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

FORM 10-K

☒ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2005

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 55,026,022 shares of voting stock held by non-affiliates of the registrant, based upon the closing sale price of the common stock on June 30, 2005, the last business day of the registrant's most recently completed second fiscal quarter, of $28.98 per share as reported on the New York Stock Exchange was $1,594,654,118. 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 15, 2006, the registrant had 56,953,893 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 2006 annual meeting of stockholders to be filed within 120 days after December 31, 2005.

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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 increase net asset value per share and earnings 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 consisting of the Williston Basin in eastern Montana and western North Dakota as well as basins in Wyoming. Recent activity in the northern Rockies includes drilling in the Middle Bakken formation, continued development in the Red River formation, and horizontal drilling prospects in the Mission Canyon and Ratcliffe formations. As a follow on to the acquisitions made in the last three years, the Company has increased its activity in Wyoming, with development of the Tensleep formation in the Big Horn Basin, development in the Wind River Basin and gas development in the Greater Green River Basin. Our development of coalbed methane reserves in the Hanging Woman Basin is included in our Rockies region;

- the Mid-Continent region in Oklahoma and northern Texas, primarily in the Anadarko and Arkoma basins. The most significant activity is in the Northeast Mayfield area in Beckham and Roger Mills counties and the Centrahoma area in Coal County where we are pursuing development of a horizontal well program in the Wapanucka limestone, Cromwell sandstone and Woodford shale formations;

- the ArkLaTex region spans northern Louisiana, southern Arkansas, Mississippi and eastern Texas. Recent activity includes the horizontal program in the James Lime formation at the Spider field. The ArkLaTex region is using its horizontal well expertise to expand into the limestones of the Glen Rose, James, Rodessa, and Pettet formations throughout the region. The ArkLaTex region manages our interest in a significant vertical well development effort at the Elm Grove field as well as our interest in the Cotten Valley interval at Terryville field;

- the Gulf Coast region consists of onshore Texas and Louisiana properties and includes the Judge Digby field in Pointe Coupee Parish, our fee property in St. Mary Parish, Louisiana, and a presence in the offshore Gulf of Mexico. The region is using 3-D seismic to identify direct hydrocarbon indicators along the Gulf Coast and in the Gulf of Mexico; and

- the Permian Basin in eastern New Mexico and western Texas, includes the waterflood projects at Parkway Delaware Unit and East Shugart Delaware Unit in New Mexico.

As of December 31, 2005, we had estimated proved reserves of 62.9 MMBbl of oil and 417.1 Bcf of natural gas, or a total of 794.5 BCFE with a PV-10 value of $2.5 billion. Of these reserves, 82 percent were proved developed and 53 percent were natural gas. This represents an increase in reserve volumes of 21 percent and a 66 percent increase in PV-10 value from a year earlier. For the year ended December 31, 2005, we produced 87.4 BCFE, representing average daily production of 239.4 MMCFE, a 16 percent increase from 2004. Our reserve replacement percentage in 2005 was 256 percent of production. This percentage would not change if sales of reserves were included in the calculation. The proved reserve total at December 31, 2005, includes 25.2 Bcf of natural gas reserves associated with our coalbed methane project at Hanging Woman Basin.

Our reserve replacement percentage, excluding acquisitions and sales, was 199 percent in 2005. This is a result of the overall strength of our drilling programs in the Bakken, at Northeast Mayfield and our participation in the Elm Grove field, as well as the exceptionally strong performance of our Paggi Broussard well in Jefferson County, Texas. The percentage of PUD reserves increased from 15 percent at the end of 2004 to 18 percent at December 31, 2005. This increase is directly related to the continuing development of our Atoka and Granite Wash program in the Northeast Mayfield area and the Centrahoma area in the Mid-Continent region as well as recognition of proved reserves in the ArkLaTex region at Elm Grove. We believe that the use of the term, “reserve replacement percentage” is widely understood and utilized by those who are involved in and those who make investment decisions related to the exploration and production industry. Therefore, this measure provides a useful basis of comparison to other companies and provides a measure of growth.

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 2005 we spent $319.3 million in capital expenditures related to drilling activities, $87.8 million on acquisition of oil and gas properties and $14.3 million on leasing activity.

Our total capital budget for 2006 is $600 million. As a company, we are placing a greater emphasis on growth through the drill bit rather than from acquisitions. This is evidenced by our reserve replacement from the drill bit, and the fact that our 2006 capital program contemplates $500 million of spending on drilling operations and $100 million on acquisitions. The increase in budgeted spending represents a 42 percent increase over 2005. This increase includes our estimate of drilling program inflation, but the majority relates to our activity level and prospect inventory. We have assembled a balanced program of low-to-medium-risk development and exploitation projects to provide the foundation for steady growth. We believe that the development of resource plays in the Bakken, Atoka and Granite Wash at Northeast Mayfield, the Wapanucka limestone, Cromwell sandstone, and Woodford shale at Centrahoma, the Cotton Valley and Hosston at Elm Grove, and coalbed methane in the Hanging Woman Basin help provide us with a core inventory of prospects for the future. We measure and rank our investment decisions based on their risk-adjusted estimated internal rate of return and return on investment. In 2005 all acquisitions were funded with cash flow generated from operations. Additionally, we were able to repay the $37 million of borrowings from our revolving credit facility that was outstanding at the beginning of the year. When we issue 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.

Although our acquisition budget is lower than in prior years on a percentage basis, we will continue to seek selective acquisitions of oil and gas properties that complement our existing operations, offer economies of scale and provide further development, exploitation and exploration opportunities based on proprietary geologic concepts. We will be focusing on areas where we have specialized geologic knowledge or operating experience to enable us to acquire attractively priced properties. In addition, we have and will pursue corporate acquisitions that we believe are accretive 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.

We divest selected non-core assets when market conditions and prices are attractive, and we will continue to evaluate such opportunities in the future as we believe it to be appropriate. During 2005 we sold properties with estimated proved reserves of 630 MMCFE, or less than one-tenth of one percent of our reserves as of the beginning of the year.

We seek to develop our existing property base and acquire acreage with additional potential in our core areas. From January 1, 2003 through December 31, 2005, we participated in the drilling or recompletion of 1,118 gross wells with a success rate of 89 percent. During the three-year period we added estimated proved reserves of 592.6 BCFE at an average finding cost of $1.64 per MCFE. These results represent a three-year average reserve replacement percentage of 247 percent, not including the effect of sales. Production has grown from an average daily rate of 210.7 MMCFE per day in 2003 to 239.4 MMCFE per day in 2005.

As of December 31, 2005, we had an acreage position of 2,106,884 gross (1,103,961 net) acres of which 1,178,845 gross (712,323 net) acres were undeveloped. 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 2004. In addition to the leased acreage position, we own 24,914 net acres of fee properties in St. Mary Parish, Louisiana, and mineral servitudes representing 14,663 gross (9,868 net) acres in other portions of Louisiana. We believe this 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 from 15 to 40 years of industry experience and lead fully-staffed regional technical offices that are supported by centralized administration from our Denver office. We use our comprehensive base of geological, geophysical, 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 reservoir stimulation techniques, horizontal drilling, secondary recovery and specialized logging tools to enhance the potential of our existing properties.

We believe it is important to control geologic and operational decisions as well as the timing of those decisions. As of December 31, 2005, we operated 67 percent of our properties on a reserve volume basis and 64 percent on a PV-10 value basis. We plan to operate approximately 73 percent of our 2006 exploration and development capital budget.

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 15 percent at the end of December 2005.

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

Significant Developments since December 31, 2004

- *2005 Acquisition of Oil and Gas Properties.* Our total acquisitions of proved and unproved oil and gas properties in 2005 were $87.8 million. The two most significant acquisitions were the Agate Petroleum, Inc. corporate acquisition that closed on January 5, 2005, for $40.0 million in cash and the Wold Oil Properties, Inc. property acquisition that closed on August 1, 2005, for $37.1 million in cash. Assets acquired from Agate Petroleum, Inc. are located in the Williston and Arkoma Basins and the properties acquired from Wold Oil Properties, Inc., are located primarily in the Wind River and Powder River Basins.

- *Coalbed Methane Development.* Our total proved reserves at Hanging Woman Basin at the end of 2005 grew to 25.2 Bcf. During 2005 we drilled 131 wells, 114 of which we operate, and our total production was 0.5 Bcf. The 2006 capital program for the Hanging Woman Basin development is currently budgeted at $50 million for approximately 260 wells. Environmental and regulatory permitting issues may impact the timing of drilling approximately 60 wells located in Montana and 60 wells located in Wyoming. The potential Montana delays are a result of the necessary regulatory approval of our water development plan on state and fee acreage. Delays in Wyoming permitting could result from the scheduling of drilling in areas that are affected by stipulations associated with sage grouse.

- *Increase in 2005 Year-End Reserves.* Proved reserves increased 21 percent to 794.5 BCFE at December 31, 2005, from 658.6 BCFE at December 31, 2004. We added 140.1 BCFE from our drilling program, 49.8 BCFE from acquisitions, and 33.9 BCFE from upward reserve revisions. Included in the revision number is 23.1 BCFE of upward revisions resulting from increases in oil and gas prices. We sold properties with reserves of less than one BCFE in 2005.

- *Drilling Results.* Reserve additions came principally from drilling results in the Rockies, Mid-Continent and ArkLaTex regions. The increase in the Rockies can be attributed primarily to continued development of the Middle Bakken play in Montana. The Red River formation continues to provide reserve additions in the Rockies as we take full advantage of 3-D seismic to identify multi-pay structures. Our Mid-Continent reserve additions were primarily from the continued development of the Northeast Mayfield area and the Centrahoma area. The Northeast Mayfield development has shifted to the Atoka and Granite Wash formations from the deeper Morrow sand that provided growth in earlier years. The Centrahoma play includes the start of a horizontal program in the Wapanucka limestone, Cromwell sandstone and Woodford shale formations. The ArkLaTex region grew from total proved reserves of 75.6 BCFE at the end of 2004 to 111.3 BCFE this year end. This growth is a reflection of the value we are deriving from the Elm Grove field development at Bossier Parish, 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 our acquisitions as well as a portion of existing production for our 2006 Northeast Mayfield development program using swap contracts.

- *Repurchase of Common Stock*. In 2005 we repurchased a total of 1,175,282 shares of our common stock at an average cost of $24.51 per share. These repurchases were funded from available cash. As of December 31, 2005, the number of additional shares that we may repurchase under the program is 3,846,118.

Major Customers

During 2005, sales to Tesoro Refining and Marketing accounted for 13 percent of our total oil and gas production revenue. During 2004 sales to Tesoro Refining and Marketing accounted for 20 percent of our total oil and gas production revenue. During 2003 sales to BP America Production Company accounted for 14 percent, sales to Midcoast Energy accounted for 13 percent and sales to Tesoro Refining and Marketing accounted for 11 percent of our total oil and gas production revenue.

Employees and Office Space

As of February 15, 2006, we had 305 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 also lease approximately 18,600 square feet of office space in Tulsa, Oklahoma; approximately 11,700 square feet in Shreveport, Louisiana; approximately 13,700 square feet in Houston, Texas; approximately 32,200 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 on properties. We have obtained title opinions or 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. In addition, pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. 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 mitigated 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 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 capital drilling budget for 2006. 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. From 1985 to the present, several major regulatory changes have been implemented by Congress and the Federal Energy Regulatory Commission that affect the economics of natural gas production, transportation and sales. In addition, the FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry that remain subject to the FERC’s jurisdiction, most notably interstate natural gas transmission companies. These initiatives may also affect the intrastate transportation of gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry.

The ultimate impact of the complex rules and regulations issued by the FERC since 1985 cannot be predicted. In addition, many aspects of these regulatory developments have not become final but are still pending judicial and final FERC decisions. Regulations implemented by the FERC in recent years could result in an increase in the cost of transportation service on certain petroleum product pipelines. In addition, some of the FERC's more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress and the courts. The natural gas industry historically has been very heavily regulated, and 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 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 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 and pooling of natural gas and oil properties and establishment of maximum rates of production from natural gas and oil wells. Some states prorate production to the market demand for oil and natural gas.

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, with a segment of the lands 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,” “intend,” “plan,” “will” and “project” 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;

- the risks of various exploration and hedging strategies;

- 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;

- drilling and operating service availability;

- uncertainties in cash flow;

- the financial strength of hedge contract counterparties;

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

- competition, litigation, environmental matters, and the potential impact of government regulations.

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. Through 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 material with, or furnish it 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

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 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 conditional 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, 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.

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

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

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.

MMBOE. One million barrels of oil equivalent.

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.

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 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 for production from 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.

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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.

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 oil price and production controls;

- pipeline, transportation, or refiner 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;
- the availability of transportation facilities;
- weather conditions; 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 and therefore 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 rapidly.

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 to evaluate and successfully bid for the properties that is not available to us. 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 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 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, 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, 2005, approximately 18 percent of our estimated proved reserves (by volume) were proved undeveloped. 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 $153 million in 2006. 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, 2005, were estimated using a calculated weighted-average sales price of $10.08 per Mcf of gas (Gulf Coast spot price) and $61.04 per Bbl of oil (NYMEX). We ensure that we consider basis and location differentials as of that date in estimating our reserves. During 2005 our monthly average realized gas prices, excluding the effect of hedging, were as high as $12.69 per Mcf and as low as $6.06 per Mcf. For the same period our monthly average realized oil prices were as high as $61.59 per Bbl and as low as $44.38 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 and natural gas purchasers; 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 deficiencies and potential 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. As a result of these factors, we may not be able to acquire oil and gas properties with economically recoverable reserves on acceptable terms.

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 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 and the delivery of equipment; 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 material 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 may 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 costs.

Our future drilling activities may not be successful, or 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; 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 encumber 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 writedown 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 producing new reserves and prices of 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, 2005, we had $100.0 million in outstanding long-term debt under our 5.75 % Senior Convertible Notes due 2022. Our long-term debt represented 15 percent of our total book capitalization as of December 31, 2005. Our credit facility has a maximum loan amount and current borrowing base of $500 million, with a current commitment amount we have elected of $200 million, against which no borrowings were outstanding as of December 31, 2005.

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, 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.

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.

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.

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 have 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 material adverse effect on us.

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.

Ownership of royalty interests by an executive officer may create conflicts of interest.

As a result of his employment with another company prior to 1995, with which St. Mary engaged in a number of transactions, Kevin E. Willson, an executive officer of St. Mary, owns royalty interests in a number of our properties, which were earned as part of the prior employer’s employee benefit programs. Accordingly, conflicts of interest may exist between Mr. Willson and us, and such conflicts may not always be resolved in our favor.

Risks Related to Our Common Stock

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

From January 1, 2004, to February 15, 2006, the last daily sale price of our common stock as reported by the New York Stock Exchange ranged from a low of $13.92 per share to a high of $44.23 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 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 15, 2006, we had 56,953,893 shares of common stock outstanding, net of 250,000 shares held in treasury. Of the net shares outstanding, 55,595,375 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 4,506,090 shares of our common stock were outstanding, of which 3,929,271 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 632,809 shares of our common stock were outstanding. 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 no more than $0.25 per share. The Board of Directors may determine in the future to reduce the current annual dividend rate of $0.10 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 five and ten percent of the outstanding shares of our common stock as of February 15, 2006. 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 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 Act of 1934.

ITEM 2. PROPERTIES

Operations

St. Mary's exploration, development and acquisition activities are focused in five core operating areas: the Rocky Mountain region; the Mid-Continent region; the ArkLaTex region; the Gulf Coast region; and the Permian Basin region. Our Hanging Woman Basin project is within our Rocky Mountain region and is managed by the personnel from our Billings office. Information concerning each of our major areas of operations is shown below in the summary of our estimated proved reserves as of December 31, 2005.

	Estimated Proved Reserves				PV-10 Value	
	Oil	Gas	MMCFE			
	(MBbl)	(MMcf)	Amount	Percent	(In thousands)	Percent
Rocky Mountain	52,870	85,492	402,712	50.7	$ 1,210,496	48.5
Hanging Woman Basin	-	25,219	25,219	3.1	65,638	2.6
Total Rocky Mountain	52,870	110,711	427,931	53.8	1,276,134	51.1
Mid-Continent	1,554	166,041	175,365	22.1	583,188	23.4
ArkLaTex	1,015	105,196	111,286	14.0	313,503	12.6
Gulf Coast	349	27,913	30,007	3.8	182,398	7.3
Permian Basin	7,115	7,214	49,904	6.3	138,946	5.6
Total	62,903	417,075	794,493	100.0	$ 2,494,169	100.0

***Rocky Mountain Region*.** Nance Petroleum Corporation, a wholly owned subsidiary of St. Mary, has conducted operations in the Williston Basin in eastern Montana and western North Dakota since 1991. Our office in Billings, Montana has a 95 full-time person staff. We have expanded this area into the Greater Green River, Powder River, Big Horn and Wind River basins of Wyoming over the past three years. The largest growth in the region came in late 2002 and early 2003 with significant property acquisitions from 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 $196.9 million in 2005 on exploration, development and acquisitions in the Rocky Mountain region, including Hanging Woman Basin, with $134.1 million of this directed towards drilling. The regional growth of reserves in 2005 was the most pronounced from the Bakken development in eastern Montana. Other organic growth has come from continued development of 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. The other significant drilling program is at our Hanging Woman Basin coalbed methane development in the northern Powder River Basin. In 2005, we spent $22.6 million drilling 131 wells and building infrastructure. Production from Hanging Woman Basin began in mid-December 2004, was 0.5 Bcf in 2005, and has exceeded our expectations. Because of potential permitting delays, 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.

Other recent transactions were the 2004 acquisition of Goldmark Engineering where we acquired a position in a mature oil field in the Big Horn Basin, and where we will focus on enhancement of wells that produce from the Tensleep formation. Our presence in Wyoming expanded in August 2005 when we acquired oil and gas properties in the Wind River, Powder River, and Greater Green River Basins for $37.1 million in cash. The allocation of the purchase price resulted in recording $43.9 million to proved and unproved oil and gas properties and a $7.0 million asset retirement obligation. This added approximately 32 BCFE of proved reserves as of the acquisition date.

Conventional oil and gas properties in the Rocky Mountain region accounted for 51 percent of our estimated proved reserves as of December 31, 2005, or 402.7 BCFE, 82 percent of which are proved developed and 79 percent of which are oil.

Our capital budget for the Rocky Mountain region now represents the largest portion of our drilling budget at approximately $191 million for 2006. This budget is distributed over several key programs, including approximately $50 million in the Hanging Woman Basin where we have approximately 260 wells planned for the year. A risk of development at Hanging Woman Basin for 2006 will be the ability to successfully obtain the necessary regulatory approval of our water development plan on state and fee acreage for approximately 60 wells in Montana. Additionally, we have another 60 wells in Wyoming that the timing of drilling could be affected by considerations relating to the mating season for sage grouse. There are approximately 30 wells planned in the Bakken formation with total capital of $47 million. We are initiating a horizontal drilling program focusing in the Ratcliffe and Mission Canyon formations with $24 million of the budget allocated for the drilling of approximately 26 wells. The planned development of the Tensleep formation results in approximately $9 million of the budget being allocated to the Fourbear, Murphy Dome and Big Sand Draw fields. The remainder is planned for our Red River program and development in the Greater Green River Basin.

On average we have a high working interest in our wells in the Rocky Mountain region. In 425 wells we have a working interest greater than 90 percent. Including the Hanging Woman Basin development, we will be the operator of properties representing approximately 84 percent of our 2006 Rocky Mountain region capital budget.

Our reserves in the Bakken are approximately 69 BCFE, representing nearly nine percent of our total reserve volumes and ten percent of our PV-10 value. The reserves in the Bakken are 83 percent oil. We have 92 wells predominately in Richland County, Montana and 70 wells concentrated in Mackenzie County, North Dakota. The Montana wells are produced from the Bakken dolomite while the North Dakota wells are mostly Bakken shale wells. The working interest in the Montana wells average 49 percent and the North Dakota ownership averages 61 percent.

Mid-Continent Region. St. Mary has been active in the Mid-Continent region since 1973. Operations for the region are managed by our 45 full-time person office in Tulsa, Oklahoma. 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 in horizontal drilling, hydraulic fracturing and innovative well completion techniques to accelerate production and associated cash flow from the region's tight gas reservoirs and developing plays. We are currently working to determine the best completion methods in our Wapanucka limestone, Cromwell sandstone and Woodford shale formations, commonly referred to as our Centrahoma area, located in Coal County, Oklahoma. We also attempt to benefit from the continuing consolidation of operators in the basin as we pursue attractive acquisition opportunities.

The Northeast Mayfield area is the largest concentration of our reserves and is located in Beckham County, Oklahoma on the western edge of the Anadarko Basin. This field represents 36.6 BCFE, or nearly five percent, of our total proved reserves and $110.0 million, or approximately four percent, of our total PV-10 value. Our average working interest in this field is 29 percent, and we have an interest in approximately 106 gross wells of which we operate 41 percent.

Other significant fields in the Mid-Continent region are the Centrahoma field in Coal County, Oklahoma and the Constitution field in Jefferson County, Texas. Centrahoma represents five percent of total proved reserves and $82.8 million, or three percent, of total PV-10 value. The Constitution field represents two percent of total proved reserves and $98.7 million of PV-10 value. We operate approximately 85 percent of the wells we have an interest in located in the Centrahoma area. We do not act as operator in the Constitution field. Other significant fields in the Mid-Continent region are the Elk City field and the Southwest Mayfield field, both in Beckham County, Oklahoma, representing a total of two percent of proved reserves and three percent of total PV-10 value. We operate 14 percent of the wells in Elk City and 45 percent of the wells in Southwest Mayfield and have an average working interest of approximately 15 and 42 percent, respectively.

We have ongoing exploration and development programs in the Anadarko and Arkoma basins, principally located in Oklahoma. The Mid-Continent region accounts for 22 percent of our estimated proved reserves as of December 31, 2005, or 175.4 BCFE, 79 percent of which are proved developed and 95 percent of which are natural gas. In 2005 our capital expenditures in the Mid-Continent were $135.6 million. We participated in drilling 91 gross wells in this region, 87 percent of which were completed as producers. We operated 28 of these drilling projects.

St. Mary's development and exploration budget in the Mid-Continent region for 2006 totals $172 million, an increase of $64 million over 2005. The 2006 budget includes $66 million of planned drilling expenditures associated with 46 budgeted Northeast Mayfield Atoka wells. Exploration efforts in 2004 and early 2005 have built a foundation for this viable multi-year play in the Atoka and Granite Wash formations at Northeast Mayfield. The other area of focus in the Mid-Continent Region is the Centrahoma area where we plan to spend $42 million on 19 wells developing the Wapanucka limestone, Cromwell sandstone and Woodford shale formations. We plan to be the operator of properties representing approximately 74 percent of our capital budget in this region during 2006 and to utilize seven drilling rigs that we will operate throughout the year.

We have allocated $21 million of our 2006 drilling budget to low-to-medium-risk development in the Red Fork, Osborne, Cottage Grove and Cleveland formations.

ArkLaTex Region. Our 21 full-time person office in Shreveport, Louisiana manages St. Mary’s operations in the ArkLaTex region. The ArkLaTex region accounts for 14 percent of our estimated proved reserves as of December 31, 2005, or 111.3 BCFE, 56 percent of which are proved developed and 95 percent of which are natural gas. Reserve growth in this region was derived primarily from recognition of the proved reserves from the Elm Grove field acquisition that we completed at the end of 2004. In 2006 we plan to spend $12 million on development at Elm Grove. This amount represents 41 percent of the total $66 million budget for the ArkLaTex region. The budget targets horizontal wells in the James, Glen Rose, Rodessa, and Pettet carbonate formations as well as vertical development in the Cotton Valley and Travis Peak formations at Terryville. Many of the Shreveport office’s successful exploration and development programs have derived from niche acquisitions. These acquisitions have provided access to strategic holdings of undeveloped acreage and proprietary packages of geologic and seismic data resulting in an active program of development and exploration.

Our holdings in the ArkLaTex region are comprised of interests in approximately 714 gross producing wells, including 139 wells we operated. We also hold interests in leases totaling approximately 157,000 gross acres and mineral servitudes totaling approximately 14,700 gross acres. Our capital expenditures in this region in 2005 were $44.0 million, including the effect of asset retirement obligations.

Our ownership at Elm Grove is six percent of our total proved reserves, representing $101.8 million of PV-10 value. We have an ownership interest in Elm Grove that is represented by 479 well locations, including PUD locations; with a working interest of up to 37 percent. Following our ownership in Elm Grove, the next most significant concentration of properties are the Spider and Box Church fields, which include a combined three percent or 24.1 BCFE of proved reserves and four percent of our total PV-10 value. We have working interests in 21 gross wells in Spider and 38 gross wells in Box Church, all of which we operate.

Gulf Coast Region. St. Mary’s presence in south Louisiana dates to the early 1900’s when our founders acquired a franchise property in St. Mary Parish on the shoreline of the Gulf of Mexico. These 24,914 acres of fee lands yielded $3.4 million of gross oil and gas royalty revenue in 2005. Our Gulf Coast region presence expanded as a result of the acquisition of King Ranch Energy, Inc. in 1999. Including the Louisiana fee lands, the Gulf Coast region accounts for four percent of our estimated proved reserves as of December 31, 2005, or 30.0 BCFE, 87 percent of which are proved developed and 93 percent of which are natural gas. Of this 30.0 BCFE, 72 percent is onshore and 28 percent is offshore in the Gulf of Mexico and coastal Texas and Louisiana. We spent $36.8 million, including the effect of asset retirement obligations, on capital expenditures in 2005.

Our 18 full-time person team based in Houston, Texas, manages St. Mary’s diverse activities in our Gulf Coast and Permian Basin regions. Our exploration and development budget in the Gulf Coast region for 2006 is $67 million, which consists of planned activity both onshore and offshore projects in Texas and Louisiana as well as low to moderate risk direct hydrocarbon indicators in state and federal waters of the Gulf of Mexico. We plan to operate approximately 42 percent of the 2006 forecasted drilling projects.

The most significant field in the Gulf Coast region is the Judge Digby Field, located outside Baton Rouge, Louisiana, in Point Coupee Parish. As of the end of December 2005, this field represented slightly less than three percent of our total PV-10 value, with 11.6 BCFE of proved reserves. Production from the Judge Digby field totaled 3.3 BCFE in 2005.

***Permian Basin Region*.** The Permian Basin area covers a significant portion of eastern New Mexico and western Texas and is one of the major producing basins in the United States. The basin includes hundreds of oil fields undergoing secondary and enhanced oil recovery projects. The use of 3-D seismic imaging of existing fields and advanced secondary recovery programs are substantially increasing oil recoveries. Our holdings in the Permian Basin resulted from a series of property acquisitions beginning in 1996. We believe that our Permian Basin operations provide us with a solid base of long-lived oil reserves and the potential for additional secondary recovery projects. In 2005, we spent $7.7 million on capital expenditures, including the effect of asset retirement obligations, in the Permian Basin region. This region accounted for 49.9 BCFE, or six percent of our proved reserves as of December 31, 2005. The PV-10 value associated with the Permian Basin was $139.0 million at year end. Our Permian reserves are 86 percent proved developed and 86 percent oil.

The Parkway Delaware waterflood project, located in Eddy County, New Mexico, represents 17.9 BCFE or two percent of our proved reserves. The East Shugart Delaware Unit is a pilot waterflood located in Lea and Eddy Counties, New Mexico, that is analogous to the Parkway Delaware Unit and is comprised of 17.5 BCFE of proved reserves. Production from the Permian Basin properties represented 2.9 BCFE or three percent of total production for the Company in 2005.

Our Permian Basin capital expenditures budget for 2006 is $4 million. We plan to drill three infill wells at Parkway Delaware during 2006.

Acquisitions and Divestitures

We spent a total of $87.8 million on acquisitions of proved and unproved oil and gas properties in 2005. The two most significant acquisitions, Agate Petroleum, Inc., and properties from Wold Oil Properties, Inc., accounted for $77.1 million. We also made several smaller acquisitions in 2005. We purchased a total of 49.8 BCFE of proved reserves in 2005.

Significant acquisitions prior to 2005 include the 2004 acquisitions of oil and gas properties from Goldmark Engineering, Inc., in the Rocky Mountain region and from Border Company in the ArkLaTex region. In January 2003 we acquired oil and gas properties in the Rocky Mountain region from Flying J Oil & Gas, Inc.

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, 2005. The table includes reserves prepared by independent petroleum engineering firms, Ryder Scott Company and Netherland, Sewell & Associates, Inc., and us. For the periods presented, Ryder Scott Company and Netherland, Sewell & Associates, Inc., evaluated properties representing a minimum of 80 percent of the total PV-10 value of our reserves. The proved oil and gas reserves prepared by Netherland Sewell in 2004 and 2005 consist of the coalbed methane development at Hanging Woman Basin as well as our non-operated interest at Atlantic Rim. 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:	2005	2004	2003
Oil (MBbl)	62,903	56,574	47,787
Gas (MMcf)	417,075	319,196	307,024
MMCFE	794,493	658,638	593,744
PV-10 value (in thousands)	$ 2,494,169	$ 1,501,123	$ 1,278,165
Standardized measure of discounted future net cash flows (in thousands)	$ 1,712,298	$ 1,033,938	$ 859,956
Proved developed reserves	82%	85%	89%
Reserve replacement - including sales	256%	186%	234%
Reserve replacement - excluding sales	256%	190%	293%
Reserve life (years) (1)	9.1	8.7	7.7

(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,		
	2005	2004	2003
Operating data:			
Net production:			
Oil (MBbl)	5,927	4,799	4,541
Gas (MMcf)	51,801	46,598	49,663
MMCFE	87,363	75,393	76,909
Average net daily production:			
Oil (Bbl)	16,238	13,113	12,441
Gas (Mcf)	141,922	127,316	136,062
MCFE	239,352	205,992	210,709
Average realized sales price, excluding the effects of hedging:			
Oil (per Bbl)	$ 53.18	$ 39.77	$ 29.40
Gas (per Mcf)	$ 8.08	$ 5.85	$ 5.12
Per MCFE	$ 8.40	$ 6.15	$ 5.04
Average realized sales price, including the effects of hedging:			
Oil (per Bbl)	$ 50.93	$ 32.53	$ 26.96
Gas (per Mcf)	$ 7.90	$ 5.52	$ 4.89
Per MCFE	$ 8.14	$ 5.48	$ 4.75
Production costs per MCFE:			
Lease operating expense	$ 0.99	$ 0.81	$ 0.77
Transportation expense	$ 0.09	$ 0.10	$ 0.09
Production taxes	$ 0.56	$ 0.36	$ 0.29

Productive Wells

As of December 31, 2005, we had working interests in 1,722 gross (843 net) productive oil wells and 2,750 gross (679 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,					
	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	83	38.09	50	18.08	36	14.88
Gas	379	152.69	180	53.23	140	43.79
Non-productive	29	9.12	36	14.29	37	15.98
	491	199.90	266	85.60	213	74.65
Exploratory:						
Oil	8	1.91	11	9.71	7	3.03
Gas	5	0.86	83	43.65	14	7.20
Non-productive	5	2.32	8	2.84	7	4.40
	18	5.09	102	56.20	28	14.63
Farmout or non-consent	18	-	5	-	10	-
Total (1)	527	204.99	373	141.80	251	89.28

(1) Does not include nine, seven, and 15 gross wells completed on St. Mary's fee lands during 2005, 2004 and 2003, 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, 2005. 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	3,365	420	207	68	3,572	488
Colorado	2,885	2,470	24,832	13,914	27,717	16,384
Louisiana	127,636	44,875	32,199	13,232	159,835	58,107
Mississippi	3,335	467	2,610	1,361	5,945	1,828
Montana	58,062	36,668	446,549	297,671	504,611	334,339
New Mexico	5,600	2,658	1,320	1,187	6,920	3,845
North Dakota	174,333	94,791	172,955	103,896	347,288	198,687
Oklahoma	281,996	81,336	44,270	26,338	326,266	107,674
Texas	128,265	34,429	48,417	24,689	176,682	59,118
Utah (3)	480	115	11,472	4,091	11,952	4,206
Wyoming	139,801	92,424	389,870	224,611	529,671	317,035
Other (4)	2,281	985	4,144	1,265	6,425	2,250
	928,039	391,638	1,178,845	712,323	2,106,884	1,103,961
Louisiana Fee Properties	9,944	9,944	14,970	14,970	24,914	24,914
Louisiana Mineral Servitudes	10,173	5,740	4,490	4,128	14,663	9,868
	20,117	15,684	19,460	19,098	39,577	34,782
Total	948,156	407,322	1,198,305	731,421	2,146,461	1,138,743

(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 40,100 gross acres in Utah.

(4) Includes interests in Alabama, Kansas, Nebraska, Nevada 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 material 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 2005.

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 ages of the executive officers are as of February 15, 2006.

Name	Age	Position
Mark A. Hellerstein	53	Chairman of the Board, President and Chief Executive Officer
Douglas W. York	44	Executive Vice President and Chief Operating Officer
Robert L. Nance	69	Senior Vice President and President and Chief Executive Officer of Nance Petroleum Corporation, a wholly-owned subsidiary of St. Mary
Jerry R. Schuyler	50	Senior Vice President and Regional Manager
Kevin E. Willson	49	Senior Vice President and Regional Manager
Robert T. Hanley	59	Vice President - Investor Relations and Management Reporting
David W. Honeyfield	39	Vice President - Chief Financial Officer, Treasurer and Secretary
Milam Randolph Pharo	53	Vice President - Land and Legal
Paul M. Veatch	39	Vice President - General Manager, ArkLaTex
Garry A. Wilkening	55	Vice President - Administration and Controller

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.

Douglas W. York was appointed Executive Vice President and Chief Operating Officer in September 2003. Mr. York served as Vice President - Acquisitions and Reservoir Engineering from 1996 to September 2003. On December 15, 2005, Mr. York notified St. Mary that it is his intention to resign from the offices of Executive Vice President and Chief Operating Officer during the first quarter of 2006.

Robert L. Nance was appointed Senior Vice President in March 2001.

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.

Kevin E. Willson was appointed Senior Vice President and Regional Manager in November 2003. Mr. Willson served as Vice President - Mid-Continent Exploration/Production from October 1998 to November 2003.

Robert T. Hanley was appointed Vice President - Investor Relations and Management Reporting in April 2003. Mr. Hanley served as Vice President - Business Development from July 2000 to April 2003.

David W. Honeyfield was appointed 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 and Controller and Chief Accounting Officer of Key Production Company, Inc., which was acquired by Cimarex in September 2002. Prior to joining Key Production Company in April 2002, Mr. Honeyfield was a senior audit manager with Arthur Andersen LLP in Denver.

Paul M. Veatch was determined by the Board of Directors to be an executive officer of the Company in February 2006. Mr. Veatch was appointed Vice President and General Manager of the ArkLaTex Region in September 2004. Mr. Veatch joined St. Mary in April 2001 and has served as Regional Acquisition Engineer & Manager of Engineering. Prior to joining St. Mary, Mr. Veatch had been with Burlington Resources in Denver, Colorado, and Midland, Texas.

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 choose to 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.

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, RELATED STOCKHOLDER 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 2005 and 2004, 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, 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
December 31, 2004	$ 21.50	$ 18.56
September 30, 2004	20.07	15.88
June 30, 2004	18.60	15.90
March 31, 2004	17.07	13.87

Holders. As of February 15, 2006, the number of record holders of St. Mary's common stock was 135. Management believes, after inquiry, that the number of beneficial owners of our common stock is in excess of 7,100.

Dividends. St. Mary has paid cash dividends to stockholders every year since 1940. Annual dividends of $0.05 per share were paid in each of the years 1998 through 2004. An annual dividend of $0.10 per share was paid in 2005. 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. Dividends are currently paid on a semi-annual basis. Dividends paid totaled $5.7 million in 2005 and $2.8 million in 2004.

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 and restricted shares issued under the Non-Employee Director Stock Compensation Plan, St. Mary has no restricted shares outstanding as of December 31, 2005.

Issuer Purchases of Equity Securities. St. Mary repurchased a total of 1,175,282 shares of its common stock during 2005.

Equity Compensation Plans. St. Mary has a stock option plan, a restricted stock plan, an incentive stock option plan, an employee stock purchase plan, and a non-employee director stock compensation 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 each of these plans. 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, 2005:

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)	
Stock Option Plan and Incentive Stock Option Plan	4,698,243	$ 12.21	-	(2)
Restricted Stock Plan	632,809	N/A	1,063,617	(2)
Employee Stock Purchase Plan	-	-	1,655,391	(1)
Non-Employee Director Stock Compensation Plan	-	N/A	20,874	
Equity compensation plans not approved by security holders	-	-	-	
Total	5,331,052	$ 12.21	2,739,882	

(1) 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.

(2) There is a common pool of shares available for the Stock Option, Incentive Stock Option, and Restricted Stock plans.

The following table provides information about purchases by the Company during the quarter and year ended December 31, 2005, of shares of the Company's common stock, which is the sole class of equity securities registered by the Company pursuant to Section 12 of the Exchange Act.

ISSUER PURCHASES OF EQUITY SECURITIES

	Total Number of Shares Purchased in 2005	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program[1]	Maximum Number of Shares that May Yet be Purchased Under the Program[1]
January 1, 2005 - March 31, 2005	-	$ -	-	5,021,400
April 1, 2005 - June 30, 2005	1,157,810	$ 24.48	1,157,810	3,863,590
July 1, 2005 - September 30, 2005	-	$ -	-	3,863,590
October 1, 2005 - October 31, 2005	17,472	$ 31.72	17,472	3,846,118
November 1, 2005 - November 30, 2005	-	$ -	-	3,846,118
December 1, 2005 - December 31, 2005	-	$ -	-	3,846,118
Total October 1, 2005 - December 31, 2005	17,472	$ 31.72	17,472	3,846,118
Total	1,175,282	$ 24.51	1,175,282	3,846,118

(1) In August 2004 the Company announced that its Board of Directors authorized the re-initiation of the Company's stock repurchase program and approved an increase in the number of shares that may be repurchased under the original authorization approved in August 1998 to 6,000,000 as of the effective date of the resolution and as adjusted for the March 2005 two-for-one stock split. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of St. Mary's existing bank credit facility agreement and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow and borrowings under St. Mary's bank credit facility. The stock repurchase program may be suspended or discontinued at any time.

The payment of dividends and repurchases of stock are subject to covenants in our bank credit facility, including the requirement that we maintain certain levels of stockholders' equity and we limit our annual dividend rate to no more than $0.25 per share.

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,				
	2005	2004	2003	2002	2001
	(In thousands, except per share data)				
Total operating revenues	$ 739,590	$ 433,099	$ 393,708	$ 196,305	$ 207,469
Income before cumulative effect of change in accounting principle	$ 151,936	$ 92,479	$ 90,140	$ 27,560	$ 40,459
Net income per share:					
Basic	$ 2.67	$ 1.60	$ 1.53	$ 0.49	$ 0.72
Diluted	$ 2.33	$ 1.44	$ 1.40	$ 0.49	$ 0.71
Total Assets at year end	$ 1,268,747	$ 945,460	$ 735,854	$ 537,139	$ 436,989
Long-term obligations:					
Line of credit	$ -	$ 37,000	$ 11,000	$ 14,000	$ 64,000
Convertible Notes	$ 99,885	$ 99,791	$ 99,696	$ 99,601	-
Cash dividends declared and paid per common share	$ 0.10	$ 0.05	$ 0.05	$ 0.05	$ 0.05

Supplemental Selected Financial and Operational Data:

	Years Ended December 31,				
	2005	2004	2003	2002	2001
	(In thousands, except per volume data)				
Balance Sheet Data:					
Total working capital	$ 4,937	$ 12,035	$ 3,101	$ 2,050	$ 34,000
Total stockholders' equity	$ 569,320	$ 484,455	$ 390,653	$ 299,513	$ 286,117
Weighted-average shares outstanding:					
Basic	56,907	57,702	62,467	55,713	55,946
Diluted	66,894	66,894	71,069	56,782	57,110
Reserves:					
Oil (Bbls)	62,903	56,574	47,787	36,119	23,669
Gas (Mcf)	417,075	319,196	307,024	274,172	241,231
MCFE	794,493	658,638	593,744	490,887	383,247
Production and Operational:					
Oil and gas production revenues, including hedging	$ 711,005	$ 413,318	$ 365,114	$ 185,670	$ 203,973
LOE and production taxes	$ 142,873	$ 95,518	$ 88,509	$ 50,839	$ 55,000
DD&A	$ 132,758	$ 92,223	$ 81,960	$ 54,432	$ 51,346
General and administrative	$ 32,756	$ 22,004	$ 21,197	$ 13,683	$ 11,762
Production Volumes:					
Oil (Bbls)	5,927	4,799	4,541	2,815	2,434
Gas (Mcf)	51,801	46,598	49,663	38,164	39,491
MCFE	87,363	75,393	76,909	55,055	54,093
Realized Price - pre hedging:					
Per Bbl	$ 53.18	$ 39.77	$ 29.40	$ 24.67	$ 24.08
Per Mcf	$ 8.08	$ 5.85	$ 5.12	$ 3.10	$ 4.22
Realized Price - net of hedging:					
Per Bbl	$ 50.93	$ 32.53	$ 26.96	$ 25.34	$ 23.29
Per Mcf	$ 7.90	$ 5.52	$ 4.89	$ 3.00	$ 3.73
Expense per MCFE:					
LOE	$ 0.99	$ 0.81	$ 0.77	$ 0.66	$ 0.75
Transportation	$ 0.09	$ 0.10	$ 0.09	$ 0.06	$ 0.04
Production taxes	$ 0.56	$ 0.36	$ 0.29	$ 0.20	$ 0.23
DD&A	$ 1.52	$ 1.22	$ 1.07	$ 0.99	$ 0.95
General and administrative	$ 0.37	$ 0.29	$ 0.28	$ 0.25	$ 0.22
Cash Flow:					
From operations	$ 409,379	$ 237,162	$ 204,319	$ 141,709	$ 127,492
For investing	$ (339,779)	$ (247,006)	$ (196,939)	$ (180,931)	$ (159,075)
From (for) financing	$ (61,093)	$ 1,435	$ (3,707)	$ 46,260	$ 29,080

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, acquisition and production of natural gas and crude oil in the United States. We earn greater than 95 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 and North Louisiana; and 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, 2005, we had estimated proved reserves of 794.5 BCFE, with PV-10 value of $2.5 billion. An after income tax value of $1.7 billion is represented by the standardized measure calculation in Note 12 of Part IV, Item 15 of this report. Our reserves are 82 percent proved developed and 53 percent natural gas. The $2.5 billion PV-10 value for proved reserves is a 66 percent increase over the prior year. This amount reflects a 21 percent increase in proved reserves, a 41 percent increase in the adjusted oil reserve pricing to $61.04 per Bbl, and a 63 percent increase in the adjusted gas reserve pricing to $10.08 per Mcf as used in the calculation. Total production of oil and natural gas increased in 2005 by 16 percent to 87.4 BCFE. Approximately 59 percent of our total production volumes are derived from sales of natural gas.

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 than we produce. Future growth will depend on our ability to continue to add reserves in excess of production.

We believe growth in net asset value per share drives appreciation in our stock price. Our challenge is to grow net asset value per share. Our goal is to replace 200 percent of annual production with new reserves and grow production by ten to 15 percent per year. Please see the additional discussion of oil and gas reserve quantities in our critical accounting policies and estimates section. In 2005 we replaced 256 percent of our reserves at a finding cost of $1.88 per MCFE. Finding cost and reserve replacement percentage are defined in the glossary at the end of Part I, Item 1 of this report. 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. You should note that aberrations, causing both relatively good and bad results, will occur over short intervals of time. Our three-year reserve replacement percentage, excluding sales, is 247 percent and our three-year average finding cost is $1.64 per MCFE. Our average finding cost was lower in 2005 than in 2004 despite an overall increase in the cost associated with drilling and an overall increase in the price of acquiring developed reserves. The relative finding cost decrease in 2005 as compared to 2004 was the result of a shift in activity in the Mid-Continent region from exploratory activities in the deeper Morrow and Springer formations of the Northeast Mayfield area to development of the shallower, lower-cost, Atoka and Granite Wash formations. Also, our finding cost per MCFE decreased because we recorded a relative increase in proved undeveloped reserves. Our overall percentage of PUD reserves increased from 15 percent at the end of 2004 to 18 percent at the end of 2005. Of the 47.2 BCFE increase in the PUD reserves, 37.8 BCFE came from the ArkLaTex region. We also saw an increase in PUD reserves of 21.1 BCFE in the Mid-Continent region related to the activity at Northeast Mayfield. PUD reserves decreased as a result of being converted to proved developed reserves or decreased because remaining PUD reserves were not supported by newly proven developed reserves. PUD reserves decreased 10.8 BCFE in the Permian region because of these factors. We expect future finding costs per MCFE to increase as the overall cost of drilling a well in our core areas has approximately doubled in the last three years. Finding costs are comparison measures used to evaluate the effectiveness of an oil and gas company's reserve replacement program and a snapshot in time of its expected future profitability.

Sustainability in our business is dependent on the ability to create new ideas and new value year after year. The challenges we face are becoming increasingly difficult 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 areas can be fully utilized. They are supported by 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 and the availability of drilling rigs to grow our drilling programs. We believe that we have sufficient staff levels and capital resources and that we will have appropriate access to drilling rigs to execute our $500 million drilling budget for 2006.

Stock Split

In March 2005 the Board of Directors approved a two-for-one stock split in the form of a stock dividend whereby one additional common share of 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 within this report have been restated to reflect this stock split.

Effects of Hurricanes Katrina and Rita

Certain properties in our Gulf Coast region were affected by Hurricanes Katrina and Rita. These two events did not have a material adverse effect on our financial position or results of operations. We did not sustain any direct damage from Hurricane Katrina, but we did sustain damage from Hurricane Rita. Approximately 1 BCFE of production was shut in during 2005 and our operated production platform at Vermilion Block 273 was sheared off its base. We believe our insurance coverage for property damage resulting from Hurricane Rita is sufficient to cover the property damage losses we incurred. Our 2005 results of operations include the cost of applicable insurance deductibles related to our insurance coverage. Approximately 41 MCFED of production remained shut in as of February 15, 2006. Restoration of the remaining shut-in production is largely dependent on repairs to transportation and processing facilities which are owned and operated by other operators and facility owners.

Potential revenue impacts caused by shut-in production from the hurricanes were offset by a sudden and significant increase in oil and gas prices caused by hurricane-related supply disruptions for both crude oil and natural gas. We benefited from higher commodity prices in all of our production areas during the month of September and October. The operations analysis later in this discussion reflects the result of higher prices for the year ended December 31, 2005.

Oil and Gas Prices

Results of our operations and financial condition are significantly affected by oil and natural gas commodity prices, which can fluctuate dramatically. In 2005, oil and gas producers benefited from high oil and gas commodity prices. Increased prices of natural gas were caused by numerous conditions. Finite storage capacity in North America, a limited import market and fluctuations in domestic demand created by weather have a significant effect on 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. News sources reported that the second and third largest producing fields in the world went on decline in 2005.

Hedging Activities

We have an active hedging program in which we hedge the first two to three years of an acquisition's equivalent production as well as a portion of our existing forecasted production on a discretionary basis. Beginning in October 2005, we hedged a significant portion of anticipated future production from our currently producing properties using zero-cost collars. These contracts supplement our previous swap and collar contracts. We also hedged a portion of specific forecasted natural gas production for 2006 and 2007 using swap contracts. Taking into account all oil and gas production hedge contracts in place through February 15, 2006, we have hedged approximately 13.0 million Bbls and 73.7 million MMBTU of our anticipated production through the year 2011. We believe we have established an economic base for our future operations, and the spread between the price floor and ceiling 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

Increases in oil and gas prices in the second half of 2005 resulted in a significant increase in the estimated future liability associated with our Net Profits Plan. The expense associated with the change in this estimated liability increased substantially in 2005. We recorded expense of $106.3 million for 2005 compared to $24.4 million for 2004 and $5.3 million for 2003. The expense associated with the change in the liability correlates closely with oil and gas prices and how quickly we recover our costs before we begin making payments, as required by the Net Profits Plan. Based on our valuation calculations as described in our accounting policies footnote, we believe the expense for this liability will be significantly less in 2006 as compared to 2005.

The calculation of this liability requires management to prepare its best 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 plan. The underlying basis for our calculations are forecasted oil and gas production from the properties that comprise each individual pool, price 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 a rolling average of actual prices received for the preceding 24 months combined with adjusted NYMEX strip prices for the next 12 months. This average is supplemented by including the effect of hedge prices for the percentage of forecasted production hedged 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 prices in our calculation by ten percent, the liability recorded at December 31, 2005, would differ by approximately $26 million, and a one percent change in the discount rate would result in a change of approximately $5 million. We frequently evaluate the assumptions used in our calculations to evaluate the possible impacts stemming from the current market environment. This review considers current oil and gas prices, discount rates and overall market conditions. The calculation of this liability will not correlate precisely to the standardized measure of discounted future net cash flows presented in Note 12 of Part IV, Item 15 of this report due to different pricing and discount assumptions.

As a result of higher prices over the last 12 months and the rate at which we have recovered costs associated with the designated properties in each pool, actual cash payments for amounts earned under the Net Profits Plan for 2005 were $20.8 million. Because of the life cycles of these pools and the existing commodity prices, we have budgeted approximately $40 million for cash payments in 2006. The actual cash payments to be made in future periods are dependent on actual production, realized prices and operating and capital costs associated with the individual pools. Actual cash payments will be inherently different from the estimated liability amount. Additional discussion is included in the analysis in the *Comparison of Financial Results and Trends* sections below.

2005 Highlights

In 2005 we experienced record production and earnings. Record production is the culmination of investment decisions made in prior years and in the current period. Significant increases in commodity prices for oil and natural gas and increased production resulted in the highest net revenues in our history. In 2006, we anticipate production to be greater than in 2005. If oil and gas prices remain high, it is reasonable to assume that revenue growth will continue. Our margins remained very strong in 2005 as a result of price increases in spite of the upward pressure from rig and service companies. In 2005, lease operating and transportation expense on a per MCFE basis increased from $0.91 per MCFE to $1.08 per MCFE. This was partially a result of a greater percentage of our production coming from oil properties which generally have higher operating costs. Other drivers for this increase include upward pressure on service costs, chemicals and labor and an increase in workover expense from $6.9 million in 2004 to $12.0 million in 2005. Increased workover costs will continue to impact us as nearly 40 percent of our production is from oil properties that require a higher amount of maintenance than required by flowing gas wells.

Highlights for 2005 also include the repurchase of 1,175,282 shares of our common stock under our stock repurchase program at an average price of $24.51 per share. We also closed on $87.8 million of oil and gas property acquisitions for a total of $73.9 million in cash. Our cash outflows were funded entirely by existing cash, operating cash inflows and short-term investments on hand. We repaid the $37.0 million of outstanding borrowings under this credit facility as of December 31, 2004, and we have no borrowings currently outstanding under our credit facility.

In 2005 oil prices rose to record levels as excess OPEC capacity shrank to its lowest level in recent time. Demand for oil was impacted by the growing economies of China and India as well as from a recovering U.S. economy. Spot market prices reflected worldwide concerns about producer ability to ensure sufficient supply to meet increasing demand amid a host of uncertainties caused by weather-related destruction, political instability, a weaker US dollar, foreign oil rig worker strikes and crude oil refining constraints. Average natural gas prices for the year were at an all-time high due to supply and transportation constraints, weather-related lost production, and continuing strong demand for natural gas in domestic markets resulting from an improving economy and the effect high oil prices have on natural gas demand. NYMEX prices for the year averaged $8.55 per MMBtu and $56.56 per Bbl, translating into a 49 percent increase to our per MCFE realized price over 2004. At December 31, 2005, the 12-month NYMEX strip was $63.18 per Bbl for oil and $10.78 per MMBtu for gas. As of February 15, 2006, pricing for the same period, including settled prices, was $60.46 per Bbl for oil and $8.36 per MMBtu for gas. As a result, the overall draws from gas storage have been lower than both the prior year and the prior five-year average.

Net income for 2005 was $151.9 million or $2.33 per diluted share compared to $92.5 million or $1.40 per diluted share for the prior year. Net cash provided by operating activities was $409.4 million, up 73 percent from 2004. Average daily production for the year increased 16 percent to 239.4 MMCFE. Our average net realized price increased 49 percent to $8.14 per MCFE. Unit costs increased for the period as lease operating and transportation expenses increased $0.17 to $1.08 per MCFE, production taxes increased $0.20 to $0.56 per MCFE, DD&A increased $0.30 to $1.52 per MCFE and general and administrative expense increased $0.08 to $0.37 per MCFE.

The table below provides information regarding selected production and financial information for the quarter ended December 31, 2005, and the immediately preceding three quarters.

	For the Three Months Ended			
	December 31, 2005	September 30, 2005	June 30, 2005	March 31, 2005
	(In millions)			
Production (MCFE)	21.9	23.1	21.8	20.6
Oil and gas production revenues before the effects of hedging	$ 231.6	$ 203.1	$ 160.4	$ 138.4
Lease operating expense	$ 23.8	$ 22.9	$ 19.2	$ 20.3
Transportation costs	$ 2.6	$ 1.8	$ 1.8	$ 1.9
Production taxes	$ 16.1	$ 13.4	$ 9.2	$ 10.0
General and administrative expense	$ 9.5	$ 9.8	$ 7.5	$ 6.0
Net income	$ 51.2	$ 27.3	$ 38.3	$ 35.1
Percentage change from previous quarter:				
Production (MCFE)	(5)%	6%	6%	
Oil and gas production revenues	14%	27%	16%	
Lease operating expense	4%	19%	(5)%	
Transportation costs	44%	0%	(5)%	
Production taxes	20%	46%	(8)%	
General and administrative expense	(3)%	31%	25%	
Net income	88%	(29)%	9%	

Outlook for 2006

Oil and gas prices remain very volatile. We have attractive prospects to drill, and rig counts are growing. However, this growth trend could be mitigated by the necessity for drilling companies to hire qualified crews to work these rigs. We have felt the impact of escalating rig and other service costs. The country's ability to supply gas remains challenged as the average decline rate from existing natural gas wells has increased from 16 percent to 30 percent over the past thirteen years, as estimated by various industry analysts. This change is a result of increased activity in the Gulf of Mexico where reserve lives are quite short, the use of 3-D seismic to identify smaller reservoirs, the use of better completion techniques that allow reserves to be produced faster, and more efficiently, and high deliverability of storage that allows wells to be produced at full capacity all year long. New sources of gas such as LNG, frontier regions (e.g. deepwater Gulf of Mexico and Mackenzie Delta, Alaska) and unconventional gas plays are all more costly and have long lead times, but at some point could have a positive impact on supply. We believe oil prices are high now due to perceptions of reduced spare capacity, increasing worldwide demand and an apparent increased target price range for OPEC. It is not possible for us to predict prices, however we believe that growing net asset value per share is the fundamental driver of our stock price over the long term.

We enter 2006 in excellent financial condition and with a capital expenditure budget of $600 million. We are successfully transitioning the emphasis of our capital program to drilling as evidenced by the 50 percent growth in our drilling budget as compared to total drilling capital expenditures of $333.7 million in 2005. We have budgeted $100 million for acquisitions in 2006, which is much lower than in prior years, on a relative percentage basis. The decreased emphasis on the acquisition component of our budget reflects the overall competitiveness of the acquisition market and the high prices being paid in recent acquisition transactions in our industry. More importantly, it reflects the strides we have made to advance our prospect inventory and activity level on the drilling side. The information below provides some detail of our plans for 2006:

- We believe that we have the necessary capital, personnel, and rigs available to execute this program. The $500 million budgeted for drilling activities in 2006 is allocated among our core areas as follows:

Rockies Conventional - $141 million - There are approximately 30 wells planned in the Bakken formation with total capital of $47 million. We are initiating a horizontal drilling program focusing on the Ratcliffe and Mission Canyon formations with $24 million of the budget allocated for the drilling of approximately 26 wells. The planned development of the Tensleep formation results in approximately $9 million of the budget being allocated to the Fourbear, Murphy Dome and Big Sand Draw fields. The remainder is planned for the Red River program, horizontal Madison, and development in the Greater Green River Basin.

Rockies - Hanging Woman Basin Coalbed Methane - $50 million - We are planning on increasing our activity to drill 260 wells in 2006, up from 131 in 2005. We intend to expand our activity into Montana. Potential Montana delays may result from uncertainties related to our ability to obtain the timely regulatory approval of our water development plan on state and fee acreage. The Wyoming delays could result from timing of drilling in areas that are affected by stipulations associated with sage grouse.

Mid-Continent - $172 million - This portion of the drilling budget is dominated by development of the Atoka program at Northeast Mayfield and the horizontal development of the Wapanucka limestone, Cromwell sandstone and Woodford shale formations at Centrahoma.

ArkLaTex - $66 million - We will continue to expand our horizontal efforts in the James Lime, Glen Rose, Pettet and Rodessa formations. We will also participate in the expansion of the development activity at Elm Grove and Terryville.

Gulf Coast and Permian - $71 million - We will concentrate primarily on targets with direct hydrocarbon indicators along the Gulf Coast and on the Gulf of Mexico shelf. We have a $4 million budget for development in the Permian Basin.

- The $100 million budgeted for acquisitions could be expected to increase production in 2006, 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 structuring experience. In addition, we may seek larger acquisitions of assets or companies that would afford opportunities to expand beyond our existing core areas. However, we would want to ensure that we also acquired the necessary personnel with expertise in a new basin in order for it to be attractive to us. We do not currently have any specifically identified pending transactions.

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

	As of and for the Years Ended			Percent Change Between	
	2005	2004	2003	2005/2004	2004/2003
Selected Operations Data (In Thousands, Except Price, Volume, and Per MCFE Amounts):					
Total proved reserves (PV-10 basis)					
Oil (MBbl)	62,903	56,574	47,787		
Natural gas (MMcf)	417,075	319,196	307,024		
MMCFE	794,493	658,638	593,744	21%	11%
Net production volumes					
Oil (MBbl)	5,927	4,799	4,541		
Natural gas (MMcf)	51,801	46,598	49,663		
MMCFE	87,363	75,393	76,909	16%	(2)%
Average daily production					
Oil (MBbl)	16	13	12		
Natural gas (MMcf)	142	127	136		
MMCFE	239	206	211	16%	(2)%
Oil & gas production revenues					
Oil production, including hedging	$ 301,860	$ 156,112	$ 122,444		
Gas production, including hedging	409,145	257,206	242,670		
Total	$ 711,005	$ 413,318	$ 365,114	72%	13%
Oil & gas production costs					
Lease operating expenses	$ 86,130	$ 61,269	$ 59,152		
Transportation costs	8,010	7,235	7,197		
Production taxes	48,733	27,014	22,160		
Total	$ 142,873	$ 95,518	$ 88,509	50%	8%
Average net realized sales price (1)					
Oil (per Bbl)	$ 50.93	$ 32.53	$ 26.96	57%	21%
Natural gas (per Mcf)	$ 7.90	$ 5.52	$ 4.89	43%	13%
Per MCFE data:					
Average net realized price (1)	$ 8.14	$ 5.48	$ 4.75	49%	15%
Lease operating expense	(0.99)	(0.81)	(0.77)	22%	5%
Transportation costs	(0.09)	(0.10)	(0.09)	(10)%	11%
Production taxes	(0.56)	(0.36)	(0.29)	56%	24%
General and administrative	(0.37)	(0.29)	(0.28)	28%	4%
Operating profit	$ 6.13	$ 3.92	$ 3.32	56%	18%
Depletion, depreciation and amortization	$ 1.52	$ 1.22	$ 1.07	25%	14%
Financial Information (In Thousands, Except Per Share Amounts):					
Working capital	$ 4,937	$ 12,035	$ 3,101	(59)%	288%
Long-term debt	$ 99,885	$ 136,791	$ 110,696	(27)%	24%
Stockholders' equity	$ 569, 320	$ 484,455	$ 390,653	18%	24%
Net income	$ 151,936	$ 92,479	$ 95,575	64%	(3)%
Basic net income per common share	$ 2.67	$ 1.60	$ 1.53	67%	5%
Diluted net income per common share	$ 2.33	$ 1.44	$ 1.40	62%	3%
Basic weighted-average shares outstanding	56,907	57,702	62,467	(1)%	(8)%
Diluted weighted-average shares outstanding	66,894	66,894	71,069	-%	(6)%
Net cash provided by operating activities	$ 409,379	$ 237,162	$ 204,319	73%	16%
Net cash used in investing activities	$ (339,779)	$ (247,006)	$ (196,939)	38%	25%
Net cash provided by (used in) financing activities	$ (61,093)	$ 1,435	$ (3,707)	(4357)%	139%

(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 oil and gas reserve volumes reflects our drilling results and acquisition activity combined with increases in natural gas and crude oil prices used to evaluate reserves. Please see Note 12 of Part IV, Item 15 for additional details. Over time, the ability to economically replace 200 percent of the total volumes produced in the current year 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 from year-to-year due to changes in these factors, some of which we can control and others which we cannot control.

The changes in production volumes, oil and gas production revenues and costs reflect the cyclical and highly volatile nature of prices our industry receives for production and the effect of the timing of acquisitions. The comparison of changes in production from 2004 to 2005 reflect the positive results from our drilling programs in 2005 and the timing of our acquisitions made in the fourth quarter of 2004. Acquisitions made during 2004 operated for a full year in 2005; therefore, incremental production increased in 2005. Production volume in 2005 was also affected by new production from producing oil and gas properties acquired in 2005.

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 changes in selected line items between years. We expect oil and gas production expenses to increase in 2006 as a result of increased activity in our higher-cost Rocky Mountain region, increased production taxes, and general inflation due to higher oil and gas pricing. Depreciation, depletion and amortization will continue to increase due to the higher costs associated with finding and acquiring crude oil and natural gas reserves. General and administrative expense is also projected to increase because of the expense associated with payments under our Net Profits Plan, increased expensing of stock-based compensation 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. Our basic and diluted weighted-average common shares outstanding used in our 2004 earnings per share calculations reflects 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 2005 were affected by similar factors as 2004. We issued 936,403 shares of common stock in 2005 as a result of stock option exercises. These share issuances were offset by the repurchase of 1,175,282 shares of common stock via our stock repurchase plan.

The remaining information in the table relates to information we have provided in the 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 and to sustain our projected growth levels, we will have to successfully 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

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 and 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. The availability of capital has a high correlation to overall commodity prices. Accordingly, a downturn in prices could adversely impact our ability to raise capital. Our current access to cash under our existing credit facility and from cash on hand and cash flows from operations is significant. We are not currently planning to access the capital markets in 2006. If additional development or attractive acquisition opportunities arise that exceed our currently available resources, we may consider other forms of financing, including the public offering or private placement of equity or debt securities.

Our current credit facility. We have a five-year, $500 million credit facility agreement with Wachovia Bank, Wells Fargo Bank and eight other participating banks. This credit facility has a borrowing base of $500 million, and we have elected a commitment amount of $200 million, which results in lower commitment fees payable to the bank syndicate. 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 believe that we would be able to increase the note amount of this facility if necessary as we believe that the actual borrowing base far exceeds the $500 million face amount. Even so, there must be a compelling reason to incur the costs associated with increasing the size of the credit facility. 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, 2005 and February 15, 2006. 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 $1.15 million. This reduces the amount available under the commitment amount on a dollar-for-dollar basis. Borrowings under the new facility are secured by the majority of our oil and gas properties and a pledge of the common stock of our material subsidiary companies.

Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the consolidated statements of operations. We had no outstanding loan balance as of December 31, 2005, and that remains true as of the date of this report. As of December 31, 2005, we had a cash and short-term investment balance of $16.4 million and as of February 15, 2006, our cash and short term investments were approximately $38 million.

We decreased our net borrowings from the previous year by $37.0 million. Our weighted-average interest rate paid in 2005 was 7.1 percent and included fees paid on the unused portion of the credit facility aggregate commitment amount, amortization of deferred financing costs, amortization of the contingent interest embedded derivative associated with the convertible notes, and the effects of interest rate swaps.

Uses of cash

We use cash for the acquisition, exploration and development of oil and gas properties and for the payment of debt obligations, trade payables, income taxes, common stock repurchases and stockholder dividends. During 2005 we spent $333.7 million on capital development, $87.8 million for property acquisitions and $28.9 million to acquire shares of our common stock using cash flows from operations. All borrowings under our credit facility were repaid from operating cash flows. We also made cash payments for income taxes of $65.8 million. The current portion of our income tax expense was 94 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 50 percent of our total tax liability in 2006 as a result of our higher capital spending program and reduced expense related to the Net Profits Plan liability.

Expenditures for exploration and development of oil and gas properties and acquisitions are the primary use of our capital resources. We anticipate spending approximately $500 million for capital and exploration expenditures in 2006 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 2006* section. We regularly review our capital expenditure budget to reflect changes in current and projected cash flows, acquisition opportunities, debt requirements and other factors.

As of December 31, 2005, we have Board authorization to repurchase up to an additional 3.8 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 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 doubles our annual cash dividend payments from 2004. 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 $5.7 million for dividends in 2005 compared with $2.8 million in 2004.

We believe that internally generated cash flows will be sufficient to fund our planned operational, drilling and acquisition expenditures for the foreseeable future. The amount and allocation of future capital and exploration expenditures will depend upon a number of factors including the number and size of available economic 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	
	2005/2004	2004/2003	2005/2004	2004/2003
Net Cash Provided By Operating Activities	$ 172,217	$ 32,843	73%	16%
Net Cash Used In Investing Activities	$ (92,773)	$ (50,067)	38%	25%
Net Cash Provided By (Used In) Financing Activities	$ (62,528)	$ 5,142	(4,357)%	139%

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 $268.6 million to $651.6 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. The future operating cash flow impact of the increased percentage of hedged production using zero-cost collars will have the effect of reducing the sensitivity to movements in oil and gas prices to the extent prices fall outside of the collar range.

Investing activities. Total cash outflow for 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 acquired in Wyoming during 2005. The year ended December 31, 2004, reflects $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.

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.

Analysis of cash flow changes between 2004 and 2003

Operating activities. Sources of cash flow from oil and gas sales increased $40.7 million from the period ended December 31, 2003, to the period ended December 31, 2004. This was a result of a 15 percent increase in our realized prices that offset a net production decrease of two percent between the comparative periods. Cash expenditures for operating expenses, exploration expense and administrative expenses increased by $2.4 million. Other revenue items decreased by $5.7 million.

Investing Activities. The increase in net cash used resulted from $75.6 million of increased drilling expenditures in 2004 over 2003 and from a 2004 cash payment of $3.8 million held as a deposit for our Agate acquisition. These increases were offset by a $7.6 million decrease in acquisition activity in 2004. Total capital expenditures increased by 34 percent to $268.2 million from $200.2 million in 2003. Proceeds from sales of oil and gas properties decreased by $20.7 million, but expiration of the restriction period for funds held for deferred tax exchange of oil and gas properties and net receipts from short-term investments resulted in a net cash provided change between periods of $41.8 million. Volumes, revenue and net operating margin from properties that were sold in 2003 and 2004 were not a material component in the consolidated statements of operations or balance sheets for any year presented, nor do they represent a group of assets that would qualify for discontinued operations accounting treatment.

Cash expended in 2003 for acquisitions of oil and gas properties included our utilization of $71.6 million of short-term investments, cash equivalents and increased borrowings under our credit facility to provide a loan to Flying J as part of our acquisition of properties. This loan was secured by the shares of our common stock issued in the transaction.

Financing activities. The $5.1 million increase in cash provided by financing activities reflects the $26.0 million we borrowed on our credit facility in 2004 to fund acquisitions and drilling activity and an $11.5 million increase in proceeds from stock option exercises over the 2003 amounts. We paid $19.4 million to repurchase our shares from Flying J on February 9, 2004, and we paid $16.3 million to repurchase shares under our stock repurchase program. In 2003 we borrowed to fund our acquisition of properties from Flying J and used cash flow from operations to reduce our outstanding debt for the year.

St. Mary had $6.4 million in cash and cash equivalents and had working capital of $12.0 million as of December 31, 2004, compared to $14.8 million in cash and cash equivalents and working capital of $3.1 million as of December 31, 2003.

Capital Expenditures

The following table sets forth certain historical information regarding the costs incurred by us in our oil and gas activities. The 2005 and 2004 amounts include capitalized costs associated with asset retirement obligations.

	Years Ended December 31,		
	2005	2004	2003
		(In thousands)	
Development costs	$ 249,518	$ 190,829	$ 111,908
Exploration costs	69,817	37,977	33,296
Acquisitions:			
Proved	84,981	69,054	73,989
Unproved	2,853	7,646	8,942
Leasing activity	14,330	7,877	7,480
Total	$ 421,499	$ 313,383	$ 235,615

The costs we incurred for capital and exploration activities in 2005 increased $108.1 million or 34 percent compared to 2004. This increase was a result of planned increases in drilling activity, an $11 million increase in acquisitions, and a $13.8 million increase in capitalized costs associated with asset retirement obligations resulting from changes in estimates and from wells drilled in 2005. We have seen a tremendous amount of cost inflation over the past three years, and we estimate that it now costs approximately twice as much to drill a well as it did three years ago.

Our ongoing development of the coalbed methane reserves in the Hanging Woman Basin area is proceeding as expected. During 2005 131 wells were drilled, 114 of which we operate. We have 154,000 net lease acres in the basin and are concentrating our initial development on 80,000 net acres located in Wyoming.

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 convertible notes, but do affect the fair value of convertible note debt.

Since we produce and sell natural gas and crude oil, our financial results are affected when prices for these commodities fluctuate. The next table reflects our estimate of the effect on cash flow from operations of a ten percent change in our average realized sales price for natural gas, for oil and in total 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 and exploration 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 revenues of a ten percent change in average sales price:

	For the Years Ended December 31,		
	2005	2004	2003
		(In thousands)	
Oil	$ 18,098	$ 9,180	$ 6,979
Natural Gas	24,502	15,280	13,889
Total	$ 42,600	$ 24,460	$ 20,868

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. We have entered into a significant volume of zero-cost collar hedging transactions that has increased our hedged positions to approximately 13 million Bbls and 74 million MMBTU of anticipated future production through 2011, including hedges entered into subsequent to year end.

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, 2005. We seek to minimize basis risk and index the majority of our oil contracts to NYMEX prices and our gas contracts to various regional index prices associated with pipelines in proximity to our areas of gas production.

Oil Contracts

Oil Swaps

Contract Period	Volumes (Bbl)	Weighted-Average Contract Price (per Bbl)	Fair Value at December 31, 2005 Asset/(Liability) (in thousands)
First quarter 2006 -			
NYMEX WTI	385,366	$ 53.23	$ (3,329)
IF Bow River	24,000	$ 39.16	(5)
Second quarter 2006 -			
NYMEX WTI	327,976	$ 54.53	(2,739)
IF Bow River	30,000	$ 40.68	(116)
Third quarter 2006 -			
NYMEX WTI	281,372	$ 54.79	(2,426)
IF Bow River	33,000	$ 40.46	(169)
Fourth quarter 2006 -			
NYMEX WTI	155,686	$ 50.57	(2,001)
IF Bow River	30,000	$ 37.54	(154)
2007 -			
NYMEX WTI	314,786	$ 39.78	(7,046)
IF Bow River	76,000	$ 38.85	(466)
2008 -			
NYMEX WTI	35,000	$ 56.63	(191)
All oil swap contracts			$ (18,642)

Oil Collars

Contract Period	NYMEX WTI Volumes (Bbl)	Weighted-Average Floor Price (per Bbl)	Weighted-Average Ceiling Price (per Bbl)	Fair Value at December 31, 2005 Asset/(Liability) (in thousands)
First quarter 2006	545,000	$ 51.34	$ 72.07	$ (76)
Second quarter 2006	537,000	$ 51.32	$ 72.05	(438)
Third quarter 2006	516,000	$ 51.31	$ 72.06	(725)
Fourth quarter 2006	607,000	$ 51.59	$ 72.28	(945)
2007	2,585,000	$ 50.57	$ 72.73	(4,826)
2008	1,668,000	$ 50.00	$ 69.82	(4,866)
2009	1,526,000	$ 50.00	$ 67.31	(4,072)
2010	1,367,500	$ 50.00	$ 64.91	(3,397)
2011	1,236,000	$ 50.00	$ 63.70	(2,629)
All oil collars				$ (21,974)

Gas Contracts

Gas Swaps

Contract Period	Volumes (MMBtu)	Weighted-Average Contract Price (per MMBtu)	Fair Value at December 31, 2005 Asset/(Liability) (in thousands)
First quarter 2006 -			
IF ANR OK	2,030,000	$ 9.10	$ 151
IF PEPL	330,000	$ 6.41	(854)
IF CIG	340,000	$ 7.51	(438)
IF NGPL	450,000	$ 11.95	1,287
IF CenterPoint	390,000	$ 6.56	(1,312)
Second quarter 2006 -			
IF ANR OK	1,960,000	$ 8.08	(2,281)
IF PEPL	330,000	$ 5.31	(1,266)
IF CIG	330,000	$ 6.30	(609)
IF NGPL	610,000	$ 9.77	278
IF CenterPoint	380,000	$ 5.67	(1,476)
Third quarter 2006 -			
IF ANR OK	1,740,000	$ 8.51	(1,774)
IF PEPL	330,000	$ 5.29	(1,364)
IF CIG	300,000	$ 6.35	(684)
IF NGPL	580,000	$ 9.94	300
IF CenterPoint	360,000	$ 5.67	(1,496)
Fourth quarter 2006 -			
IF ANR OK	1,020,000	$ 9.06	(652)
IF PEPL	110,000	$ 5.31	(442)
IF CIG	300,000	$ 6.70	(655)
IF NGPL	550,000	$ 10.24	126
IF CenterPoint	160,000	$ 5.71	(687)
2007 -			
IF ANR OK	1,640,000	$ 9.22	(118)
IF NGPL	3,280,000	$ 9.16	(246)
IF CIG	630,000	$ 6.42	(1,211)
All gas swap contracts			$ (15,423)

Gas Collars

Contract Period	Volumes (MMBtu)	Weighted-Average Floor Price (per MMBtu)	Weighted-Average Ceiling Price (per MMBtu)	Fair Value at December 31, 2005 Asset/(Liability) (in thousands)
First quarter 2006 -				
IF ANR OK	150,000	$ 8.00	$ 9.15	(57)
IF PEPL	820,000	$ 9.12	$ 19.78	621
IF HSC	570,000	$ 8.97	$ 20.99	388
NYMEX Henry Hub	440,000	$ 10.00	$ 24.00	119
Second quarter 2006 -				
IF ANR OK	350,000	$ 6.89	$ 9.13	(322)
IF PEPL	760,000	$ 7.27	$ 13.55	28
IF CIG	70,000	$ 7.00	$ 11.52	8
IF HSC	480,000	$ 7.71	$ 13.80	35
NYMEX Henry Hub	400,000	$ 8.00	$ 14.50	(11)
Third quarter 2006 -				
IF ANR OK	450,000	$ 6.92	$ 9.28	(528)
IF PEPL	720,000	$ 7.27	$ 13.54	(71)
IF CIG	210,000	$ 7.00	$ 11.52	(16)
IF HSC	430,000	$ 7.71	$ 13.80	(66)
NYMEX Henry Hub	330,000	$ 8.00	$ 14.50	(37)
Fourth quarter 2006 -				
IF ANR OK	100,000	$ 7.00	$ 9.82	(96)
IF PEPL	655,000	$ 7.90	$ 14.07	(21)
IF CIG	390,000	$ 7.23	$ 12.51	(31)
IF HSC	400,000	$ 8.10	$ 14.20	11
NYMEX Henry Hub	270,000	$ 8.63	$ 15.54	(33)
2007 -				
IF PEPL	7,960,000	$ 7.35	$ 10.74	(5,033)
IF CIG	3,120,000	$ 6.66	$ 9.36	(1,787)
IF HSC	1,240,000	$ 7.84	$ 10.60	(902)
NYMEX Henry Hub	790,000	$ 8.28	$ 11.32	(646)

Gas Collars (continued)

Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at December 31, 2005 Asset/(Liability)
	(MMBtu)	(per MMBtu)	(per MMBtu)	(in thousands)
2008 -				
IF PEPL	6,600,000	$ 6.28	$ 9.42	(5,353)
IF CIG	2,880,000	$ 5.60	$ 8.72	(1,658)
IF HSC	960,000	$ 6.57	$ 9.70	(755)
NYMEX Henry Hub	480,000	$ 7.00	$ 10.57	(365)
2009 -				
IF PEPL	5,510,000	$ 5.30	$ 9.25	(4,537)
IF CIG	2,400,000	$ 4.75	$ 8.82	(1,175)
IF HSC	840,000	$ 5.57	$ 9.49	(690)
NYMEX Henry Hub	360,000	$ 6.00	$ 10.35	(266)
2010 -				
IF PEPL	4,945,000	$ 5.31	$ 7.61	(4,157)
IF CIG	2,040,000	$ 4.85	$ 7.08	(1,011)
IF HSC	600,000	$ 5.57	$ 7.88	(496)
NYMEX Henry Hub	240,000	$ 6.00	$ 8.38	(195)
2011 -				
IF PEPL	4,225,000	$ 5.31	$ 6.51	(3,438)
IF CIG	1,800,000	$ 5.00	$ 6.32	(621)
IF HSC	480,000	$ 5.57	$ 6.77	(392)
NYMEX Henry Hub	120,000	$ 6.00	$ 7.25	(93)
All gas collars				$ (33,649)

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 convertible notes on October 3, 2003. Due to continuing increases in interest rates, we entered into a floating-to-fixed interest rate swap on April 13, 2005, through March 20, 2007, on 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. Increasing interest rates and a higher average outstanding credit facility balance resulted in a higher interest expense of $8.2 million in 2005 compared with $6.2 million in 2004.

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, although we had no floating rate debt outstanding as of December 31, 2005. Our fixed rate debt outstanding at this same date was $99.9 million associated with the Convertible Notes. Based on the character of our debt outstanding as of the end of the year, we do not believe there is any cash flow impact that could result from a change in interest rates.

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	$ 107.8	$ 6.2	$ 101.6	$ -	$ -
Operating Leases	9.3	2.5	4.1	2.3	0.4
Other Long-Term Liabilities	76.6	5.2	69.3	1.0	1.1
Total	$ 193.7	$ 13.9	$ 175.0	$ 3.3	$ 1.5

This table excludes the unfunded portion of our estimated pension liability of $1.9 million, as we cannot determine with accuracy the timing of future payments. We have made payments of $1.1 million, $1.3 million, and $901,000 in 2005, 2004 and 2003, respectively, towards the pension liability. The table also excludes estimated payments associated with our Net Profits Plan. We record a liability for the estimated future payments. However, predicting the precise 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. We do believe that the cash outflow in the next two years will be greater than the magnitude of payments that were made in 2005. We have excluded asset retirement obligations because we are not able to precisely predict the 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.

Two leases for office space will expire in less than one year, and two office space leases will expire in the second year. Estimated costs to replace these leases are not included in the table above.

For purposes of the table we assume that the holders of our Convertible Notes will not exercise the conversion feature. If the holders do exercise their conversion feature, we will not have to repay the $99.9 million upon conversion but instead will issue 7,692,307 shares of common stock.

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.

Included in the other long-term liabilities line is approximately $64 million related to noncurrent accrued derivative liability.

Off-Balance Sheet Arrangements

Aside from operating leases 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, development, acquisition and production of natural gas and crude oil. Our discussion of financial condition and results of operation 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 at 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 which include 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 proved producing oil and gas properties, we make considerable effort to estimate our reserves, including the use of 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,					
	2005		2004		2003	
	MMCFE Change	Percent of total Additions	MMCFE Change	Percent of total Additions	MMCFE Change	Percent of total Additions
Revisions resulting from price changes	23,095	10%	16,206	11%	6,750	3%
Revisions resulting From performance	10,817	5%	(26,127)	(18)%	14,290	6%
Total	33,912	15%	(9,921)	(7)%	21,040	9%

Over the three-year period, we added 592.6 BCFE of reserves. Of these, 46.1 BCFE, or eight percent, was a result of price changes. A one BCFE reduction in reserves was a result of changes in estimates based on the performance of our oil and gas properties. 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,					
	2005		2004		2003	
	MMCFE Change	Percent Change	MMCFE Change	Percent Change	MMCFE Change	Percent Change
A 10% decrease in pricing	(28,940)	(4%)	(16,672)	(3%)	(9,479)	(2%)
A 10% decrease in proved undeveloped reserves	(14,554)	(2%)	(9,839)	(1%)	(6,744)	(1%)

Additional reserve information can be found in the reserve table and discussion included in Item 1 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 $13.9 million in 2005.

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 2005, 2004 and 2003 by the following amounts: ($57.2 million), $2.6 million, and ($14.3 million), respectively, if our hedges did not qualify as cash flow deferral hedges under SFAS 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 as well as 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 $2.4 million for the year ended December 31, 2005.

Stock-based compensation. We have historically 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. 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 currently use the Black-Scholes option valuation model to calculate required disclosures under SFAS No. 123, Accounting for Stock Based Compensation. As of January 1, 2006, we have adopted the provision of SFAS No. 123(R), "Share-Based Payment." 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 expect to record compensation expense associated with unvested stock options totaling $2.2 million recorded in future periods under the modified-prospective adoption method. We have recorded expense associated with the issuance of restricted stock units since the plan was adopted in 2004 and units were first issued. Going forward this expense will decrease on a relative per share basis for all units that have already been issued because the accounting standard requires cost recognition using fair value estimates of the restricted stock units, rather than intrinsic value.

Additional Comparative Data in Tabular Format:

	Change Between Years	
Oil and Gas Production Revenues:	2005 and 2004	2004 and 2003
Increase in oil and gas production revenues (in thousands)	$ 297,687	$ 48,204

Components of Revenue Increases (Decreases):

	2005 and 2004	2004 and 2003
Oil		
Realized price change per Bbl	$ 18.40	$ 5.57
Realized price percentage change	57%	21%
Production change (MBbl)	1,128	258
Production percentage change	23%	6%
Natural Gas		
Realized price change per Mcf	$ 2.38	$ 0.63
Realized price percentage change	43%	13%
Production change (MMcf)	5,204	(3,065)
Production percentage change	11%	(6)%

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

	Years Ended December 31,		
Revenue	2005	2004	2003
Oil	42%	38%	34%
Natural Gas	58%	62%	66%
Production			
Oil	41%	38%	35%
Natural Gas	59%	62%	65%

Information regarding the effects of oil and gas hedging activity:

	Years Ended December 31, 2005	2004	2003
Oil Hedging			
Percentage of oil production hedged	24%	45%	54%
Oil volumes hedged (MBbl)	1,419	2,156	2,474
Decrease in oil revenue	$ (13.3 million)	$ (34.8 million)	$ (11.1 million)
Average realized oil price per Bbl before hedging	$ 53.18	$ 39.77	$ 29.40
Average realized oil price per Bbl after hedging	$ 50.93	$ 32.53	$ 26.96
Natural Gas Hedging			
Percentage of gas production hedged	25%	25%	40%
Natural gas volumes hedged (MMBtu)	14.0 million	12.9 million	21.7 million
Decrease in gas revenue	$ (9.2 million)	$ (15.5 million)	$ (11.4 million)
Average realized gas price per Mcf before hedging	$ 8.08	$ 5.85	$ 5.12
Average realized gas price per Mcf after hedging	$ 7.90	$ 5.52	$ 4.89

Information regarding the components of exploration expense:

Summary of Exploration Expense (in millions)	Years Ended December 31, 2005	2004	2003
Geological and geophysical expenses	$ 7.9	$ 7.3	$ 5.1
Exploratory dry holes	8.1	4.2	8.5
Overhead and other expenses	28.9	17.1	11.7
Total	$ 44.9	$ 28.6	$ 25.3

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 hedge 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 current year 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.

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 incurred as we increased the size of our geologic and exploration staff and incentive compensation related to those individuals.

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 has 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 have triggered additional Net Profits Plan payouts and have increased the amounts payable to plan participants. Consequently, the current period realized expense associated with the Net Profits Plan has increased by $12.8 million in 2005. The increase in Net Profits Plan payments is the result of the significantly higher oil and gas prices received, which has 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 are in payout status as of the end of 2005. The cash bonus and RSU bonus are $8.3 million higher than last 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 reflects 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 reflects 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 reflects changes in the mix of the highest marginal state tax rates as a result of acquisition and drilling activity and also reflects 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 is $80.8 million compared to $22.5 million in 2004. These amounts are 94 percent and 42 percent of total income tax expense for the respective periods. The difference results 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. We project that the current portion of taxable income will be lower in 2006 as a result of our increased drilling budget.

Comparison of Financial Results and Trends between 2004 and 2003

Oil and gas production revenues. Average net daily production decreased two percent to 206.0 MMCFE for 2004 compared with 210.7 MMCFE in 2003. Wells completed and properties acquired in 2003 and during 2004 added revenue of $102.8 million and average net daily production of 38.2 MMCFE in 2004 compared to 2003. These increases are offset by natural declines in production from older properties and 3.9 MMCFE per day of 2003 production from properties that were sold in 2003.

Oil and gas hedge loss. As noted in the table above, the 124 percent increase in total oil and gas hedge loss to $50.3 million for 2004 was caused by a 35 percent increase in the average pre-hedge oil price and a 14 percent increase in the pre-hedge gas price.

Oil and gas production expenses. Total production costs increased $7.0 million or eight percent to $95.5 million for 2004, from $88.5 million in 2003. Our acquisition of properties added $2.8 million of incremental production costs, and wells completed in 2003 and 2004 added $7.7 million of incremental production costs in 2004 that were not reflected in 2003. 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 $0.12 to $1.27 for 2004, compared with $1.15 for 2003. This increase is comprised of the following:

- A $0.07 increase in production taxes due to higher realized per MCFE prices;
- A $0.01 increase in transportation costs;
- A $0.01 decrease in LOE relating to workover charges;

- A $0.04 increase in LOE that reflects increasing costs in our Rocky Mountain region; and

- A $0.01 increase reflecting a general increases in LOE per MCFE in our other core areas.

Exploration expense. Exploration expense increased 13 percent in 2004. The most significant component of our increase to exploration expense was $5.5 million for exploration overhead we incurred as we increased the size of our geologic and exploration staff.

General and administrative expense. General and administrative expenses increased $807,000 or four percent to $22.0 million for 2004, compared with $21.2 million in 2003. The increase in cost on a per MCFE basis of $0.01 reflects the effect of the four percent increase in G&A and a two percent decrease in production between the respective periods.

An increase in our employee count from 226 to 249 resulted in a general increase in G&A of $4.2 million between 2004 and 2003. That increase plus a $913,000 increase in fees that are directly related to Sarbanes-Oxley compliance, and a $959,000 increase in other professional fees were offset by an increase of $5.5 million of general and administrative expense we allocated to exploration expense.

Change in Net Profits Plan liability. For the year ended December 31, 2004, the expense related to the change in the estimated liability for this plan increased to $24.4 million from $5.3 million for 2003. This increase is due to the performance of individual pools, the effect of a higher price environment, and the application of lower discount rates to reflect the current economics of the market.

Interest expense. Interest expense decreased by $1.7 million to $6.2 million for 2004 compared to $8.0 million for 2003. The decrease reflects the benefit of interest rate swaps we entered into on October 3, 2003, and decreased average borrowings under our credit facility in 2004 relative to the prior year.

Income tax expense. Income tax expense totaled $53.7 million for 2004 and $55.9 million in 2003, resulting in effective tax rates of 36.8 percent and 38.3 percent, respectively. The effective rate change from 2003 reflects percentage depletion and other permanent differences as well as changes in the composition of the highest marginal state tax rates as a result of acquisition and drilling activity. The cumulative effect of the change in marginal state tax rates that we recorded in 2004 was a result of filing our 2003 income tax returns and completing the evaluation of the impact on future temporary difference reversals.

The current portion of the income tax expense in 2004 was $22.5 million compared to $32.2 million in 2003. These amounts are 42 percent and 58 percent of the total tax for the respective periods. The difference results from decreased estimated taxable income caused by an increase in the estimated percentage of deductible intangible drilling costs relative to total income and the effect of an increase in stock option exercises.

Cumulative effect of change in accounting principal, net of income tax

On January 1, 2003 we adopted SFAS No. 143. The impact of adoption resulted in income to us of $8.8 million offset by the deferred income tax effect of $3.4 million. See Note 9 in Part IV, Item 15 of this report.

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. At December 31, 2005, we recorded a $290,000 pre-tax loss in accumulated other comprehensive income related to this plan. We believe this obligation will be funded from future cash flows 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 actual rate of return was 7.8 percent for 2005 and was 10.4 percent for 2004. 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 flows from operating activities in future years.

For the 2005 plan year, a 0.25 percentage point decrease in the discount rate combined with a 1.9 percentage point increase in the estimated rate of future compensation increases caused a $401,000 increase 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 flows 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 2005 plan year, a 0.25 percentage point decrease in the discount rate combined with a 1.9 percentage point increase in the estimated rate of future compensation increases and the payment of $298,000 in prior year benefits caused a $464,000 decrease in the projected benefit obligation for this plan. This plan's accumulated benefit obligation was $1.1 million at December 31, 2005, and $1.2 million at December 31, 2004. We believe this obligation will be funded from future cash flows from operating activities.

Accounting Matters

We recognized a $5.4 million gain net of income tax in 2003 from the adoption of SFAS No. 143 effective January 1, 2003.

Environmental

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item is provided under the captions "Commodity Price Risk and Interest Rate Risk," "Summary of Oil and Gas Production Hedges in Place," and "Summary of Interest Rate Hedges in Place" in Item 7 above and is incorporated herein by reference.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

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

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Stockholders' of St. Mary Land & Exploration Company

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. The Company's internal control over financial reporting includes those policies and procedures that:

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

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

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

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

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2005. 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, 2005.

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, CEO and President	Vice President - CFO, Secretary & Treasurer
February 23, 2006	February 23, 2006

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, 2005, 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, 2005, 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, 2005, 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, 2005, of the Company, and our report dated February 23, 2006, expressed an unqualified opinion on those financial statements.

/S/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 23, 2006

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required by this Item concerning St. Mary's Directors is incorporated by reference to the information provided under the captions "Election of Directors" and "Nominees for Election of Directors" in St. Mary's definitive proxy statement for the 2006 annual meeting of stockholders to be filed within 120 days from December 31, 2005. 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 2006 annual meeting of stockholders to be filed within 120 days from December 31, 2005.

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," "Report of the Compensation Committee on Executive Compensation," "Retirement Plans," "Performance Graph," and "Employee Agreements and Termination of Employment and Change-in-Control Arrangements" in St. Mary's definitive proxy statement for the 2006 annual meeting of stockholders to be filed within 120 days from December 31, 2005.

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 2006 annual meeting of stockholders to be filed within 120 days from December 31, 2005.

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

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 2006 annual meeting of stockholders to be filed within 120 days from December 31, 2005.

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 2006 annual meeting of stockholders to be filed within 120 days from December 31, 2005.

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 with or incorporated by reference into this report on Form 10-K:

Exhibit Number	Description
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	St. Mary Land & Exploration Company 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)
10.1†	St. Mary Land & Exploration Company 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†	St. Mary Land & Exploration Company Incentive Stock Option Plan, As Amended on March 25, 1999, January 27, 2000, March 29, 2001, March 27, 2003 and 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†	St. Mary Land & Exploration Company 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 St. Mary Land & Exploration Company 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)

Exhibit Number	Description
10.8†	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)
10.9†	Employment Agreement between Registrant and 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)
10.10	St. Mary Land & Exploration Company 5.75% Senior Convertible Notes Due 2002 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)
10.11	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)
10.12†	St. Mary Land & Exploration Company 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)
10.13	First Amendment to Credit Agreement dated January 27, 2003 among St. Mary Land & Exploration Company, Wachovia Bank, National Association as Issuing Bank and Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.41 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference)
10.14†	Net Profits Interest Bonus Plan, As Amended on February 3, 2004 (filed as Exhibit 10.42 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference)
10.15†	St. Mary Land & Exploration Company 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)
10.16	Second Amendment to Credit Agreement dated September 20, 2004 among St. Mary Land & Exploration Company, Wachovia Bank, National Association as Issuing Bank and 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 September 30, 2004 and incorporated herein by reference)
10.17	Third Amendment to Credit Agreement dated October 20, 2004 among St. Mary Land & Exploration Company, Wachovia Bank, National Association as Issuing Bank and Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2004 and incorporated herein by reference)
10.18†	Form of Restricted Stock Unit Award Memorandum under the St. Mary Land & Exploration Company Restricted Stock Plan (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2004 and incorporated herein by reference)
10.19†	Attachment A to Form of Change of Control Severance Agreement (filed as Exhibit 10.47 to the registrants Annual Report on Form 10-K for the year ended December 31, 2004 and incorporated herein by reference)
10.20†	Second Amendment to the St. Mary Land & Exploration 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)
10.21	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)
10.22	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)

Exhibit Number	Description
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†	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 March 31, 2005 and incorporated herein by reference)
10.30†	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)
10.31†	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)
10.32†	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)
10.33	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)
10.34†	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)
10.35*†	Summary of Compensation Arrangements for Non-Employee Directors
12.1*	Computation of Ratio of Earnings to Fixed Charges
14.1	Code of Business Conduct and Ethics (filed as Exhibit 14.1 to the registrant's Annual Report on Form 10-k for the year ended December 31, 2003 and incorporated herein by reference)
21.1*	Subsidiaries of Registrant
23.1*	Consent of Deloitte & Touche LLP
23.2*	Consent of Ryder Scott Company, L.P.
23.3*	Consent of Netherland, Sewell & Associates, Inc.
24.1*	Power of Attorney (included in signature page hereof)

Exhibit Number	Description
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes - Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes - Oxley Act of 2002
32.1*	Certification pursuant to U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002

* Filed with this Form 10-K.

† Exhibit constitutes a management contract or compensatory plan or arrangement

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of St. Mary Land & Exploration Company and subsidiaries (the “Company”) as of December 31, 2005 and 2004, 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, 2005. 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, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 9 to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations in 2003 with the implementation of Statement of Financial Accounting Standards No. 143 “Accounting for Asset Retirement Obligations”.

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, 2005, 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 23, 2006, 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 23, 2006

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

ASSETS	December 31, 2005	December 31, 2004
Current assets:		
Cash and cash equivalents	$ 14,925	$ 6,418
Short-term investments	1,475	1,412
Accounts receivable	165,197	104,964
Prepaid expenses and other	7,283	5,863
Deferred income taxes	8,252	-
Accrued derivative asset	6,799	8,270
Total current assets	203,931	126,927
Property and equipment (successful efforts method), at cost:		
Proved oil and gas properties	1,441,959	1,124,810
Less - accumulated depletion, depreciation and amortization	(497,621)	(399,013)
Unproved oil and gas properties, net of impairment allowance of $9,862 in 2005 and $9,867 in 2004	44,383	41,969
Wells in progress	55,505	35,515
Other property and equipment, net of accumulated depreciation of $8,046 in 2005 and $6,459 in 2004	5,340	5,244
	1,049,566	808,525
Noncurrent assets:		
Goodwill	9,452	-
Accrued derivative asset	575	115
Other noncurrent assets	5,223	9,893
Total noncurrent assets	15,250	10,008
Total Assets	**$ 1,268,747**	**$ 945,460**
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 164,957	$ 110,117
Accrued derivative liability	34,037	2,502
Deferred income taxes	-	2,273
Total current liabilities	198,994	114,892
Noncurrent liabilities:		
Long-term credit facility	-	37,000
Convertible notes	99,885	99,791
Asset retirement obligation	66,078	40,911
Net Profits Plan liability	136,824	30,561
Deferred income taxes	128,296	129,830
Accrued derivative liability	64,137	2,970
Other noncurrent liabilities	5,213	5,050
Total noncurrent liabilities	500,433	346,113
Commitments and Contingencies *(Note 6)*		
Stockholders' equity:		
Common stock, $0.01 par value: authorized - 200,000,000 shares; issued: 57,011,740 shares in 2005 and 57,458,246 shares in 2004; outstanding, net of treasury shares: 56,761,740 shares in 2005 and 56,958,246 shares in 2004	570	574
Additional paid-in capital	123,278	127,374
Treasury stock, at cost: 250,000 shares in 2005 and 500,000 shares in 2004	(5,148)	(5,295)
Deferred stock-based compensation	(5,593)	(5,039)
Retained earnings	510,812	364,567
Accumulated other comprehensive income (loss)	(54,599)	2,274
Total stockholders' equity	569,320	484,455

Total Liabilities and Stockholders' Equity	**$ 1,268,747**	**$ 945,460**

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,		
	2005	2004	2003
Operating revenues:			
Oil and gas production revenue	$ 733,544	$ 463,617	$ 387,553
Oil and gas hedge loss	(22,539)	(50,299)	(22,439)
Marketed gas revenue	25,269	15,551	13,438
Gain on sale of proved properties	222	1,803	7,278
Other revenue	3,094	2,427	7,878
Total operating revenues	739,590	433,099	393,708
Operating expenses:			
Oil and gas production expense	142,873	95,518	88,509
Depletion, depreciation, amortization and abandonment liability accretion	132,758	92,223	81,960
Exploration	44,931	28,560	25,318
Impairment of proved properties	-	494	185
Abandonment and impairment of unproved properties	5,780	1,420	3,796
General and administrative	32,756	22,004	21,197
Change in Net Profits Plan liability	106,263	24,398	5,317
Marketed gas system operating expense	24,164	14,230	12,229
Unrealized derivative loss	1,615	260	310
Other expense	2,456	2,077	1,576
Total operating expenses	493,596	281,184	240,397
Income from operations	245,994	151,915	153,311
Nonoperating income (expense):			
Interest income	456	557	717
Interest expense	(8,213)	(6,244)	(7,958)
Income before income taxes and cumulative effect of change in accounting principle	238,237	146,228	146,070
Income tax expense	(86,301)	(53,749)	(55,930)
Income before cumulative effect of change in accounting principle	151,936	92,479	90,140
Cumulative effect of change in accounting principle, net of income tax	-	-	5,435
Net income	**$ 151,936**	**$ 92,479**	**$ 95,575**
Basic weighted-average common shares outstanding	56,907	57,702	62,467
Diluted weighted-average common shares outstanding	66,894	66,894	71,069
Basic earnings per common share:			
Income before cumulative effect of change in accounting principle	$ 2.67	$ 1.60	$ 1.44
Cumulative effect of change in accounting principle, net of income tax	-	-	0.09
Basic net income per common share	**$ 2.67**	**$ 1.60**	**$ 1.53**
Diluted earnings per common share:			
Income before cumulative effect of change in accounting principle	$ 2.33	$ 1.44	$ 1.32
Cumulative effect of change in accounting principle, net of income tax	-	-	.08
Diluted net income per common share	**$ 2.33**	**$ 1.44**	**$ 1.40**

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		Additional Paid-in	Treasury Stock		Deferred Stock-Based	Retained	Accumulated Other Comprehensive	Total Stockholders'
	Shares	Amount	Capital	Shares	Amount	Compensation	Earnings	Income (Loss)	Equity
Balances, December 31, 2002	**57,966,220**	**$ 580**	**$ 140,398**	**(2,019,800)**	**$ (16,210)**	**$ -**	**$ 182,512**	**$ (7,767)**	**$ 299,513**
Comprehensive income, net of tax:									
Net income	-	-	-	-	-	-	95,575	-	95,575
Unrealized net gain on marketable equity securities available for sale	-	-	-	-	-	-	-	716	716
Change in derivative instrument fair value	-	-	-	-	-	-	-	(21,873)	(21,873)
Reclassification to earnings	-	-	-	-	-	-	-	13,846	13,846
Minimum pension liability adjustment	-	-	-	-	-	-	-	197	197
Total comprehensive income									88,461
Cash dividends declared, $ 0.05 per share	-	-	-	-	-	-	(3,150)	-	(3,150)
Issuance of common stock under Employee Stock Purchase Plan	33,988	-	375	-	-	-	-	-	375
Value of option right granted to Flying J	-	-	995	-	-	-	-	-	995
Sale of common stock, including income tax benefit of stock option exercises	490,038	4	4,302	-	-	-	-	-	4,306
Directors' stock compensation	-	-	-	14,400	153	-	-	-	153
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 declared, $ 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)	-	-	-
Accrued stock-based compensation	-	-	1,106	-	-	-	-	-	1,106
Directors' stock compensation	-	-	-	25,200	349	-	-	-	349
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 declared, $ 0.10 per share	-	-	-	-	-	-	(5,691)	-	(5,691)
Treasury stock purchases	-	-	-	(1,175,282)	(28,902)	-	-	-	(28,902)
Retirement of treasury stock	(1,411,356)	(14)	(28,729)	1,411,356	28,743	-	-	-	-
Issuance of common stock under Employee Stock Purchase Plan	28,447	-	601	-	-	-	-	-	601
Sale of common stock, including income tax benefit of stock option exercises	936,403	10	16,619	-	-	-	-	-	16,629
Deferred compensation related to issued restricted stock unit awards, net of forfeitures	-	-	3,404	-	-	(3,404)	-	-	-
Accrued stock-based compensation	-	-	4,009	-	-	-	-	-	4,009
Directors' stock compensation	-	-	-	13,926	306	(306)	-	-	-
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 CASH FLOWS
(In thousands)

	For the Years Ended December 31,		
	2005	2004	2003
Reconciliation of net income to net cash provided by operating activities:			
Net income	$ 151,936	$ 92,479	$ 95,575
Adjustments to reconcile net income to net cash provided by operating activities:			
Gain on sale of proved properties	(222)	(1,803)	(7,278)
Depletion, depreciation, amortization and abandonment liability accretion	132,758	92,223	81,960
Exploratory dry hole expense	8,104	4,162	8,482
Impairment of proved properties	-	494	185
Abandonment and impairment of unproved properties	5,780	1,420	3,796
Unrealized derivative loss	1,615	260	310
Change in Net Profits Plan liability	106,263	24,398	5,317
Deferred and accrued stock-based compensation	7,165	4,189	-
Income tax benefit from the exercise of stock options	6,037	3,816	1,151
Deferred income taxes	5,547	31,217	23,692
Other	281	(1,948)	2,088
Cumulative effect of change in accounting principle, net of tax	-	-	(5,435)
Changes in current assets and liabilities, net of acquisitions:			
Accounts receivable	(57,113)	(39,880)	(29,685)
Prepaid expenses and other	(1,210)	157	490
Accounts payable and accrued expenses	42,438	25,978	23,671
Net cash provided by operating activities	**409,379**	**237,162**	**204,319**
Cash flows from investing activities:			
Proceeds from sale of oil and gas properties	1,213	2,829	23,497
Capital expenditures	(270,881)	(199,385)	(123,823)
Acquisition of oil and gas properties, including related $71,594 loan to Flying J in 2003	(73,905)	(68,805)	(76,413)
Deposits to short-term investments available-for-sale	(1,502)	(1,470)	(12,529)
Receipts from short-term investments available-for-sale	1,427	12,500	2,450
Receipts from restricted cash	-	10,353	11,500
Deposits to restricted cash	-	-	(21,853)
Other	3,869	(3,028)	232
Net cash used in investing activities	**(339,779)**	**(247,006)**	**(196,939)**
Cash flows from financing activities:			
Proceeds from credit facility	284,090	181,500	142,020
Repayment of credit facility	(321,090)	(155,500)	(145,020)
Proceeds from sale of common stock	11,193	14,030	3,530
Repurchase of common stock	(28,902)	(35,743)	-
Dividends paid	(5,691)	(2,849)	(3,150)
Other	(693)	(3)	(1,087)
Net cash provided by (used in) financing activities	**(61,093)**	**1,435**	**(3,707)**
Net change in cash and cash equivalents	8,507	(8,409)	3,673
Cash and cash equivalents at beginning of period	6,418	14,827	11,154
Cash and cash equivalents at end of period	**$ 14,925**	**$ 6,418**	**$ 14,827**

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,		
	2005	2004	2003
		(in thousands)	
Cash paid for interest, net of capitalized interest	$ 8,458	$ 6,887	$ 7,555
Cash paid for income taxes	$ 65,752	$ 14,787	$ 28,858

Included in the accounts payable and accrued expenses account balances as of December 31, 2005 and 2004 are $51.0 million and $39.2 million, respectively, of additions to oil and gas properties. These oil and gas property additions are reflected in cash used in investing activities in the periods that the payables are settled.

In March 2005 and June 2004 the Company issued 194,508 and 465,722 restricted stock units, respectively, pursuant to the Company's restricted stock plan. The total value of the ssuances were $4.9 million and $8.3 million, respectively.

In May 2005, May 2004, January 2004, and January 2003 the Company issued 13,926, 16,800, 8,400 and 14,400 shares, respectively, of common stock from treasury to its non-employee directors. The Company recorded compensation expense related to the issuances of $179,000 and $349,000 and $153,000 for the years ended December 31, 2005, 2004 and 2003 respectively.

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 January 2003 the Company issued 6,761,636 restricted shares of common stock to Flying J Oil & Gas Inc. and Big West Oil & Gas Inc. (collectively, "Flying J") and entered into a put and call option agreement, valued at $995,000 for financial reporting purposes, with Flying J with respect to those shares in connection with the acquisition of oil and gas properties and related assets and liabilities.

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

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 entirely in the Continental United States and 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 and 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 Plan liability, each of which represents a significant component of the consolidated financial statements.

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 consists of investment-grade marketable debt, which 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, 2005 and 2004, the Company held $1.5 million and $1.4 million, respectively, 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, 2005, 2004 and 2003, the Company had $36.8 million, $22.2 million, and $23.5 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. 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 productive or nonproductive.

Geological and geophysical costs and the costs of carrying and retaining unproved properties are expensed as incurred. DD&A of capitalized costs of proved oil and gas properties is provided 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 equipment salvage. As of December 31, 2005, the Company's capitalized proved oil and gas properties included $76.1 million of estimated salvage value, which is excluded from the depletable property costs when calculating DD&A.

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 revenues 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 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 provided using the straight-line method over the estimated useful lives of the assets from three to 15 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 our gas revenue whereby we recognize sales revenue on all gas sold to our purchasers, regardless of whether the sales are proportionate to our ownership in the property. An asset or a liability is recognized to the extent that we have an imbalance in excess of the remaining gas reserves on the underlying properties. The Company's gas imbalance position at December 31, 2005 and 2004 resulted in the recording of $1.6 million and $1.5 million, respectively, to receivables, and $869,000 and $726,000, 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 SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," 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; however, no amounts are 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 calculated based on a number of 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 modified 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. The estimated Net Profits Plan liability is recorded separately as a noncurrent liability in the accompanying consolidated balance sheets.

The amounts due 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 paid 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 RSUs for the periods presented:

	For the Years Ended December 31,		
	2005	2004	2003
Dilutive	2,293,768	1,499,288	910,110
Anti-dilutive	-	186	1,426,764

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 restricted stock units for any periods presented.

Shares associated with the conversion feature of the Convertible Notes are accounted for using the if-converted method as described above. A total of 7,692,307 potentially dilutive shares related to the Convertible Notes were included in the calculation of diluted net income per common share for the years ended December 31, 2005, 2004 and 2003. The Convertible Notes were issued in March 2002.

During the first quarter of 2003, the Company issued 6,761,636 shares of common stock as part of an acquisition. In February 2004 the Company repurchased and retired these shares (see Note 11-Repurchase of Common Stock). These shares were considered outstanding from January 29, 2003, to February 9, 2004, for purposes of calculating basic and diluted net income per common share and were weighted accordingly in the calculation of common shares outstanding.

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

	For the Years Ended December 31,		
	2005	2004	2003
	(In thousands, except per share amounts)		
Income before cumulative effect of change in accounting principle	$ 151,936	$ 92,479	$ 90,140
Cumulative effect of change in accounting principle, net of income tax	-	-	5,435
Net income	151,936	92,479	95,575
Adjustments to net income for dilution:			
Add: interest expense avoided if Convertible Notes are converted to equity	6,337	6,354	6,337
Less: other adjustments	(64)	(64)	(63)
Less: income tax effect of dilutive items	(2,275)	(2,312)	(2,403)
Net income adjusted for the effect of dilution	$ 155,934	$ 96,457	$ 99,446
Basic weighted-average common shares outstanding	56,907	57,702	62,467
Add: dilutive effect of stock options and RSUs	2,295	1,500	910
Add: dilutive effect of Convertible Notes using the if-converted method	7,692	7,692	7,692
Diluted weighted-average common shares outstanding	66,894	66,894	71,069
Basic earnings per common share:			
Income before cumulative effect of change in accounting principle	$ 2.67	$ 1.60	$ 1.44
Cumulative effect of change in accounting principle, net of income tax	-	-	0.09
Total	$ 2.67	$ 1.60	$ 1.53
Diluted earnings per common share:			
Income before cumulative effect of change in accounting principle	$ 2.33	$ 1.44	$ 1.32
Cumulative effect of change in accounting principle, net of income tax	-	-	0.08
Total	$ 2.33	$ 1.44	$ 1.40

Stock-Based Compensation

At December 31, 2005, the Company had stock-based employee compensation plans that included restricted stock units (“RSUs”) and stock options issued to employees and non-employee directors as more fully described in Note 7 - Compensation Plans. The Company has historically 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 as 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 currently uses the Black-Scholes option valuation model to calculate required disclosures under SFAS No. 123, “Accounting for Stock-Based Compensation.” As of January 1, 2006, the Company has adopted the provisions of SFAS No. 123(R), “Share-Based Payment.” This statement requires the Company to record expense associated with the fair value of stock-based compensation. As a result of the adoption of this statement, the Company expects to record compensation expense associated with unvested stock options totaling $2.2 million in future periods under the modified-prospective adoption method. The Company has recorded expense of costs associated with the issuance of restricted stock units since the plan was adopted in 2004 and units were first granted. 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 used under APB 25.

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, "Accounting for Stock-Based Compensation," to stock-based employee compensation:

	For the Years Ended December 31,		
	2005	2004	2003
	(In thousands, except per share amounts)		
Net income			
As reported:	$ 151,936	$ 92,479	$ 95,575
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)	(5,859)
Pro forma	$ 150,107	$ 89,290	$ 89,716
Pro forma basic earnings per share			
Income before cumulative effect of change in accounting principle	$ 2.64	$ 1.54	$ 1.34
Cumulative effect of change in accounting principle, net of income tax	-	-	0.09
Total	$ 2.64	$ 1.54	$ 1.43
Pro forma diluted earnings per share			
Income before cumulative effect of change in accounting principle	$ 2.30	$ 1.39	$ 1.24
Cumulative effect of change in accounting principle, net of income tax	-	-	0.08
Total	$ 2.30	$ 1.39	$ 1.32

For purposes of pro forma disclosures, the estimated fair values of the options 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.

Comprehensive Income

Comprehensive income consists of net income, unrealized gains and losses on marketable equity securities 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 balances of components comprising accumulated 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, 2004			
Before tax amount	$ 27,401	$ 168	$ 27,569
Tax (expense) benefit	(10,347)	(67)	(10,414)
After tax amount	$ 17,054	$ 101	$ 17,155
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)

Major Customers

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. During 2003 three customers individually accounted for 14 percent, 13 percent and 11 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, development, production and sale of natural gas and crude oil, and 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 activities of our gas marketing personnel directly support the underlying sale of oil and gas production and are not viewed by management as a discrete reporting segment.

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.

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. Each reporting unit is defined as the oil and gas properties in a region.

Suspended Well Costs

In 2005, the Company adopted FASB Staff Position No. FAS 19-1, "Accounting for Suspended Well Costs," ("FSP FAS 19-1"). Upon adoption of the FSP FAS 19-1 the Company evaluated all existing capitalized exploratory well costs under the provisions of the FSP FAS 19-1. As a result, the Company determined that no suspended well costs should be impaired.

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"), or SPEs which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. As of December 31, 2005, 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,	
	2005	2004
	(In thousands)	
Accrued oil and gas sales	$ 138,521	$ 79,107
Due from joint interest owners	21,696	20,587
Other	4,980	5,270
Total accounts receivable	$ 165,197	$ 104,964

Accounts payable and accrued expenses are comprised of the following:

	As of December 31,	
	2005	2004
	(In thousands)	
Accrued drilling costs	$ 40,071	$ 33,998
Revenue payable	61,924	41,875
Accrued lease operating expense	9,738	13,066
Accrued taxes	6,202	800
Accrued interest	1,861	1,779
Joint owner advances	2,955	448
Accrued compensation	16,618	5,555
Trade payables	14,265	7,506
Oil hedge accrual	1,000	3,027
Other	10,323	2,063
Total account payable and accrued expenses	$ 164,957	$ 110,117

Note 3 - Acquisitions and Divestitures

Agate Acquisition

On January 5, 2005, the Company acquired Agate Petroleum, Inc. (“Agate”) in exchange for $40.0 million in cash. The Company allocated the purchase price based on the estimated fair values of the acquired assets and liabilities. The Company finalized the purchase price allocation in 2005 as all amounts related to receivables and payables were determined with certainty. The final allocation did not result in any material adjustments to the preliminary purchase price. 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. The acquisition was accounted for using the purchase method of accounting and was funded with cash on hand and borrowings under the Company’s credit facility. Operating results from the acquired properties have been included in the consolidated statements of operations from the date of closing.

The goodwill and deferred income tax liability result from the use of present value considerations in the economic decision process that cannot be applied to the amounts recorded for deferred income taxes from acquiring oil and gas assets in a transaction in which the tax basis of the assets acquired is lower than the book basis fair value. The strategic benefits to the Company that support the recognition of goodwill in this acquisition include the mix of complementary high-quality assets in two of our existing core areas, lower-risk exploitation opportunities, and increased cash flow from operations available for investing activities.

Wold Acquisition

On August 1, 2005, the Company acquired oil and gas properties primarily in the Wind River and Powder River Basins of Wyoming from Wold Oil Properties, Inc. (“Wold”) for $37.1 million in cash. The Company allocated the purchase price based on the fair values 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. The $7.0 million asset retirement obligation includes approximately $4.7 million related to shut in and temporarily abandoned wells included in the acquisition. The Company finalized the allocation of the purchase price as all post-closing adjustments were determined with certainty prior to the end of 2005. The acquisition was accounted for using the purchase method of accounting and was funded with cash on hand and borrowings under the Company’s credit facility. Operating results from the acquired properties have been included in the consolidated statement of operations from the date of closing.

Goldmark Acquisition

On November 1, 2004, the Company acquired Goldmark Engineering Inc. along with proved and unproved oil and gas properties from various other parties (collectively, “Goldmark”) in exchange for $23.5 million of cash. The allocation of the purchase price was $29.6 million of proved reserves and unproved acreage, $1.2 million of cash, $753,000 of other assets, $446,000 of payables, a $2.8 million asset retirement liability, and a $4.8 million deferred tax liability.

Border Acquisition

On December 15, 2004, the Company completed the acquisition of proved and unproved oil and gas properties from Border Company and other parties in exchange for $34.8 million in cash. The allocation of the purchase price was $35.5 million of proved reserves and unproved acreage and a $649,000 asset retirement obligation.

Sales of Properties

Throughout 2005, the Company sold interests in certain properties, received cash proceeds of $1.2 million and recognized a gain of approximately $222,000 from these sales. Throughout 2004 and 2003, the Company sold interests in certain properties and received $2.8 million and $23.5 million, respectively, in net proceeds and recognized a gain of approximately $1.8 million and $7.3 million, respectively, from these sales.

Note 4 - Income Taxes

The provision for income taxes consists of the following:

	For the Years Ended December 31,		
	2005	2004	2003
		(In thousands)	
Current taxes:			
Federal	$ 75,848	$ 21,143	$ 29,582
State	4,906	1,389	2,656
Deferred taxes	5,547	31,217	23,692
Total income tax expense	$ 86,301	$ 53,749	$ 55,930

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 $6.0 million in 2005, $3.8 million in 2004, and $1.2 million in 2003.The components of the net deferred tax liability are as follows:

	December 31,	
	2005	2004
	(In thousands)	
Deferred tax liabilities:		
Oil and gas properties	$ 204,745	$ 146,427
Interest on Convertible Notes	5,600	4,192
Unrealized derivative gain included in accumulated other comprehensive income	-	2,246
Other	2,750	435
Total deferred tax liabilities	213,095	153,300
Deferred tax assets:		
Net Profits Plan liability	51,712	11,598
Unrealized derivative loss included in accumulated other comprehensive income	33,441	1,033
Stock compensation	4,585	1,590
State tax net operating loss carryforward or carryback	2,928	2,981
State and federal income tax benefit	1,587	1,100
Deferred capital loss	761	758
Employee benefits and other	609	969
Federal net operating loss carryforward	-	2,882
Total deferred tax assets	95,623	22,911
Valuation allowance	(2,572)	(1,714)
Net deferred tax assets	93,051	21,197
Total net deferred tax liabilities	120,044	132,103
Less: current deferred income tax liabilities	(1,328)	(2,357)
Add: current deferred income tax assets	9,580	84
Non-current net deferred tax liabilities	$ 128,296	$ 129,830
Current federal income tax payable	$ 3,346	$ 939
Current state refundable income tax	$ -	$ 139
Current state income tax payable	$ 2,856	$ -

At December 31, 2005, the Company had state net operating loss carryforwards of approximately $40.1 million and state tax credits of $125,000, which expire between 2006 and 2024. 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 as a result of payments under the plan.

Federal income tax expense and benefit differs 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,		
	2005	2004	2003
		(In thousands)	
Federal statutory taxes	$ 83,307	$ 51,180	$ 49,668
Increase (reduction) in taxes resulting from:			
State taxes (net of federal benefit)	4,185	2,586	5,812
Domestic production activities deduction	(1,717)	-	-
Statutory depletion	(224)	(224)	(224)
Other	(108)	(665)	559
Change in valuation allowance	858	872	115
Income tax expense from operations	$ 86,301	$ 53,749	$ 55,930

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 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 appointment factors are evaluated upon completion of the prior year income tax return after significant acquisitions are closed and at the end of the year.

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. The new 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 $500 million, and is subject to regular semi-annual redeterminations. The borrowing base redetermination process considers the value of St. Mary's oil and gas properties and other assets, as determined by the bank syndicate. The Company has elected an aggregate commitment amount of $200 million under the credit facility. The Company must comply with certain financial and non-financial covenants. Interest and commitment fees are accrued based on the borrowing base utilization percentage table below. Euro-dollar loans accrue interest at LIBOR plus the applicable margin from the utilization table, and Alternative Base Rate (ABR) loans accrue interest at prime plus the applicable margin from the utilization table. Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the consolidated statements of operations.

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

The Company had no outstanding loans under its revolving credit agreement on either December 31, 2005 or February 15, 2006.

5.75% Senior Convertible Notes Due 2022

As of December 31, 2005, 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 one-half of one 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 2005. Based on the trading price of the Convertible Notes over the determination period, the Company will be subject to the contingent interest payments for the period from September 16, 2005, to March 15, 2006.

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 $13.00 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 note holders have the option of requiring 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 (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 our 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 $286 million as of December 31, 2005, and approximately $172 million as of December 31, 2004.

Weighted-Average Interest Rate Paid and Capitalized Interest

The weighted-average interest rate paid in 2005 and 2004 was 7.1 percent, 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 lower average outstanding loan balance results in a higher weighted-average interest rate. The Company capitalized interest costs of $1.9 million, $1.4 million, and $780,000 for the years ended December 31, 2005, 2004, and 2003, respectively.

Note 6 - Commitments and Contingencies

The Company leases office space under various operating leases with terms extending as far as May 31, 2012. Rent expense, net of sublease income, was $1.3 million, $1.5 million, and $1.3 million in 2005, 2004 and 2003, respectively. The Company also leases office equipment under various operating leases. The Company has a non-cancelable sublease of approximately $1.2 million through 2012. The annual minimum lease payments for the next five years and thereafter are presented below:

Years Ending December 31,	(In thousands)
2006	2,447
2007	1,570
2008	1,370
2009	1,238
2010	1,192
Thereafter	1,507
Total	$ 9,324

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 up to 50 percent of their aggregate base salary. Any awards under the cash bonus plans are based on a combination of Company and individual performance. The Company accrued $7.4 million for cash bonuses in 2005 that will be paid in 2006, and $2.0 million for cash bonuses in 2004 that were paid in 2005.

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 designated as participants by the Company's Compensation Committee of the Board of Directors, upon recommendation by senior management, and employed by the Company on the last day of that year become entitled to bonus payments after the Company has received net cash flows returning 100 percent of all costs associated with that pool. Thereafter, ten percent of future net cash flows generated by the pool are allocated among the participants and distributed at least annually. The portion of net cash flows from the pool to be allocated among the participants increases to 20 percent after the Company has recovered 200 percent of the total costs for the pool, including payments made under the Net Profits Plan at the ten percent level. The Net Profits Plan has been in place since 1991. Pool years prior to and including 2005 are fully vested. Pool years beginning in 2006 will carry a vesting period of three years and a maximum benefit to full participants from a particular year's pool of 300 percent of each participating individual's salary paid to such individual during the year to which the pool relates. A partial interest participant's benefit is prorated proportionally from the 300 percent.

Expense for distributions made or accrued under the Net Profits Plan related to current period operations for the years ended 2005, 2004, and 2003 were $20.8 million, $8.0 million, and $8.9 million, respectively. These amounts relate to the current period realized results from oil and gas operations for the properties associated with the respective pools that have achieved payout status.

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 utilizing a discount rate of predominately 15 percent, 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 price assumptions are currently formulated by applying a price that is derived from a rolling average of actual prices realized from the prior 24 months together with adjusted NYMEX strip prices for the ensuing 12 months. This calculation is supplemented with hedge prices for the percentage of forecast production hedged. The forecast expense associated with this significant management estimate increased substantially in 2005 as a result of the significant increase of oil and gas prices during the year, together with the impact of pricing that is assured to the Company as a result of executing its expanded hedging strategy. In addition, these higher prices have moved more pools to 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 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 prices in our calculation by ten percent, the liability recorded at December 31, 2005, would differ by approximately $26 million, and a one percent change in the discount rate would result in a change of approximately $5 million. Actual cash payments to be made in future periods are dependent on realized actual production, prices, and costs associated with the individual pools of the Net Profits Plan. Consequently, actual cash payments will be inherently different from the amounts estimated.

The following table presents the changes in the estimated liability attributable to the Net Profits Plan:

	As of December 31,	
	2005	2004
	(In thousands)	
Beginning liability for Net Profits Plan	$ 30,561	$ 6,163
Increase in liability	127,064	32,410
Reduction in liability for cash payments made or accrued and recognized as compensation expense under the Net Profits Plan	(20,801)	(8,012)
Ending liability for Net Profits Plan	$ 136,824	$ 30,561

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 increase or decrease to expense in the current period. The amount recorded as an increase or decrease to expense associated with the change in the estimated liability is not allocated to general and administrative costs or exploration costs because it is an estimate at the current time of the adjustment to the liability that is associated with the future net cash flows from oil and gas properties in the respective pools rather than current period realized performance. The table below presents the estimated allocation of the change in the liability if the Company did allocate the adjustment to these specific line items:

	For the Years Ended December 31,		
	2005	2004	2003
		(In thousands)	
General and administrative expense	$ 51,419	$ 14,609	$ 3,982
Exploration expense	54,844	9,789	1,335
Total	$ 106,263	$ 24,398	$ 5,317

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 $966,000, $834,000, and $746,000 for the years ended December 31, 2005, 2004, and 2003, respectively. No discretionary contributions were made by the Company to the 401(k) Plan in any of these three 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. Shares issued under the ESPP totaled 28,447 in 2005, 27,748 in 2004, and 33,988 in 2003. Total proceeds to the Company for the issuance of these shares were $601,000 in 2005, $375,000 in 2004, and $375,000 in 2003.

Stock Option Plans

The Company has a Stock Option Plan and an Incentive Stock Option Plan (collectively, the "Option Plans"). The Option Plans grant options to purchase shares of the Company's common stock to eligible employees, contractors, and current and former members of the Board of Directors. There are 11.2 million shares of the Company's common stock reserved for issuance under the Option Plans. This number is reduced to the extent that restricted stock or restricted stock units are granted under the Restricted Stock Plan. All options granted to date under the Option Plans have been granted at exercise prices equal to the respective market prices of the Company's common stock on the grant dates. There were 1,063,617 shares available for grant under the Option Plans (including the Restricted Stock Plan, as described later) as of December 31, 2005.

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

	For the Years Ended December 31,					
	2005		2004		2003	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Outstanding, start of year	5,651,350	$ 12.06	7,050,256	$ 11.55	6,123,132	$ 10.67
Granted	-	-	117,356	18.90	1,716,862	13.35
Exercised	(936,403)	11.31	(1,399,052)	10.03	(490,038)	6.44
Forfeited	(16,704)	13.24	(117,210)	12.50	(299,700)	12.00
Outstanding, end of year	4,698,243	12.21	5,651,350	12.06	7,050,256	11.55
Exercisable, end of year	4,121,424	12.07	4,441,362	11.76	4,882,492	11.18
Weighted-average fair value of options granted during the year	$ -		$ 8.44		$ 6.14	

A summary of additional information related to options outstanding as of December 31, 2005, follows:

Range of Exercise Prices			Options Outstanding: Number Outstanding	Options Outstanding: Weighted-Average Remaining Contractual Life	Options Outstanding: Weighted-Average Exercise Price	Options Exercisable: Number Exercisable	Options Exercisable: Weighted-Average Exercise Price
$ 4.62	-	5.13	145,270	3.0 years	4.63	145,270	4.63
5.13	-	8.75	666,394	4.0 years	6.91	666,394	6.91
8.75	-	11.95	1,175,680	6.4 years	11.35	925,680	11.29
11.95	-	12.90	1,075,639	7.2 years	12.46	971,363	12.43
12.90	-	14.25	794,806	7.8 years	13.88	631,579	13.87
14.25	-	16.72	772,050	5.2 years	16.66	742,050	16.66
16.72	-	20.87	68,404	9.0 years	20.87	39,088	20.87
Total			4,698,243			4,121,424	

SFAS No. 123 establishes a fair value method of accounting for stock-based compensation plans through either recognition or disclosure. The Company accounts for stock-based compensation under the intrinsic value method pursuant to APB No. 25 and has elected to adopt SFAS No. 123 through compliance with the disclosure requirements set forth in the Statement. Because the exercise price of the Company's stock options equals the market price of the underlying stock on the date of grant, no compensation expense is recognized under APB No. 25. Pro forma information regarding net income and earnings per share is required by SFAS No. 123 and has been determined as if the Company had accounted for its employee stock options under the fair value method of that Statement. This pro forma information is prominently disclosed in Note 1 - Summary of Significant Accounting Policies.

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

	For the Years Ended December 31, 2005	2004	2003
Risk free interest rate:			
Stock options	-	4.1%	3.6%
Employee stock purchase plan	2.5%	3.1%	3.7%
Dividend yield:			
Stock options	-	0.3%	0.4%
Employee stock purchase plan	0.4%	0.3%	0.4%
Volatility factor of the expected market price of the Company's common stock:			
Stock options	-	35.9%	39.9%
Employee stock purchase plan	36.3%	23.8%	20.2%
Expected life of the options (in years)			
Stock options	-	9.0	7.0
Employee stock purchase plan	0.5	0.5	0.5

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.

Restricted Stock Plan

In May 2004 the Restricted Stock Plan was approved by the Company's stockholders. This established a long-term incentive program whereby grants of restricted stock or restricted stock units ("RSUs") may be 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 restriction period. The total number of shares of the Company's common stock reserved for issuance under the Restricted Stock Plan is 11,200,000. This number is reduced to the extent that stock options are granted under the Company's Option Plans.

St. Mary issued 194,508 RSUs on March 15, 2005, related to 2004 performance. The total expense associated with this issuance was $4.9 million as measured on the grant date. The total unvested portion of the measured expense was initially recorded as deferred stock-based compensation and is being charged to compensation expense based on the vesting schedule. The granted RSUs vest 25 percent immediately upon grant and 25 percent on each of the next three anniversary dates of the grant. The vested shares underlying the RSU grants will be issued on the third anniversary of the grant, at which time the shares carry no further restrictions. As of December 31, 2005, there were a total of 632,809 RSUs outstanding, of which 276,746 were vested. Total compensation expense related to the RSUs for the year ended December 31, 2005, was $7.0 million. This amount includes $4.0 million of compensation expense related to the 2005 plan year for the estimated value of grants expected to be issued in 2006.

Non -Employee Director Stock Compensation Plan

In May 2003, stockholders approved a Non-Employee Director Stock Compensation Plan to authorize the issuance of up to 60,000 shares of St. Mary's common stock to non-employee directors as part of their compensation over an anticipated period of up to five years. The purpose of the plan is to attract, retain, and motivate non-employee directors. As of December 31, 2005, 39,126 shares have been issued under this plan.

Note 8 - Pension Benefits

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

Obligations and Funded Status for Both Plans

	For the Years Ended December 31,		
	2005	2004	2003
		(In thousands)	
Change in benefit obligations:			
Projected benefit obligation at beginning of year	$ 10,174	$ 8,048	$ 6,330
Service cost	1,385	1,139	963
Interest cost	535	489	428
Actuarial loss	(4)	1,236	620
Benefits paid	(190)	(738)	(293)
Projected benefit obligation at end of year	$ 11,900	$ 10,174	$ 8,048
Change in plan assets:			
Fair value of plan assets at beginning of year	$ 4,675	$ 3,694	$ 2,478
Actual return on plan assets	412	434	608
Employer contribution	1,058	1,285	901
Benefits paid	(190)	(738)	(293)
Fair value of plan assets at end of year	$ 5,955	$ 4,675	$ 3,694
Funded status:	$ (5,945)	$ (5,499)	$ (4,354)
Unrecognized net loss	3,450	3,754	2,874
Unrecognized prior service cost	-	-	(15)
Accrued benefit cost	$ (2,495)	$ (1,745)	$ (1,495)

Amounts Recognized in the Consolidated Balance Sheets for Both Plans

	As of December 31,	
	2005	2004
	(In thousands)	
Accrued benefit cost	$ 2,495	$ 1,745
Accumulated other comprehensive income	290	746
Net amount recognized	$ 2,785	$ 2,491

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

	As of December 31,	
	2005	2004
	(In thousands)	
Projected benefit obligation	$ 11,900	$ 10,174
Accumulated benefit obligation	$ 8,429	$ 7,143
Fair value of plan assets	$ 5,955	$ 4,675

The Company's accumulated benefit obligation for the Qualified Pension Plan was $7.3 million at December 31, 2005, and $5.9 million at December 31, 2004. The accumulated benefit obligation exceeds plan assets by $1.3 million. The tax-adjusted liability of $180,000 was recorded in other comprehensive income at December 31, 2005.

The Company's accumulated benefit obligation for the Nonqualified Pension Plan was $1.1 million at December 31, 2005, and $1.2 million at December 31, 2004. There are no plan assets in the Nonqualified Pension Plan due to the nature of the plan.

Components of Net Periodic Benefit Cost for Both Plans

	For the Years Ended December 31,		
	2005	2004	2003
		(In thousands)	
Components of net periodic benefit cost:			
Service cost	$ 1,385	$ 1,139	$ 963
Interest cost	535	489	428
Expected return on plan assets	(354)	(295)	(172)
Amortization of prior service cost	-	(16)	(25)
Amortization of net actuarial loss	241	218	329
Net periodic benefit cost	$ 1,807	$ 1,535	$ 1,523

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.

Additional Information

The minimum liability included in other accumulated comprehensive income, net of taxes, decreased by $283,000, $101,000 and $197,000 for the years ended December 31, 2005, 2004 and 2003, respectively.

Assumptions

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

	As of December 31,	
	2005	2004
Projected benefit obligation		
Discount rate	5.50%	5.75%
Expected return on plan assets	7.50%	8.00%
Rate of compensation increase	5.93%	4.00%
Net periodic benefit cost		
Discount rate	5.75%	6.25%
Expected return on plan assets	7.50%	8.00%
Rate of compensation increase	5.93%	3.50%

Plan Assets

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

	Target	As of December 31,	
Asset Category	2006	2005	2004
Equity securities	60%	61.6%	63.0%
Debt securities	40%	38.2%	34.7%
Other	-	0.2%	2.3%
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 7.8 percent for 2005 and 10.4 percent for 2004. 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 $1.1 million, $1.3 million, and $901,000, to the pension plans in the years ended December 31, 2005, 2004, and 2003, respectively. St. Mary expects to contribute approximately $1.4 million to the pension plans in 2006.

Benefit Payments

The Plans made actual benefit payments of $190,000, $738,000, and $293,000 in the years ended December 31, 2005, 2004, and 2003, respectively. Expected benefit payments over the next ten years follows:

Years Ended December 31,		(in thousands)
2006	$	310
2007	$	413
2008	$	534
2009	$	732
2010	$	793
2011 through 2015	$	10,181

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.

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.

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

	As of December 31,			
	2005		2004	
	(In thousands)			
Beginning asset retirement obligation	$	40,911	$	25,485
Liabilities incurred		13,188		7,187
Liabilities settled		(955)		(620)
Accretion expense		3,279		1,984
Revision to estimated cash flows		9,655		6,875
Ending asset retirement obligation	$	66,078	$	40,911

Note 10 - Derivative Financial Instruments

To mitigate a portion of the potential exposure to adverse market changes, the Company has entered into various derivative contracts. The Company realized a net loss of $24.4 million, $49.8 million, and $22.7 million from its derivative contracts for the years ended December 31, 2005, 2004, and 2003 respectively.

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

	For the Years Ended December 31,		
	2005	2004	2003
		(In thousands)	
Derivative contract settlements included in oil and gas hedge loss	$ (22,539)	$ (50,299)	$ (22,439)
Ineffective portion of hedges qualifying for hedge accounting included in derivative gain (loss)	(1,754)	113	(246)
Non-qualified derivative contracts included in derivative gain (loss)	139	(373)	(64)
Interest rate derivative contract settlements	(247)	795	-
Total loss	$ (24,401)	$ (49,764)	$ (22,749)

Oil and Gas Commodity Hedges

The Company has in place derivative contracts, which included swap and collar arrangements, for the sale of oil and natural gas. Including oil and natural gas collar arrangements entered into subsequent to December 31, 2005, the Company has hedge contracts in place through 2011 for a total of approximately 13.0 million Bbls and 73.7 million MMBTU of anticipated production. The Company anticipates that all forecasted transactions will occur by the end of their originally specified periods. All contracts are entered into for other than trading purposes.

The Company attempts to qualify its oil and natural gas derivative instruments as cash flow hedges for accounting purposes. As of December 31, 2005, all oil and natural gas derivative instruments qualified as cash flow hedges for accounting purposes. The estimated fair value of oil and natural gas derivative contracts designated and qualifying as cash flow hedges under SFAS No. 133 was a net liability of $90 million at December 31, 2005.

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

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

Derivative gain or loss for the years ended December 31, 2005, 2004, and 2003, includes a net loss of $1.8 million, a net gain of $113,000, and a net loss of $246,000, respectively, from ineffectiveness related to oil and natural gas derivative contracts.

As of December 31, 2005, the amount of unrealized loss 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 $17.0 million.

Interest Rate Derivative Contracts

In October 2003 the Company entered into fixed-to-floating interest rate swaps for a total notional amount of $50 million through March 20, 2007. Under the swaps, St. Mary will be paid a fixed interest rate of 5.75 percent and will pay a variable interest rate of 235 basis points above the six-month LIBOR rate as determined on the semi-annual settlement date. The payment dates of the swaps match exactly with the interest payment dates of the Convertible Notes.

The Company entered into a floating-to-fixed interest rate swap on April 13, 2005, for a total notional amount of $50 million through March 20, 2007, that effectively offsets the fixed-to-floating interest rate swaps described above. Under the swap, St. Mary 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 payment dates of the swap match exactly with the interest payment dates of the Convertible Notes and the fixed-to-floating interest rate swaps. The impact of this instrument, when combined with the other interest rate swaps, is that the Company has fixed its net liability related to the interest rate swaps and will pay a 1.1 percent interest factor on $50 million of notional debt through March 2007.

During the year ended December 31, 2005, the Company made payments of $247,000, and during the year ended December 31, 2004, the Company received payments of $795,000 under the swap arrangements. These payments are included in the Company's interest expense.

The fair value of the interest rate derivatives was a liability of $646,000 as of December 31, 2005. The Company recorded a net derivative loss in the consolidated statements of operations of $213,000, $328,000, and $104,000 for the years ended December 31, 2005, 2004, and 2003, respectively, from mark-to-market adjustments for these derivatives. These swaps do not qualify for fair value hedge treatment under SFAS No. 133 and related pronouncements.

Convertible Note Derivative Interest

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 the years ended December 2005, 2004, and 2003, includes $95,000 of annual amortization of the original value of this derivative. Derivative gain (loss) in the consolidated statements of operations for the years ended December 31, 2005, 2004, and 2003, includes a net gain of $352,000, a net loss of $45,000, and a net gain of $40,000, respectively, from mark-to-market adjustments for this derivative. The fair value of this derivative was a liability of $468,000 and $820,000 at December 31, 2005 and 2004, respectively.

Note 11 - Repurchase of Common Stock

Stock Repurchase Program

In August 2004 the Company's Board of Directors approved an increase in the number of shares that may be repurchased under the original authorization approved in August 1998 to 6,000,000 as of the effective date of the resolution. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of St. Mary's existing credit facility agreement and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow and borrowings under the credit facility. As of December 31, 2005, 2,153,882 shares of the Company's common stock had been repurchased under the plan. The Company repurchased 1,175,282 and 978,600 shares in 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 2005, 2004 and 2003 amounts include $22.8 million, $14.1 million, and $5.5 million, respectively, of capitalized costs associated with asset retirement obligations.

	For the Years Ended December 31,		
	2005	2004	2003
		(In thousands)	
Development costs	$ 249,518	$ 190,829	$ 111,908
Exploration	69,817	37,977	33,296
Acquisitions:			
Proved	84,981	69,054	73,989
Unproved	2,853	7,646	8,942
Leasing activity	14,330	7,877	7,480
Total	$ 421,499	$ 313,383	$ 235,615

The following table reflects the net changes in capitalized exploratory well costs during 2005, 2004 and 2003, and does not include amounts that were capitalized and either subsequently expensed or reclassified to producing well costs in the same period. Capitalized exploratory well costs for fiscal years ending December 31, 2004 and December 31, 2003 are presented based on the Company's previous accounting policy.

	For the Years Ended December 31,		
	2005	2004	2003
		(In thousands)	
Beginning balance at January 1,	$ 189	$ 544	$ 3,335
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	7,994	189	544
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	(189)	-	(333)
Capitalized exploratory well costs charged to expense	-	(544)	(3,002)
Ending balance as December 31,	$ 7,994	$ 189	$ 544

No exploratory well costs have been capitalized for a period greater than one year from the completion of exploratory drilling.

Oil and Gas Reserve Quantities (Unaudited):

For all years presented, Ryder Scott Company L.P. and/or Netherland, Sewell and Associates, Inc. ("NSAI") prepared the reserve information for greater than 80 percent of the PV-10 value. The Company engaged NSAI for the first time in 2004. St. Mary 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,					
	2005		2004		2003	
	Oil or Condensate (MBbl)	Gas (MMcf)	Oil or Condensate (MBbl)	Gas (MMcf)	Oil or Condensate (MBbl)	Gas (MMcf)
Developed and undeveloped:						
Beginning of year	56,574	319,196	47,787	307,024	36,119	274,172
Revisions of previous estimate	1,593	24,354	1,994	(21,885)	2,856	3,904
Discoveries and extensions	5,839	105,091	6,306	63,185	3,681	69,189
Purchases of minerals in place	4,831	20,823	5,773	17,635	11,952	41,335
Sales of reserves	(7)	(588)	(487)	(165)	(2,280)	(31,913)
Production	(5,927)	(51,801)	(4,799)	(46,598)	(4,541)	(49,663)
End of year [a]	62,903	417,075	56,574	319,196	47,787	307,024
Proved developed reserves:						
Beginning of year	47,992	272,295	43,693	264,140	33,580	228,973
End of year	55,971	313,125	47,992	272,295	43,693	264,140

(a) At December 31, 2005, 2004, and 2003 amounts include approximately 435,480, and 1,119 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," 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:

	2005	2004	2003
Gas (per Mcf)	$ 8.34	$ 5.80	$ 5.70
Oil (per Bbl)	$ 55.63	$ 40.06	$ 31.01

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,		
	2005	2004	2003
		(In thousands)	
Future cash inflows	$ 6,979,279	$ 4,118,188	$ 3,232,605
Future production costs	(2,146,590)	(1,349,380)	(963,226)
Future development costs	(385,379)	(164,797)	(101,935)
Future income taxes	(1,448,444)	(827,368)	(735,947)
Future net cash flows	2,998,866	1,776,643	1,431,497
10 percent annual discount	(1,286,568)	(742,705)	(571,541)
Standardized measure of discounted future net cash flows	$ 1,712,298	$ 1,033,938	$ 859,956

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

	For the Years Ended December 31,		
	2005	2004	2003
		(In thousands)	
Standard measure, beginning of year	$ 1,033,938	$ 859,956	$ 581,862
Sales of oil and gas produced, net of production costs	(590,671)	(368,099)	(299,044)
Net changes in prices and production costs	725,154	166,826	168,661
Extensions, discoveries and other, net of production costs	422,481	279,763	226,181
Purchase of minerals in place	132,185	73,875	178,264
Development costs incurred during the year	55,324	46,156	22,763
Changes in estimated future development costs	(42,710)	(17,489)	11,175
Revisions of previous quantity estimates	117,763	(24,271)	45,551
Accretion of discount	150,112	125,175	78,869
Sales of reserves in place	(1,000)	(3,906)	(47,270)
Net change in income taxes	(314,685)	(75,389)	(211,381)
Changes in timing and other	24,407	(28,659)	104,325
Standardized measure, end of year	$ 1,712,298	$ 1,033,938	$ 859,956

Note 13 - Quarterly Financial Information (Unaudited)

The Company's quarterly financial information for fiscal 2005 and 2004 is as follows (in thousands, except per share amounts):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
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 and cumulative effect of change in accounting principle	$ 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	$ -
Year Ended December 31, 2004				
Total revenue	$ 96,482	$ 102,151	$ 108,078	$ 126,388
Less: costs and expenses	60,603	65,566	71,575	83,440
Income from operations	$ 35,879	$ 36,585	$ 36,503	$ 42,948
Income before income taxes and cumulative effect of change in accounting principle	$ 34,535	$ 35,262	$ 35,125	$ 41,306
Net income	$ 21,449	$ 21,836	$ 22,565	$ 26,629
Basic net income per common share	$ 0.36	$ 0.38	$ 0.40	$ 0.46
Diluted net income per common share	$ 0.33	$ 0.34	$ 0.36	$ 0.41
Dividends declared per common share	$ -	$ 0.025	$ 0.025	$ -

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: February 23, 2006

By: /s/ MARK A. HELLERSTEIN

Mark A. Hellerstein
Chairman of the Board of Directors, President
and Chief Executive Officer

GENERAL POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints each of Mark A. Hellerstein and David W. Honeyfield his or her true and lawful attorney-in-fact and agent with full power of substitution and resubstitution, and each with full power to act alone, for the undersigned and in his or her name, place and stead, in any and all capacities, to sign any amendments to this Annual Report on Form 10-K for the fiscal year ended December 31, 2005, and to file the same, with exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, hereby ratifying and confirming all that each of said attorney-in-fact, or his substitute or substitutes, may do or cause to be done by virtue hereof.

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

Signature	Title	Date
/S/ MARK A. HELLERSTEIN	Chairman of the Board of Directors,	February 23, 2006
Mark A. Hellerstein	President and Chief Executive Officer	
S/ DAVID W. HONEYFIELD	Vice President-Chief Financial Officer,	February 23, 2006
David W. Honeyfield	Secretary and Treasurer	
/S/ GARRY A. WILKENING	Vice President-Administration	February 23, 2006
Garry A. Wilkening	and Controller	

Signature	Title	Date
/S/ BARBARA M. BAUMANN Barbara M. Baumann	Director	February 23, 2006
/S/ LARRY W. BICKLE Larry W. Bickle	Director	February 23, 2006
/S/ THOMAS E. CONGDON Thomas E. Congdon	Director	February 23, 2006
/S/ WILLIAM J. GARDINER William J. Gardiner	Director	February 23, 2006
/S/ WILLIAM D. SULLIVAN William D. Sullivan	Director	February 23, 2006
/S/ JOHN M. SEIDL John M. Seidl	Director	February 23, 2006

EXHIBIT 10.35

SUMMARY OF COMPENSATION ARRANGEMENTS FOR NON-EMPLOYEE DIRECTORS

The following is a summary of the standard compensation arrangements for the non-employee members of the Board of Directors of St. Mary Land & Exploration Company (the "Company") for 2006.

For service for the fiscal period from May 25, 2005 through approximately May 17, 2006, the total annual target compensation for each non-employee director is approximately $140,000. As discussed below, the actual value of compensation may be higher or lower depending on the results of the restricted stock unit ("RSU") component of director compensation.

A. The cash component of the compensation for non-employee directors is as follows:

1. Payment of $750 for each Board meeting attended.

2. Directors serving on a committee are paid $600 for each committee meeting attended and $375 for each telephonic committee meeting.

3. Directors are reimbursed for expenses incurred in attending Board and committee meetings.

B. The equity-based compensation for non-employee directors is comprised of two components:

1. A retainer payable upon election to the Board by the stockholders valued at approximately $60,000. In May 2005 this resulted in the grant to each non-employee director of 2,321 restricted shares of the Company's common stock issued under the Company's Non-Employee Director Stock Compensation Plan.

2. An RSU grant that will be issued in the first quarter of 2006 based on the following formula:

a. The dollar base to determine the number of RSUs to be issued will be the average of CEO and COO Peer Group Compensation divided by 3.5;

b. This quotient will be multiplied by the average cash bonus percentage for the Company's CEO and COO;

c. This product will be multiplied by the 4X multiplier that is applied to calculate the Company's CEO and COO RSU grants; and

d. The resultant dollar amount will be divided by the average of the Company's quarterly closing price over the performance year to determine the number of RSUs to be issued.

Vesting will be 25% upon issuance and 25% on each of the next three anniversary dates.

C. The committee chairs will receive the following cash payments in recognition of the additional workload of their respective committee assignments. These amounts are to be paid at the beginning of the annual service period.

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1. Audit Committee - $15,000
2. Compensation Committee - $5,000
3. Nominating and Corporate Governance Committee - $5,000

EXHIBIT 12.1

ST. MARY LAND & EXPLORATION COMPANY
RATIO OF EARNINGS TO FIXED CHARGES

Years Ended December 31,				
2005	**2004**	**2003**	**2002**	**2001**
23.2%	18.7%	17.3%	9.9%	69.4%

The ratio of earnings to fixed charges has been computed by dividing earnings available for fixed charges (earnings from continuing operations before income taxes) by fixed charges (interest expense plus capitalized interest).

EXHIBIT 21.1

SUBSIDIARIES
OF
ST. MARY LAND & EXPLORATION COMPANY

A. Wholly-owned subsidiaries of St. Mary Land & Exploration Company, a Delaware corporation:

1. Nance Petroleum Corporation, a Montana corporation
2. St. Mary Energy Company, a Delaware corporation
3. Four Winds Marketing LLC, a Colorado limited liability company
4. SMT Texas LLC, a Colorado limited liability company

B. Other subsidiaries of St. Mary Land & Exploration Company:

1. Box Church Gas Gathering LLC, a Colorado limited liability company (58.6754%)
2. Trinity River Services LLC, a Texas limited liability company (25%)

C. Wholly-owned subsidiaries of St. Mary Energy Company:

1. SMEC Texas LLC, a Colorado limited liability company

D. Partnership interests held by St. Mary Land & Exploration Company:

1. Hilltop Investments, a Colorado general partnership (50%)
2. Parish Ventures, a Colorado general partnership (100%)

E. Partnership interests held by SMT Texas LLC:

1. St. Mary East Texas LP, a Texas limited partnership (99%) (the remaining 1% interest is held by St. Mary Land & Exploration Company)

F. Partnership interests held by SMEC Texas LLC:

1. St. Mary Energy Texas LP, a Texas limited partnership (99%) (the remaining 1% interest is held by St. Mary Energy Company)

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 and 333-58273 on Form S-8 and Registration Statement No. 333-88712 on Form S-3 of our reports dated February 23, 2006, relating to the financial statements (which report expresses an unqualified opinion and includes an explanatory paragraph for the adoption of Statement of Financial Accounting Standards No. 143 "Accounting for Asset Retirement Obligations"), of St. Mary Land & Exploration Company and management's report on the effectiveness of internal control over financial reporting, appearing in this Annual Report on Form 10-K of St. Mary Land & Exploration Company for the year ended December 31, 2005.

/S/DELOITTE & TOUCHE LLP

Denver, Colorado
February 23, 2006

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 of St. Mary Land & Exploration Company for the year ended December 31, 2005. We hereby further consent to the use of information contained in our reports, as of December 31, 2005 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
February 23, 2006

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 of St. Mary Land & Exploration Company for the year ended December 31, 2005. We hereby further consent to the use of information contained in our reports, as of December 31, 2005 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/ FREDERIC D. SEWELL

Frederic D. Sewell
Chairman and Chief Executive Officer

Dallas, Texas
February 23, 2006

CERTIFICATION

I, Mark A. Hellerstein, certify that:

1. I have reviewed this annual report on Form 10-K 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: February 23, 2006

/s/ MARK A. HELLERSTEIN

Mark A. Hellerstein
Chief Executive Officer

CERTIFICATION

I, David W. Honeyfield, certify that:

1. I have reviewed this annual report on Form 10-K 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: February 23, 2006

/s/ DAVID W. HONEYFIELD

David W. Honeyfield
Chief Financial Officer

EXHIBIT 32.1

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

In connection with the Annual Report on Form 10-K of St. Mary Land & Exploration Company (the "Company") for the fiscal year ended December 31, 2005 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Mark A. Hellerstein, as Chief Executive Officer of the Company, and David W. Honeyfield, as Vice President - Chief Financial Officer of the Company, each hereby certifies, pursuant to and solely for the purpose of 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to the best of his knowledge and belief, that:

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

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

/s/ MARK A. HELLERSTEIN

Mark A. Hellerstein
Chief Executive Officer
February 23, 2006

/s/ DAVID W. HONEYFIELD

David W. Honeyfield
Vice President - Chief Financial Officer
February 23, 2006