, the liability recorded on the balance sheet at December 31, 2006, would differ by approximately $14 million. A one percentage point change in the discount rate would result in a change to the liability of approximately $7 million. We frequently re-evaluate the assumptions used in our calculations and consider the possible impacts stemming from the current market environment including current and future oil and gas prices, discount rates, and overall market conditions.

2006 Highlights

In 2006, we experienced record production and earnings. Record production is the realization of operational and investment decisions made in prior years as well as the current period. Our record earnings reflect our balanced production profile and high oil prices throughout the year. Our hedging program contributed to our earnings as we received meaningful cash flows from the realization of in-the-money natural gas hedges. We anticipate production for 2007 to be greater than 2006 due to existing and planned wells from the Sweetie Peck Field, expanded drilling programs in most of our regions, and the strength with which we exited 2006. Our operating margins remained strong in 2006 despite being impacted by increasing operating costs and declining natural gas prices. Our 2006 operating margin was $6.28 per MCFE compared to $6.50 per MCFE in 2005.

We had $334.0 million outstanding on our credit facility as of December 31, 2006. The majority of this related to the $247.6 million Sweetie Peck acquisition which closed in late December 2006. Throughout the year, we also utilized our credit facility as needed to fund our exploration and development operations and to repurchase $123.1 million of our common stock.

Net income for 2006 was $190.0 million or $2.94 per diluted share compared to $151.9 million or $2.33 per diluted share for the prior year. Net cash provided by operating activities was $467.7 million, up 14 percent from 2005. Average daily production for the year increased 6 percent to 254.2 MMCFE. Our average net realized price increased $0.04 to $8.18 per MCFE. Unit costs increased for the period as lease operating and transportation expenses increased $0.29 to $1.37 per MCFE, production taxes decreased $0.02 to $0.54 per MCFE, DD&A increased $0.15 to $1.67 per MCFE and general and administrative expense increased $0.05 to $0.42 per MCFE. The significant increase in lease operating costs was a result of some overall increases in oil and gas operating costs, but the majority of this increase was driven by a high level of workover costs throughout the Company.

The table below provides information regarding selected production and financial information for the quarter ended December 31, 2006, and the immediately preceding three quarters. Additional details of per MCFE costs are contained later in this section.

	For the Three Months Ended			
	December 31, 2006	September 30, 2006	June 30, 2006	March 31, 2006
	(In millions)			
Production (BCFE)	25.1	23.2	22.6	22.0
Oil and gas production revenues, excluding the effects of hedging	$ 180.6	$ 188.2	$ 178.0	$ 184.1
Lease operating expense	$ 31.2	$ 30.1	$ 28.3	$ 26.3
Transportation costs	$ 3.0	$ 2.4	$ 2.7	$ 2.8
Production taxes	$ 12.9	$ 12.5	$ 12.2	$ 12.0
General and administrative expense	$ 7.9	$ 9.7	$ 10.4	$ 10.8
Net income	$ 43.5	$ 55.9	$ 40.1	$ 50.5
Percentage change from previous quarter:				
Production (MCFE)	8%	3%	3%	—%
Oil and gas production revenues, excluding the effects of hedging	(4)%	6%	(3)%	(21)%
Lease operating expense	4%	6%	8%	11%
Transportation costs	25%	(11)%	(4)%	8%
Production taxes	3%	2%	2%	(25)%
General and administrative expense	(19)%	(7)%	(4)%	14%
Net income	(22)%	39%	(21)%	(1)%

Outlook for 2007

We enter 2007 with the largest prospect inventory in our history. Our plan is to drill or participate in over 750 wells this year. Over the past several years we have felt the impact of escalating drilling and service costs. We enter 2007 believing that the worst of this drilling cost escalation is behind us. Drilling companies are feeling the effects of having a larger number of available drilling rigs combined with some indication of scaled back drilling activity in the face of declining natural gas prices. Our outlook for 2007 drilling costs is that they should remain somewhat flat and there may be room to reduce costs as more rigs come into the operating rig fleet. Service costs also appear to have leveled off in recent months. We are less optimistic about the prospect of reducing service costs this year, but we don’t believe that we will see the rapid escalation of costs that we have experienced in recent years. We expect geologic risk and the execution of operations will have an impact on our ability to deliver on our program.

Our 2007 capital budget was built on NYMEX prices of $7.00 per Mcf and $50.00 per barrel. Current strip prices for oil and natural gas support our plans for the year. However, we are keenly aware of how volatile oil and natural gas prices are and how quickly they can move. We will continue to evaluate the economics of each well prior to drilling using the most current commodity price and cost information available to ensure it meets our economic and operational thresholds. Our anticipated exploration and development budget is $721 million for 2007, which is 38 percent larger than the $522.6 million we spent in 2006. The key drivers of this increase in capital spending are the development program at the newly acquired Sweetie Peck Field in the Permian Basin, increased activity in the ArkLaTex region at Elm Grove, increased horizontal drilling in the James limestone, and an acceleration of the development program at Hanging Woman Basin. We plan to increase our operated rig count from 12 at the beginning of the year to 18 rigs by the end of the year. We have budgeted $100 million as a placeholder for acquisitions in 2007. Our solid financial condition gives us the ability to execute transactions significantly larger than

our budget for the year, but we also have the discipline to not pursue acquisitions when conditions do not meet our criteria. The information below provides some detail of our plans for 2007:

- We believe that we have the necessary capital, personnel, and rigs available to execute this program. The $721 million budgeted for drilling activities in 2007 is allocated among our core areas as described below. Included in the discussion are highlights of the program in each region this year.

  Rockies Conventional—$155 million—Our operated program in the Rockies this year is predominately focused on a re-entry program targeting the Mississippian formations in the Williston Basin, namely the Madison and Ratcliffe formations. Also planned in the northern Rockies are several Bakken and Red River wells. Non-operated activity in the northern Rockies is primarily focused on horizontal Bakken and Madison wells. The southern Rockies operated program is centered on continued development of our legacy oil projects in the Big Horn and Wind River basins. We also plan to drill wells in the Green River and Powder River basins. Our southern Rockies non-operated activity is dominated by our participation at Atlantic Rim.

  Rockies—Hanging Woman Basin Coalbed Methane—$58 million—We are planning on increasing our activity to drill or participate in 258 wells in 2007, up from 138 in 2006. The timing of the supplemental EIS covering federal acreage in Montana is uncertain, therefore we have not planned any activity in Montana for 2007. Our plans for 2007 are focused on development of the shallow and intermediate coals in Wyoming, with eight horizontal wells planned to further test the deeper Roberts and

Kendrick coals.

*Mid-Continent—$206 million—*This portion of the drilling budget is dominated by development of the Atoka/Granite Wash program in the Mayfield development area and the horizontal program targeting the Woodford shale formation in the Arkoma Basin. The Mayfield development program is one that is highly sensitive to natural gas prices. While we have hedged existing production equal to the amount of the anticipated production for the 2007 drilling program to protect our economic returns, we will continue to monitor the natural gas price and cost environment to ensure it makes sense to continue this program in the current year. In the horizontal Arkoma program, our activity is focused on the Woodford shale for 2007 as it is the deepest zone of interest and allows us to hold acreage to the deepest interval.

*ArkLaTex—$131 million—*Elm Grove is the dominant program in the ArkLaTex region for 2007. Our operating partners have not only escalated the level of activity, but are also moving south in the field into areas where we have higher working interests. While development of the traditional Lower Cotton Valley target continues to be successful, recompletions of the uphole Hosston formation are also proving to be highly economic. Eighty-seven grass root wells and 20 Hosston recompletions are planned for 2007. We will also be ramping up activity in our horizontal limestone program this year. We will operate the vast majority of this program which is primarily focused on the James and Glen Rose limestone formations.

*Permian—$111 million—*Activity in the Permian will focus on executing the drilling program at the newly acquired Sweetie Peck Field. We opened a regional office in Midland in February 2007 to assume operation of the field. Two rigs are currently running there, and we plan to increase to four rigs by year end. We also plan to continue infill and optimization projects at the East Shugart Delaware unit and Parkway Delaware unit waterflood projects.

*Gulf Coast— $60 million—*We will concentrate primarily on targets with direct hydrocarbon indicators along the Gulf Coast and on the Gulf of Mexico shelf. We also have three non-operated projects in the intermediate deep water that will require funding for continued participation.

· The $100 million budgeted for acquisitions could increase production in 2007, depending on the availability and timing of acquisition opportunities. We continuously evaluate opportunities in the

marketplace for oil and gas properties and, accordingly, may be a buyer or a seller of properties at various times. We will continue to emphasize smaller niche acquisitions within our existing core areas utilizing our technical expertise, financial flexibility, and transaction structuring experience. In addition, we may seek larger acquisitions of assets or companies that would afford opportunities to expand beyond our existing core areas. If this occurs, we will ensure that we have access to the necessary personnel possessing expertise in a new basin for such opportunities to be attractive to us.

A year-to-year overview of selected reserve, production and financial information, including trends:

	As of and for the Years Ended			Percent Change Between	
	2006	2005	2004	2006/2005	2005/2004
Selected Operations Data (In Thousands, Except Price, Volume, and Per MCFE Amounts):					
Total proved reserves (PV-10 basis)					
Oil (MBbl)	74,195	62,903	56,574		
Natural gas (MMcf)	482,475	417,075	319,196		
MMCFE	927,647	794,493	658,638	17%	21 %
Net production volumes					
Oil (MBbl)	6,057	5,927	4,799		
Natural gas (MMcf)	56,448	51,801	46,598		
MMCFE	92,788	87,363	75,393	6%	16 %
Average daily production					
Oil (MBbl)	17	16	13		
Natural gas (MMcf)	155	142	127		
MMCFE	254	239	206	6%	16 %
Oil & gas production revenues					
Oil production, including hedging	$ 342,810	$ 301,860	$ 156,112		
Gas production, including hedging	416,103	409,145	257,206		
Total	$ 758,913	$ 711,005	$ 413,318	7%	72 %
Oil & gas production costs					
Lease operating expenses	$ 115,896	$ 86,130	$ 61,269		
Transportation costs	10,999	8,010	7,235		
Production taxes	49,695	48,733	27,014		
Total	$ 176,590	$ 142,873	$ 95,518	24%	50 %
Average net realized sales price(1)					
Oil (per Bbl)	$ 56.60	$ 50.93	$ 32.53	11%	57 %
Natural gas (per Mcf)	$ 7.37	$ 7.90	$ 5.52	(7)%	43 %
Per MCFE data					
Average net realized price(1)	$ 8.18	$ 8.14	$ 5.48	—%	49 %
Lease operating expense	(1.25)	(0.99)	(0.81)	26%	22 %
Transportation costs	(0.12)	(0.09)	(0.10)	33%	(10)%
Production taxes	(0.54)	(0.56)	(0.36)	(4)%	56 %
General and administrative	(0.42)	(0.37)	(0.29)	14%	28 %
Operating profit	$ 5.85	$ 6.13	$ 3.92	(5)%	56 %
Depletion, depreciation and amortization	$ 1.67	$ 1.52	$ 1.22	10%	25 %
Financial Information (In Thousands, Except Per Share Amounts):					
Working capital	$ 22,870	$ 4,937	$ 12,035	363%	(59)%
Long-term debt	$ 433,980	$ 99,885	$ 136,791	334%	(27)%
Stockholders' equity	$ 743,374	$ 569, 320	$ 484,455	31%	18 %
Net income	$ 190,015	$ 151,936	$ 92,479	25%	64 %
Basic net income per common share	$ 3.38	$ 2.67	$ 1.60	27%	67 %
Diluted net income per common share	$ 2.94	$ 2.33	$ 1.44	26%	62 %
Basic weighted-average shares outstanding	56,291	56,907	57,702	(1)%	(1)%

Diluted weighted-average shares outstanding	65,961	66,894	66,894	(1)%	— %
Net cash provided by operating activities	$ 467,700	$ 409,379	$ 237,162	14%	73 %
Net cash used in investing activities	$ (724,719)	$ (339,779)	$ (247,006)	113%	38 %
Net cash provided by (used in) financing activities	$ 243,558	$ (61,093)	$ 1,435	499%	(4357)%

(1) Includes the effects of our hedging activities.

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

The increase in our proved reserves reflects our drilling results and acquisition activity. Please see Note 12 of Part IV, Item 15 for additional details. Over time, our ability to economically replace at least 200 percent of the total volumes produced annually has proven to be a key factor that determines whether we are successful in achieving our goal of increasing net asset value per share by 15 percent per year. We anticipate that we must continue our successful drilling program and average one or more relatively significant acquisitions per year in the current price environment to achieve this level of ongoing growth. The measure of our success will vary year-to-year due to changes in these factors.

Rapid changes in production volumes, oil and gas production revenues, and costs reflect the cyclical and highly volatile prices our industry receives for production, as well as the impact of the timing of acquisitions. The comparison of changes in production from 2005 to 2006 reflects the positive results from our drilling programs in 2006 and the full year impact of our acquisition made in the third quarter of 2005. Production volumes in 2006 were also affected by production from oil and gas properties acquired in 2006 and flush production from new drilling activity.

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. Our year-to-year comparison of financial results presented later provides additional details for the analysis of changes between years in selected line items. We expect oil and gas production expenses to increase in 2007 as a result of increased activity in our Permian region and a higher percentage of oil production. Depreciation, depletion, and amortization will continue to significantly increase due to higher costs associated with finding and acquiring crude oil and natural gas reserves. General and administrative expense is also projected to increase as a result of a new fully-staffed Midland, Texas office, the expected $35 million expense associated with payments under our Net Profits Plan, and overall upward pressure on compensation in the exploration and production industry.

We have in-the-money stock options, unvested restricted stock units, and convertible notes that are considered potentially dilutive securities. At times these dilutive securities can affect our earnings per share. Consequently both basic and diluted earnings per share are presented in the table above. A detailed explanation is presented in Note 1 of Part IV, Item 15 of this report. Basic and diluted weighted-average common shares outstanding used in our 2004 earnings per share calculations reflect a decrease in shares caused by the repurchase of our common stock from Flying J and the re-initiation of our stock repurchase program, offset by an increase in outstanding shares related to stock option exercises. Basic and diluted weighted-average shares outstanding in 2006 and 2005 were affected by similar factors as 2004. We issued 1,489,636 shares of common stock in 2006, 936,403 shares in 2005, and 1,399,052 shares in 2004 as a result of stock option exercises. These share issuances were offset by the repurchase of 3,319,300 shares of common stock in 2006, 1,175,282 shares in 2005, and 978,600 shares in 2004 through our stock repurchase plan.

The remaining information in the table relates to information we have provided in our operations update press releases and is intended to supplement the discussion above.

Overview of Liquidity and Capital Resources

We own depleting assets. In order to maintain our current size or to sustain our projected growth levels, we will have to effectively invest capital into new projects and acquisitions. The following analysis and discussion includes our assessments of market risk and possible effects of inflation and changing prices.

Sources of cash

Based on our current forecast, we expect that our 2007 capital spending under the drilling and acquisition program will exceed our cash flow generated from operations. Accordingly, we are expecting to access cash funding either through the expansion of our revolving credit facility, the issuance of long-term debt, the issuance of equity, or some combination of these. Although we are not contemplating any property sales, in the event there are property sales, we would likely use these proceeds to fund our capital programs.

Our primary sources of liquidity are the cash provided by operating activities, debt financing, sales of non-strategic 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 gas, although we are able to influence the amount of our net revenues related to oil and gas sales through the use of derivative contracts. A decrease in market prices would reduce expected cash flow from operating activities and could reduce the borrowing base of our credit facility as well as the value of non-strategic properties we might consider selling. Historically, decreases in market prices have limited our industry's access to the capital markets. The debt and equity financing capital markets are currently favorable to energy companies that operate in the exploration and production industry. This is a result of strong commodity prices and the general strength reflected in the balance sheets of the companies in this industry.

Our current credit facility. We have a five-year, $500 million credit facility agreement with Wachovia Bank, Wells Fargo Bank and nine other participating banks. This credit facility has a borrowing base of $900 million. We have elected a commitment amount of $500 million. We believe this commitment level is adequate for our near-term liquidity requirements. The credit agreement has a maturity date of April 7, 2010. We must comply with certain financial and non-financial covenants under our existing credit facility and we are in compliance with all covenants as of December 31, 2006, and February 16, 2007. As of February 16, 2007, we had $149 million of available borrowing capacity under this facility. Interest and commitment fees are accrued based on the borrowing base utilization percentage. Euro-dollar loans accrue interest at LIBOR plus the applicable margin from the utilization table located in Note 5 of Part IV, Item 15 of this report, and Alternate Base Rate loans accrue interest at prime plus the applicable margin from the utilization table. We have a single letter-of-credit outstanding under our facility in the amount of $1.1 million. This reduces the amount available under the commitment amount on a dollar-for-dollar basis. Borrowings under the new facility are secured by mortgages on the majority of our oil and gas properties and a pledge of the common stock of our material subsidiary companies.

Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the consolidated statements of operations. We had an outstanding loan balance of $334.0 million as of December 31, 2006. As of December 31, 2006, we had a cash and short-term investment balance of $2.9 million.

We increased our net borrowings from the previous year by $334.0 million. An increase in interest rates and an increase in the average outstanding credit facility balance, offset by an increase in the amount of interest capitalized, resulted in a slightly higher interest expense of $8.5 million in 2006 compared with $8.2 million in 2005. This increase in our net borrowings resulted in a $1.6 million increase in the amount of interest capitalized to $3.5 million in 2006 compared to $1.9 million in 2005. Our weighted-average interest rate paid in 2006 was 7.6 percent and included fees paid on the unused portion of the credit facility aggregate commitment amount, amortization of deferred financing costs, amortization of the contingent interest embedded derivative associated with the Senior Convertible Notes, and the effects of interest rate swaps. Given the higher level of debt outstanding, we are anticipating that the interest expense in 2007 will be approximately three times the 2006 amount.

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. During 2006 we spent $455.1 million on capital development, $270.6 million for property acquisitions and $123.1 million to acquire shares of our common stock using cash flows from operations. We also made cash payments for income taxes of $25.5 million. The current portion of our income tax expense was 29 percent of our total income tax expense. We expect to remain a highly taxable entity, although the percentage of our current income tax expense is expected to be closer to 15 percent of our total tax liability in 2007 as a result of our higher capital spending program.

Expenditures for exploration and development of oil and gas properties and acquisitions are the primary use of our capital resources. We anticipate spending approximately $721 million for capital and exploration expenditures in 2007 with an additional $100 million allocated for acquisitions of oil and gas properties. The capital expenditures budget is described in more detail earlier in the *Outlook for 2007* section. We regularly review our capital expenditure budget to assess changes in current and projected cash flows, acquisition opportunities, debt requirements, and other factors.

We recently announced that we are calling our $100 million Senior Convertible Notes. The date of redemption for the notes will be March 20, 2007. Given the conversion price of $13.00 per share for these notes, it is expected that we will issue 7,692,300 shares of common stock as the holders are anticipated to seek conversion. Accordingly, we are not planning that this event will create a cash outflow for us.

As of December 31, 2006, we have Board authorization to repurchase up to an additional six million shares of our common stock under our stock repurchase program. These shares may be repurchased from time to time in open market transactions or privately negotiated transactions and are subject to market conditions and other factors including certain provisions of our existing bank credit facility agreement and compliance with securities laws.

In connection with our two-for-one stock split in March 2005, we announced that the semi-annual dividend rate would remain at $0.05 per share. This effectively doubled our cash dividend payment on an annual basis. Our intention is to continue to make these dividend payments for the foreseeable future subject to our future earnings, our financial condition, possible credit facility covenants, and other currently unexpected factors which could arise. We paid $5.6 million for dividends in 2006 compared with $5.7 million in 2005 and $2.8 million in 2004.

The amount and allocation of future capital expenditures will depend upon a number of factors including the number and size of available economic acquisitions and drilling opportunities, our cash flows from operating and financing activities, and our ability to assimilate acquisitions we make. Also, the impact of oil and gas prices on investment opportunities, the availability of capital and borrowing facilities, and the success of our development and exploratory activities could lead to changes in funding requirements for future development.

The following table presents amounts and percentage changes between years in net cash flows from our operating, investing, and financing activities. The analysis following the table should be read in conjunction with our consolidated statements of cash flows in Part IV, Item 15 of this report.

	Amount of Change Between		Percent of Change Between	
	2006/2005	2005/2004	2006/2005	2005/2004
Net Cash Provided By Operating Activities	$ 58,321	$ 172,217	14%	73 %
Net Cash Used In Investing Activities	$ (384,940)	$ (92,773)	113%	38 %
Net Cash Provided By (Used In) Financing Activities	$ 304,651	$ (62,528)	499%	(4,357)%

Analysis of cash flow changes between 2006 and 2005

Operating activities. Cash received from oil and gas sales, net of the realized effects of hedging, increased $152.5 million to $802.1 million for the year ended December 31, 2006. Included in the oil and gas sales amount is $28.2 million of realized hedging gains. This increase was the result of a six percent increase in production offset by lower realized prices. Net cash payments made for income taxes decreased $40.2 million.

Investing activities. Total cash outflow for 2006 capital expenditures, as adjusted for accruals and including acquisitions of oil and gas properties, increased $380.9 million or 110 percent to $725.7 million. This increase reflects increased drilling expenditures and net cash paid for oil and gas properties acquired in the Sweetie Peck Field during 2006.

Financing activities. Net borrowings against our credit facility were $334.0 million for the year ended December 31, 2006, versus net payments of $37.0 million in 2005. We paid $123.1 million to acquire shares of our common stock under our stock repurchase program in 2006, compared to $28.9 million paid in 2005. We also received $6.5 million more from the exercise of stock options in 2006 compared to 2005, and we had a $16.1 million increase in income tax benefit resulting from the exercise of stock options in 2006 compared to 2005.

We had $1.5 million in cash and cash equivalents and had working capital of $22.9 million as of December 31, 2006, compared to $14.9 million in cash and cash equivalents and working capital of $4.9 million as of December 31, 2005.

Analysis of cash flow changes between 2005 and 2004

Operating activities. Cash received from oil and gas sales, net of the effects of hedging, increased $265.0 million to $649.6 million for the year ended December 31, 2005. This increase was the result of a 16 percent increase in production and a 49 percent increase in our net realized prices between the two periods. Changes in current assets and liabilities combined with cash expenditures for oil and gas production expenses, exploration expenses, and administrative expenses increased by $75.0 million between the two comparable periods, and net cash payments made for income taxes increased $51.0 million.

Investing activities. Total cash outflow for 2005 capital expenditures, as adjusted for accruals and including acquisitions of oil and gas properties, increased $76.6 million or 29 percent to $344.8 million. This increase reflects increased drilling expenditures and net cash paid for the acquisition of Agate Petroleum, Inc. and for oil and gas properties in Wyoming. The year ended December 31, 2004, reflects $21.4 million net cash received from short-term investments and from the expiration of the restriction period for funds held for tax-deferred exchange of oil and gas properties.

Financing activities. Net payments against our credit facility were $37.0 million for the year ended December 31, 2005, versus net borrowings of $26.0 million in 2004. We paid $28.9 million to acquire shares of our common stock under our stock repurchase program in 2005, compared to $16.3 million paid in 2004. In 2004 $19.4 million was paid to repurchase shares of our common stock and to settle the loan receivable from Flying J. We received $2.8 million less from the exercise of stock options in 2005 compared to 2004. As a result of our two-for-one stock split, cash paid for dividends was $5.7 million in 2005 compared to the $2.8 million paid in 2004.

We had $14.9 million in cash and cash equivalents and had working capital of $4.9 million as of December 31, 2005, compared to $6.4 million in cash and cash equivalents and working capital of $12.0 million as of December 31, 2004.

Capital Expenditures

The following table sets forth certain historical information regarding the costs incurred by us in our oil and gas activities. The below amounts include capitalized costs associated with asset retirement obligations.

	Years Ended December 31,		
	2006	2005	2004
		(In thousands)	
Development costs	$ 367,546	$ 249,518	$ 190,829
Exploration costs	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

The costs we incurred for capital and exploration activities in 2006 increased $384.0million or 91 percent compared to 2005. This increase was a result of planned increases in drilling activity and a $195.0 million increase in acquisitions mainly attributable to the acquisition of oil and gas properties located in the Sweetie Peck Field. We have experienced significant cost inflation over the past three years. These cost increases explain a portion of the increase year over year. However, we are beginning to see a flattening of drilling and service costs and expect to see this remain the case due to the recent softening in commodity prices.

Commodity Price Risk and Interest Rate Risk

We are exposed to market risk, including the effects of changes in oil and gas commodity prices and changes in interest rates as discussed below under the caption "*Summary of Interest Rate Hedges in Place.*" 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 Senior Convertible Notes, but do affect the fair market value.

Since we produce and sell natural gas and crude oil, our financial results are affected when prices for these commodities fluctuate.The following table reflects our estimate of the effect on cash flows from operations of a ten percent change in our average realized sales price for natural gas, for oil, and in combination for the years presented. These amounts have been reduced by the effective income tax rate applicable to each period since a reduction in revenue would reduce cash requirements to pay income taxes. General and administrative expenses have not been adjusted. To fund the capital expenditures we incurred in those years we would have been required to utilize different amounts under our credit facility as a source of funds. In each of these years we would have had sufficient borrowing base available under our credit facility to meet this contingency without reducing or eliminating expenditures and affecting our growth strategy.

Pro Forma effect on cash flow from operations of a ten percent change in average realized sales price:

	For the Years Ended December 31,		
	2006	2005	2004
		(In thousands)	
Oil	$ 20,496	$ 18,098	$ 9,180
Natural Gas	25,117	24,502	15,280
Total	$ 45,613	$ 42,600	$ 24,460

We enter into hedging transactions in order to reduce the impact of fluctuations in commodity prices. Note 10 of Part IV, Item 15 of this report contains important information about our oil and gas derivative contracts, and additional information is below under the caption *Summary of Oil and Gas Production Hedges in Place.* We do not anticipate significant changes in existing hedge contracts or derivative contract transactions.

Summary of Oil and Gas Production Hedges in Place

Our oil and natural gas derivative contracts include swap and collar arrangements. All contracts are entered into for other-than-trading purposes. Please refer to Note 10 —Derivative Financial Instruments in Part IV, Item 15 of this report for additional information regarding accounting for our derivative transactions.

Our net realized oil and gas prices are impacted by hedges we have placed on future forecasted production. 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 lock-in a significant portion of an equivalent amount of existing production to the prices we used to evaluate the risked economics of our acquisition. We also hedge a portion of our forecasted production on a discretionary basis. Including hedges entered into subsequent to year end, we have hedged approximately 15 million Bbls of oil, 83 million MMBtu of natural gas, and 40 million gallons of natural gas liquids of anticipated future production through 2011.

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

The following tables describe the volumes, average contract prices, and fair value of contracts we have in place as of December 31, 2006. Separate tables are provided for hedge contracts entered into after December 31, 2006. We seek to minimize basis risk and index the majority of our oil contracts to NYMEX prices and our gas contracts to various regional index prices associated with pipelines in proximity to our areas of gas production.

Oil Contracts

Oil Swaps

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at December 31, 2006 Asset/(Liability)
	(Bbl)	(per Bbl)	(in thousands)
First quarter 2007—			
NYMEX WTI	321,410	$ 58.34	$ (1,351)
IF Bow River	30,000	$ 37.42	(281)
Second quarter 2007—			
NYMEX WTI	340,072	$ 59.95	(1,568)
IF Bow River	34,000	$ 39.74	(332)
Third quarter 2007—			
NYMEX WTI	335,684	$ 60.55	(1,760)
IF Bow River	12,000	$ 39.86	(130)
Fourth quarter 2007—			
NYMEX WTI	331,620	$ 61.17	(1,789)
2008—			
NYMEX WTI	1,270,000	$ 67.88	485
2009—			
NYMEX WTI	1,335,000	$ 67.65	672
2010—			
NYMEX WTI	1,239,000	$ 66.47	116
2011—			
NYMEX WTI	1,032,000	$ 65.36	(340)
All oil swap contracts			$ (6,278)

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at December 31, 2006 Asset/(Liability)
	(Bbl)	(per Bbl)	(per Bbl)	(in thousands)
First quarter 2007	756,000	$ 51.60	$ 72.76	$ (43)
Second quarter 2007	736,000	$ 51.59	$ 72.77	(590)
Third quarter 2007	716,000	$ 51.58	$ 72.78	(1,129)
Fourth quarter 2007	689,000	$ 51.58	$ 72.81	(1,574)
2008	1,668,000	$ 50.00	$ 69.82	(7,071)
2009	1,526,000	$ 50.00	$ 67.31	(7,734)
2010	1,367,500	$ 50.00	$ 64.91	(7,800)
2011	1,236,000	$ 50.00	$ 63.70	(7,032)
All oil collars				$ (32,973)

Gas Contracts

Gas Swaps

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at December 31, 2006 Asset/(Liability)
	(MMBtu)	(per MMBtu)	(in thousands)
First quarter 2007—			
IF CIG	1,050,000	$ 8.13	$ 3,614
IF PEPL	960,000	$ 9.04	3,290
IF NGPL	900,000	$ 10.86	4,720
IF ANR OK	440,000	$ 11.05	2,380
IF EL PASO	180,000	$ 6.92	221
IF HSC	110,000	$ 9.43	376
Second quarter 2007—			
IF CIG	1,050,000	$ 6.88	1,960
IF PEPL	960,000	$ 7.63	1,678
IF NGPL	1,040,000	$ 7.82	1,998
IF ANR OK	420,000	$ 8.35	1,018
IF EL PASO	180,000	$ 6.60	129
IF HSC	120,000	$ 8.00	180
Third quarter 2007—			
IF CIG	870,000	$ 6.89	1,458
IF PEPL	960,000	$ 8.05	1,680
IF NGPL	1,220,000	$ 7.74	1,759
IF ANR OK	400,000	$ 8.39	823
IF EL PASO	190,000	$ 7.20	117
IF HSC	140,000	$ 8.37	204
Fourth quarter 2007—			
IF CIG	780,000	$ 7.56	1,416
IF PEPL	960,000	$ 8.69	1,797

IF NGPL	1,220,000	$ 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

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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

Natural Gas Liquid Swaps*

	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:

Oil and Gas Production Revenues:	Change Between Years 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;

- 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/A. 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/A. 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	/s/ DAVID W. HONEYFIELD
Mark A. Hellerstein	David W. Honeyfield
Chairman and CEO	Vice President—CFO, Secretary & Treasurer
February 22, 2007	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

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:

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
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/A.

** Furnished with this Form 10-K/A.

*** Previously filed.

† 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

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.

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.

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 (in thousands)	2004
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	2005	2004
	(In thousands)		
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	2005
	(In thousands)	
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%	³50%<75%	³75%<90%	³90%
Euro-dollar 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 Form 10-K/A reflects a change from the previously filed Form 10-K which showed 0.250%.

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.

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	Effect of Adopting SFAS No. 158	As Reported
		(In thousands)	
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	2005	2004
		(In thousands)	
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%

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 atDecember 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 operationsDerivative 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	2005	2004
		(In thousands)	
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
(Registrant)

Date: March 20, 2007

By: /s/ ANTHONY J. BEST
Anthony J. Best
President, Chief Executive Officer,
and Director

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
* Mark A. Hellerstein	Chairman of the Board of Directors	March 20, 2007
/s/ ANTHONY J. BEST Anthony J. Best	President, Chief Executive Officer, and Director	March 20, 2007
/s/ DAVID W. HONEYFIELD David W. Honeyfield	Senior Vice President-Chief Financial Officer, Secretary, and Treasurer	March 20, 2007
* Mark T. Solomon	Controller	March 20, 2007
* Barbara M. Baumann	Director	March 20, 2007
* Larry W. Bickle	Director	March 20, 2007
* Thomas E. Congdon	Director	March 20, 2007
* William J. Gardiner	Director	March 20, 2007
* Julio M. Quintana	Director	March 20, 2007
* William D. Sullivan	Director	March 20, 2007
* John M. Seidl	Director	March 20, 2007
*By: /s/ DAVID W. HONEYFIELD David W. Honeyfield (as attorney-in-fact for each of the persons indicated)		March 20, 2007

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Post-Effective Amendment No. 1 to Registration Statement Nos. 333-30055, 333-35352, 333-88780, and 333-106438 on Form S-8 and Registration Statement Nos. 033-61850, 333-58273 and 333-134221 on Form S-8 and Registration Statement No. 333-88712 on Form S-3 of our reports dated February 22, 2007 relating to the financial statements (which report expresses an unqualified opinion and includes an explanatory paragraph for the change in method of accounting and disclosure for stock-based compensation and defined benefit pension plans) of St. Mary Land & Exploration Company and management's report on the effectiveness of internal control over financial reporting appearing in the Annual Report on Form 10-K/A of St. Mary Land & Exploration Company for the year ended December 31, 2006.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
March 20, 2007

EXHIBIT 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K/A of St. Mary Land & Exploration Company for the year ended December 31, 2006. We hereby further consent to the use of information contained in our reports, as of December 31, 2006 setting forth the estimates of revenues from St. Mary Land & Exploration Company's oil and gas reserves. We further consent to the incorporation by reference thereof into St. Mary Land & Exploration Company's Post-Effective Amendment No. 1 to Registration Statement Nos. 333-30055, 333-35352, 333-88780, and 333-106438 on Form S-8 and Registration Statement Nos. 033-61850 and 333-58273 on Form S-8, and Registration Statement No. 333-88712 on Form S-3.

/s/ RYDER SCOTT COMPANY L.P.
RYDER SCOTT COMPANY, L.P.

Denver, CO
March 20, 2007

EXHIBIT 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K/A of St. Mary Land & Exploration Company for the year ended December 31, 2006. We hereby further consent to the use of information contained in our reports, as of December 31, 2006 setting forth the estimates of revenues from St. Mary Land & Exploration Company's oil and gas reserves. We further consent to the incorporation by reference thereof into St. Mary Land & Exploration Company's Post-Effective Amendment No. 1 to Registration Statement Nos. 333-30055, 333-35352, 333-88780, and 333-106438 on Form S-8 and Registration Statement Nos. 033-61850 and 333-58273 on Form S-8, and Registration Statement No. 333-88712 on Form S-3.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ C.H. (SCOTT) REES III
C.H. (Scott) Rees III
President and Chief Operating Officer

Dallas, Texas
March 20, 2007

EXHIBIT 31.1

CERTIFICATION

I, Anthony J. Best, certify that:

1. I have reviewed this annual report on Form 10-K/A of St. Mary Land & Exploration Company;

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

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

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

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

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

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

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

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

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

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

Date: March 20, 2007

/s/ ANTHONY J. BEST
Anthony J. Best
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, David W. Honeyfield, certify that:

1. I have reviewed this annual report on Form 10-K/A of St. Mary Land & Exploration Company;

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

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

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

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

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

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

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

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

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

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

Date: March 20, 2007

/s/ DAVID W. HONEYFIELD
David W. Honeyfield
Senior Vice-President—Chief Financial Officer, Secretary, and Treasurer

EXHIBIT 32.1

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

In connection with the Annual Report on Form 10-K/A of St. Mary Land & Exploration Company (the “Company”) for the fiscal year ended December 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Anthony J. Best, as President and Chief Executive Officer of the Company, and David W. Honeyfield, as Senior Vice President — Chief Financial Officer, Secretary, and Treasurer of the Company, each hereby certifies, pursuant to and solely for the purpose of 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to the best of his knowledge and belief, that:

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

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

/s/ ANTHONY J. BEST
Anthony J. Best
President and Chief Executive Officer
March 20, 2007

/s/ DAVID W. HONEYFIELD
David W. Honeyfield
Senior Vice President — Chief Financial Officer, Secretary, and Treasurer
March 20, 2007