ST MARY LAND & EXPLORATION CO
Form 10-K
February 24, 2009

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

FORM 10-K

þ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2008
or
o 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 (State or other jurisdiction of incorporation or organization)	41-0518430 (I.R.S. Employer Identification No.)
1776 Lincoln Street, Suite 700, Denver, Colorado (Address of principal executive offices)	80203 (Zip Code)

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

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 þ No o

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 o   No þ

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. YesþNoo

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.o

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

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

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

The aggregate market value of the 61,794,217 shares of voting stock held by non-affiliates of the registrant, based upon the closing sale price of the common stock on June 30, 2008, the last business day of the registrant's most recently completed second fiscal quarter, for $64.64 per share as reported on the New York Stock Exchange was $3,994,378,187. 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 17, 2009, the registrant had 62,305,557 shares of common stock outstanding, which is net of 176,987 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 2009 annual meeting of stockholders to be filed within 120 days after December 31, 2008.

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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 of Oil and Natural Gas Terms." 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.

ITEMS 1. and 2. BUSINESS and PROPERTIES

General

We are an independent oil and gas company engaged in the exploration, exploitation, development, acquisition, and production of natural gas and crude oil in North America. We were founded in 1908 and incorporated in Delaware in 1915. Our initial public offering of common stock took place in December 1992. The common stock of the Company trades on the New York Stock Exchange under the ticker "SM."

Our principal offices are located at 1776 Lincoln Street, Suite 700, Denver, Colorado 80203, and our telephone number is (303) 861-8140.

Strategy

Our mission is to deliver outstanding net asset value per share growth to our investors via attractive oil and gas investments. Historically, a key part of meeting the goal of building stockholder value was the successful execution and integration of niche acquisitions at attractive costs. Recently we shifted the emphasis of our efforts to focus on the exploration for and development of onshore resource plays in North America. This shift was due to the fact that, as we grew, the universe of potential niche acquisition targets became smaller and less impactful to the growth of the Company. Additionally, we believe that we will be able to create more long-term value for our shareholders by building an asset base that is more predictable and does not rely solely on acquisitions to fuel its growth. Our strategy is based on the following points:

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

Significant Developments in 2008

- Broad Economic Downturn and Impacts on Capital Markets and Commodity Prices. During 2008 the global economy experienced a significant downturn. The crisis began over concerns related to the U.S. financial system and quickly grew to impact a wide range of industries. There were two significant ramifications to the exploration and production industry as the economy continued to deteriorate. The first was that capital markets essentially froze. Equity, debt, and credit markets shut down. We were able to weather this initial shock as a result of our strong liquidity position and relatively limited capital commitments. The second impact to the industry was that fear of global recession resulted in a significant decline in oil and gas prices. We have been able to cope with the downturn in prices as a result of our ability to quickly scale down our activity and keep our capital investments within cash flow. Our existing commodity hedge position provided a further backstop as commodity prices continued to decline. We believe the environment in 2009 will continue to be challenging with respect to financing and commodity pricing.

- Significant Volatility in Commodity Prices. As mentioned above, 2008 saw the exploration and production sector impacted by significant volatility in the prices for crude oil and natural gas. Our operations and financial condition are significantly impacted by these prices. Our crude oil is sold on contracts that pay us the average of posted prices for the period in which the crude oil is sold. The spot price for NYMEX crude oil in 2008 ranged from a high of $145.29 per barrel in early July to a low of $31.41 per barrel in late December. The average spot price for oil during the year was $99.92 per barrel. The volatility in oil prices during the year was a result of geopolitical unrest in various producing regions overseas as well as domestic concerns about refinery utilization and petroleum product inventories pushing prices up during the first half of the year. Global demand destruction drove prices down as the economy weakened in the second half of 2008.

We sell the majority of our natural gas on contracts that are based on first of the month (also frequently referred to as bid week) index pricing. The Inside FERC bid week price for Henry Hub, a widely used industry measuring point, averaged $9.04 per MMBtu in 2008, with a high of $13.11 per MMBtu in July and a low of $6.47 per MMBtu in November. Natural gas prices came under pressure in the second half of the year as a result of lower domestic product demand that was caused by the weakening economy and concerns over excess supply of natural gas due to high levels of drilling activity. Some of the regional markets where we sell gas have seen increased downward pressures on price as a result of high levels of activity in the region and either a lack of pipeline takeaway capacity or local demand. This has been most pronounced in our Mid-Continent and Rocky Mountain regions.

- Decrease in Year-End Reserves. Due in large part to the price declines in the second half of 2008 described above, proved reserves decreased 20 percent to 865.5 BCFE at December 31, 2008, from 1,086.5 BCFE at December 31, 2007. We added 170.1 BCFE from our drilling program and 29.1 BCFE from acquisitions during the year. During the year, 61.4 BCFE were sold in divestitures, primarily in the Rocky Mountain and Mid-Continent regions. We had a negative revision of 244.2 BCFE that consisted of 44.5 BCFE in downward performance revisions and a downward pricing revision of 199.7 BCFE due primarily to meaningfully lower commodity prices at the end of 2008. The prices used for the 2008 year-end reserves decreased significantly from a year earlier. Oil prices declined 54 percent from $95.98 per barrel to $44.60 per barrel while natural gas prices dropped 16 percent from $6.80 per MMBtu to $5.71 per MMBtu. Over half of the pricing revisions occurred in the oil-weighted Rocky Mountain region, which saw its proved reserves adversely impacted by low prices and wider differentials at the end of 2008. We also saw meaningful price and performance revisions in the Gulf Coast region related primarily to our Olmos shallow gas properties in South Texas. A large decline in the natural gas liquid fractionation spread year over year resulted in a significantly lower price for natural gas in the determination of proved reserves for the region at year-end. The performance revision is due to poorer reservoir performance then we initially expected. The reservoir is more compartmentalized then originally assumed and we have seen lower reserve outcomes while attempting to infill parts of the field.

- Impairment of Proved Properties. The low prices at year-end for oil and gas and the decrease in proved reserves described above both contributed to a pre-tax non-cash impairment of proved properties in the amount of $302.2 million in 2008. There was no impairment of proved properties in 2007. Approximately $154.0 million of the 2008 impairment was related to assets in South Texas that were acquired in 2007. We also saw an impairment associated with proved properties in the Gulf of Mexico, the Greater Green River Basin in Wyoming, and our coalbed methane project at Hanging Woman Basin.

- Abandonment and Impairment of Unproved Properties. During the year, we abandoned or impaired $39.0 million related to unproved properties. Approximately $13.4 million was related to acreage to which we had assigned value in 2007 acquisitions targeting the Olmos shallow gas. The remaining write-offs were related to acreage we believe we will not be able to hold due to current limited capital availability and to acreage that we do not believe is prospective.

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- Drilling Results. Reserve additions of 170.1 BCFE from drilling activities were driven primarily by results in the Mid-Continent and Permian Basin regions, with those regions contributing 43 percent and 22 percent, respectively, to our drilling additions. The ArkLaTex and Rocky Mountain regions contributed 14 percent and 15 percent, respectively, to our drilling additions. The Mid-Continent region had a very strong year. Additions in the Mid-Continent region were derived principally by successful drilling by us and our operating partners in the horizontal Woodford shale formation in the Arkoma Basin, as well as positive results from a program targeting the deep Springer interval in the Anadarko Basin. In the Permian region, additions were the result of successful drilling in our Wolfberry tight oil program. The ArkLaTex region added reserves from successful Cotton Valley formation development drilling by us at Carthage Field and by an operating partner at Elm Grove Field. Coalbed methane projects at Atlantic Rim and in Hanging Woman Basin accounted for the majority of drilling additions in the Rocky Mountain Region.

- Potential Resource Play Additions. In 2008 we established meaningful positions in several new potential resource plays which emerged in the exploration and development industry, principally the Haynesville shale, the Eagle Ford shale, and the Marcellus shale. Although no proved reserves have been booked in any of these emerging resource plays at the end of 2008, each of these plays could provide for significant future growth in reserves and production if development proves successful. The Haynesville shale emerged early in 2008 in North Louisiana and East Texas and quickly became the hottest resource play in the country. As a result of our previous Cotton Valley and James Lime activity and the acquisition of additional properties in Panola County, Texas in early 2008, we now have approximately 50,000 net acres that could be prospective for the Haynesville shale. Our Eagle Ford shale position in the Maverick Basin in South Texas was seeded through two acquisitions in 2007 and then built through leasing efforts and a joint venture over the course of 2008. If we earn all of the acreage available under the joint venture, St. Mary will control approximately 210,000 net acres in this play. Lastly, late in 2008 we entered into two arrangements that allow us to earn up to 43,000 net acres in the Marcellus shale in north central Pennsylvania.

- Divestiture of Non-Strategic Properties. In 2008 we sold a number of non-strategic properties in an effort to optimize our portfolio. Prior to this year we had been a limited seller of assets. The primary objectives of these sales were to dispose of properties with limited upside drilling potential and to focus our employees on the core strategic assets that will help the Company grow in the future. During 2008 we sold 61.4 BCFE of reserves, the vast majority of which were proved producing. The sales occurred throughout the year and we received $178.9 million in proceeds from these sales. The properties we sold were located primarily in the Rocky Mountain and Mid-Continent regions.

- Senior Management Change. On March 21, 2008, David Honeyfield, Senior Vice President - Chief Financial Officer and Secretary, resigned as an officer of St. Mary, to pursue an opportunity in an unrelated industry. On September 8, 2008, A. Wade Pursell joined St. Mary as Executive Vice President and Chief Financial Officer. Mr. Pursell was employed at Helix Energy Solutions as Chief Financial Officer from 2000 until mid-2008 and as Vice President – Finance and Treasurer from 1997 through 2000. Prior to that, he spent nine years in the audit practice of Arthur Andersen in positions of increasing responsibility.

- Repurchase of Common Stock. During the first quarter of 2008, we repurchased a total of 2,135,600 shares of common stock in the open market for a weighted-average price of $36.13 per share, including commissions. At the time we repurchased our shares, we entered into hedges for a commensurate amount of our production that was represented by the share repurchase in order to lock in the discounted price at which we believed our shares were trading. As of the date of this filing, we are authorized by the Board to repurchase 3,072,184 additional shares under our share repurchase program. The shares may be repurchased from time to time in open market transactions or in privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our existing credit facility agreement and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow, and/or borrowings under

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the credit facility. Given current economic conditions, we do not currently anticipate that in the near term we will be utilizing our liquidity and capital resources for capital investment to conduct stock repurchases.

Outlook for 2009

As of the date of this report, indications are that the credit market is very tight and the capital markets are still not widely accessible or at a minimum very expensive. Furthermore, commodity prices, both on a spot and futures basis, have continued to be under downward pressure as a result of the continuing deterioration of the economy. Given the uncertainty surrounding our ability to access the capital markets and the current low commodity price environment, we are proceeding cautiously in 2009. We continue to maintain our financial and operating flexibility, so we can accelerate activity should industry conditions improve or decelerate activity should circumstances warrant. We have limited exposure to expiring leasehold and few long-term commitments for rigs which allow us to slow down quickly if needed. Rather than set a specific capital expenditures budget for 2009, our plan is to invest capital at or within cash flows for the year. We have deliberately deferred development projects into the second half of 2009, and perhaps beyond, to improve returns on invested capital with either improved commodity prices and/or lower drilling and completion costs. Our focus in 2009 will be to test the potential of three emerging resource plays to which we have exposure – the Haynesville shale in our ArkLaTex region, the Eagle Ford shale in South Texas, and the Marcellus shale in Pennsylvania.

Our financial position entering 2009 is solid; we have no near-term maturities of debt, limited long-term commitments, and significant availability under our current revolving credit facility. This credit facility expires in early April of 2010, and we are currently in discussions with commercial lenders to replace it with a new facility. We expect to have the new facility in place by the end of the first half of 2009. Our intent is to increase the amount of commitments available to us in the new revolver. We believe that given current industry and macro economic conditions, we could see some unique opportunities come to the market and we want to have the financial capacity available to pursue those opportunities.

Assets

As of December 31, 2008, we had estimated proved reserves of 51.4 MMBbl of oil and 557.4 Bcf of natural gas. Prices in effect on December 31, 2008, used to estimate proved reserves were $44.60 per barrel of oil and $5.71 per MMBtu of gas, which were down 54 percent and 16 percent, respectively, from prices used to estimate proved reserves as of December 31, 2007. On an equivalent basis, our proved reserves were 865.5 BCFE as of December 31, 2008, a decrease of 20 percent from 1,086.5 BCFE at the end of the prior year. The decrease in proved reserves during the year was related to significant pricing and sizable performance revisions and to property sales that occurred throughout the year, offset to some extent by acquisitions and additions from drilling activity. On an equivalent basis, 83 percent of our proved reserves were classified as proved developed as of year-end. Total proved oil and gas reserves had a before income tax PV-10 value of $1.3 billion and a standardized measure value of $1.1 billion including the effect of income taxes. A reconciliation between these two amounts is shown under the Reserves section in Part I, Items 1 and 2 of this report. During 2008 our average daily production was 204.7 MMcf of gas and 18.1 MBbl of oil, for an average equivalent production rate of 313.1 MMCFE per day, which is a new annual record for us.

In 2008 we incurred costs of $856.7 million for drilling and exploration activities and acquisitions. This was seven percent lower than the $926.1 million incurred in 2007. During 2008 we incurred costs of $678.8 million for exploration and development activities which compares to $702.5 million incurred in 2007. In 2008 we incurred costs of $126.4 million for leasehold, including costs attributable to unproved properties in acquisitions compared to $61.9 million in 2007. The increase in leasehold incurred costs is a result of our shift in strategy to a focus on acquiring productive leasehold earlier in its life cycle and benefiting from improved returns of organic development. We incurred costs of $51.6 million for the acquisition of proved properties in 2008, which is 68 percent less than the $161.7 million incurred in 2007.

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Our operations are currently concentrated in five core operating areas in the United States. The following table summarizes the production, proved reserves and PV-10 value of our core operating areas as of December 31, 2008.

	ArkLaTex	Mid-Continent	Gulf Coast	Permian	Rocky Mountain	Total (1)
2008 Proved Reserves						
Oil (MMBbl)	0.5	1.1	0.7	19.8	29.2	51.4
Gas (Bcf)	167.1	227.8	39.4	37.1	86.0	557.4
Equivalents (BCFE)	170.0	234.5	43.8	155.9	261.4	865.5
Relative percentage	20%	27%	5%	18%	30%	100%
Proved Developed %	67%	79%	92%	79%	97%	83%
PV-10 Value (in millions)	$ 221.4	$ 379.2	$ 47.9	$ 284.6	$ 332.2	$ 1,265.4
Relative percentage	18%	30%	4%	22%	26%	100%
2008 Production						
Oil (MMBbl)	0.2	0.4	0.2	1.8	4.1	6.6
Gas (Bcf)	17.6	30.8	12.9	3.3	10.3	74.9
Equivalent (BCFE)	18.6	33.0	14.3	13.8	34.9	114.6
Avg. Daily Equivalents (MMCFE/d)	50.7	90.2	39.0	37.8	95.4	313.1
Relative percentage	16%	29%	12%	12%	31%	100%

(1) Totals may not add due to rounding

ArkLaTex Region. St. Mary's operations in the ArkLaTex region are managed from our office in Shreveport, Louisiana. The ArkLaTex region was the first operating office for the Company, originating from an acquisition in 1992. For years the activities of this region focused on the tight sandstone Cotton Valley, James Lime, and Travis Peak formations in the region. In 2008 the Haynesville shale emerged as a new potential resource play in East Texas and North Louisiana.

The ArkLaTex region incurred costs of $218.4 million in 2008 for exploration, development, and acquisition activities, which is 46 percent higher than the $149.8 million spent in 2007. The primary driver of this increase relates to acquisitions of operated Cotton Valley properties in East Texas for approximately $60 million. St. Mary's operated activity in the ArkLaTex region was primarily focused on drilling horizontal Cotton Valley and James Lime wells. We had two operated rigs running throughout most of the year. In addition, we participated in partner-operated development at Elm Grove. The region's 2008 production increased 34 percent to 18.6 BCFE. Our 2008 year-end proved reserves were 170.0 BCFE, essentially flat with 2007 year-end proved reserves of 170.1 BCFE. The slight decrease in proved reserves is the result of 18.6 BCFE of production and 31.3 BCFE of downward performance and pricing revisions negating 51.9 BCFE of drilling additions and acquisitions that we had during the year. At year-end 2008 we have no proved reserves recorded for our potential in the Haynesville shale.

The Elm Grove Field is the highest value field in the ArkLaTex region at year-end 2008, with proved reserves of 77.1 BCFE and PV-10 value of $87.1 million. Elm Grove comprises roughly 39 percent of the region's PV-10 value and approximately seven percent of St. Mary's entire PV-10 value. We own interests in over 480 producing wells in the field and believe many of those wells have future uphole recompletion potential. Our working interest in the field is as high as 37 percent; higher working interests are located in the southern portion of the acreage where recent activity has been occurring. Reserves in this field are primarily natural gas.

Our plans for 2009 in the ArkLaTex region, subject to capital availability, include drilling several operated horizontal Haynesville shale wells to test the resource potential of this emerging shale play on portions of the 50,000 net acres we control that could be prospective for this formation. We also have plans to drill several James Lime wells during 2009. Currently, we have no plans to drill any operated wells in the Cotton Valley

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formation in 2009. We will participate with an operating partner in the drilling of Cotton Valley wells at Elm Grove, as well as recompletions of the uphole Hosston formation.

Mid-Continent Region. St. Mary has been active in the Mid-Continent region since 1973. Operations for the region are managed by our office in Tulsa, Oklahoma. We have been active in the Anadarko Basin of western Oklahoma since our entry into the region. In recent years we have begun operating in the Arkoma Basin in eastern Oklahoma where the current focus is on horizontal development of the Woodford shale. The Mid-Continent region will also oversee our Marcellus shale activity in north central Pennsylvania.

In 2008 we incurred costs of $162.0 million in the Mid-Continent region for exploration, development, and acquisition activity, which is 13 percent less than the $185.7 million deployed in 2007. Approximately $31.0 million was incurred for non-producing leasehold in 2008, the bulk of which consists of upfront payments related to our entry into the Marcellus shale. Our Mid-Continent activity during 2008 consisted of the continued successful development of our Woodford shale assets in the Arkoma Basin and continued exploration success in the Anadarko Basin drilling deep Springer wells. Mid-Continent production in 2008 was 33.0 BCFE, a decrease of three percent from the 34.0 BCFE produced in 2007. The decrease in production is primarily attributable to the divestment of non-core properties in January 2008. Excluding the impact of the sale of these assets, the Mid-Continent region would have grown 0.5 BCFE, or 2%, from 2007 to 2008. Proved reserves at the end of 2008 were 234.4 BCFE, an increase of 16 percent from the 201.3 BCFE report for the prior year. The increase in proved reserves was due to the performance of our horizontal Woodford shale program, where we have been successful at adding and converting reserves, and the successful deep Springer drilling program in the Anadarko Basin.

The Centrahoma Field in the Arkoma Basin is the highest value field in the Mid-Continent region with proved reserves of 102.1 BCFE and a PV-10 value of $108.8 million. This field comprises 44 percent of the region's proved reserves and 29 percent of the region's PV-10 value. At year-end, we have over 130 producing wells in the field. We believe our acreage at year-end has approximately 30 proved undeveloped drilling locations and numerous unproved drilling locations that have Woodford shale potential. Additionally, we believe that there is future uphole development potential in the Cromwell and Wapanucka formations.

Our plans in the Mid-Continent region for 2009 will involve conducting our initial tests of the Marcellus shale, where we currently plan to drill two operated wells to earn and test our acreage position. Additionally, we plan to continue our successful drilling programs in the horizontal Woodford and deep Springer.

Gulf Coast Region. St. Mary's presence in south Louisiana dates to the early 1900s when our founders acquired our namesake property in St. Mary Parish, Louisiana abutting the Gulf of Mexico. These 24,914 acres of fee land yielded $15.5 million of oil and gas royalty revenue in 2008. Our Gulf Coast regional presence expanded as a result of the acquisition of King Ranch Energy, Inc. in 1999. In 2007, we made two acquisitions in the Maverick Basin in South Texas that targeted Olmos shallow gas assets in South Texas and provided an entry into this multi-pay basin. In 2008, we began testing the potential of two of the deeper horizons in the basin, the Pearsall and Eagle Ford shales. The Gulf Coast region is managed from our office in Houston, Texas.

Our capital expenditures for exploration, development, and acquisition activity in the Gulf Coast region decreased significantly from $278.5 million in 2007 to $120.9 million in 2008. The amount for 2007 includes $178.2 million for the two acquisitions we made in the Maverick Basin. During 2008 we integrated these acquired assets and continued developing the Olmos shallow gas assets. We also began developing an understanding of the geology related to two formations that lie below the Olmos in the Maverick Basin - the Eagle Ford and Pearsall shales. Results from the Olmos development did not meet our expectations, and midway through 2008 we stopped development to conduct a technical review. While parts of the technical review are still underway, the initial results have cast doubt on the viability of the Olmos development on the scale we originally contemplated at the time these acquisitions were made. These findings, combined with lower natural gas prices at year-end 2008, resulted in a meaningful downward proved reserve revision and a significant impairment of proved properties and undeveloped leasehold at the end of 2008. While our results from the Olmos program were disappointing, our activities targeting the deeper formations in the basin have been promising. We participated during the year in a joint venture with two other exploration and production companies that allows us to earn

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acreage in an area of the basin that has potential for both the Eagle Ford and Pearsall formations. We have been encouraged by the early results of the four test wells drilled in the joint venture and have committed to the second phase of that program. Concurrent with our joint venture activity, we began leasing acreage in 2008 in parts of the basin that we believe will be prospective for the Eagle Ford shale. Recent offset activity targeting the Eagle Ford shale is encouraging. We currently have exposure to approximately 210,000 and 160,000 net acres in the Eagle Ford and Pearsall shales, respectively, assuming that we meet all obligations to earn the acreage.

While the focus of the region is on onshore resource plays, we did have some meaningful activity related to Gulf Coast and Gulf of Mexico properties in 2008. During Hurricane Ike, our last operated production platform in the Gulf of Mexico, Vermilion 281, was toppled and our production facilities in Galveston Bay were damaged. We are in the process of assessing and remediating the damage related to the Vermilion 281 platform. The damaged properties at Galveston Bay have been repaired and were brought back online in late 2008. The estimated remediation costs for all of our assets damaged during Hurricane Ike are believed to exceed the maximum insurance policy limit we have for this event by approximately $7 million. The partner-operated intermediate deepwater Pegasus project came on production late in 2008. This project was the last of the commitments we had in the Gulf of Mexico.

Production for the Gulf Coast region in 2008 was 14.3 BCFE, an increase of 39 percent from the 10.3 BCFE produced in 2007. The increase in production year over year is primarily attributable to a full year of contribution from the South Texas properties acquired in 2007 along with first production from two discovery wells brought on-line early in the year. Proved reserves at the end of 2008 were 43.8 BCFE, a decrease of 63 percent from the 116.8 BCFE reported in the prior year. The significant reduction in proved reserves is primarily the result of negative performance and pricing revisions related to the Olmos shallow gas assets described above.

Despite the difficulties with the Olmos program, the properties associated with the Rockford acquisition in South Texas in 2007 remain the most significant assets in the Gulf Coast region. There were 306 producing wells associated with this acquisition as of year-end. At December 31, 2008, the Rockford assets had a PV-10 value of $23.9 million with 25.7 BCFE of proved reserves, which represent 50 percent and 59 percent of the regional total for those respective metrics.

Our plans for 2009 in the Gulf Coast region focus exclusively on the Eagle Ford shale. We plan to participate as a non-operating partner in four wells targeting this formation. Additionally, we plan to drill four operated Eagle Ford wells on acreage outside that joint venture. We will continue to look for opportunities to expand our leasehold position in the Maverick Basin in 2009.

Permian Basin Region. The Permian Basin area covers a significant portion of western Texas and eastern New Mexico and is one of the major producing basins in the United States. Our holdings in the Permian Basin began with a series of property acquisitions in 1996. In December 2006 we made a $240.6 million acquisition of predominately oil properties in our Sweetie Peck project area. To manage the significant increase in operated properties associated with the Sweetie Peck acquisition, we opened a regional office in Midland, Texas in February 2007.

We incurred costs of $163.2 million in the region in 2008 compared to $135.1 million in 2007. The majority of this capital was deployed to develop projects in the Wolfberry tight oil play, which targets the stacked carbonate Wolfcamp and Spraberry formations found in the basin. We participated in two substantial Wolfberry programs during 2008 – our operated Sweetie Peck program and the outside operated program at Halff East. We began testing 40-acre infill locations in 2008, and the results to date indicate that these wells are performing comparable to wells drilled on 80-acre spacing. This has the potential to allow for meaningful future proved reserve additions. Production in the region increased 29 percent over the prior year, from 10.7 BCFE in 2007 to 13.8 BCFE in 2008. Proved reserves as of the end of 2008 were 155.9 BCFE, which is an increase of one percent from 2007 year-end reserves of 154.7 BCFE. In spite of our generally successful drilling program in the region during 2008, year-end oil prices used to determine our proved reserves negatively impacted our reported proved reserves. We saw 17.8 BCFE in negative price revisions as of December 31, 2008.

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As of the end of December 2008, the Sweetie Peck assets in the Permian Basin represented a PV-10 value of $164.2 million with 91.8 BCFE of proved reserves. This accounts for approximately 13 percent of St. Mary's entire PV-10 value. The Sweetie Peck asset consisted of 153 producing wells and approximately 40 proved undeveloped drilling locations as of the end of 2008. Additionally, we believe that we have a meaningful number of unproved drilling locations.

As a result of the dramatic pull back in oil prices over the second half of 2008 and into 2009, we will have a significantly lower activity level in 2009 in the Permian region. Given our current assumptions, we plan to drill five operated wells at Sweetie Peck and participate only as required to hold critical acreage in other areas.

Rocky Mountain Region. St. Mary has conducted operations in the Williston Basin in eastern Montana and western North Dakota since 1991. The region is managed by our office in Billings, Montana. In recent years, we have expanded our operations into the Greater Green River, Powder River, Big Horn, and Wind River basins of Wyoming through a series of acquisitions. The largest growth in the region came in late 2002 and early 2003 with significant property acquisitions from Choctaw, Burlington Resources, and Flying J. These transactions brought with them a large acreage position that has precipitated additional growth in this region.

We incurred costs of $190.3 million in 2008 for exploration, development, and acquisitions in the Rocky Mountain region, compared to $178.3 million in 2007. A significant portion of our 2008 program was operated by others. In the Williston Basin, our investments focused primarily on the Bakken formation. In Wyoming, we made investments to complete wells in the Hanging Woman Basin coalbed methane project. Proved reserves for the Rocky Mountain region were 261.4 BCFE at year-end, down 41 percent from 443.6 BCFE as of the end of 2007. The significant decrease in proved reserves is the result of two items. First, we sold 38.4 BCFE of proved reserves in the region throughout the year as part of a divestiture of non-strategic assets. Second, as a result of lower prices for oil and wider than normal differentials at year-end, the region saw a negative price revision of 131.2 BCFE. Production in the Rocky Mountain region for 2008 was 34.9 BCFE. Total regional production was down 10 percent from 38.7 BCFE in 2007. Adjusting for the effect of the divestitures, production in the region would have declined 0.7 BCFE, or two percent, year over year.

The Elm Coulee Field is the highest value field in the region at year-end 2008, with proved reserves of 28.2 BCFE and a PV-10 value of $47.5 million. The reserves in this field are predominately oil and the Bakken is the formation of primary interest. This field comprises approximately four percent of our entire PV-10 value.

We will invest significantly fewer dollars in the Rocky Mountain region in 2009. Current oil prices and differentials do not support significant investment activity in the region and since we have limited long-term commitments and no meaningful lease commitments, we have elected to slow down capital investment. We will participate in a handful of horizontal Bakken wells, as well as conduct a few exploration tests during the year.

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, 2008. For all years presented, Netherland, Sewell and Associates, Inc. ("NSAI") prepared the reserve information for the Company's coalbed natural gas projects at Hanging Woman Basin in the northern Powder River Basin and St. Mary's non-operated coalbed methane interest in the Green River Basin. We engaged Ryder Scott Company, L.P. to review internal engineering estimates for 80 percent of the PV-10 value of our proven conventional oil and gas reserves in 2008, 2007, and 2006. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of all new discoveries and undeveloped locations are more imprecise than estimates of established producing oil and gas properties. Accordingly, these estimates are expected to change as new information becomes available in the future. 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. The following table should be read along with the section entitled "Risk Factors – Risks Related to Our Business – The actual quantities and present values of our proved oil and natural gas reserves may be less than we have estimated." No estimates of our proved reserves have been filed with or included in reports to any federal

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authority or agency, other than the Securities and Exchange Commission, since the beginning of the last fiscal year.

The ability to replace the reserves produced is important to the sustainability of all exploration and production companies. Our 2008 ratio of reserves replaced through drilling and acquisition activity was 174%. The Mid-Continent, Permian, and ArkLaTex regions each were able to replace at least two MCFE of reserves for every MCFE of production in 2008. The Gulf Coast and Rocky Mountain regions were not able to replace production during the year. This metric is calculated using information from the Oil and Gas Reserve Quantities section of Note 17 – Disclosures about Oil and Gas Producing Activities of Part IV, Item 15 of this report. The numerator consists of the sum of discoveries and extensions and infill reserves in an existing proved field, which is then divided by production. We believe the concept of reserve replacement as described above, as well as permutations which may include other captions of the Oil and Gas Reserve Quantities section of Note 17 – Disclosures about Oil and Gas Producing Activities of Part IV, Item 15 of this report, are widely understood by those who make investment decisions related to the oil and gas exploration business. For additional information about reserve replacement metrics, see the reserve replacement terms in the Glossary section of this report.

	As of December 31,		
Proved Reserves Data:	2008	2007	2006
Oil (MMBbl)	51.4	78.8	74.2
Gas (Bcf)	557.4	613.5	482.5
BCFE	865.5	1,086.5	927.6
Standardized measure of discounted future cash flows (in thousands)	$ 1,059,069	$ 2,706,914	$ 1,576,437
PV-10 value (in thousands)	$ 1,265,385	$ 3,861,187	$ 2,157,449
Proved developed reserves	83%	77%	78%
Reserve replacement – drilling and acquisitions, excluding performance and price revisions	174%	211%	232%
All in – including sales of reserves	(93)%	248%	244%
All in – excluding sales of reserves	(39)%	249%	247%
Reserve life (years) (1)	7.6	10.1	10.0

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

The following table reconciles the standardized measure of discounted future net cash flows to the PV-10 value. The difference has to do with the PV-10 value measure excluding the impact of income taxes. Please see the definitions of standardized measure of discounted future net cash flows and PV-10 value in the Glossary.

	As of December 31,		
	2008	2007	2006
	(In thousands)		
Standardized measure of discounted future net cash flows	$ 1,059,069	$ 2,706,914	$ 1,576,437
Add: 10 percent annual discount, net of income taxes	724,840	2,321,983	1,238,308
Add: future income taxes	419,544	2,316,637	1,125,955
Undiscounted future net cash flows	$ 2,203,453	$ 7,345,534	$ 3,940,700

Less: 10 percent annual discount without tax effect	(938,068)	(3,484,347)	(1,783,251)
PV-10 value	$ 1,265,385	$ 3,861,187	$ 2,157,449

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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,		
	2008	2007	2006
Net production			
Oil (MMBbl)	6.6	6.9	6.1
Gas (Bcf)	74.9	66.1	56.4
BCFE	114.6	107.5	92.8
Average net daily production			
Oil (MBbl)	18.1	18.9	16.6
Gas (MMcf)	204.7	181.0	154.7
MMCFE	313.1	294.5	254.2
Average realized sales price, excluding the effects of hedging			
Oil (per Bbl)	$ 92.99	$ 67.56	$ 59.33
Gas (per Mcf)	$ 8.60	$ 6.74	$ 6.58
Per MCFE	$ 10.99	$ 8.48	$ 7.88
Average realized sales price, including the effects of hedging			
Oil (per Bbl)	$ 75.59	$ 62.60	$ 56.60
Gas (per Mcf)	$ 8.79	$ 7.63	$ 7.37
Per MCFE	$ 10.11	$ 8.71	$ 8.18
Production costs per MCFE			
Lease operating expense	$ 1.46	$ 1.31	$ 1.25
Transportation expense	$ 0.19	$ 0.14	$ 0.12
Production taxes	$ 0.71	$ 0.58	$ 0.54

Productive Wells

As of December 31, 2008, St. Mary had working interests in 2,157 gross (1,057 net) productive oil wells and 3,745 gross (1,510 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 on 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,					
	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	221	81.46	164	77.91	81	35.32
Gas	559	205.18	518	204.62	446	178.97
Non-productive	25	13.70	30	13.18	31	10.65
	805	300.34	712	295.71	558	224.94
Exploratory:						
Oil	2	0.40	3	1.92	10	5.53
Gas	10	2.75	9	4.01	15	3.68
Non-productive	1	0.76	5	2.58	8	1.81
	13	3.91	17	8.51	33	11.02
Farmout or non-consent	7	-	1	-	2	-
Total (1)	825	304.25	730	304.22	593	235.96

(1) Does not include three gross wells completed on St. Mary’s fee lands during 2006, in which we have only a royalty interest.

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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, 2008. 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	1,434	182	147	60	1,581	242
Colorado	1,646	1,455	6,663	5,225	8,309	6,680
Kansas	-	-	2,240	560	2,240	560
Louisiana	121,688	44,831	39,146	7,462	160,834	52,293
Mississippi	4,329	1,069	103,609	41,843	107,938	42,912
Montana	59,535	39,985	430,981	287,836	490,516	327,821
Nevada	-	-	243,147	243,147	243,147	243,147
New Mexico	5,026	2,561	3,033	2,343	8,059	4,904
North Dakota	125,104	86,104	219,674	126,153	344,778	212,257
Oklahoma	250,915	78,571	110,121	53,864	361,036	132,435
Texas	233,201	112,387	490,081	230,856	723,282	343,243
Utah	-	-	3,328	591	3,328	591
Wyoming	127,443	87,223	397,361	228,070	524,804	315,293
	930,321	454,368	2,049,531	1,228,010	2,979,852	1,682,378
Louisiana Fee Properties	10,499	10,499	14,415	14,415	24,914	24,914
Louisiana Mineral Servitudes	7,653	4,404	4,622	4,260	12,275	8,664
	18,152	14,903	19,037	18,675	37,189	33,578
Total	948,473	469,271	2,068,568	1,246,685	3,017,041	1,715,956

(1) Developed acreage is acreage assigned to producing wells for the spacing unit of the producing formation. Developed acreage 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 reserves.

Major Customers

During 2008, 2007 and 2006, no customer individually accounted for ten percent or more of the Company's total oil and gas production revenue.

Employees and Office Space

As of February 17, 2009, we had 560 full-time employees. Our 2008 business plan involved a change in operations philosophy to utilize more St. Mary employed lease operators as opposed to contracting lease operators. 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 78,000 square feet of office space in Denver, Colorado for our executive and administrative offices, of which approximately 9,000 square feet is subleased. We lease approximately 22,000 square feet of office space in Tulsa, Oklahoma; approximately 21,000 square feet in Shreveport, Louisiana; approximately 20,000 square feet in Houston, Texas; approximately 12,000 square feet in Midland, Texas; approximately 36,000 square feet in Billings, Montana; approximately 9,000 square feet in Williston, North Dakota; approximately 5,000 square feet in Sheridan, Wyoming; and approximately 2,000 square feet in Casper, Wyoming.

Title to Properties

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

Seasonality

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

Competition

The oil and gas industry is intensely competitive. This is particularly true in the competition for acquisitions of prospective oil and natural gas properties and oil and gas reserves. We believe that our leasehold position provides a sound foundation for a solid drilling program. Our competitive position also depends on our geological, geophysical, and engineering expertise, and our financial resources. We believe that the location of our leasehold acreage, our exploration, drilling, and production expertise, and the experience and knowledge of our management and industry partners enable us to compete effectively in our core operating areas. Notwithstanding our talents and assets, we still face stiff competition from a substantial number of major and independent oil and gas companies that have larger technical staffs and greater financial and operational resources than we do. Many of these companies not only engage in the acquisition, exploration, development, and production of oil and natural gas reserves, but also have refining operations, market refined products, own drilling rigs, and generate electricity. We also compete with other oil and natural gas companies in attempting to secure drilling rigs and other equipment necessary for the drilling and completion of wells. Consequently, drilling equipment may be in short supply from time to time. Currently, access to incremental drilling equipment in certain regions is difficult but is not anticipated to have any material negative impact on our ability to deploy our drilling capital budget for 2009. We are seeing signs of loosening rig availability, although it is quite specific by region. Finally, we also compete for people. Throughout the industry, the need for talented people has grown at a time when the number of people available is constrained. We are not insulated from this resource constraint, and we must be willing to compete in this market in order to be successful.

Government Regulations

Our business is extensively regulated by numerous federal, state, and local laws and government regulations. These laws and regulations may be changed from time to time in response to economic or political conditions, and our regulatory burden may increase in the future. Laws and regulations increase our cost of doing business and, consequently, affect our profitability. However, we do not believe that we are affected to a materially greater or lesser extent than others in our industry.

Energy Regulations. Many of the states in which we conduct our operations have adopted laws and regulations governing the exploration for and production of crude oil and natural gas, including laws and regulations requiring permits for the drilling of wells, imposing bonding requirements in order to drill or operate wells, and governing the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the plugging and abandonment of wells. Our operations are also subject to various state conservation laws and regulations, including regulations governing the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, the spacing of wells, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and may impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Some of our operations are conducted on federal lands pursuant to oil and gas leases administered by the Bureau of Land Management (BLM) or the Minerals Management Service (MMS). These leases contain relatively standardized terms and require compliance with detailed regulations and orders, which are subject to change. In addition to permits required from other regulatory agencies, lessees must obtain a permit from the BLM or MMS before drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of offshore Gulf of Mexico wells, the valuation of production and payment of royalties, the removal of facilities, and the posting of bonds to ensure that lessee obligations are met. Under certain circumstances, the BLM or the MMS, as applicable, may require our operations on federal leases to be suspended or terminated.

Our sales of natural gas are affected by the availability, terms, and cost of natural gas pipeline transportation. The Federal Energy Regulatory Commission (FERC) has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce. The FERC's current regulatory framework generally provides for a competitive and open access market for sales and transportation of natural gas. However, FERC regulations continue to affect the midstream and transportation segments of the industry, and thus can indirectly affect the sales prices we receive for natural gas production. In addition, the less stringent regulatory approach recently pursued by the FERC and the U.S. Congress may not continue indefinitely.

Environmental Regulations. Our operations are subject to stringent federal, state, and local laws and regulations relating to environmental protection. 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, govern the handling and disposal of waste material, 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 for, developing, or producing oil and gas and may prevent or delay the commencement or continuation of certain projects. 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 these laws and regulations.

Our coalbed methane gas production requires state permits for the use of well-site pits and infiltration ponds for the disposal of the water produced from the coalbed methane wells. Groundwater produced from the coal seams can generally be discharged into certain areas without a permit if it does not exceed surface discharge permit levels, and meets state and federal primary drinking water standards. The 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 underground rock formations.

To date we have not experienced any materially 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 materially 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 with respect to our financial condition, results of operations, or economic performance that we expect, believe, or anticipate will or may occur in the future, or that address plans and objectives of management for future operations, are forward-looking statements. The words "anticipate," "assume," "believe," "budget," "estimate," "expect," "forecast," "intend," "plan," "project," "will," and similar ex 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 liquidity and capital resources to fund capital expenditures
- The drilling of wells and other exploration and development activities and plans, as well as possible future acquisitions
- Reserve estimates and the estimates of both future net revenues and the present value of future net revenues that are included in their calculation
- Future oil and natural gas production estimates
- Our outlook on future oil and natural gas prices and service costs
- Cash flows, anticipated liquidity, and the future repayment of debt
- Business strategies and other plans and objectives for future operations, including plans for expansion and growth of operations or to defer capital investment, and our outlook on our future financial condition or results of operations
- Other similar matters such as those discussed in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section in Item 7 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 and performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. These risks are described in the "Risk Factors" section in Item 1A of this Form 10-K, and include such factors as:

- The volatility and level of realized oil and natural gas prices
- A contraction in demand for oil and natural gas as a result of adverse general economic conditions
- The availability of economically attractive exploration, development, and property acquisition opportunities and any necessary financing, including constraints on the availability of opportunities and financing due to currently distressed capital and credit market conditions
- Our ability to replace reserves and sustain production

- Unexpected drilling conditions and results
- Unsuccessful exploration and development drilling

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- The risks of hedging strategies
- The uncertain nature of the expected benefits from acquisitions and divestitures of oil and natural gas properties, including uncertainties in evaluating oil and natural gas reserves of acquired properties and associated potential liabilities
- The imprecise nature of oil and natural gas reserve estimates
- Uncertainties inherent in projecting future rates of production from drilling activities and acquisitions
- Declines in the values of our oil and natural gas properties resulting in write-downs
- The ability of purchasers of production to pay for amounts purchased
- Drilling and operating service availability
- Uncertainties in cash flow
- The financial strength of hedge contract counterparties and credit facility participants, and the risk that one or more of those parties may not satisfy their contractual commitments
- The negative impact that lower oil and natural gas prices could have on our ability to borrow and fund capital expenditures
- The potential effects of increased levels of debt financing
- Our ability to compete effectively against other independent and major oil and natural gas companies
- Litigation, environmental matters, the potential impact of government regulations, and the use of management estimates.

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

Available Information

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

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

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

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

Glossary of Oil and Natural Gas Terms

The oil and natural gas terms defined in this section are used throughout this Form 10-K. The definitions of the terms exploratory well, field, proved developed reserves, proved reserves, and proved undeveloped reserves have been abbreviated from the respective definitions under Rule 4-10(a) of Regulation S-X promulgated by the SEC. The entire definitions of those terms under Rule 4-10(a) of Regulation S-X can be located through the SEC's website at http://www.sec.gov.

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

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

Development well. A well drilled within the proved area of an oil or natural 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 natural gas in sufficient commercial quantities.

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

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

Fee land. The most extensive interest that can be owned in land, including surface and mineral (including oil and natural 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 and/or stratigraphic condition.

Finding cost. Expressed in dollars per MCFE. Finding cost metrics provide information as to the cost of adding proved reserves from various activities, and are widely utilized within the exploration and production industry, as well as by investors. The information used to calculate these metrics is included in Note 16 – Oil and Gas Activities and Note 17 – Disclosures about Oil and Gas Producing Activities of the Notes to Consolidated Financial Statements included in this report. It should be noted that finding cost metrics have limitations. For example, exploration efforts related to a particular set of proved reserve additions may extend over several years. As a result, the exploration costs incurred in earlier periods are not included in the amount of exploration costs incurred during the period in which that set of proved reserves is added. In addition, consistent with industry practice, future capital costs to develop proved undeveloped reserves are not included in costs incurred. Since the additional development costs that will need to be incurred in the future before the proved undeveloped reserves are ultimately produced are not included in the amount of costs incurred during the period in which those reserves were added, those development costs in future periods will be reflected in the costs associated with adding a different set of reserves. The calculations of various finding cost metrics are explained below.

Finding cost – Drilling, excluding performance and price revisions. Calculated by dividing the amount of total capital expenditures for oil and natural gas activities, including the effect of asset retirement obligations, by the amount of estimated net proved reserves added through discoveries, extensions, and infill drilling, during the same period.

Finding cost – Drilling and acquisitions, excluding performance and price revisions. Calculated by dividing the amount of total capital expenditures for oil and natural gas activities, including the effect of asset retirement obligations, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling and acquisitions during the same period.

Finding cost – All in, excluding sales of reserves. Calculated by dividing the amount of total capital expenditures for oil and natural gas activities, including the effect of asset retirement obligations, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, acquisitions, and revisions of pricing and previous estimates during the same period.

Finding cost –All in, including sales of reserves. Calculated by dividing the amount of total capital expenditures for oil and natural gas activities, including the effect of asset retirement obligations, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, acquisitions, and revisions of pricing and previous estimates less sales of reserves during the same period.

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

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

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

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

Lease operating expenses. The expenses of lifting oil or natural gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs, and other expenses incidental to production, but not including lease acquisition or drilling or completion expenses.

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

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

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

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

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

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

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

MMCFE. One million cubic feet of natural gas equivalent. Natural gas equivalents are determined using the ratio of six Mcf of natural gas (including natural 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.

Play. A term used to describe a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and natural gas reserves.

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 ten 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 natural gas or that is capable of commercial production.

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

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

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

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

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

Reserve replacement. Reserve replacement metrics are used as indicators of a company's ability to replenish annual production volumes and grow its reserves, and provide information related to how successful a company is at growing its proved reserve base. These are believed to be useful non-GAAP measures that are widely utilized within the exploration and production industry, as well as by investors. They are easily calculable metrics, and the information used to calculate these metrics is included in Note 17 – Disclosures about Oil and Gas Producing Activities of the Notes to Consolidated Financial Statements included in this report. It should be noted that reserve replacement metrics have limitations. They are limited because they typically vary widely based on the extent and timing of new discoveries and property acquisitions. Their predictive and comparative value is also limited for the same reasons. In addition, since the metrics do not embed the cost or timing of future production of new reserves, they cannot be used as a measure of value creation. The calculations of various reserve replacement metrics are explained below.

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Reserve replacement – Drilling, excluding performance and price revisions. Calculated as a numerator comprised of the sum of reserve extensions and discoveries and infill reserves in an existing proved field divided by production for that same period of time. Sales from reserves should be included in the numerator to consider the impact any divestitures of proved reserves would have on this metric in the respective period. This metric is an indicator of the relative success a company is having in replacing its production through drilling activity.

Reserve replacement – Drilling and acquisitions, excluding performance and price revisions. Calculated as a numerator comprised of the sum of reserve acquisitions and reserve extensions and discoveries and infill reserves in an existing proved field divided by production for that same period of time. Sales from reserves should be included in the numerator to consider the impact any divestitures of proved reserves would have on this metric in the respective period. This metric is an indicator of the relative success a company is having in replacing its production through drilling and acquisition activities.

Reserve replacement percentage – All in, excluding sales of reserves. 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.

Reserve replacement percentage –All in, including sales of reserves. The sum of sales of reserves, reserve extensions and discoveries, reserve acquisitions, and reserve revisions of previous estimates for a specified period of time divided by production for that same period of time.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Resource play. A term used to describe an accumulation of oil and/or natural gas known to exist over a large area expanse and/or thick vertical section, which when compared to a conventional play typically has a lower expected geological and/or commercial development risk and a lower expected average decline rate.

Royalty. The amount or fee paid to the owner of mineral rights, expressed as a percentage of gross income from oil and natural 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 natural gas property entitling the owner to shares of oil and natural gas production free of costs of exploration, development, and production operations.

Seismic. An exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of subsurface rock formations.

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

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural 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 declines in prices adversely affect our profitability, financial condition, cash flows, access to capital, and ability to grow.

Our revenues, operating results, profitability, future rate of growth, and the carrying value of our oil and natural gas properties depend heavily on the prices we receive for oil and natural gas sales. Oil and natural gas prices also affect our cash flows available for capital expenditures and other items, our borrowing capacity, and the amount and value of our oil and natural gas reserves. For example, the amount of our borrowing base under our credit facility is subject to periodic redeterminations based on oil and natural gas prices specified by our bank group at the time of redetermination. In addition, we may have oil and natural gas property write-downs if prices fall significantly, as has been the case in the past several months.

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

- Global and domestic supplies of oil and natural gas, and the productive capacity of the industry as a whole
- The level of consumer demand for oil and natural gas
- Overall global and domestic economic conditions
- Weather conditions
- The availability and capacity of transportation or refining facilities in regional or localized areas that may affect the realized price for oil or natural gas
- The price and level of foreign imports of crude oil, refined petroleum products, and liquefied natural gas
- The price and availability of alternative fuels
- Technological advances affecting energy consumption
- The ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls
- Political instability or armed conflict in oil or natural gas producing regions
- Governmental regulations and taxes.

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

The current economic and financial crisis may have impacts on our business that we cannot predict.

The continued economic and credit crisis and related turmoil in the global and domestic financial systems may continue to have an impact on our business, and we may face challenges if economic and credit conditions do not improve. The recent general economic slowdown has affected the demand for oil and natural gas, and recent significant declines in oil and natural gas prices from the highs of June and early July of 2008 have reduced our operating cash flows and may ultimately affect our access to the capital markets. Although we currently believe that our liquidity and available capital resources through operating cash flows and our existing credit facility with ten participating banks are sufficient to fund our ongoing operational obligations and anticipated capital expenditures for the foreseeable future, continued distressed capital and credit market conditions and decreased oil and natural gas prices could ultimately limit our access to capital and have a materially adverse effect on our liquidity, financial condition, results of operations, and cash flows. The current economic situation could also adversely affect the collectability of our trade receivables and cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection. In addition, the current economic situation could lead to further reductions in the demand for oil and natural gas, and lower prices for oil and natural gas, or both, which could have a materially adverse effect on our revenues, results of operations, cash flows, liquidity, and financial condition.

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

Substantial capital is required to replace our reserves.

We must 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, prices received for oil and natural gas sales, our success in locating and acquiring new reserves, and the orderly functioning of credit and capital markets. As we currently note, when oil or natural gas prices decrease or if we encounter operating difficulties that result in our cash flows from operations being less than expected, we must reduce our capital expenditures unless we can raise additional funds through debt or equity financing or the divestment of assets. Debt or equity financing may not always be available to us in sufficient amounts or on acceptable terms, and the proceeds offered to us for potential divestitures may not always be of acceptable value to us.

When our revenues decrease due to lower oil or natural gas prices, decreased production, or other reasons, and if we cannot obtain capital through our revolving credit facility, other acceptable debt or equity financing arrangements, or the sale of non-core assets, our ability to execute development plans, replace our reserves, or maintain production levels could be greatly limited.

The debt and equity financing markets are currently very constrained due to the global and domestic economic and financial crisis, and it is possible that circumstances may arise where one or more of the ten participating banks in our credit facility, at some point, will not be able to fulfill their portion of the lending commitments to us under the facility. Continued adverse conditions in the credit markets may increase the cost of borrowings and decrease our ability to access new sources of capital.

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

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

We also compete for human resources. Over the last few years, the need for talented people across all disciplines in the industry has grown, while the number of people available has been constrained.

The actual quantities and present values of our proved oil and natural 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 natural gas reserves and the estimated future net revenues from those reserves. These estimates are based on various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes, timing of operations, and availability of funds. The process of estimating oil and natural gas reserves is complex. The process involves 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. Therefore, these estimates are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, production taxes, development expenditures, operating expenses, and quantities of recoverable oil and natural gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities of and present values related to 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 activity, prevailing oil and natural gas prices, costs to develop and operate properties, 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, 2008, approximately 17 percent, or 149.7 BCFE, of our estimated proved reserves were proved undeveloped, and approximately 12 percent, or 104.5 BCFE, were proved developed non-producing. Estimates of proved undeveloped reserves and proved developed non-producing reserves are nearly always based on volumetric calculations rather than the performance data used to estimate producing reserves. In order to develop our proved undeveloped reserves, an estimated $281 million of capital expenditures would be required. Production revenues from proved developed non-producing reserves will not be realized until sometime in the future and after some investment of capital. In order to bring production on-line for our proved developed non-producing reserves, we estimate capital expenditures of $61 million will be deployed in future years. 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. The balance of our currently anticipated capital expenditures for 2009 is directed towards projects that are not yet classified within the construct of proved reserves as defined by Regulation S-X promulgated by the SEC.

You should not assume that the PV-10 value and standardized measure of discounted future net cash flows included in this Form 10-K represent the current market value of our estimated proved 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 current SEC requirements, whereas actual future prices and costs may be materially higher or lower. For example, values of our reserves as of December 31, 2008, were estimated using a calculated sales price of $5.71 per MMBtu of natural gas (NYMEX Henry Hub spot price) and $44.60 per Bbl of oil (NYMEX West Texas Intermediate spot price). We then adjust these base prices to reflect appropriate basis, quality, and location differentials as of that date in estimating our proved reserves. During 2008, our monthly average realized natural gas prices, excluding the effect of hedging, were as high as $12.65 per Mcf and as low as $4.61 per Mcf. For the same period, our monthly average realized oil prices before hedging were as high as $129.40 per Bbl and as low as $32.42 per Bbl. Many other factors will affect actual future net cash flows, including:

- Amount and timing of actual production
- Supply and demand for oil and natural gas
- Curtailments or increases in consumption by oil purchasers and natural gas pipelines
- Changes in government 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, costs of capital, and other risks to which our business and the oil and natural gas industry in general are subject.

Our 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 natural gas prices, operating costs, and potential environmental and other liabilities. These assessments are not precise and their accuracy is inherently uncertain.

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

In addition, significant acquisitions can change the nature of our operations and business if the acquired properties have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent 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 natural 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 natural gas drilling and production activities may be shortened, delayed, or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- Unexpected drilling conditions
- Title problems
- Pressure or geologic irregularities in formations
- Equipment failures or accidents
- Hurricanes or other 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 crews, fracture stimulation crews and equipment, chemicals, and supplies.

The prevailing prices of oil and natural gas affect the cost of and the demand for drilling rigs, production equipment, and related services. However, changes in costs may not occur simultaneously with corresponding changes in prices. 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. In addition, the current economic and financial crisis has adversely affected the financial condition of some drilling contractors, which may constrain the availability of drilling services in some areas.

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

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

Drilling results in our newer shale plays, such as the Eagle Ford, Haynesville, Marcellus, and Pearsall shales, may be more uncertain than in shale plays that are more developed and have longer established production histories. For example, our experience with horizontal drilling in these shales, as well as the industry’s drilling and production history, is more limited than in the Woodford shale play. Completion techniques that have proven to be successful in other shale formations to maximize recoveries are being used in the early development of these new shales; however, we can provide no assurance of the ultimate success of these drilling and completion techniques.

In addition, a significant part of our strategy involves increasing our drilling location inventories for multi-year programs scheduled out over several years. Such multi-year drilling inventories can be more susceptible to long-term horizon uncertainties that could materially alter the occurrence or timing of actual drilling. Because of these uncertainties, we do not know if the potential drilling locations we have identified will ever be drilled, or if we will be able to produce oil or natural gas from these or any other potential drilling locations.

Our future drilling activities may not be successful. Our overall drilling success rate or our drilling success rate 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 activities may result in financial losses or may limit the prices that we receive for oil and natural gas sales.

To manage our exposure to price risks in the sale of our oil and natural gas production, we enter into commodity price risk management arrangements periodically 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. As of December 31, 2008, we were in a net accrued asset position of approximately $105.3 million with respect to our oil and natural gas hedging activities. These activities may expose us to the risk of financial loss in certain circumstances, including instances in which:

- Our production is less than expected
- One or more counterparties to our hedge contracts default on their contractual obligations
- There is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement.

The risk that one or more counterparties may default on their obligations is heightened by the recent global and domestic economic and financial crisis affecting many banks and other financial institutions, including our counterparties or their affiliates. These circumstances may adversely affect the ability of the counterparties to meet their obligations to us on hedge transactions, which could reduce our revenues from hedges at a time when we are also receiving a lower price for our natural gas and oil sales, which triggered the hedge payment obligations by the counterparties. As a result, our financial condition, results of operations, and cash flows could be materially adversely affected if our counterparties default on their contractual obligations under our hedge contracts.

In addition, commodity price hedging may limit the prices that we receive for our oil and natural gas sales if oil or natural gas prices rise substantially over the price established by the hedge. 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 could impact our liquidity and capital resources. In addition, some of our hedging transactions use derivative instruments that may involve basis risk. Basis risk in a hedging contract occurs when the index upon which the contract is based is more or less variable than the index upon which the hedged asset is based, thereby making the hedge less effective. For example, a NYMEX index used for hedging certain volumes of production may have more or less variability than the regional price index used for the sale of that production.

The inability of one or more of our customers to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the energy industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by various economic and other conditions, including the current global and domestic economic and financial crisis.

Future oil and natural 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 natural 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 natural gas properties, on a field basis, cannot exceed the estimated undiscounted future net cash flows of that field. If net capitalized costs exceed undiscounted future net revenues, we must write down the costs of each such field to our estimate of its fair market value. Unproved properties are evaluated at the lower of cost or fair market value. Oil and natural gas prices declined significantly throughout the second half of 2008. Prices in effect on December 31, 2008, used to estimate proved reserves were $44.60 per barrel and $5.71 per MMBtu of gas. As a result of these price declines, we incurred impairment of proved property write-downs, impairment of unproved properties, and goodwill impairment totaling $302.2 million, $39.0 million, and $9.5 million, respectively, during 2008. Significant further declines in oil or natural gas prices in the future or unsuccessful exploration efforts could cause further impairment write-downs of capitalized costs.

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

Lower oil or natural gas prices could limit our ability to borrow under our revolving credit facility.

Our revolving credit facility has a maximum commitment amount of $500 million, subject to a borrowing base that the lenders periodically redetermine based on the bank group's assessment of the value of our oil and natural gas properties, which in turn is based in part on oil and natural gas prices. The current borrowing base under our credit facility is $1.4 billion, which was determined as of October 1, 2008. Oil and natural gas prices have declined since October 1, 2008, and unless prices increase, we currently expect that the borrowing base will be lower at the next scheduled redetermination date of April 1, 2009. Further declines in oil or natural gas prices in the future could limit our borrowing base and reduce our ability to borrow under the credit facility.

Our amount of debt may limit our ability to obtain financing for acquisitions, make us more vulnerable to adverse economic conditions, and make it more difficult for us to make payments on our debt.

As of December 31, 2008, we had $287.5 million of total long-term senior unsecured debt outstanding under our 3.50% Senior Convertible Notes due 2027, and $300.0 million of secured debt outstanding under our revolving credit facility. As of February 17, 2009, we had an outstanding balance of $318.5 million drawn against our revolving credit facility, resulting in $181.5 million of available debt capacity under our revolving credit facility assuming the borrowing conditions of this facility were met. Our long-term debt represented 34 percent of our total book capitalization as of December 31, 2008.

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

- Making it more difficult for us to obtain additional financing in the future for our operations and potential acquisitions, working capital requirements, capital expenditures, debt service, or other general corporate requirements

- Requiring us to dedicate a substantial portion of our cash flows from operations to the repayment of our debt and the service of interest costs associated with our debt, rather than to productive investments

- Limiting our operating flexibility due to financial and other restrictive covenants, including restrictions on incurring additional debt, creating liens on our properties, making acquisitions, and paying dividends

    - Placing us at a competitive disadvantage compared to our competitors that have less debt

- Making us more vulnerable in the event of adverse economic or industry conditions or a downturn in our business.

Our ability to make payments on our debt and to refinance our debt and fund planned capital expenditures will depend on our ability to generate cash in the future. This, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory, and other factors that are beyond our control. If our business does not generate sufficient cash flow from operations or future sufficient borrowings are not available to us under our revolving credit facility or from other sources, we might not be able to service our debt or fund our other liquidity needs. If we are unable to service our debt, due to inadequate liquidity or otherwise, we may have to delay or cancel acquisitions, defer capital expenditures, sell equity securities, sell assets, or restructure or refinance our debt. We might not be able to sell our equity securities, sell our assets, or restructure or refinance our debt on a timely basis or on satisfactory terms or at all. In addition, the terms of our existing or future debt agreements, including our existing and future credit agreements, may prohibit us from pursuing any of these alternatives. The indenture for our 3.50% Senior Convertible Notes due 2027 provides that under certain circumstances we have the option to settle our obligations under these notes through the issuance of shares of our common stock if we so elect.

Our debt instruments, including our revolving credit facility agreement, also permit us to incur additional debt in the future. In addition, the entities we may acquire in the future could have significant amounts of debt outstanding which we could be required to assume in connection with the acquisition, or we may incur our own significant indebtedness to consummate an acquisition.

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

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

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

Following the severe Atlantic hurricanes in 2004, 2005, and 2008, the insurance markets suffered significant losses. As a result, insurance coverage has become substantially more expensive, and future availability and costs of coverage are uncertain.

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 natural 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 natural 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 natural gas drilling and production, including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of interests in oil and natural gas properties, environmental matters, safety standards, the sharing of markets, production limitations, plugging and abandonment standards, and restoration. To cover the various obligations of leaseholders of offshore interests 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 for Gulf Coast operations in all cases. Under limited circumstances, federal authorities may require any of our ongoing or planned operations on federal leases to be delayed, suspended, or terminated. Any such delay, suspension, or termination could have a materially adverse effect on our operations.

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. Under existing or future environmental laws and regulations, we could face significant liability to governmental authorities and third parties, including joint and several as well as strict liability, for discharges of oil, natural gas, or other pollutants into the air, soil, or water, and we could be required to spend substantial amounts on investigations, litigation, and remediation. Existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced, or altered in the future, may have a materially adverse effect on us.

Possible regulations related to global warming and climate change could have an adverse effect on our operations and the demand for oil and natural gas.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases,” may be contributing to the warming of the Earth’s atmosphere. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of refined oil products and natural gas, are examples of greenhouse gases. The U.S. Congress is considering climate-related legislation to reduce emissions of greenhouse gases. In addition, at least nine states in the Northeast and five states in the West have developed initiatives to regulate emissions of greenhouse gases, primarily through the planned development of greenhouse gas emissions inventories and/or regional greenhouse gas cap and trade programs. The U.S. Environmental Protection Agency is separately considering whether it will regulate greenhouse gases as “air pollutants” under the existing federal Clean Air Act. Passage of climate change legislation or other regulatory initiatives by Congress or various states or the adoption of regulations by the EPA or analogous state agencies that regulate or restrict emissions of greenhouse gases, including methane or carbon dioxide, in areas in which we conduct business could have an adverse effect our operations and the demand for oil and natural gas.

We depend on transportation facilities owned by others.

The marketability of our oil and natural 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 natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines, and general economic conditions could adversely affect our ability to produce, gather, and transport oil and natural gas.

Risks Related to Our Common Stock

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

From January 1, 2008 to February 17, 2009, the closing daily sales price of our common stock as reported by the New York Stock Exchange ranged from a low of $15.31 per share to a high of $64.64 per share. 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
- Future sales of our common stock
- Changes in the national and global economic outlook.

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

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

Our certificate of incorporation and by-laws 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 members 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.

Shares eligible for future sale may cause the market price of our common stock to drop significantly, even if our business is doing well.

The potential for sales of substantial amounts of our common stock in the public market may have a materially adverse effect on our stock price. As of February 17, 2009, 62,189,800 shares of our common stock 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 1,494,208 shares of our common stock were outstanding, of which all were exercisable. These options are exercisable at prices ranging from $6.19 to $20.87 per share. In addition, restricted stock units providing for the issuance of up to a total of 396,241 shares of our common stock

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and 458,480 performance share awards were outstanding. The PSAs represent the right to receive, upon settlement of the PSAs after the completion of a three-year performance period, a number of shares of our common stock that may be from zero to two times the number of PSAs granted, depending on the extent to which the underlying performance criteria have been achieved and the extent to which the PSAs have vested. As of February 17, 2009, there were 62,305,557 shares of common stock outstanding, which is net of 176,987 treasury shares.

We may not always pay dividends on our common stock.

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

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

ITEM 3. LEGAL PROCEEDINGS

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

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 2008.

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth the names, ages and positions held by St. Mary's executive officers. The age of the executive officers is as of February 17, 2009.

Name	Age	Position
Anthony J. Best	59	Chief Executive Officer and President
Javan D. Ottoson	50	Executive Vice President and Chief Operating Officer
A. Wade Pursell	43	Executive Vice President and Chief Financial Officer
Mark D. Mueller	44	Senior Vice President and Regional Manager
Milam Randolph Pharo	56	Senior Vice President and General Counsel
Paul M. Veatch	42	Senior Vice President and Regional Manager
Stephen C. Pugh	50	Senior Vice President and Regional Manager
Gregory T. Leyendecker	51	Vice President – Regional Manager
John R. Monark	56	Vice President – Human Resources and Administration
Lehman E. Newton, III	53	Vice President – Regional Manager
Kenneth J. Knott	44	Vice President – Business Development and Land and Assistant Secretary
David J. Whitcomb	46	Vice President – Marketing
Dennis A. Zubieta	42	Vice President – Engineering and Evaluation
Mark T. Solomon	40	Controller

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

Anthony J. Best joined St. Mary in June 2006 as President and Chief Operating Officer. In December 2006 Mr. Best relinquished his position as Chief Operating Officer when Javan D. Ottoson was elected to that office. Mr. Best was elected Chief Executive Officer of St. Mary in February 2007, when Mark Hellerstein retired from that position. From November 2005 to June 2006, Mr. Best was developing a business plan and raising capital for a start-up exploration and production entity. From 2003 to October 2005, Mr. Best was President and Chief Executive Officer of Pure Resources, Inc., an independent oil and natural gas exploration and production company that was a subsidiary of Unocal, where he managed all of Unocal's onshore U.S. assets. From 2000 to 2002, Mr. Best had an oil and gas consulting practice working with various energy firms. From 1979 to 2000, Mr. Best was with ARCO in a variety of positions, including a period as President - ARCO Permian, President - ARCO Latin America, Field Manager for Prudhoe Bay and VP - External Affairs for ARCO Alaska.

Javan D. Ottoson joined St. Mary in December 2006 as Executive Vice President and Chief Operating Officer. Mr. Ottoson has been in the oil and gas industry for over 25 years. From April 2006 until he joined St. Mary in December 2006, Mr. Ottoson was Senior Vice President – Drilling and Engineering at Energy Partners, Ltd., an independent oil and natural gas exploration and production company, where his responsibilities included overseeing all aspects of its drilling and engineering functions. Mr. Ottoson managed Permian basin assets for Pure Resources, Inc., a Unocal subsidiary, and its successor owner, Chevron, from July 2003 to April 2006. From April 2000 to July 2003, Mr. Ottoson owned and operated a homebuilding company in Colorado and ran his family farm. Prior to 2000 Mr. Ottoson worked for ARCO in management and operational roles. These roles included President of ARCO China, Commercial Director of ARCO British, and Vice President of Operations and Development, ARCO Permian.

A. Wade Pursell joined St. Mary in September 2008 as Executive Vice President and Chief Financial Officer. Mr. Pursell was Executive Vice President and Chief Financial Officer for Helix Energy Solutions Group, Inc., a global provider of life-of-field services and development solutions to offshore energy producers and an oil and gas producer, from February 2007 to September 2008. From October 2000 to February 2007 he was Senior Vice President and Chief Financial Officer of Helix. He joined Helix in May 1997, as Vice President — Finance and Chief Accounting Officer. From 1988 through 1997 he was with Arthur Andersen LLP, lastly as an Experienced Manager specializing in the offshore services industry.

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Mark D. Mueller joined St. Mary in September 2007 as Senior Vice President. Mr. Mueller was appointed as the Regional Manager of the Rocky Mountain Region effective January 1, 2008. Mr. Mueller has been in the energy industry for 22 years. From September 2006 to September 2007 he was Vice President and General Manager at Samson Exploration Ltd., an oil and gas exploration and production company that was a subsidiary of Samson Investment Company, in Calgary, Canada; his responsibilities included fiscal performance, reserves, and all operational functions of the company. From April 2005 until its sale in August 2006, Mr. Mueller was Vice President and General Manager for Samson Canada Ltd., an oil and gas exploration and production company that was a subsidiary of Samson Investment Company, where he was responsible for all business units and the eventual sale of the company. Mr. Mueller joined Samson Canada Ltd. as Project Manager in May 2003 to build a new Basin-Centered Gas business unit and was Vice President from December 2003 to August 2006. Prior to joining Samson, Mr. Mueller was West Central Alberta Engineering Manager for Northrock Resources Ltd., a Canadian oil and gas company that was a wholly-owned subsidiary of Unocal Corporation, in Calgary, Canada. From 1986 to 2003, Mr. Mueller held positions of increasing responsibility in engineering and management for UNOCAL throughout North America and Southeast Asia.

Milam Randolph Pharo was appointed Senior Vice President and General Counsel in August 2008. He served as Vice President – Land and Legal and Assistant Secretary from 1996 to August 2008. Prior to joining St. Mary, Mr. Pharo served in private practice as an attorney specializing in oil and gas matters since 1979.

Paul M. Veatch was appointed Senior Vice President and Regional Manager in March 2006. Mr. Veatch joined St. Mary in April 2001 as Regional A & D Engineer. He was Vice President – General Manager, ArkLaTex from August 2004 to March 2006 and Manager of Engineering for the ArkLaTex Region from April 2003 to August 2004.

Stephen C. Pugh joined St. Mary as Senior Vice President – Regional Manager of the ArkLaTex Region in July 2007. Mr. Pugh has over 27 years of experience in the oil and gas industry. Prior to joining St. Mary, Mr. Pugh was Managing Director for Scotia Waterous, a global leader in oil and gas merger and acquisition advisory services. Mr. Pugh was responsible for new business development, managing client relationships and providing merger and acquisition advice, including transaction execution to clients in the energy sector. Mr. Pugh held this position from July 2006 to July 2007. Prior to joining Scotia Waterous, Mr. Pugh had over 17 years of experience in A&D, operations and engineering with Burlington Resources, Inc., and its successor-by-merger, ConocoPhillips. His most recent position with Burlington Resources, Inc. and ConocoPhillips was General Manager, Engineering and Operations – Gulf Coast, a position he held from May 2004 to June 2006. Prior to that, he was Vice President - Acquisitions and Divestitures for Burlington Resources Canada. He held that position from May 2000 to May 2004. Mr. Pugh began his career with Superior Oil (subsequently Mobil Oil) in Lafayette, Louisiana, where he worked in production, drilling, and reservoir engineering.

Gregory T. Leyendecker was appointed Vice President - Regional Manager in July 2007. Mr. Leyendecker joined St. Mary in December 2006 as Operations Manager for the Gulf Coast Region in Houston. Mr. Leyendecker has worked for 28 years in the energy industry and held various positions with Unocal Corporation, an independent oil and natural gas exploration and production company, from 1980 until its acquisition in 2005. During this time he was the Asset Manager for Unocal Gulf Region USA from 2003 to June 2004 and Production and Reservoir Engineering Technology Manager for Unocal from June 2004 to August 2005. He was appointed Drilling and Workover Manager for the San Joaquin Valley business unit of Chevron, as successor-by-merger of Unocal Corporation, in Bakersfield, California in August 2005 and held this position until January 2006. Immediately prior to joining St. Mary, Mr. Leyendecker was Vice President of Drilling Management Services for Enventure Global Technology, the industry’s leading provider of solid expandable tubular technology, a position he held from February 2006 to November 2006.

John R. Monark was appointed Vice President – Human Resources in July 2008. Mr. Monark joined St. Mary in May of 2008 as Director of Human Resources. Mr. Monark was Director – Human Resources for JF Shea Corporation, a leading construction and homebuilding company, from 2004 to July 2008. He served as Vice President – Human

Resources for Pameco Corporation, a distributor of HVAC systems and equipment and refrigeration products, from 2000 to 2004. From 1996 to 2000 he served as Vice President – Human Resources for CH2M HILL.

Lehman E. Newton, III joined St. Mary in December 2006 as General Manager for the Midland office and was appointed to Vice President, Permian Region, in June 2007. Mr. Newton has over 27 years of E&P experience in engineering, operations, and business development. From November 2005 to November 2006 Mr. Newton served as Project Manager for one of Chevron's largest lower 48 projects. Mr. Newton joined Pure Resources in February 2003 as the Business Development Manager and worked in that capacity until October 2005. Mr. Newton was a founding partner in Westwin Energy, an independent Permian Basin E&P firm, from June 2000 to January 2003. Prior to that, Mr. Newton spent 21 years with ARCO in various engineering, operations and management roles. These assignments included Asset Manager, ARCO's East Texas operations, Vice President, Business Development, ARCO Permian, and Vice President of Operations and Development, ARCO Permian.

Kenneth J. Knott was appointed Vice President – Business Development and Land and Assistant Secretary in August 2008. Mr. Knott joined St. Mary in November 2000 as Senior Landman for the Gulf Coast Region in Lafayette, LA and later assumed the position of Gulf Coast Regional Land Manager when the office was moved to Houston in March 2004. Mr. Knott has worked for 21 years in the energy industry holding various Land and Business Development positions with ARCO, Vastar Resources and BP Amoco. Between 1987 and 1993, Mr. Knott worked for ARCO in a land capacity handling land and business development responsibilities in several geographic areas, such as Permian, Mid-Continent, Michigan and California. Upon ARCO's spin-off of Vastar Resources in 1993, he joined Vastar Resources as a Senior Landman working the Gulf Coast and Gulf of Mexico Regions until 1999, at which time he assumed the role of Director of Business Development for the Gulf Coast Region. He remained in that capacity until the merger of Vastar Resources into BP Amoco in September 2000, whereby he assumed a Senior Landman position working the Gulf Coast Region.

David J. Whitcomb was appointed Vice President – Marketing in August 2008. Mr. Whitcomb joined St. Mary in November 1994 as Gas Contract Analyst and was named Assistant Vice President of Gas Marketing in October 1995. In March 2007 his responsibilities were expanded to include oil marketing at which time his title was changed to Assistant Vice President – Director of Marketing. From 1991 until the time of his employment with St. Mary, Mr. Whitcomb worked for Anderman/Smith Operating Company as a Gas Contract Analyst during which time his primary responsibility was to resolve take-or-pay gas contract disputes. Mr. Whitcomb began his career in the industry in 1986 with Apache Corporation where he worked as an internal auditor for several years and then moved into marketing where he worked as a Gas Controller and Gas Contracts Analyst.

Dennis A. Zubieta was appointed Vice President – Engineering and Evaluation in August 2008. Mr. Zubieta joined St. Mary in June 2000 as Corporate A&D Engineer, assumed the role of Reservoir Engineer in February 2003, and was appointed Reservoir Engineering Manager in August 2005. Mr. Zubieta was employed by Burlington Resources Oil & Gas Company (formerly known as Meridian Oil, Inc.) from June 1988 to May 2000 in various operations and reservoir engineering capacities.

Mark T. Solomon was appointed Controller in January 2007. Mr. Solomon was also appointed Acting Principal Financial Officer from April 30, 2008 to September 8, 2008, which was during the period of time that the Company's Chief Financial Officer position was vacant. Mr. Solomon joined St. Mary in 1996. He served as Financial Reporting Manager from February 1999 to September 2002, Assistant Vice President – Financial Reporting from September 2002 to May 2006 and Assistant Vice President - Assistant Controller from May 2006 to January 2007. Prior to joining St. Mary, Mr. Solomon was an auditor with Ernst & Young.

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 2008 and 2007, as reported by the New York Stock Exchange:

Quarter Ended	High	Low
December 31, 2008	$ 35.81	$ 14.76
September 30, 2008	65.58	32.53
June 30, 2008	65.00	37.73
March 31, 2008	39.95	31.70
December 31, 2007	$ 44.50	$ 35.40
September 30, 2007	37.15	31.20
June 30, 2007	40.19	34.91
March 31, 2007	38.20	33.55

PERFORMANCE GRAPH

The following performance graph compares the cumulative total stockholder return on St. Mary's common stock for the period beginning December 31, 2003 and ending on December 31, 2008, with the cumulative total returns of the Dow Jones U.S. Exploration and Production Board Index, and the Standard & Poor's 500 Stock Index.

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

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

Holders. As of February 17, 2009, the number of record holders of St. Mary's common stock was 105. Based on inquiry, management believes that the number of beneficial owners of our common stock is approximately 24,300.

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. Annual dividends of $0.10 per share were paid in 2005 through 2008. We expect that our practice of paying dividends on our common stock will continue, although the payment of future dividends will continue to depend on our earnings, capital requirements, financial condition, and other factors. In addition, the payment of dividends is subject to covenants in our credit facility, including the requirement that we maintain certain levels of stockholders' equity and the limitation of our annual dividend rate to no more than $0.25 per share per year. Dividends are currently paid on a semi-annual basis. Dividends paid totaled $6.2 million in 2008 and $6.3 million in 2007.

Restricted Shares. Aside from Rule 144 restrictions on shares for insiders, shares are subject to transfer restrictions under the provisions of the Employee Stock Purchase Plan, restricted shares issued to directors under the Non-Employee Director Stock Compensation Plan, and shares issued to directors under the 2006 Equity Incentive Compensation Plan (the "2006 Equity Plan"). St. Mary has no restricted shares outstanding as of December 31, 2008.

Equity Compensation Plans. St. Mary has the 2006 Equity Plan under which options and shares of St. Mary common stock are authorized for grant or issuance as compensation to eligible employees, consultants, and members of the Board of Directors. Our stockholders have approved this plan. See Note 7 – Compensation Plans in the Notes to Consolidated Financial Statements included in Part IV, Item 15 of this report for further information about the material terms of our equity compensation plans. The following table is a summary of the shares of common stock authorized for issuance under the equity compensation plans as of December 31, 2008:

	(a)	(b)	(c)
Plan category	Number of securities to be issued upon exercise of outstanding options, warrants, and rights	Weighted-average exercise price of outstanding options, warrants, and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders:			
2006 Equity Incentive Compensation Plan			
Stock options and incentive stock options (1)	1,509,710	$ 12.69	-
Restricted stock (1)	409,388	-	-
Performance share awards (1)	464,333	$ 26.48	1,529,140
Total for 2006 Equity Incentive Compensation Plan	2,383,431	$ 15.93	1,529,140
Employee Stock Purchase Plan (2)	-	-	1,554,583
Equity compensation plans not approved by security holders	-	-	-
Total for all plans	2,383,431	$ 15.93	3,083,723

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

instruments evidencing such grants or issuances. In late 2007, St. Mary transitioned to PSA grants as the primary form of long-term equity incentive compensation for eligible employees in place of grants of RSUs. The Company's Board of Directors approved an amendment and restatement of the 2006 Equity Incentive Compensation Plan on March 28, 2008, and the amended plan was approved by stockholders at the Company's annual stockholders' meeting May 21, 2008. Awards granted in 2008, 2007, and 2006 under the 2006 Equity Plan and the Predecessor Plans were 932,767, 135,138, and 547,678, respectively.

(2) Under the St. Mary Land & Exploration Company Employee Stock Purchase Plan (the "ESPP"), eligible employees may purchase shares of the Company's common stock through payroll deductions of up to 15 percent of their eligible compensation. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on the first or last day of the purchase period, and shares issued under the ESPP are restricted for a period of 18 months from the date issued. The ESPP is intended to qualify under Section 423 of the Internal Revenue Code. Shares issued under the ESPP totaled 45,228, 29,534, and 26,046 in 2008, 2007, and 2006, respectively.

Issuer Purchases of Equity Securities. St. Mary repurchased a total of 2,135,600 shares of its common stock during 2008. St. Mary did not repurchase any shares of its common stock during the fourth quarter of 2008.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth supplemental selected financial and operating data for St. Mary as of the dates and 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. 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.

	Years Ended December 31,				
	2008	2007	2006	2005	2004
	(In thousands, except per share data)				
Total operating revenues	$ 1,301,301	$ 990,094	$ 787,701	$ 739,590	$ 433,099
Net income	$ 91,553	$ 189,712	$ 190,015	$ 151,936	$ 92,479
Net income per share:					
Basic	$ 1.47	$ 3.07	$ 3.38	$ 2.67	$ 1.60
Diluted	$ 1.45	$ 2.94	$ 2.94	$ 2.33	$ 1.44
Total assets at year end	$ 2,695,016	$ 2,571,680	$ 1,899,097	$ 1,268,747	$ 945,460
Long-term obligations:					
Line of credit	$ 300,000	$ 285,000	$ 334,000	$ -	$ 37,000
Senior convertible notes	$ 287,500	$ 287,500	$ 99,980	$ 99,885	$ 99,791
Cash dividends declared and paid per common share	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.05

Supplemental Selected Financial and Operations Data

	Years Ended December 31,				
	2008	2007	2006	2005	2004
	(In thousands, except per share data)				
Balance Sheet Data					
Total working capital (deficit)	$ 15,193	$ (92,604)	$ 22,870	$ 4,937	$ 12,035
Total stockholders' equity	$ 1,127,485	$ 863,345	$ 743,374	$ 569,320	$ 484,455
Weighted-average shares outstanding					
Basic	62,243	61,852	56,291	56,907	57,702
Diluted	63,133	64,850	65,962	66,894	66,894
Reserves					
Oil (MMBbl)	51.4	78.8	74.2	62.9	56.6
Gas (Mcf)	557.4	613.5	482.5	417.1	319.2
MCFE	865.5	1,086.5	927.6	794.5	658.6
Production and Operational:					
Oil and gas production revenues, including hedging	$ 1,158,304	$ 936,577	$ 758,913	$ 711,005	$ 413,318
Oil and gas production expenses	$ 271,355	$ 218,208	$ 176,590	$ 142,873	$ 95,518
DD&A	$ 314,330	$ 227,596	$ 154,522	$ 132,758	$ 92,223
General and administrative	$ 79,503	$ 60,149	$ 38,873	$ 32,756	$ 22,004
Production Volumes:					
Oil (MMBbl)	6.6	6.9	6.1	5.9	4.8
Gas (Bcf)	74.9	66.1	56.4	51.8	46.6
BCFE	114.6	107.5	92.8	87.4	75.4
Realized price – pre hedging:					
Per Bbl	$ 92.99	$ 67.56	$ 59.33	$ 53.18	$ 39.77
Per Mcf	$ 8.60	$ 6.74	$ 6.58	$ 8.08	$ 5.85
Realized price – net of hedging:					
Per Bbl	$ 75.59	$ 62.60	$ 56.60	$ 50.93	$ 32.53
Per Mcf	$ 8.79	$ 7.63	$ 7.37	$ 7.90	$ 5.52
Expense per MCFE:					
LOE	$ 1.46	$ 1.31	$ 1.25	$ 0.99	$ 0.81

Transportation	$	0.19	$	0.14	$	0.12	$	0.09	$	0.10
Production taxes	$	0.71	$	0.58	$	0.54	$	0.56	$	0.36
DD&A	$	2.74	$	2.12	$	1.67	$	1.52	$	1.22
General and administrative	$	0.69	$	0.56	$	0.42	$	0.37	$	0.29
Cash Flow:										
Provided by operations	$	678,221	$	630,792	$	467,700	$	409,379	$	237,162
Used in investing	$	(672,785)	$	(803,872)	$	(724,719)	$	(339,779)	$	(247,006)
Provided by (used in) financing	$	(42,815)	$	215,126	$	243,558	$	(61,093)	$	1,435

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, Items 1 and 2 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 development, exploration, exploitation, acquisition, and production of natural gas and crude oil in North America. We generate nearly all our revenues and cash flows from the sale of produced natural gas and crude oil. Our oil and gas reserves and operations are concentrated primarily in various Rocky Mountain basins, including the Williston, Big Horn, Wind River, Powder River and Greater Green River basins; the Mid-Continent Anadarko and Arkoma basins; the Permian Basin; the tight sandstone reservoirs of East Texas and North Louisiana; the Maverick Basin in South Texas; and the onshore Gulf Coast and offshore Gulf of Mexico. We have developed a balanced and diverse portfolio of proved reserves, development drilling opportunities, and unconventional resource prospects.

Our mission is to economically grow our production and proved reserves, which we believe builds stockholder value over the long-term. Historically, we have relied on a strategy of growing through niche acquisitions focused in the continental United States. Over the last few years, we have shifted our strategy to focus more on capturing potential resource plays earlier and at lower cost. We believe that this shift will allow for more stable and predictable production and proved reserves growth. Going forward, we will focus on continuing to acquire significant leasehold positions in existing and emerging resource plays in North America.

In 2008 we achieved the following financial and operational results:

- Average daily gas production of 204.7 MMcf per day was up 13 percent from 2007. Average daily oil production of 18.1 MBbl per day was down 4 percent from 2007. Average total equivalent daily production was 313.1 MMCFE which was an annual record for the Company.

- Estimated proved reserves of 51.4 MMBbls of oil and 557.4 Bcf of natural gas, or 865.5 BCFE, as of December 31, 2008. This was a decrease of 20 percent from year-end 2007 proved reserves of 1,086.5 BCFE and reflects the divestiture of 61.4 BCFE of non-strategic properties, 44.5 BCFE in downward performance revisions, and 199.7 BCFE of negative price revisions.

- Diluted earnings per share for 2008 were $1.45 on net income of $91.6 million. This reflects a decrease in net income when compared to 2007.

- Cash flow from operating activities of $678.2 million, an increase of eight percent from 2007.

Our operations are generally funded first through cash flows from operating activities and then through borrowings under our existing credit facility. Acquisitions may be funded with proceeds from sales of public or private debt and equity, borrowings under our existing facility, property sales, and cash flow from operating activities. In 2008 we invested $745.6 million for development and exploration and invested $81.8 million for acquisitions of oil and gas properties.

A major determination of the value of our Company is the value of our proved reserves. At year-end 2008 we had proved reserves of 865.5 BCFE of which 64 percent were natural gas and 83 percent were characterized as proved developed. Base oil and gas prices used for our SEC proved reserves were significantly lower at year-end 2008 compared to the prior year. Additionally, we saw wider than normal differentials at year-end, particularly for oil in the Rocky Mountain region. We used significantly lower prices at year-end to determine our proved reserves; these adjusted year-end prices were $5.71 per MMBtu and $44.60 per Bbl, which are down 16 percent and 54 percent, respectively, from the prior year. As a result, we had 199.7 BCFE in negative pricing revisions at the end of 2008. The majority of these pricing revisions relate to the oil-dominated Rocky Mountain region, which was impacted by lower oil prices and wider product differentials. These differentials for oil have improved significantly since year-end. Additionally, we had pricing revisions related to properties in South Texas as pricing for natural gas liquids deteriorated significantly year over year. We had 44.5 BCFE of negative performance revisions. The majority of our performance revisions relate to Olmos shallow gas assets in South Texas that were acquired in 2007. The Olmos reservoir is demonstrating poorer reservoir performance then was originally modeled. The reservoir is more compartmentalized then we initially thought and we have seen lower reserve outcomes while attempting to infill parts of the field. Our additions through the drill-bit were 170.1 BCFE, 78 percent, of which was natural gas. We added 29.1 BCFE of proved reserves through acquisitions in 2008, 93 percent of which was natural gas and 59 percent of which was proved undeveloped. Throughout 2008, we divested 61.4 BCFE of proved reserves associated with non-core properties. The SEC has adopted new rules that will be effective at the end of 2009 that change certain factors regarding the calculation of proved reserves, including changes regarding prices to be used. Under the new rules, which will use an average price throughout the year rather than a year-end price, we believe the negative pricing revision would have been less severe and our proved reserves would have been meaningfully higher.

The before income tax PV-10 value of our proved reserves was $1.3 billion as of December 31, 2008. The after tax value of $1.1 billion as represented by the standardized measure calculation is presented in Note 17 – Disclosures about Oil and Gas Producing Activities of Part IV, Item 15 of this report. A reconciliation between these two amounts is shown under Reserves in Part I, Items 1 and 2 of this report.

Reserve Replacement, Finding Costs, and Growth

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

The following table provides various reserve replacement and finding cost metrics for the year ended December 31, 2008:

	Reserve Replacement Percentage		Finding Cost per MCFE	
	Excluding sales	Including sales	Excluding sales	Including sales
Drilling, excluding performance and price revisions	148%	95%	$ 3.99	$ 6.25
Drilling, including performance revisions	110%	56%	$ 5.40	$ 10.57
Drilling and acquisitions, excluding performance and price revisions	174%	120%	$ 3.67	$ 5.30
Drilling and acquisitions, including performance revisions	135%	81%	$ 4.72	$ 7.83
Acquisitions	25%	N/A	$ 1.77	N/A
All-in, excluding price revisions	135%	81%	$ 5.54	$ 9.18
All-in, including performance and price revisions	(39)%	(93)%	$ (19.04)	$ (8.05)

The following table provides three-year average reserve replacement and finding cost metrics for the years ended December 31, 2008, 2007, and 2006:

	Reserve Replacement Percentage		Finding Cost per MCFE	
	Excluding sales	Including sales	Excluding sales	Including sales
Drilling, excluding performance and price revisions	133%	112%	$ 4.48	$ 5.32
Drilling, including performance revisions	142%	121%	$ 4.20	$ 4.93
Drilling and acquisitions, excluding performance and price revisions	204%	183%	$ 3.63	$ 4.05
Drilling and acquisitions, including performance revisions	213%	192%	$ 3.48	$ 3.86
Acquisitions	71%	N/A	$ 2.03	N/A
All-in, excluding price revisions	213%	192%	$ 3.87	$ 4.29
All-in, including performance and price revisions	144%	123%	$ 5.73	$ 6.71

Our challenge is to grow net asset value per share , which we believe drives appreciation in our stock price over the long term. To accomplish this, we believe it is important to economically replace at least 200 percent of annual production with new reserves and to grow production greater than ten percent per year. We believe annual reserve replacement percentage and finding cost amounts are important analytical measures that are widely used by investors and industry peers in evaluating and comparing the performance of oil and gas companies. While single-year measurements have some meaning in terms of a trend, we believe that aberrations, causing both relatively good and bad results, will occur over short intervals of time. The information used to calculate the above reserve replacement and finding cost metrics is included in Note 16 - Oil and Gas Activities and Note 17 - Disclosures about Oil and Gas Producing Activities of the Notes to Consolidated Financial Statements included in Part IV, Item 15 of this report. For additional information about these metrics, see the reserve replacement and finding cost terms in the Glossary at the end of Part I, Items 1 and 2 of this report.

Financial Standing and Liquidity

During and subsequent to the third quarter of 2008, specific issues related to the financial sector have rippled through the broader economy. The failure or takeover of several large financial institutions has adversely impacted the wider equity, debt, and credit markets. Financial standing and liquidity have become increasingly important as concerns have been raised regarding the pace of drilling activity in the exploration and production industry and the ability of companies to fund their planned activity. In addition, fears of global recession have resulted in a significant decline in oil and natural gas demand and consequently prices. Our exploration and development program at the beginning of 2008 was designed to stay within generated cash flow. We met this goal with our investment of $745.6 million during the year. In addition to exploration and development activities, we spent $81.8 million on acquisitions and $77.2 million for share repurchases in 2008. These two expenditures were offset by the divestiture of non-strategic properties that provided $178.9 million.

We continue to believe we have adequate liquidity available to us through our credit facility. On October 1, 2008, the lending group redetermined our reserve-backed borrowing base under the credit facility at an amount of $1.4 billion. Based on our expected requirements, we currently have a $500 million commitment amount in place. We had $300.0 million and $318.5 million drawn on the credit facility at December 31, 2008, and February 17, 2009, respectively. Management believes the current commitment is sufficient and that if necessary we could request a higher commitment amount from the lending group, although it would likely be at different terms and interest rates than are currently in place. To date, we have experienced no issues drawing upon our credit facility, and all ten participating banks have continued to fund. Except for Wells Fargo Bank, N.A., who recently merged with Wachovia Bank, National Association and represents 22 percent of the lending commitment, no individual bank participating in the credit facility represents more than 11 percent of the lending commitments under the credit facility. The existing credit facility expires in April of 2010, and we have begun discussions with the banks within the existing bank group, as well as banks not in the existing facility, about a new credit facility. With commodity prices currently significantly lower than those used at our last determination, we believe that our borrowing base will be lower than the $1.4 billion calculated in October 2008, but still above the current $500 million commitment amount. We may increase the commitment amount available to us under the new facility from the $500 million we currently have committed. Given current market conditions, we anticipate higher pricing and more fees on the new facility. Our intention is to have a new credit facility in place during the first half of 2009.

Oil and Gas Prices

Oil and natural gas prices increased significantly during the first half of 2008, reaching all time highs in June and early July, and have declined even more significantly since that time. The results of our operations and financial condition are significantly affected by oil and natural gas commodity prices. We sell a majority of our natural gas under contracts that use first of the month index pricing, which means that gas produced in that month is sold at the first of the month price regardless of the spot price on the day the gas is produced. Our crude oil is sold using contracts that pay us the average of either the NYMEX West Texas Intermediate daily settlement price or the average of alternative posted prices for the periods in which the crude oil is produced, adjusted for quality, transportation, and location differentials. The following table is a summary of commodity price data for the years ended December 31, 2008, 2007, and 2006.

	For the Years Ended December 31,		
	2008	2007	2006
Crude Oil (per Bbl):			
NYMEX price	$ 99.65	$ 72.34	$ 66.22
Realized price, before the effects of hedging	$ 92.99	$ 67.56	$ 59.33
Net realized price, including the effects of hedging	$ 75.59	$ 62.60	$ 56.60
Natural Gas (per Mcf):			
NYMEX price	$ 8.95	$ 6.92	$ 7.26
Realized price, before the effects of hedging	$ 8.60	$ 6.74	$ 6.58
Net realized price, including the effects of hedging	$ 8.79	$ 7.63	$ 7.37

Average quarterly NYMEX crude oil prices increased 38 percent to $99.65 per barrel for the year ended December 31, 2008, compared to $72.34 per barrel for 2007. The price of crude oil has been pressured downward as a result of a forecasted decrease in global demand, which is a consequence of the broad economic slowdown. The 36-month forward strip price for crude oil as of December 31, 2008, was $62.15 per barrel. On February 17, 2009, the 36-month forward contract had decreased from year-end by an additional 15 percent to $52.82 per barrel. The near month price for crude oil as of December 31, 2008, was $44.60 per barrel. On February 17, 2009, the near month price had decreased from year-end by an additional 22 percent to $34.93 per barrel.

Average quarterly NYMEX natural gas prices increased 29 percent to $8.95 per Mcf for the year ended December 31, 2008, compared to $6.92 per Mcf for 2007. Natural gas prices have been pressured downward in recent months as a result of a forecasted decrease in global demand and over concerns of forecasted excess gas supply that will be generated from the ramp up in the number of horizontal wells planned in a number of new shale plays across the United States. The 36-month forward strip price for natural gas as of December 31, 2008, was $6.90 per Mcf. On February 17, 2009, the 36-month forward contract had decreased from year-end by an additional 12 percent to $6.07 per Mcf. The near month price for natural gas as of December 31, 2008, was $5.62 per Mcf. On February 17, 2009, the near month price had decreased from year-end by an additional 25 percent to $4.20 per Mcf.

While changes in quoted NYMEX oil and Henry Hub natural gas prices are generally used as a basis for comparison within our industry, the price we receive for oil and natural gas is affected by quality, energy content, location, and transportation differentials for these products. We refer to this price as our realized price, which excludes the effects of hedging. We are beginning to see wider differentials for both oil and natural gas in recent months in regions that have high levels of industry activity. In particular, differentials for oil in the Williston Basin have been pressured as activity in the area has accelerated in recent months and differentials for natural gas in the Mid-Continent have widened as regional demand has not kept pace with the growth in supply generated by several successful shale plays in the general vicinity. Our realized price is further impacted by the result of our hedging contracts that are settled in the respective periods. We refer to this price as our net realized price. Our net natural gas price realization for year ended December 31, 2008, was positively impacted by $14.0 million of realized hedge gains and our net oil price realization was negatively impacted by $115.1 million of realized hedge losses. On a percentage basis, we currently have hedged more forecasted crude oil production than forecasted natural gas production using a combination of swaps and costless collars.

Hedging Activities

Hedging is an important part of our financial risk management program. The amount of production we hedge is driven by the amount of debt on our consolidated balance sheet and the level of capital commitments we have in place. In the case of a significant acquisition of producing properties, we will hedge in order to lock in a portion of the economics assumed in the acquisition. Taking into account all oil and gas production hedge contracts in place at December 31, 2008, we have hedged anticipated future production of approximately 8 million Bbls of oil, 54 million MMBtu of natural gas, and 1 million Bbl of natural gas liquids through the year 2011. We believe we have established an economic base for our future operations, and the spread between the price floors and ceilings on our collars allows us to continue to participate in a higher oil and gas price environment. Please see Note 10 – Derivative Financial Instruments of Part IV, Item 15 of this report for additional information regarding our oil and gas hedges, and see the caption, Summary of Oil and Gas Production Hedges in Place, later in this section.

Net Profits Plan

Payments made from the Net Profits Plan have been expensed as compensation costs in the amounts of $51.5 million, $31.9 million, and $26.1 million for the years ended December 31, 2008, 2007, and 2006, respectively. The actual cash payments we make are dependent on actual production, realized prices, and operating and capital costs associated with the properties in each individual pool. Actual cash payments will be inherently different from the estimated liability amounts. More detailed discussion is included in the analysis in the Comparison of Financial Results and Trends sections below and in Note 11 – Fair Value Measurements in Part IV, Item 15. An increasing percentage of the costs associated with the payments for the Net Profits Plan are attributable to general and administrative expense as compared to exploration expense. This is a function of the normal departure of employees who previously contributed to exploration efforts. We determined that because of the change in circumstances, a greater percentage of the payments should be recorded as general and administrative expense beginning in 2007. In December 2007, our Board approved an incentive compensation plan restructuring, whereby the Net Profits Plan was replaced with a long-term incentive program utilizing performance shares in 2008. As a result, the 2007 Net Profits Plan pool was the last pool established.

The calculation of the estimated liability for the Net Profits Plan is highly sensitive to our price estimates and discount rate assumptions. For example, if we changed the commodity prices in our calculation by five percent, the liability recorded on the balance sheet at December 31, 2008, would differ by approximately $14 million. A one percentage point decrease in the discount rate would result in an increase to the liability of approximately $9 million, while a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $8 million. We frequently re-evaluate the assumptions used in our calculations and consider the possible impacts stemming from the current market environment including current and future oil and gas prices, discount rates, and overall market conditions.

The table below provides information regarding selected production and financial information for the quarter ended December 31, 2008, and the immediately preceding three quarters. Additional details of per MCFE costs are contained later in this section.

	For the Three Months Ended			
	December 31, 2008	September 30, 2008	June 30, 2008	March 31, 2008
	(In millions, except production sales data)			
Production (BCFE)	30.0	27.7	28.6	28.3
Oil and gas production revenue excluding the effects of hedging	$ 190.5	$ 358.5	$ 400.0	$ 310.4
Realized oil and gas hedge gain (loss)	$ 44.8	$ (53.5)	$ (68.4)	$ (24.0)
Lease operating expense	$ 47.7	$ 43.6	$ 41.0	$ 35.1
Transportation costs	$ 6.1	$ 6.6	$ 5.6	$ 3.9
Production taxes	$ 11.8	$ 22.5	$ 27.0	$ 20.5
DD&A	$ 95.1	$ 72.4	$ 76.4	$ 70.4
Exploration	$ 17.7	$ 10.7	$ 17.4	$ 14.3
Impairment of proved properties	$ 292.1	$ 0.5	$ 9.6	$ -
Abandonment and impairment of unproved properties	$ 34.7	$ 1.2	$ 2.1	$ 1.0
Impairment of goodwill	$ 9.5	$ -	$ -	$ -
General and administrative expense	$ 12.4	$ 24.1	$ 21.9	$ 21.1
Net income	$ (126.0)	$ 88.0	$ 33.6	$ 96.0
Percentage change from previous quarter:				
Production (BCFE)	8%	(3)%	1%	(1)%
Oil and gas production revenue excluding the effects of hedging	(47)%	(10)%	29%	13%
Realized oil and gas hedge gain (loss)	(184)%	(22)%	185%	105%
Lease operating expense	9%	6%	17%	(7)%
Transportation costs	(8)%	18%	44%	3%
Production taxes	(48)%	(17)%	32%	7%
DD&A	31%	(5)%	9%	8%
Exploration	65%	(39)%	22%	(11)%
Impairment of proved properties	58320%	(95)%	N/A	N/A
Abandonment and impairment of unproved properties	2792%	(43)%	110%	11%
Impairment of goodwill	N/A	N/A	N/A	N/A
General and administrative expense	(49)%	10%	4%	39%

Net income	(243)%	162%	(65)%	192%

2008 Highlights

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

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acres in this play. Lastly, late in 2008 we entered into two arrangements that could allow us to access 43,000 net acres in the Marcellus shale in north central Pennsylvania.

Acquisitions and divestitures. We continue to optimize our portfolio of assets as part of our overall strategic goals and objectives. As part of this strategy, on January 31, 2008, we completed the divestiture of certain non-strategic oil and gas properties located primarily in the Rocky Mountain and Mid-Continent regions to Abraxas Petroleum Corporation and Abraxas Operating, LLC. The cash received at closing was $129.6 million, net of commission costs. The economics of the transaction were further enhanced by utilizing a tax-advantaged exchange structure that will allow us to defer most of the gain on the sale. In June 2008 the Company completed the divestiture of certain non-strategic oil and gas properties located in the Greater Green River Basin. We also utilized a tax-advantaged exchange structure for this divestiture. The cash received at closing, net of all commission costs, was $21.7 million. The final sale price is subject to normal post-closing adjustments and is expected to be finalized during the first quarter of 2009. During 2008 we recorded a $63.6 million gain on the sale of proved properties, which included the gain from the Abraxas and Greater Green River divestitures, as well as other smaller divestitures.

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

On December 31, 2008, we closed on a transaction whereby we received an increased interest in our operated tight oil assets at Sweetie Peck in West Texas and approximately $17.6 million of cash in exchange for our interests in the Judge Digby Field in Pointe Coupee Parish, Louisiana. The Sweetie Peck tight oil program has a multi-year drilling inventory, with potential for increased density drilling, which we plan to exploit over the coming years.

Effects of Hurricanes Gustav and Ike. During the third quarter of 2008, assets in which we have an interest were impacted by Hurricanes Gustav and Ike. The most impactful damage caused by the storms was to power and processing facilities and infrastructure in the Gulf Coast area, causing us to shut-in production throughout our Gulf Coast region. We lost the Vermilion 281 producing platform in the Gulf of Mexico and incurred damage to our Goat Island production facilities in Galveston Bay during Hurricane Ike. We are in the process of assessing and remediating the damage related to the Vermilion 281 platform. Most of this expense will be covered by insurance as noted below. The damage to two wells and our production facilities located at Goat Island in Galveston Bay have been repaired and these wells were back on production by year-end 2008.

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

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

Repurchase of common stock. Throughout the first quarter of 2008, we repurchased a total of 2,135,600 shares of our common stock in the open market. The shares were repurchased at a weighted-average cost of

$36.13 per share, including commissions, using cash on hand and borrowings under our revolving credit facility. These shares were purchased under a share repurchase program approved by the Board. At the time we repurchased our shares, we entered into hedges for a commensurate amount of our production represented by the share repurchase in order to lock in the discounted price at which our shares were trading. As of the date of this filing, we are authorized to repurchase an additional 3,072,184 shares under this program.

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

Senior management change. On March 21, 2008, David W. Honeyfield, Senior Vice President – Chief Financial Officer and Secretary resigned as an officer. On September 8, 2008, A. Wade Pursell commenced employment as Executive Vice President and Chief Financial Officer.

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

Financial and production results. Our net income for the year ended December 31, 2008, was $91.6 million or $1.45 per diluted share compared to 2007 results of $189.7 million or $2.94 per diluted share. We discuss these financial results and trends in more detail below.

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

	ArkLaTex	Mid-Continent	Gulf Coast	Permian	Rocky Mountain	Total(1)
2008 Production:						
Oil (MBbl)	159	367	230	1,753	4,106	6,615
Gas (MMcf)	17,599	30,825	12,886	3,325	10,275	74,910
Equivalent (MMCFE)	18,554	33,026	14,270	13,841	34,910	114,601
Avg. Daily Equivalents (MMCFE/per day)	50.7	90.2	39.0	37.8	95.4	313.1
Relative percentage	16%	29%	12%	12%	31%	100%

(1) Totals may not add due to rounding

In 2008 we experienced record production and strong operating cash flows. Our record production is a realization of operational and investment decisions made in prior years as well as the current period. Our operating margins remained strong in 2008 despite increasing operating costs. Our 2008 operating margin was $7.75 per MCFE compared to $6.68 per MCFE in 2007.

Net cash provided by operating activities was $678.2 million, up eight percent from 2007. Average daily production for the year increased six percent to a record 313.1 MMCFE. Our average net realized price increased $1.40 to $10.11 per MCFE. Unit cost increased for the period as lease operating expenses increased $0.15 to $1.46 per MCFE. While general industry costs associated with drilling and completing wells are flat or declining year over year, costs related to the ongoing operation of oil and gas properties continue to experience upward pressure. This increase over last year's comparable period is driven by continued pressure on costs related to the servicing of wells, such as disposal and trucking, as well as workover and labor costs. As a company with a significant oil component in our production mix, our property base inherently requires more labor than operations that are dominated by natural gas production. Labor costs continue to be a significant driver of our lease operating expense. In addition to the higher costs we are incurring on our base activity, we have been actively incurring workover expense to restore or increase production in the Gulf Coast and Rocky Mountain regions. Transportation costs increased $0.05 per MCFE, or 36 percent to $0.19 per MCFE as compared to a year ago. The increase is due to newly drilled wells with higher transportation costs. Production taxes increased $0.13 per MCFE to $0.71 per MCFE and are a reflection of higher average commodity prices.

Depletion, depreciation, and amortization, including asset retirement obligation accretion expense, increased $0.62 to $2.74 per MCFE. The depletion, depreciation, and amortization increase is reflective of higher costs on a per MCFE basis for new reserve additions relative to the base cost of our oil and gas properties. General and administrative expense increased $0.13 per MCFE to $0.69 per MCFE. The increase in general and administrative expenses is driven by our growing employee base and higher payments from the Net Profits Plan. Exploration expense for 2008 was $60.1 million, which was $1.4 million higher than the $58.7 million incurred during 2007 due to an increase in exploration overhead offset by decreases in exploratory dry hole expense.

Impairment of proved properties for the year ended December 31, 2008, totaled $302.2 million. There was no impairment of proved properties in 2007. The decrease in proved reserves described above caused the majority of this pre-tax non-cash impairment of proved properties. The largest portion of the impairment was $154.0 million related to assets in South Texas that were acquired in 2007. We also saw an impairment associated with proved properties in the Gulf of Mexico, the greater Green River Basin in Wyoming, and our coalbed methane project at Hanging Woman Basin. We discuss these financial results and trends in more detail below.

Outlook for 2009

Unlike prior years, we enter 2009 without a firm dollar amount budgeted for exploration and production activities. Our plan is to spend at or within cash flow for exploration and development activities in 2009. Given the volatility of commodity prices in recent months, we have established a flexible program to deploy capital rather than set a fixed number. Our first priority in 2009 is to test the potential of several of the emerging resource plays where we have gained exposure in the past year. We plan to test wells in the Haynesville shale in East Texas and northern Louisiana, the Marcellus shale in Pennsylvania, and the Eagle Ford shale in South Texas. This testing is critical to growing the long-term value of the company and is likely to proceed unless we see significant declines in commodity prices from current levels. Our second priority is rational development of existing assets. We believe that with the significant decline in commodity prices, the exploration and production industry will slow its level of activity which in turn will lead to a decline in the cost of services provided by the oilfield service industry. We believe the prices for drilling and completion services will continue to decline throughout 2009 as a result of continued decreasing rig utilization. Accordingly, we have chosen to defer much of our capital investment with the goal of improving our returns on invested capital. With limited exceptions, we do not have any significant long-term rig commitment or any meaningful issues with potential leasehold expirations. As such, we believe we can be more patient than many of our competitors in choosing when to invest capital. Most of our existing rig commitments will expire in the first half of 2009, and we will use very short-term rig contracts to operate a significantly smaller rig fleet throughout 2009 than we used in 2008. We are striving to maintain a high degree of flexibility in the current environment. Our objective is to be able to slow down should economic conditions continue to warrant while preserving the ability to ramp up activity quickly when industry conditions improve or with near term success from our multiple resource play tests this year.

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

	As of and for the Years Ended December 31,			Percent Change Between	
	2008	2007	2006	2008/2007	2007/2006
Selected Operations Data (In Thousands, Except Price, Volume, and Per MCFE Amounts)					
Total proved reserves					
Oil (MMBbl)	51.4	78.8	74.2		
Natural gas (Bcf)	557.4	613.5	482.5		
BCFE	865.5	1,086.5	927.6	(20)%	17%
Net production volumes					
Oil (MMBbl)	6.6	6.9	6.1		
Natural gas (Bcf)	74.9	66.1	56.4		
BCFE	114.6	107.5	92.8	7%	16%
Average daily production					
Oil (MBbl)	18.1	18.9	16.6		
Natural gas (MMcf)	204.7	181.0	154.7		
MMCFE	313.1	294.5	254.2	6%	16%
Oil & gas production revenues					
Oil production, including hedging	$ 500,062	$ 432,375	$ 342,810		
Gas production, including hedging	658,242	504,202	416,103		
Total	$ 1,158,304	$ 936,577	$ 758,913	24%	23%
Oil & gas production costs					
Lease operating expenses	$ 167,384	$ 140,389	$ 115,896		
Transportation costs	22,205	15,529	10,999		