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.

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- 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.

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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

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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.

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.

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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.

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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

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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 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.

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:

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
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

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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)

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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

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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 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		
Production taxes	81,766	62,290	49,695		
Total	$ 271,355	$ 218,208	$ 176,590	24%	24%
Average net realized sales price (1)					
Oil (per Bbl)	$ 75.59	$ 62.60	$ 56.60	21%	11%
Natural gas (per Mcf)	$ 8.79	$ 7.63	$ 7.37	15%	4%
Per MCFE data					
Average net realized price (1)	$ 10.11	$ 8.71	$ 8.18	16%	6%
Lease operating expense	(1.46)	(1.31)	(1.25)	11%	5%

Transportation costs		(0.19)		(0.14)		(0.12)	36%	17%
Production taxes		(0.71)		(0.58)		(0.54)	22%	7%
General and administrative		(0.69)		(0.56)		(0.42)	23%	33%
Operating profit	$	7.06	$	6.12	$	5.85	15%	5%
Depletion, depreciation and amortization	$	2.74	$	2.12	$	1.67	29%	27%
Financial information (In Thousands, Except Per Share Amounts):								
Working capital (deficit)	$	15,193	$	(92,604)	$	22,870	116%	(505)%
Long-term debt	$	587,500	$	572,500	$	433,980	3%	32%
Stockholders' equity	$	1,127,485	$	863,345	$	743,374	31%	16%
Net income	$	91,553	$	189,712	$	190,015	(52)%	-%
Basic net income per common share	$	1.47	$	3.07	$	3.38	(52)%	(9)%
Diluted net income per common share	$	1.45	$	2.94	$	2.94	(51)%	-%
Basic weighted-average shares outstanding		62,243		61,852		56,291	1%	10%
Diluted weighted-average shares outstanding		63,133		64,850		65,962	(3)%	(2)%
Net cash provided by operating activities	$	678,221	$	630,792	$	467,700	8%	35%
Net cash used in investing activities	$	(672,785)	$	(803,872)	$	(724,719)	(16)%	11%
Net cash provided by (used in) financing activities	$	(42,815)	$	215,126	$	243,558	(120)%	(12)%

(1) Includes the effects of our hedging activities.

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

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Proved reserves decreased 20 percent to 865.5 BCFE at December 31, 2008, from 1,086.5 BCFE at December 31, 2007. Please see Note 17 – Disclosures about Oil and Gas Producing Activities of Part IV, Item 15 of this report and the above discussion under the caption General Overview for additional details and discussion on the individual components of the change. Over time, our ability to economically replace volumes produced annually has proven to be a key factor that determines whether we are successful in achieving our goal of increasing net asset value per share. The measure of our success will vary year-to-year due to changes in these factors.

Changes in production volumes, oil and gas production revenues, and costs generally reflect the cyclical and highly volatile nature of our industry. We present per MCFE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends that we believe require analysis. We anticipate that oil and gas production expenses will decrease in 2009 due to our internal focus on managing these costs and due to the effects that declining commodity prices are anticipated to have on direct costs of services used to produce oil and natural gas. Additionally, many exploration and production companies have begun to slow their activity, which should have a moderating impact on the upward cost pressure we have seen in recent quarters. Production taxes are largely dependent on the prices we receive for oil and natural gas, in the current environment we would expect them to decrease. Depreciation, depletion, and amortization generally has been pressured upward in recent years as production related to higher cost properties acquired or developed became a larger percentage of our production mix. However, as a result of our impairment of proved properties in 2008 we could see a decline in DD&A rate in 2009. Our general and administrative expense will be impacted by cash payments made under the Net Profits Plan, which are impacted by realized prices. Part of executing our business plan in 2008 consisted of adding employees, particularly lease operators who manage our operations in the field. The increase in personnel would be expected to drive general and administrative costs higher in 2009. Additionally, competition for personnel in the exploration and production industry remains aggressive, and we have seen the cost to hire and retain personnel increase significantly.

We have in-the-money stock options, unvested RSUs, and PSAs that may be potentially dilutive securities. These dilutive securities affect our earnings per share. Both basic and diluted earnings per share are presented in the table above. We account for our 3.50% Senior Convertible Notes under the treasury stock method. There is no impact on the diluted share calculation for the periods presented since the Company's average stock price for the relevant reporting periods has not exceeded the conversion price. The 3.50% Senior Convertible Notes were issued April 4, 2007, and have not been dilutive for a reporting period since their issuance. There were no potentially dilutive shares related to the PSAs included in the diluted earnings per share calculation for the year ended December 31, 2008. A detailed explanation is presented under the caption Earnings per Share included in Note 1 – Summary of Significant Accounting Policies, in Part IV, Item 15 of this report.

Basic and diluted weighted-average common shares outstanding used in our 2008, 2007, and 2006 earnings per share calculations reflect our stock repurchases, offset by increases in outstanding shares related to stock option exercises, ESPP shares issued, and vested RSUs. We issued 868,372 shares of common stock in 2008, 733,650 shares in 2007, and 1,489,636 shares in 2006 as a result of stock option exercises. These share issuances were offset by the repurchase of 2,135,600 shares of common stock in 2008, 792,216 shares in 2007, and 3,319,300 shares in 2006 through our stock repurchase plan. Additionally, the number of RSUs that vested in 2008, 2007, and 2006 were 291,659, 268,123, and 298,352, respectively.

Overview of Liquidity and Capital Resources

In order to maintain our current size or to meet our projected growth targets, we will have to effectively invest capital into new projects and acquisitions. The following analysis and discussion includes our assessment of market risk and possible effects of inflation and changing prices.

Sources of cash

Based on our current outlook, we expect our exploration and development budget to be at or within our generated cash flow from operations in 2009. Accordingly, we do not expect to access the capital markets in 2009. Throughout 2008, we divested of non-core oil and gas properties. Net cash proceeds from these transactions, after commission costs, were $178.9 million. We anticipate that we will continue to evaluate our property base for the divestiture of properties that we consider non-core to our strategic goals. We currently have identified assets that we intend to market for sale in 2009, however given our strong financial position we will not be forced to sell these properties unless we receive appropriate value.

Our primary sources of liquidity are the cash provided by operating activities, debt financing, sales of non-core properties, and access to capital markets. All of these sources can be impacted by the general condition of the broad economy, our industry and by significant fluctuations in oil and gas prices, operating costs, and volumes produced. We have no control over the market prices for oil and natural gas, although we are able to influence the amount of our net realized revenues related to oil and gas sales through the use of derivative contracts. A decrease in market prices would reduce expected cash flow from operating activities and could reduce the borrowing base of our credit facility as well as the value of non-strategic properties we might consider selling. Historically, decreases in market prices have limited our industry's access to the capital markets. The public debt markets for energy companies appear to be opening up in recent weeks after several months of being closed as a result of broader issues in the financial markets caused by widely reported sub-prime and leveraged loan market issues. Credit spreads have increased materially and the volume of transactions being placed in the market are down dramatically. Equity and convertible debt financings are still an available alternative. This is a result of the general strength reflected in the balance sheets of the companies in this industry as well as the historically low credit defaults of energy companies. We do not anticipate any need to raise either public debt or equity financing in the foreseeable future. We intend to rely on our credit facility for borrowings. However, a significant transaction could necessitate raising additional public debt or equity financing.

Current credit facility

We have a revolving credit facility agreement with ten participating banks. 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. On October 1, 2008, the lending group redetermined our reserve-based borrowing base under the credit facility at the previous amount of $1.4 billion. We have elected a commitment amount of $500.0 million. We believe this commitment level is adequate for our near-term liquidity requirements. 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. Our intention is to have a new credit facility in place during the first half of 2009.

As of February 17, 2009, we had $181.5 million of available borrowing capacity under this facility. Interest and commitment fees are accrued based on the borrowing base utilization percentage. Euro-dollar loans accrue interest at LIBOR plus the applicable margin from the utilization table located in Note 5 of Part IV, Item 15 of this report, and Alternate Base Rate loans accrue interest at Prime plus the applicable margin from the utilization table. This reduces the amount available under the commitment amount on a dollar-for-dollar basis. Borrowings under the facility are secured by mortgages on the majority of our oil and gas properties and pledge of the common stock of our material subsidiary companies.

Our weighted-average interest rate paid in 2008 was 4.4 percent and included fees paid on the unused portion of the credit facility aggregate commitment amount, amortization of deferred financing costs, and the effects of interest rate swaps. We increased our net borrowings from the previous year by $15.0 million when comparing the ending 2008 and 2007 balance sheet amounts. An increase in the average outstanding credit facility balance throughout 2008, offset by a decrease in interest rates and a decrease in the amount of capitalized interest of $1.7 million, resulted in higher interest expense of $20.3 million in 2008 compared with $19.9 million in 2007.

We are subject to customary financial and non-financial covenants under our credit facility, including limitations on dividend payments and requirements to maintain certain financial ratios, which include debt to earnings before interest, taxes, depreciation, and amortization of less than 3.5 to 1.0 and a current ratio as defined by our credit agreement of not less than 1.0. As of December 31, 2008, our debt to EBITDA ratio and current ratio as defined by our credit agreement, were 0.75 and 1.73, respectively. We are in compliance with all financial and non-financial covenants under this credit facility and expect to be in compliance for the foreseeable future.

We may from time to time repurchase certain amounts of our outstanding debt securities for cash and/or through exchanges for other securities. Such repurchases or exchanges may be made in open market transactions, privately negotiated transactions, or otherwise. Any such repurchases or exchanges will depend on prevailing market conditions, our liquidity requirements, contractual restrictions, compliance with securities laws and other factors. The amounts involved in any such transaction may be material.

Uses of cash

We use cash for the acquisition, exploration, and development of oil and gas properties, and for the payment of debt obligations, trade payables, income taxes, common stock repurchases, and stockholder dividends. During 2008 we spent $745.6 million of cash on capital development and $81.8 million of cash for property acquisitions. These amounts differ from the cost incurred amounts based on the timing of cash payments associated with these activities as compared to the accrual based activity upon which the costs incurred amounts are presented. These cash flows were funded using cash inflows from operations, proceeds from the sale of assets, and available borrowing capacity under our revolving credit facility.

Expenditures for exploration and development of oil and gas properties and acquisitions are the primary use of our capital resources. We expect that our capital and exploration expenditures in 2009 will be within operating cash flows. The amount and allocation of future capital expenditures will depend upon a number of factors including the number and size of available economic acquisitions and drilling opportunities, our cash flows from operating and financing activities, and our ability to assimilate acquisitions. Also the impact of oil and gas prices on investment opportunities, the availability of capital and borrowing facilities, and the success of our development and exploratory activities could lead to changes in funding requirements for future development. We regularly review our capital expenditure budget to assess changes in current and projected cash flows, acquisition opportunities, debt requirements, and other factors.

The current portion of our income tax expense was 32 percent of our total income tax expense for 2008. We made estimated payments during the calendar year, and as of December 31, 2008, we anticipate an income tax refund of $13.2 million will be due to the Company.

During 2008 we purchased 2,135,600 shares of our common stock in the open market at a weighted-average price of $36.13, including commissions, for a total of $77.2 million. As of this filing date we have Board authorization to repurchase up to an additional 3,072,184 shares of our common stock under our stock repurchase program. Shares may be repurchased from time to time in open market transactions or privately negotiated transactions subject to market conditions and other factors including certain provisions of our existing bank credit facility agreement, compliance with securities laws, and the terms and provisions of our stock repurchase program.

In 2008 we paid $6.2 million in dividends to our stockholders. Our intention is to continue to make these dividend payments for the foreseeable future subject to our future earnings, our financial condition, possible credit facility covenants, and other currently unexpected factors which could arise.

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

	Amount of Changes Between		Percent of Change Between	
	2008/2007	2007/2006	2008/2007	2007/2006
Net Cash Provided By Operating Activities	$ 47,429	$ 163,092	8%	35%
Net Cash Provided By Investing Activities	$ 131,087	$ (79,153)	(16)%	11%
Net Cash Provided By (Used In) Financing Activities	$ (257,941)	$ (28,432)	(120)%	(12)%

Analysis of cash flow changes between 2008 and 2007

Operating activities. Cash received from oil and gas production revenues, net of the realized effects of hedging, increased $265.2 million to $1.2 billion for the year ended December 31, 2008. The increase was the result of a seven percent increase in production and a 16 percent increase in our net realized price after hedging, resulting in a 24 percent increase in production revenue. Included in the oil and gas production revenue amounts is $101.1 million of net realized hedging losses. Net cash payments made for income taxes increased $18.5 million due to fluctuating oil and gas prices which increased our estimated quarterly income tax payments in 2008.

Investing activities. Total cash outflow for 2008 capital expenditures for leasehold and drilling activities increased $107.9 million or 17 percent to $745.6 million. Total cash outflow for 2008 related to the acquisition of oil and gas properties decreased $101.1 million or 55 percent to $81.8 million. Cash received from the sale of oil and gas properties increased $178.4 million and deposits to restricted cash increased $14.4 million for the period ended December 31, 2008, as compared to the same period in 2007.

Financing activities. Net repayments to our credit facility decreased $64.0 million for the period ended December 31, 2008, compared to 2007. We received $280.7 million less during 2008, compared to the same period in 2007, from the issuance of senior convertible debt. Our income tax benefit attributable to the exercise of stock options increased $3.9 million to $13.9 million for the year ended December 31, 2008, compared with the same period in 2007. We received $1.9 million more proceeds from the sale of common stock in 2008, compared to 2007. Additionally, we invested $51.3 million more to repurchase shares of our common stock during 2008, compared to 2007.

We had $6.1 million in cash and cash equivalents and working capital of $15.2 million as of December 31, 2008, compared to $43.5 million in cash and cash equivalents and a working capital deficit of $92.6 million as of December 31, 2007.

Analysis of cash flow changes between 2007 and 2006

Operating activities. Cash received from oil and gas production revenues, net of the realized effects of hedging, increased $123.0 million to $925.1 million for the year ended December 31, 2007. Included in the oil and gas production revenue amounts is $24.5 million of net realized hedging gains. The increase was the result of a 16 percent increase in production and a six percent increase in our net realized price after hedging, resulting in a 23 percent increase in production revenue. Net cash payments made from income taxes decreased $26.7 million relative to the prior year and the Company was able to deduct a larger amount of intangible drilling costs due to the expanded 2007 capital program.

Investing activities. Net cash proceeds from an insurance settlement related to Hurricane Rita totaled $5.9 million for the period ended December 31, 2007. Total cash outflow for 2007 capital expenditures for leasehold and drilling activities increased $182.7 million or 40 percent to $637.7 million. Total cash outflow for 2007 related to the acquisition of oil and gas properties decreased $87.8 million or 32 percent to $182.9 million. Cash received from short-term investments increased $1.4 million and deposits to short-term investments increased $1.2 million for the period ended December 31, 2007, as compared to the same period in 2006. Cash received from other sources for the period ended December 31, 2007 included a deposit of $10 million related to the divestiture of non-core oil and gas assets that was completed on January 31, 2008.

Financing activities. Net repayments to our credit facility increased $383 million and payments to our short-term note payable increased $4.5 million for the period ended December 31, 2007, compared to 2006. In March 2007, we received $280.7 million, net of $6.8 million of deferred financing costs, from the issuance of the 3.50% Senior Convertible Notes. Our income tax benefit attributable to the exercise of stock options decreased $6.2 million to $9.9 million for the year ended December 31, 2007. We received $7.7 million less from the sale of common stock related to stock option exercises and issuances under the employee stock purchase plan in 2007, compared to 2006. Additionally, we invested $97.2 million less to repurchase shares of our common stock during 2007, compared to the same period in 2006.

We had $43.5 million in cash and cash equivalents and had a working deficit of $92.6 million as of December 31, 2007, compared to $1.5 million in cash and cash equivalents and working capital of $22.9 million as of December 31, 2006. The large increase in the cash balance as of the end of 2007 compared to prior periods was a reflection of timing of maturities of the LIBOR denominated tranches on our credit facility.

Capital Expenditures

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

	For the Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Development costs (1)	$ 586,579	$ 591,013	$ 367,546
Exploration costs	92,199	111,470	126,220
Acquisitions			
Proved properties	51,567	161,665	238,400
Unproved properties – acquisitions of proved properties (2)	43,274	23,495	44,472
Unproved properties - other	83,078	38,436	28,816
Total, including asset retirement obligations (3)	$ 856,697	$ 926,079	$ 805,454

(1) Includes capitalized interest of $3.7 million, $5.4 million, and $3.5 million in 2008, 2007, and 2006, respectively.
(2) Represents a portion of the allocated purchase price of unproved properties acquired as part of the acquisition of proved properties. Refer to Note 3 – Acquisitions, Divestitures, and Assets Held for Sale in Part IV, Item 15 of this report for additional information.
(3) Includes amounts relating to estimated asset retirement obligations of $15.4 million, $27.6 million, and $7.8 million in 2008, 2007, and 2006, respectively.

Commodity Price Risk and Interest Rate Risk

We are exposed to market risk, including the effects of changes in oil and gas commodity prices and changes in interest rates as discussed below under the caption "Summary of Interest Rate Hedges in Place." Changes in interest rates can affect the amount of interest we earn on our cash, cash equivalents, and short-term investments and the amount of interest we pay on borrowings under our revolving credit facility. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate 3.50% Senior Convertible Notes, but do affect their fair market value.

Since we produce and sell natural gas and crude oil, our financial results are affected when prices for these commodities fluctuate. The following table reflects our estimate of the effect on net cash flows from operations of a ten percent change in our average realized sales price, inclusive of the impact of hedging, for natural gas, for oil, and in combination for the years presented. These amounts have been reduced by the effective income tax rate applicable to each period since a reduction in revenue would reduce cash requirements to pay

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income taxes. General and administrative expenses have not been adjusted. To fund the capital expenditures we incurred in those years we would have been required to utilize amounts under our credit facility as a source of funds. In each of these years we would have had sufficient borrowing base available under our credit facility to meet this contingency without reducing or eliminating expenditures or altering our growth strategy.

Pro forma effect on net cash flow from operations of a ten percent change in average realized sales price:						
	For the Years Ended December 31,					
	2008		2007		2006	
	(In thousands)					
Oil	$	27,818	$	25,248	$	20,496
Natural Gas		37,288		29,998		25,117
Total	$	65,106	$	55,246	$	45,613

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

Summary of Oil and Gas Production Hedges in Place

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

Our net realized oil and gas prices are impacted by hedges we have placed on future forecasted production. We have historically entered into hedges of existing production around the time we make acquisitions of producing oil and gas properties. Our intent has been to lock in a significant portion of an equivalent amount of existing production to the prices we used to evaluate the risked economics of our acquisitions. We have also hedged a portion of our forecasted production on a discretionary basis. As of December 31, 2008, and through the date of this filing our hedged positions of anticipated production through 2011 totaled approximately 8 million Bbls of oil, 54 million MMBtu of natural gas, and 1 million Bbls of natural gas liquids.

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

The following table describes the volumes, average contract prices, and fair value of contracts we have in place as of December 31, 2008. We seek to minimize basis risk and index the majority of our oil contracts to NYMEX prices and our gas contracts to various regional index prices associated with pipelines in proximity to our areas of gas production.

Oil contracts

Oil Swaps			
Contract Period	Volumes (Bbl)	Weighted-Average Contract Price (per Bbl)	Fair Value at December 31, 2008 Asset/(Liability) (in thousands)
First quarter 2009 - NYMEX WTI	411,000	$ 71.66	$ 9,344
Second quarter 2009 - NYMEX WTI	401,000	$ 71.65	7,131
Third quarter 2009 - NYMEX WTI	389,000	$ 71.59	5,673
Fourth quarter 2009 - NYMEX WTI	369,000	$ 71.67	4,535
2010 NYMEX WTI	1,239,000	$ 66.47	3,430
2011 NYMEX WTI	1,032,000	$ 65.36	(2,779)
All oil swap contracts	3,841,000		$ 27,334

Oil Collars				
Contract Period	NYMEX WTI Volumes (Bbl)	Weighted-Average Floor Price (per Bbl)	Weighted-Average Ceiling Price (per Bbl)	Fair Value at December 31, 2008 Asset/(Liability) (in thousands)
First quarter 2009	376,500	$ 50.00	$ 67.31	$ 1,869
Second quarter 2009	380,500	$ 50.00	$ 67.31	1,041
Third quarter 2009	384,500	$ 50.00	$ 67.31	268
Fourth quarter 2009	384,500	$ 50.00	$ 67.31	(475)
2010	1,367,500	$ 50.00	$ 64.91	(8,067)
2011	1,236,000	$ 50.00	$ 63.70	(12,338)
All oil collars	4,129,500			$ (17,702)

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Gas Contracts

Gas Swaps			
Contract Period	Volumes (MMBtu)	Weighted-Average Contract Price (per MMBtu)	Fair Value at December 31, 2008 Asset/(Liability) (in thousands)
First quarter 2009			
IF ANR OK	580,000	$ 8.96	$ 2,594
IF CIG	930,000	$ 8.72	4,220
IF EL PASO	300,000	$ 7.85	938
IF HSC	2,490,000	$ 9.41	10,222
IF NGPL	130,000	$ 7.71	418
IF PEPL	1,500,000	$ 9.10	7,072
NYMEX Henry Hub	300,000	$ 10.13	1,292
Second quarter 2009			
IF ANR OK	570,000	$ 7.47	1,458
IF CIG	930,000	$ 7.11	3,103
IF EL PASO	300,000	$ 6.64	537
IF HSC	2,700,000	$ 8.09	6,744
IF NGPL	120,000	$ 6.63	258
IF PEPL	1,500,000	$ 7.17	4,121
NYMEX Henry Hub	300,000	$ 8.47	785
Third quarter 2009			
IF ANR OK	100,000	$ 7.11	213
IF CIG	300,000	$ 6.64	695
IF EL PASO	300,000	$ 6.94	458
IF HSC	2,680,000	$ 8.25	6,032
IF NGPL	100,000	$ 6.86	159
IF PEPL	360,000	$ 7.47	821
NYMEX Henry Hub	330,000	$ 8.59	796
Fourth quarter 2009			
IF ANR OK	90,000	$ 7.43	151
IF CIG	150,000	$ 7.42	437
IF EL PASO	300,000	$ 7.01	376
IF HSC	2,620,000	$ 8.60	5,935
IF NGPL	90,000	$ 7.14	129
NYMEX Henry Hub	350,000	$ 8.98	761
2010			
IF ANR OK	60,000	$ 7.98	89
IF EL PASO	1,090,000	$ 6.79	563
IF HSC	6,080,000	$ 8.40	9,377
IF NGPL	60,000	$ 7.60	66

NYMEX Henry Hub	1,440,000	$ 8.66		2,062
2011				
IF EL PASO	880,000	$ 6.34		(131)
IF HSC	360,000	$ 9.01		478
All gas swap contracts	30,390,000		$	73,229

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Gas Collars

Contract Period	Volumes (MMBtu)	Weighted-Average Floor Price (per MMBtu)	Weighted-Average Ceiling Price (per MMBtu)	Fair Value at December 31, 2008 Asset/(Liability) (in thousands)
First quarter 2009				
IF CIG	600,000	$ 4.75	$ 8.82	$ 398
IF HSC	210,000	$ 5.57	$ 9.49	105
IF PEPL	1,365,000	$ 5.30	$ 9.25	1,347
NYMEX Henry Hub	90,000	$ 6.00	$ 10.35	44
Second quarter 2009				
IF CIG	600,000	$ 4.75	$ 8.82	688
IF HSC	210,000	$ 5.57	$ 9.49	124
IF PEPL	1,375,000	$ 5.30	$ 9.25	1,535
NYMEX Henry Hub	90,000	$ 6.00	$ 10.35	65
Third quarter 2009				
IF CIG	600,000	$ 4.75	$ 8.82	517
IF HSC	210,000	$ 5.57	$ 9.49	102
IF PEPL	1,385,000	$ 5.30	$ 9.25	1,003
NYMEX Henry Hub	90,000	$ 6.00	$ 10.35	59
Fourth quarter 2009				
IF CIG	600,000	$ 4.75	$ 8.82	520
IF HSC	210,000	$ 5.57	$ 9.49	73
IF PEPL	1,385,000	$ 5.30	$ 9.25	736
NYMEX Henry Hub	90,000	$ 6.00	$ 10.35	35
2010				
IF CIG	2,040,000	$ 4.85	$ 7.08	841
IF HSC	600,000	$ 5.57	$ 7.88	(154)
IF PEPL	4,945,000	$ 5.31	$ 7.61	(15)
NYMEX Henry Hub	240,000	$ 6.00	$ 8.38	(42)
2011				
IF CIG	1,800,000	$ 5.00	$ 6.32	86
IF HSC	480,000	$ 5.57	$ 6.77	(398)
IF PEPL	4,225,000	$ 5.31	$ 6.51	(2,237)
NYMEX Henry Hub	120,000	$ 6.00	$ 7.25	(81)
All gas collars	23,560,000			$ 5,351

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Natural Gas Liquid Contracts

Natural Gas Liquid Swaps	Volumes (Bbls)	Weighted-Average Contract Price (per Bbl)	Fair Value at December 31, 2008 (in thousands)
First quarter 2009	264,000	$ 41.47	$ 4,570
Second quarter 2009	262,000	$ 41.53	4,410
Third quarter 2009	218,000	$ 41.46	3,370
Fourth quarter 2009	70,000	$ 45.95	1,335
2010	140,000	$ 49.59	2,998
2011	20,000	$ 49.01	375
All natural gas liquid swaps	974,000		$ 17,058

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

Summary of Interest Rate Hedges in Place

Effective September 13, 2007, we entered into a one year floating-to-fixed interest rate derivative contract for a notional amount of $75 million. Under the agreement, we paid a fixed rate of 4.90 percent and were paid a variable rate equal to the one-month LIBOR rate. This contract expired during the third quarter of 2008.

In relation to our 5.75% Senior Convertible Notes we entered into fixed-to-floating interest rate swaps on $50 million of principal in October 2003. Due to an increase in interest rates, we entered into a floating-to-fixed interest rate swap in April 2005 through the redemption date of the notes on March 20, 2007, for this same notional amount of $50 million in order to effectively offset our fixed-to-floating interest rate swaps. Under the floating-to-fixed interest rate swap, we were paid a variable interest rate of 235 basis points above the six-month LIBOR rate as determined on the semi-annual settlement date and paid a fixed interest rate of 6.85 percent. The impact of this instrument, when combined with the other interest rate swaps, was that we fixed the net liability related to the interest rate swaps, and paid a 1.1 percent interest rate on $50 million of notional debt through March 2007. The payment dates of the swap matched exactly with the interest payment dates of the 5.75% Senior Convertible Notes and the fixed-to-floating interest rate swaps. All of the interest rate hedges related to the 5.75% Senior Convertible Notes expired in March 2007.

Market risk is estimated as the potential change in fair value resulting from an immediate hypothetical one percentage point parallel shift in the yield curve. For fixed-rate debt, interest changes affect the fair market value but do not impact results of operations or cash flows. Conversely, interest rate changes for floating-rate debt generally do not affect the fair market value but do impact future results of operations and cash flows, assuming other factors are held constant. The carrying amount of our floating-rate debt typically approximates its fair value. We had $300 million of floating-rate debt outstanding as of December 31, 2008. Our fixed-rate debt outstanding at this same date was $287.5 million.

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

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Schedule of contractual obligations

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

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-Term Debt	$ 620.2	$ 10.1	$ 320.1	$ 290.0	$ -
Operating Leases	46.2	33.3	10.5	2.2	0.2
Other Long-Term Liabilities	257.6	60.1	111.5	59.7	26.3
Total	$ 924.0	$ 103.5	$ 442.1	$ 351.9	$ 26.5

This table includes our 2008 minimum pension contribution of $395,000 expected to be paid in the second quarter of 2009. The table also includes the remaining unfunded portion of our estimated pension liability of $8.2 million even though we recognize that we cannot determine with accuracy the timing of future payments. We made payments of $2.5 million, $2.2 million, and $1.3 million in 2008, 2007, and 2006, respectively, towards the pension liability. We have included $178.8 million in other long-term liabilities, which represents six years of undiscounted forecasted payments for the Net Profits Plan. Payments are expected to be similar on an annual basis for the years beyond what is shown in this table. The amounts recorded on the consolidated balance sheets reflect the impact of discounting and therefore differ from the amounts disclosed in this table. The variability in the amount of payments will be a direct reflection of commodity prices, production rates, capital expenditures, and operating costs in future periods. Predicting the timing and amounts of payments associated with this liability is contingent upon estimates of appropriate discount factors, adjusting for risk and time value, and upon a number of factors that we cannot control. The components of the operating leases are discussed in more detail in Note 6 – Commitments and Contingencies of Part IV, Item 15 of this report.

The scheduled repayment of the long-term credit facility is 2010. Accordingly, it has been disclosed in the table as such. Since this is a revolving credit facility, the actual payments will vary significantly. We anticipate refinancing this obligation. For purposes of this table, we assume we will net share settle the 3.50% Senior Convertible Notes. Accordingly, $32.7 million of interest payments related to the 3.50% Senior Convertible Notes are included in the table above. We have excluded asset retirement obligations because we are not able to accurately predict the precise timing of these amounts. Pension liabilities and asset retirement obligations are discussed in Note 8 – Pension Benefits and Note 9 – Asset Retirement Obligations of Part IV, Item 15, respectively, and the Net Profits Plan is discussed in Note 7 – Compensation Plans of Part IV, Item 15 of this report.

This table also includes estimated oil and natural gas derivative payments of $54.9 million based on future market prices as of December 31, 2008. This amount represents only the cash outflows; it does not include oil and gas receipts of $163.0 million that would be paid based on December 31, 2008, market prices. The net of $108.1 million represents cash flows from the intrinsic value of our swap and collar arrangements and differs in amount from our recorded fair value, which as of December 31, 2008, was a net asset of $105.3 million. The fair value considers time value, volatility and the risk of non-performance for the Company and for the Company's counterparties. Both the intrinsic value and fair value will change as oil and natural gas commodity prices change. Please refer to the discussion above under the caption Summary of Oil and Gas Production Hedges in Place in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and to Note 10 – Derivative Financial Instruments in Part IV, Item 15 of this report for additional information regarding our oil and gas hedges.

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

Off-balance Sheet Arrangements

As part of our ongoing business, we have not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. As of December 31, 2008, we have not been involved in any unconsolidated SPE transactions.

We evaluate our transactions to determine if any variable interest entities exist. If it is determined that we are the primary beneficiary of a variable interest entity, that entity is consolidated into our consolidated financial statements.

Critical Accounting Policies and Estimates

We are engaged in the exploration, exploitation, development, acquisition, and production of natural gas and crude oil. Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these consolidated financial statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses as well as the disclosure of contingent assets and liabilities as of the date of our financial statements. We base our decisions affecting the estimates we use on historical experience and various other sources that are believed to be reasonable under the circumstances. Actual results may differ from the estimates we calculate due to changes in business conditions or unexpected circumstances. Policies we believe are critical to understanding our business operations and results of operations are detailed below. For additional information on our significant accounting policies refer to Note 1 – Summary of Significant Accounting Policies, Note 9 – Asset Retirement Obligations, and Note 17 – Disclosures About Oil and Gas Producing Activities in Part IV, Item 15 of this report.

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

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

	For the Years Ended December 31,		
	2008	2007	2006
	BCFE Change	BCFE Change	BCFE Change
Revisions resulting from price changes	(199.7)	34.5	(52.2)
Revisions resulting from performance	(44.5)	6.4	66.3
Total	(244.2)	40.9	14.1

Over the three-year period, excluding divestitures, we have added 451.8 BCFE of reserves. Of these, 28.2 BCFE, or six percent, was a result of changes in estimates based on the performance of our oil and gas properties. A 217.4 BCFE decrease in reserves was a result of price changes. As previously noted, oil and gas prices are volatile, and estimates of reserves are inherently imprecise. Consequently, we anticipate we will continue to experience these types of changes.

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

	For the Years Ended December 31,					
	2008		2007		2006	
	BCFE Change	Percentage Change	BCFE Change	Percentage Change	BCFE Change	Percentage Change
A 10% decrease in pricing	(120.8)	(14)%	(16.3)	(2)%	(28.2)	(3)%
A 10% decrease in proved undeveloped reserves	(15.0)	(2)%	(25.0)	(2)%	(20.0)	(2)%

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

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

Revenue recognition. Our revenue recognition policy is significant because revenue is a key component of our results of operations and our forward-looking statements contained in our analysis of liquidity and capital resources. We derive our revenue primarily from the sale of produced natural gas and crude oil. We report revenue as the gross amounts we receive before taking into account production taxes and transportation costs, which are reported as separate expenses. Revenue is recorded in the month our production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to a purchaser. At the end of each month we make estimates of the amount of production delivered to the purchaser and the price we will receive. We use our knowledge of our properties, their historical performance, NYMEX and local spot market prices, and other factors as the basis for these estimates. Variances between our estimates and the actual amounts received are recorded in the month payment is received. A ten percent change in our year-end revenue accrual would have impacted net income before tax by $8.5 million in 2008.

Crude oil and natural gas hedging. Our crude oil and natural gas hedging contracts are intended and usually qualify for cash flow deferral hedge accounting under SFAS No. 133. Under this accounting pronouncement a majority of the gain or loss from a contract qualifying as a cash flow hedge is deferred as to statement of operations recognition. The position reflected in the statement of operations is based on actual settlements. If our natural gas and crude oil hedge contracts did not qualify for hedge accounting treatment or we chose not to use this hedge accounting methodology, our periodic consolidated statements of operations could include significant changes in the estimate of non-cash derivative gain or loss due to swings in the value of these contracts. Consequently, we would report a different amount of oil and gas hedge loss in our statements of operations. These fluctuations could be especially significant in a volatile pricing environment such as what we have encountered over the last three years. The amounts recorded to accumulated other comprehensive income (loss) of $223.5 million of income, $170.0 million of loss, and $69.0 million of income for 2008, 2007, and 2006 respectively, would have increased or decreased net income after tax if our hedges did not qualify as cash flow deferral hedges under SFAS No. 133.

Change in Net Profits Plan Liability. We record the estimated liability of future payments for our Net Profits Plan. The estimated liability is calculated based on a number of assumptions, including estimates of oil and gas reserves, recurring and workover lease operating expense, production and ad valorem tax rates, present value discount factors, and pricing assumptions. Additional discussion is included in the analysis in the above section titled Overview of the Company, under the heading Net Profits Plan. 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. As a result, the 2007 Net Profits Plan pool was the last pool established.

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

Valuation of long-lived and intangible assets. Our property and equipment are recorded at cost. An impairment allowance is provided on unproven property when we determine that the property will not be developed or the carrying value will not be realized. We evaluate the realizability of our proved properties and other long-lived assets whenever events or changes in circumstances indicate that impairment may be appropriate. Our impairment test compares the expected undiscounted future net revenues from property, using escalated pricing, with the related net capitalized cost of the property at the end of each period. When the net capitalized costs exceed the undiscounted future net revenue of a property, the cost of the property is written down to our estimate of fair value, which is determined by applying a discount rate that we believe is indicative of the current market. Our criteria for an acceptable internal rate of return are subject to change over time. Different pricing assumptions or discount rates could result in a different calculated impairment. We recorded a $302.2 million impairment of proved oil and gas properties in 2008. This impairment was primarily due to downward price adjustments to reserves and declining performance for properties primarily located in the Gulf Coast and in South Texas, as well as for gas properties in the Rocky Mountain region.

Income taxes. We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements in accordance with SFAS No. 109. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Additionally, our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared, therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits, and net operating and capital loss carryforwards and carrybacks. Adjustments related to differences between the estimates we used and actual amounts we report are recorded in the periods in which we file our income tax

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returns. These adjustments and changes in our estimates of asset recovery and liability settlement could have an impact on our results of operations. A one percent change in our effective tax rate would have changed our calculated income tax expense by $1.5 million for the year ended December 31, 2008.

Additional Comparative Data in Tabular Format:

	Change Between Years	
Oil and Gas Production Revenues:	2008 and 2007	2007 and 2006
Increase in oil and gas production revenues, net of hedging (in thousands)	$ 221,727	$ 177,664

Components of Revenue Increases (Decreases):

Oil		
Realized price change per Bbl, net of hedging	$ 12.99	$ 6.00
Realized price percent change	21%	11%
Production change (MBbl)	(292)	851
Production percentage change	(4)%	14%
Natural Gas		
Realized price change per Mcf, net of hedging	$ 1.16	$ 0.26
Realized price percentage change	15%	4%
Production change (MMcf)	8,849	9,613
Production percentage change	13%	17%

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

	Years Ended December 31,		
Revenue	2008	2007	2006
Oil	43%	46%	45%
Natural Gas	57%	54%	55%
Production			
Oil	35%	39%	39%
Natural Gas	65%	61%	61%

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Information regarding the effects of oil and gas hedging activity:

	Years Ended December 31,		
	2008	2007	2006
Oil Hedging			
Percentage of oil production hedged	61%	66%	66%
Oil volumes hedged (MBbl)	4,022	4,565	4,021
Decrease in oil revenue	$ (115.1 million)	$ (34.3 million)	$ (16.6 million)
Average realized oil price per Bbl before hedging	$ 92.99	$ 67.56	$ 59.33
Average realized oil price per Bbl after hedging	$ 75.59	$ 62.60	$ 56.60
Natural Gas Hedging			
Percentage of gas production hedged	46%	46%	40%
Natural gas volumes hedged (MMBtu)	36.4 million	32.5 million	24.2 million
Increase in gas revenue	$ 14.0 million	$ 58.7 million	$ 44.7 million
Average realized gas price per Mcf before hedging	$ 8.60	$ 6.74	$ 6.58
Average realized price per Mcf after hedging	$ 8.79	$ 7.63	$ 7.37

Information regarding the components of exploration expense:

	Years Ended December 31,		
Summary of Exploration Expense (in millions)	2008	2007	2006
Geological and geophysical expenses	$ 14.2	$ 17.0	$ 9.5
Exploratory dry holes	6.8	14.4	10.2
Overhead and other expenses	39.1	27.3	32.2
Total	$ 60.1	$ 58.7	$ 51.9

Comparison of Financial Results and Trends between 2008 and 2007

Oil and gas production revenue. Production increased seven percent to 114.6 BCFE for the year ended December 31, 2008, compared with 107.5 BCFE for the year ended December 31, 2007. Production for the year ended December 31, 2007, includes approximately 6.8 BCFE related to non-core properties divested throughout 2008. The following table presents the regional changes in our production and oil and gas revenues and costs between the two years:

	Average Net Daily Production	Pre-Hedge Oil and Gas Revenue Added	Production Costs Increase

	Added/(Lost)				
	(MMCFE)		(In millions)		(In millions)
ArkLaTex	12.8	$	76.1	$	8.3
Mid-Continent	(2.8)		30.4		3.9
Gulf Coast	10.8		75.4		17.5
Permian	8.5		85.6		11.5
Rocky Mountain	(10.7)		79.8		11.9
Total	18.6	$	347.3	$	53.1

We grew daily production by approximately 18.6 MMCFE during 2008 compared to 2007. The largest regional increase occurred in the ArkLaTex region as a result of the success in the Cotton Valley and James Lime programs. Production in the Gulf Coast region increased as a result of two acquisitions of properties targeting the shallow Olmos gas formation that were made in the second half of 2007 as well as several successful offshore wells. The production growth in the Permian region is the result of continued development of the Wolfberry assets at Sweetie Peck and Halff East. The declines in production in the Mid-Continent and Rocky Mountain regions are the result of the divestiture of non-core properties in these regions, which resulted in a smaller production base for 2008.

Oil and gas realized hedge gain (loss). We recorded a realized hedge loss of $101.1 million for the year ended December 31, 2008, mainly related to settlements on oil hedges. For the year ended December 31, 2007, we recorded a realized hedge gain of $24.5 million mainly due to favorable settlements on natural gas hedges.

Marketed gas system revenue and expense. Marketed gas system revenue increased $32.2 million to $77.4 million for the year ended December 31, 2008, compared with $45.1 million for the comparable period of 2007. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $29.7 million to $72.2 million for the year ended December 31, 2008, compared with $42.5 million for the comparable period of 2007. The net margin has stayed consistent with historical performance. We expect that marketed gas system revenue and expense will continue to coincide with increases and decreases in production and our net realized price.

Other revenues. Other revenues decreased $6.6 million to $2.1 million for the year ended December 31, 2008, compared with $8.7 for 2007. The decrease is due primarily to a $5.2 million gain recognized in 2007 associated with a global insurance settlement attributed to Hurricane Rita. As of December 31, 2008, all Hurricane Rita plugging and abandonment activities have been completed.

Gain on sale of proved properties. We recorded a gain on sale of proved properties of $63.6 million for the year ended December 31, 2008, mainly related to the Abraxas divestiture in January of 2008. The final gain on sale of proved properties will be adjusted for normal post-closing adjustments and is expected to be finalized during the first quarter of 2009. We expect to continue to evaluate potential divestitures of non-strategic properties.

Oil and gas production expenses. Total production costs increased $53.1 million or 24 percent to $271.4 million for 2008, from $218.2 million in 2007. Total oil and gas production costs per MCFE increased $0.33 to $2.36 for 2008, compared with $2.03 for 2007. This increase is comprised of the following:

- A $0.05 increase in overall transportation cost on a per MCFE basis was driven by the addition of Olmos shallow gas assets in the Maverick Basin that were acquired in the fourth quarter of 2007, as well as recently completed wells which have higher transportation costs

- A $0.13 increase in production taxes on a per MCFE basis due to the increase in realized prices between periods, particularly in the oil-weighted Rocky Mountain and Permian regions

- A $0.10 increase in recurring lease operating expense on a per MCFE basis is related to higher costs, particularly in oil-weighted regions, for items such as fuel and fluid disposal and an increase in the Gulf Coast region due to wells acquired and developed in South Texas during the fourth quarter of 2007

- A $0.05 overall increase in workover lease operating expense on a per MCFE basis relating to workover charges in the Mid-Continent and Gulf Coast regions.

Depletion, depreciation, amortization and asset retirement obligation liability accretion. DD&A increased $86.7 million, or 38 percent, to $314.3 million in 2008 compared with $227.6 million in 2007. DD&A expense per MCFE increased 29 percent to $2.74 in 2008 compared to $2.12 in 2007. This increase is due to a higher per unit rate associated with our acquisition and drilling costs in 2008 and 2007 caused by overall upward cost pressure in the industry in recent years. Additionally, this increase reflects the costs of production facilities in the offshore Gulf Coast that have increased significantly in recent years and that are now impacting our DD&A rate as those projects begin production. The DD&A per MCFE rate was further affected by downward revisions of 244.2 BCFE of proved reserves due to pricing and performance between December 31, 2008, and December 31, 2007, causing a general increase in DD&A.

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Exploration expense. Exploration expense increased $1.4 million or two percent to $60.1 million in 2008 compared with $58.7 million for 2007. The increase is due to a $2.8 million increase in drilling arrangements and a $9.0 million increase in exploration overhead. These increases were offset by a $2.8 million decrease in geological and geophysical expense as well as a $7.6 million decrease related to exploratory dry hole expense due to fewer and less expensive dry holes.

Impairment of proved properties. We recorded a $302.2 million impairment of proved oil and gas properties in 2008 compared to no impairment in 2007. This impairment was primarily due to downward price adjustments to reserves and declining performance for properties primarily located in the Gulf Coast and in South Texas, as well as for gas properties in the Rocky Mountain region. Further decreases in oil and gas commodity prices could cause additional impairments of proved properties.

Impairment of Goodwill. We recorded a $9.5 million impairment of goodwill in 2008. The goodwill was the result of our purchase of Agate Petroleum, Inc. in January 2005. The impairment was a result of downward price adjustments to reserves for properties located in our Mid-Continent and Rocky Mountain regions and represented our entire goodwill balance.

Abandonment and impairment of unproved properties. During the year, we abandoned or impaired $39.0 million of unproved properties. Approximately $13.4 million related to acreage to which we had assigned value in 2007 acquisitions targeting the Olmos shallow gas formation. The remaining write-offs relate to acreage that we believe we either will not be able to hold in the current period of limited capital availability or to acreage that we do not believe will be prospective. If commodity prices continue to decline we could see additional abandonments and impairments of unproved property as we have less capital to invest for exploration and development activities.

General and administrative. General and administrative expenses increased $19.4 million or 32 percent to $79.5 million for 2008, compared with $60.1 million for 2007. G&A increased $0.13 to $0.69 per MCFE for 2008 compared to $0.56 per MCFE for the same period in 2007 as G&A grew at a faster rate than the seven percent increase in production. A significant increase in employee count has resulted in an increase in base employee compensation, including taxes and benefits, of approximately $23.9 million between 2008 and 2007. A significant driver of this headcount increase has been the conversion from contract lease operators to internal lease operators.

An increase in 2008 oil and gas commodity prices triggered additional Net Profits Plan. Additionally, an increased percentage of the distribution dollars under the Net Profits Plan associated with general and administrative expense contributed to the current period realized expense associated with the Net Profits Plan increase by $4.4 million in 2008 compared with the same period in 2007. In the current commodity price environment, we do not expect this trend to continue in 2009.

Cash bonus and long-term incentive compensation expense increased by $8.4 million for the year ended December 31, 2008, compared with the same period in 2007. The increase results from the application of the Cash Bonus Plan as amended on March 28, 2008 and an increase in our employee count.

The amounts described above were offset by a $9.1 million increase in the amount of G&A that was allocated to exploration expense and an $8.2 million increase in COPAS overhead reimbursements. COPAS overhead reimbursements from operations increased due to an increase in our operated well count from our drilling program.

Change in Net Profits Plan liability. For the year ended December 31, 2008, this non-cash item was a benefit of $34.0 million compared to an expense of $50.8 million for the same period in 2007. Significant decreases in oil and gas commodity prices during the last half of 2008 and payments out of the plan have decreased the estimated liability for the future amounts to be paid to plan participants. This liability is a significant management estimate. Adjustments to the liability are subject to estimation and may change dramatically from period to period based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, tax rates, and production costs.

Bad debt expense. We recorded $16.7 million of bad debt expense in 2008, of which $16.6 million was a result of SemGroup, L.P. and certain of its North American subsidiaries filing for bankruptcy protection. Certain SemGroup entities had purchased a portion of our crude oil production. This amount related to oil produced in June and July of 2008 that was fully reserved in the year ended December 31, 2008.

Interest expense. Interest expense increased by $380,000 to $20.3 million for 2008 compared to $19.9 million for 2007. The increase reflects an increase in our average outstanding borrowings offset by lower interest rates in 2008 compared with 2007. We also capitalized $3.7 million of interest in 2008 compared to $5.4 million in 2007.

Income tax expense. Income tax expense totaled $59.9 million for 2008 and $110.6 million for 2007, resulting in effective tax rates of 39.5 percent and 36.8 percent, respectively. The effective rate change from 2007 was primarily due to the impact of goodwill impairment, changes in the mix of the highest marginal state tax rates, and also reflects other permanent differences including differing estimated effects between years of the domestic production activities deduction.

The current portion of income tax expense in 2008 is $19.2 million compared to $17.6 million in 2007. These amounts are 32 percent and 16 percent of the total income tax expense for the respective periods.

Comparison of Financial Results and Trends between 2007 and 2006

Oil and gas production revenue. Production increased 16 percent to 107.5 BCFE for the year ended December 31, 2007, compared with 92.8 BCFE for the year ended December 31, 2006. The following table presents the regional changes in our production and oil and gas revenues and costs between the two years:

	Average Net Daily Production Added/(Lost) (MMCFE)	Pre-Hedge Oil and Gas Revenue Added (In millions)	Production Costs Increase (In millions)
ArkLaTex	8.9	$ 27.2	$ 2.8
Mid-Continent	11.3	40.1	4.7
Gulf Coast	1.6	8.7	5.0
Permian	20.7	91.7	15.3
Rocky Mountain	(2.2)	13.7	13.8
Total	40.3	$ 181.4	$ 41.6

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

Oil and gas realized hedge gain (loss). The 13 percent decrease in total oil and gas hedge gain to $24.5 million was caused by a change in the composition of our hedge position and changes in oil and gas commodity prices.

Marketed gas system revenue and expense. Marketed gas system revenue increased $24.2 million to $45.1 million for the year ended December 31, 2007, compared with $20.9 million for the comparable period of 2006. The increase is due to the addition of a new marketed gas system in western Oklahoma that increased the number of wells for which we currently market gas, as well as increased production in the Woodford shale formation located in Coal County, Oklahoma. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased

$24.0 million to $42.5 million for the year ended December 31, 2007, compared with $18.5 million for the comparable period of 2006.

Other revenues. Other revenues increased $7.8 million to $8.7 million for the year ended December 31, 2007, compared with $942,000 for the comparable period of 2006. The increase is due primarily to a $5.2 million gain associated with a global insurance settlement attributable to Hurricane Rita. The gain calculation is net of approximately $12.1 million of costs associated with the plugging and abandonment of one offshore platform.

Oil and gas production expenses. Total production costs increased $41.6 million or 24 percent to $218.2 million for 2007, from $176.6 million in 2006. Our 2007 and 2006 acquisition of properties added $13.6 million of incremental production costs, and other wells completed in 2006 and 2007 added $13.7 million of incremental production costs in 2007 that were not reflected in 2006. The production cost increases are offset by natural declines in production costs from older properties to result in the net increase in production costs between the years presented. We experienced an increase in production taxes consistent with the increase in revenue from higher realized prices.

Total oil and gas production costs per MCFE increased $0.12 to $2.03 for 2007, compared with $1.91 for 2006. This increase is comprised of the following:

- A $0.02 increase in overall transportation cost due to an increase in the Rocky Mountain region resulting from a change in the sale measurement point, as well as newly drilled wells with higher transportation costs

- An $0.11 increase in recurring lease operating expense related to continued cost pressure from the oil and gas service sector

- A $0.05 overall decrease in lease operating expense relating to workover expense, primarily in the Rockies

- A $0.04 increase in production taxes related to increased production in the Permian region.

Depletion, depreciation, amortization and asset retirement obligation liability accretion. DD&A increased $73.1 million, or 47 percent, to $227.6 million in 2007 compared with $154.5 million in 2006. DD&A expense per MCFE increased 27 percent to $2.12 in 2007 compared to $1.67 in 2006. The increase reflects overall upward cost pressure in the industry and specifically our drilling in 2007 and 2006 that added costs at a higher per unit rate relative to the prior year's base. The DD&A per MCFE rate was further affected by upward adjustments to reserves due to pricing differences between December 31, 2007, and December 31, 2006 although this had the impact of lowering DD&A.

Exploration expense. Exploration expense increased $6.8 million or 13 percent to $58.7 million in 2007 compared with $51.9 million for 2006. This increase is due to a $7.5 million increase in geologic and geophysical expense to support a larger overall program as well as a $4.2 million increase in exploratory dry hole expense related to three wells located in the Gulf Coast region and one in the Rockies region. These increases were offset by a $4.9 million decrease in exploration overhead expense related to a reduction in amounts recorded in exploration expense related to payments under the Net Profits Plan. In 2007, we had a change in our accounting estimate to reflect the view that Net Profits Plan distributions should be reclassified to exploration overhead only for individuals who are currently employed by us and who continue to be involved in our exploration efforts. Therefore Net Profits Plan payments associated with the distributions under the Net Profits Plan for ex-employees were reclassified to general and administrative expense since there is no longer any functional link to exploration expense as there is by definition no periodic cost associated with geologic, geophysical and exploration related work by those ex-employees.

General and administrative. General and administrative expenses increased $21.3 million or 55 percent to $60.1 million for 2007, compared with $38.9 million for 2006. G&A increased $0.14 to $0.56 per MCFE for 2007 compared to $0.42 per MCFE for the period in 2006 as G&A grew at a faster rate than the 16 percent increase in production. A 23 percent increase in employee count has contributed to an increase in base employee

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compensation, including taxes and benefits, of approximately 29 percent, or $8.5 million, between the year ended December 31, 2007, and the same period of 2006.

An increase in oil and gas prices in 2007 triggered additional Net Profits Plan payouts and has increased the amounts payable to plan participants. Additionally, an increased percentage amount of the distribution dollars under the Net Profits Plan associated with general and administrative expense contributed to the 2007 realized expense associated with the Net Profits Plan increased by $5.8 million in 2007 compared with the same period in 2006. An increase in employee count resulted in an increase in cash bonus expense of $2.4 million to $5.2 million for the year ended December 31, 2007, compared with $2.8 million for the year ended December 31, 2006.

RSU bonus expense remained relatively flat decreasing by $100,000 for the year ended December 31, 2007, compared with the same period in 2006. Compensation expense related to stock options for the year ended December 31, 2007, decreased $1.4 million to $437,000 from $1.9 million in the comparable period in 2006 because virtually all of the stock options are now vested. No stock options have been granted since 2004.

The amounts described above, combined with a net $5.4 million increase in other G&A expense, including office supplies and employee development, were offset by a $5.0 million decrease in the amount of G&A that was allocated to exploration expense due to the aforementioned change in our Net Profits Plan accounting estimate and a $4.3 million increase in COPAS overhead reimbursements. COPAS overhead reimbursements from operations increased due to an increase in our operated well count from our drilling program.

Change in Net Profits Plan liability. For the year ended December 31, 2007, this expense increased $27.1 million to $50.8 million from $23.8 million for 2006. This increase reflects a decrease in the discount rate used to calculate the present value of future payments from a base rate of 15 percent to 12 percent. The decrease in the discount rate to 12 percent resulted from our divestiture marketing process and our assessment that the overall market for oil and gas reserves is ever more competitive.

Interest expense. Interest expense increased by $11.4 million to $19.9 million for 2007 compared to $8.5 million for 2006. The increase reflects an increase in our average outstanding borrowings in 2007 compared with 2006. Additionally, the increase reflects that we have $287.5 million of 3.50% Senior Convertible Notes outstanding at December 31, 2007, compared with $100.0 million of 5.75% Senior Convertible Notes outstanding as of December 31, 2006. We also capitalized $5.4 million of interest in 2007 compared to $3.5 million in 2006.

Income tax expense. Income tax expense totaled $110.6 million for 2007 and $105.3 million for 2006, resulting in effective tax rate of 36.8 percent and 35.7 percent, respectively. The effective rate change from 2006 reflects changes in the mix of the highest marginal state tax rates as a result of enacted Texas margin tax legislation, the benefit of federal and state estimated percentage depletion expense, acquisition and drilling activity, and also reflects other permanent differences including differing estimated effects between years of the domestic production activities deduction.

The current portion of income tax expense in 2007 was $17.6 million compared to $30.5 million in 2006. These amounts are 16 percent and 29 percent of the total income tax expense for the respective periods. The decrease resulted from significant drilling activity reflecting the deduction of intangible drilling costs in the year incurred, thereby reducing current taxable income.

Other Liquidity and Capital Resources Information

Pension Benefits

Substantially all of our employees who meet age and service requirements participate in a non-contributory defined benefit pension plan. At December 31, 2008, and 2007, we had $4.4 million and $2.5 million, respectively, of pre-tax loss in accumulated other comprehensive income. We believe this obligation will be funded from future cash flows from operating activities. For purposes of calculating our obligation under the plan, we have used an expected return on plan assets of 7.5 percent. We think this rate of return is appropriate over a long-term given the mix of plan investments, 60 percent equity and 40 percent debt securities, and the historical rate of return provided by equity and debt securities since the 1920s. Our actual rate of return was negative 20.9 percent for 2008 and positive 6.5 percent for 2007. The difference in investment income using our projected rate of return compared to our actual rates of return was not material in the long run and will not have a material effect on results of operations or cash flows from operating activities in future years.

For the 2008 plan year, the discount rate assumption was changed from 6.1 percent to 6.6 percent. The lump sum interest rate was increased from 5.5 percent to 6.0 percent. The lump sum mortality table was updated to the Pension Protection Act 2009 Optional Combined Unisex table. The actuarial gain/(loss) due to demographic experience, including any assumption changes, and investment return differences from assumptions during the prior year was $101,000 and negative $2.3 million, respectively causing a $2.3 million increase in the projected benefit obligation of the plan. The plan's accumulated benefit obligation was $9.9 million and $10.4 million at December 31, 2008, and 2007, respectively. We do not believe this change was material and we project that it will not have a material effect on the results of operations or on cash flow from operating activities in future periods.

We also have a supplemental non-contributory defined benefit pension plan that covers certain management employees. There are no plan assets for this plan. For the 2008 plan year, the discount rate assumption was changed from 6.1 percent to 6.6 percent. The lump sum interest rate was increased from 5.5 percent to 6.0 percent. The lump sum mortality table was updated to the Pension Protection Act 2009 Optional Combined Unisex table. The actuarial gain/(loss) due to demographic experience, including any assumption changes, and investment return differences from assumptions during the prior year was $64,000 and zero, respectively causing a $64,000 decrease in projected benefit obligation of the plan. The plan's accumulated benefit obligation was $546,000 and $1.0 million at December 31, 2008, and 2007, respectively. We believe this obligation will be funded from future cash flows from operating activities.

Accounting Matters

Please see Note 11 – Fair Value Measurements and the section entitled "Recently Issued Accounting Standards" under Note 1 – Summary of Significant Accounting Policies in Part IV, Item 15 of this report for accounting matters.

Environmental

St. Mary's compliance with applicable environmental regulations has not resulted in any significant capital expenditures or materially adverse effects to our liquidity or results of operations. We believe we are in substantial compliance with environmental regulations and do not currently foresee that material expenditures will be required in the future. However, we are unable to predict the impact that future compliance with regulations may have on future capital expenditures, liquidity, and results of operations.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

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

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

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

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

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

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2008. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework.

Based on our assessment and those criteria, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2008.

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

/s/ ANTHONY J. BEST	/s/ A. WADE PURSELL
Anthony J. Best	A. Wade Pursell
President and Chief Executive Officer	Executive Vice President and Chief Financial Officer
February 23, 2009	February 23, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of St. Mary Land & Exploration Company and subsidiaries (the "Company") as of December 31, 2008, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2008, of the Company and our report dated February 23, 2009, expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 23, 2009

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item concerning St. Mary's Directors and corporate governance is incorporated by reference to the information provided under the captions "Election of Directors," "Nominees for Election as Directors," "Corporate Governance" and "Board and Committee Meetings" in St. Mary's definitive proxy statement for the 2009 annual meeting of stockholders to be filed within 120 days from December 31, 2008. The information required by the Item concerning St. Mary's executive officers is incorporated by reference to the information provided in Part I – Item 4A – EXECUTIVE OFFICERS OF THE REGISTRANT, included in this Form 10-K.

The information required by this Item concerning compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated by reference to the information provided under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" in St. Mary's definitive proxy statement for the 2009 annual meeting of stockholders to be filed within 120 days from December 31, 2008.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information provided under the captions, "Director Compensation," "Compensation Discussion and Analysis," "Executive Compensation and Summary Compensation Table," "Summary Compensation Table For 2007 and 2008," "Grants of Plan-Based Awards in 2008," "Outstanding Equity Awards at 2008 Fiscal Year-End," "Nonqualified Deferred Compensation," "Option Exercises and Stock Vested," "Retirement Plans," "2008 Pension Benefits," "Equity Compensation Plans," "Compensation Committee Interlocks and Insider Participation," "Compensation Committee Report," "Employment Agreements and Termination of Employment," and "Change-of-Control Arrangements" in St. Mary's definitive proxy statement for the 2009 annual meeting of stockholders to be filed within 120 days from December 31, 2008.

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

The information required by this Item concerning security ownership of certain beneficial owners and management is incorporated by reference to the information provided under the caption "Security Ownership of Certain Beneficial Owners and Management" in St. Mary's definitive proxy statement for the 2009 annual meeting of stockholders to be filed within 120 days from December 31, 2008.

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

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

The information required by this Item is incorporated by reference to the information provided under the caption "Certain Relationships and Related Transactions," "Election of Directors," "Corporate Governance," and "Board and

Committee Meetings" in St. Mary's definitive proxy statement for the 2009 annual meeting of stockholders to be filed within 120 days from December 31, 2008.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is incorporated by reference to the information provided under the caption "Independent Accountants" and "Audit Committee Preapproval Policy and Procedures" in St. Mary's definitive proxy statement for the 2009 annual meeting of stockholders to be filed within 120 days from December 31, 2008.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

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

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

Exhibit Number	Description
2.1	Purchase and Sale Agreement dated November 1, 2006, among Henry Petroleum LP, Henry Holding LP, Henry Group, Entre Energy Partners LP, and St. Mary Land & Exploration Company (filed as Exhibit 2.1 to the registrant's Current Report on Form 8-K filed on December 18, 2006, and incorporated herein by reference)
2.2	Purchase and Sale Agreement dated August 2, 2007, among Rockford Energy Partners II, LLC and St. Mary Land & Exploration Company (filed as Exhibit 2.1 to the registrant's Current Report on Form 8-K filed on October 5, 2007, and incorporated herein by reference)
2.3	Purchase and Sale Agreement dated December 11, 2007, among St. Mary Land & Exploration Company, Ralph H. Smith Restated Revocable Trust Dated 8/14/97, Ralph H. Smith Trustee, Kent. J. Harrell, Trustee of the Kent J. Harrell Revocable Trust Dated January 19, 1995, and Abraxas Operating LLC (filed as Exhibit 2.1 to the registrant's Current Report on Form 8-K filed on February 1, 2008, and incorporated herein by reference)
2.4	Ratification and Joinder Agreement dated January 31, 2008, among St. Mary Land & Exploration Company, Ralph H. Smith, Kent J. Harrell, Abraxas Operating, LLC and

	Abraxas Petroleum Corporation (filed as Exhibit 2.2 to the registrant's Current Report on Form 8-K filed on February 1, 2008, and incorporated herein by reference)
3.1	Restated Certificate of Incorporation of St. Mary Land & Exploration Company as amended on May 25, 2005 (filed as Exhibit 3.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 and incorporated herein by reference)
3.2	Restated By-Laws of St. Mary Land & Exploration Company amended as of December 18, 2008 (filed as Exhibit 3.1 to the registrant's Current Report on Form 8-K filed on December 23, 2008, and incorporated herein by reference)

Exhibit Number	Description
4.1	Shareholder Rights Plan adopted on July 15, 1999 (filed as Exhibit 4.1 to the registrant's Quarterly Report on Form 10-Q/A for the quarter ended June 30, 1999 and incorporated herein by reference)
4.2	First Amendment to Shareholders Rights Plan dated March 15, 2002 as adopted by the Board of Directors on July 19, 2001 (filed as Exhibit 4.2 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2001 and incorporated herein by reference)
4.3	Second Amendment to Shareholder Rights Plan dated April 24, 2006 (filed as Exhibit 4.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2006 and incorporated herein by reference)
4.4	Indenture related to the 3.50% Senior Convertible Notes due 2027, dated as of April 4, 2007, between St. Mary Land & Exploration Company and Wells Fargo Bank, National Association, as trustee (including the form of 3.50% Senior Convertible Note due 2027) (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on April 4, 2007, and incorporated herein by reference)
4.5	Registration Rights Agreement, dated as of April 4, 2007, among St. Mary Land & Exploration Company and Merrill Lynch, Pierce, Fenner & Smith Incorporated and Wachovia Capital Markets, LLC, for themselves and as representatives of the Initial Purchasers (filed Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on April 4, 2007, and incorporated herein by reference)
10.1†	Stock Option Plan, as Amended on May 22, 2003 (filed as Exhibit 99.1 to the registrant's Registration Statement on Form S-8 (Registration No. 333-106438) and incorporated herein by reference)
10.2†	Incentive Stock Option Plan, as Amended on May 22, 2003 (filed as Exhibit 99.2 to the registrant's Registration Statement on Form S-8 (Registration No. 333-106438) and incorporated herein by reference)
10.3†	Cash Bonus Plan (filed as Exhibit 10.5 to the registrant's Registration Statement on Form S-1 (Registration No. 333-53512) and incorporated herein by reference)
10.4†	Summary Plan Description/Pension Plan dated December 30, 1994 (filed as Exhibit 10.35 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1994 and incorporated herein by reference)
10.5†	Non-qualified Unfunded Supplemental Retirement Plan, as amended (filed as Exhibit 10.8 to the registrant's Registration Statement on Form S-1 (Registration No. 333-53512) and incorporated herein by reference)
10.6†	Employee Stock Purchase Plan (filed as Exhibit 10.48 for the registrant's Annual Report on Form 10-K for the year ended December 31, 1997 and incorporated herein by reference)
10.7†	First Amendment to Employee Stock Purchase Plan dated February 27, 2001 (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001 and incorporated herein by reference)
10.8†	Second Amendment to the Employee Stock Purchase Plan dated February 18, 2005 (filed as Exhibit 10.48 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2004 and incorporated herein by reference)
10.9†	Form of Change of Control Severance Agreements (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001 and incorporated herein by reference)
10.10†	Amendment to Form of Change of Control Severance Agreement (filed as Exhibit 10.9 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 and

	incorporated herein by reference)
10.11	Amendment to an Extension of Office Lease dated as of December 14, 2001 (filed as Exhibit 10.45 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference)
10.12†	Non-Employee Director Stock Compensation Plan as adopted on March 27, 2003 (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 and incorporated herein by reference)

Exhibit Number	Description
10.13†	Restricted Stock Plan as adopted on April 18, 2004 (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 and incorporated herein by reference)
10.14†	Amendment to Restricted Stock Plan, dated December 15, 2005 (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on December 19, 2005 and incorporated herein by reference)
10.15†	Form of Restricted Stock Unit Award Agreement under the Restricted Stock Plan (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on March 15, 2005 and incorporated herein by reference)
10.16	Amended and Restated Credit Agreement dated as of April 7, 2005 among St. Mary Land & Exploration Company, Wachovia Bank, National Association, as Administrative Agent, and the lenders party thereto (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference)
10.17	2006 Equity Incentive Compensation Plan (filed on May 17, 2006 as Exhibit 99.1 to the registrant's Registration Statement on Form S-8 (Registration No. 333-134221) and incorporated herein by reference)
10.18	Form of Non-Employee Director Restricted Stock Award Agreement (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on May 18, 2006 and incorporated herein by reference)
10.19	Guaranty Agreement by St. Mary Energy Company in favor of Wachovia Bank, National Association, as Administrative Agent, dated April 7, 2005 (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference)
10.20	Guaranty Agreement by Nance Petroleum Corporation in favor or Wachovia Bank, National Association, as Administrative Agent, dated April 7, 2005 (filed as Exhibit 10.3 to the registrant's quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference)
10.21	Guaranty Agreement by NPC Inc. in favor of Wachovia Bank, National Association, as Administrative Agent, dated April 7, 2005 (filed as Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference)
10.22	Pledge and Security Agreement between St. Mary Land & Exploration Company and Wachovia Bank, National Association, as Administrative Agent, dated April 7, 2005 (filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference.)
10.23	Pledge and Security Agreement between Nance Petroleum Corporation and Wachovia Bank, National Association, as Administrative Agent, dated April 7, 2005 (filed as Exhibit 10.6 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference.)
10.24	First Supplement and Amendment to Deed of Trust, Mortgage, Line of Credit, Assignment, Security Agreement, Fixture Filing and Financing Statement for the Benefit of Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 7, 2005 (filed as Exhibit 10.7 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference)
10.25	Deed of Trust – St. Mary Land & Exploration Company to Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 7, 2005 (filed as Exhibit

	10.8 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference)
10.26†	Net Profits Interest Bonus Plan, as Amended on December 15, 2005 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on December 19, 2005 and incorporated herein by reference)
10.27	Summary of Charitable Contributions in Honor of Thomas E. Congdon (filed as Exhibit 10.4 to the registrant's Current Report on Form 8-K filed on December 19, 2005 and incorporated herein by reference)

Exhibit Number	Description
10.28†	Summary of 2006 Base Salaries for Named Executive Officers (filed as Exhibit 10.5 to the registrant's Current Report on Form 8-K filed on December 19, 2005 and incorporated herein by reference)
10.29	Employment Agreement of A.J. Best dated May 1, 2006 (filed as Exhibit 10.5 to the registrant's Current Report on Form 8-K filed on May 4, 2006 and incorporated herein by reference)
10.30*†	Summary of Compensation Arrangements for Non-Employee Directors
10.31	Purchase Agreement, dated March 29, 2007, among St. Mary Land & Exploration Company, Merrill Lynch & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Wachovia Capital Markets, LLC, Bear Stearns & Co. Inc., BNP Paribas Securities Corp., and UBS Securities LLC (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on April 4, 2007, and incorporated herein by reference)
10.32	First Amendment to Amended and Restated Credit Agreement, dated March 19, 2007, among St. Mary Land & Exploration Company, the lenders party thereto, Wachovia Bank, National Association, as issuing bank and administrative agent, Wells Fargo Bank, N.A., as syndication agent, and BNP Paribas, Comerica Bank-Texas and JPMorgan Chase Bank, N.A., as co-documentation agents (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on April 4, 2007, and incorporated herein by reference)
10.33†	Net Profits Interest Bonus Plan, As Amended and Restated by the Board of Directors on July 19, 2007 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on July 25, 2007, and incorporated herein by reference)
10.34†	Cash Bonus Plan as Amended on March 28, 2008 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on April 3, 2008 and incorporated herein by reference)
10.35	Second Amended and Restated Credit Agreement dated April 10, 2008, among St. Mary Land & Exploration Company, the lenders party thereto, Wachovia Bank, National Association, as Administrative Agent, Wells Fargo Bank, N.A., as syndication agent, and BNP Paribas, Comerica Bank and JPMorgan Chase Bank, N.A., as co-documentation agents (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q filed on May 5, 2008 and incorporated herein by reference)
10.36†	2006 Equity Incentive Compensation Plan as Amended and Restated as of March 28, 2008 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on May 27, 2008 and incorporated herein by reference)
10.37†	Form of Performance Share Award Agreement (filed as Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q filed on August 5, 2008 and incorporated herein by reference)
10.38†	Form of Performance Share Award Notice (filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q filed on August 5, 2008 and incorporated herein by reference)
12.1*	Computation of Ratio of Earnings to Fixed Charges
21.1*	Subsidiaries of Registrant
23.1*	Consent of Deloitte & Touche LLP
23.2*	Consent of Ryder Scott Company L.P.
23.3*	Consent of Netherland, Sewell & Associates, Inc.
24.1*	Power of Attorney
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
31.2*	

	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
32.1**	Certification pursuant to U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes- Oxley Act of 2002

* Filed with this Form 10-K
** Furnished with this Form 10-K
† Exhibit constitutes a management contract or compensatory plan or agreement.

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

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of St. Mary Land & Exploration Company and subsidiaries (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of operations, stockholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of St. Mary Land & Exploration Company and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

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

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 23, 2009, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 23, 2009

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PART II. FINANCIAL INFORMATION
ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

	December, 31	
ASSETS	2008	2007
Current assets:		
Cash and cash equivalents	$ 6,131	$ 43,510
Short-term investments	1,002	1,173
Accounts receivable, net of allowance for doubtful accounts of $16,788 in 2008 and $152 in 2007	157,690	159,149
Refundable income taxes	13,161	933
Prepaid expenses and other	22,161	14,129
Accrued derivative asset	111,649	17,836
Deferred income taxes	-	33,211
Total current assets	311,794	269,941
Property and equipment (successful efforts method), at cost:		
Land	1,350	-
Proved oil and gas properties	3,007,946	2,721,229
Less - accumulated depletion, depreciation, and amortization	(947,207)	(804,785)
Unproved oil and gas properties, net of impairment allowance of $42,945 in 2008 and $10,319 in 2007	168,817	134,386
Wells in progress	90,910	137,417
Oil and gas properties held for sale less accumulated depletion, depreciation, and amortization	1,827	76,921
Other property and equipment, net of accumulated depreciation of $13,848 in 2008 and $11,549 in 2007	13,458	9,230
	2,337,101	2,274,398
Other noncurrent assets:		
Goodwill	-	9,452
Accrued derivative asset	21,541	5,483
Restricted cash subject to Section 1031 Exchange	14,398	-
Other noncurrent assets	10,182	12,406
Total other noncurrent assets	46,121	27,341
Total Assets	$ 2,695,016	$ 2,571,680

LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities:				
Accounts payable and accrued expenses	$	254,811	$	254,918
Accrued derivative liability		501		97,627
Deposit associated with oil and gas properties held for sale		-		10,000
Deferred income taxes		41,289		-
Total current liabilities		296,601		362,545
Noncurrent liabilities:				
Long-term credit facility		300,000		285,000
Senior convertible notes		287,500		287,500
Asset retirement obligation		108,755		96,432
Asset retirement obligation associated with oil and gas properties held for sale		238		8,744
Net Profits Plan liability		177,366		211,406
Deferred income taxes		358,334		257,603
Accrued derivative liability		27,419		190,262
Other noncurrent liabilities		11,318		8,843
Total noncurrent liabilities		1,270,930		1,345,790
Commitments and contingencies				
Stockholders' equity:				
Common stock, $0.01 par value: authorized - 200,000,000 shares;				
issued: 62,465,572 shares in 2008 and 64,010,832 shares in 2007;				
outstanding, net of treasury shares: 62,288,585 shares in 2008				
and 63,001,120 shares in 2007		625		640
Additional paid-in capital		99,440		170,070
Treasury stock, at cost: 176,987 shares in 2008 and 1,009,712 shares in 2007		(1,892)		(29,049)
Retained earnings		964,019		878,652
Accumulated other comprehensive income (loss)		65,293		(156,968)
Total stockholders' equity		1,127,485		863,345
Total Liabilities and Stockholders' Equity	$	2,695,016	$	2,571,680

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

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ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share amounts)

	For the Years Ended December 31, 2008	2007	2006
Operating revenues and other income:			
Oil and gas production revenue	$ 1,259,400	$ 912,093	$ 730,737
Realized oil and gas hedge gain (loss)	(101,096)	24,484	28,176
Marketed gas system revenue	77,350	45,149	20,936
Gain (loss) on sale of proved properties	63,557	(367)	6,910
Other revenue	2,090	8,735	942
Total operating revenues and other income	1,301,301	990,094	787,701
Operating expenses:			
Oil and gas production expense	271,355	218,208	176,590
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	314,330	227,596	154,522
Exploration	60,121	58,686	51,889
Impairment of proved properties	302,230	-	7,232
Abandonment and impairment of unproved properties	39,049	4,756	4,301
Impairment of goodwill	9,452	-	-
General and administrative	79,503	60,149	38,873
Bad debt expense	16,735	-	-
Change in Net Profits Plan liability	(34,040)	50,823	23,759
Marketed gas system expense	72,159	42,485	18,526
Unrealized derivative (gain) loss	(11,209)	5,458	7,094
Other expense	10,415	2,522	2,649
Total operating expenses	1,130,100	670,683	485,435
Income from operations	171,201	319,411	302,266
Nonoperating income (expense):			
Interest income	485	746	1,576
Interest expense	(20,275)	(19,895)	(8,521)
Income before income taxes	151,411	300,262	295,321
Income tax expense	(59,858)	(110,550)	(105,306)
Net income	$ 91,553	$ 189,712	$ 190,015

Basic weighted-average common shares outstanding		62,243		61,852		56,291
Diluted weighted-average common shares outstanding		63,133		64,850		65,962
Basic net income per common share	$	1.47	$	3.07	$	3.38
Diluted net income per common share	$	1.45	$	2.94	$	2.94

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

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

	Common Stock		Additional Paid-in	Treasury Stock		Deferred Stock-Based	Retained	Accunulated Other Comprehensive	Total Stockholders'
	Shares	Amount	Capital	Shares	Amount	Compensation	Earnings	Income (Loss)	Equity
Balances, December 31, 2005	57,011,740	$ 570	$ 123,278	(250,000)	$ (5,148)	$ (5,593)	$ 510,812	$ (54,599)	$ 569,320
Comprehensive income, net of tax:									
Net income	-	-	-	-	-	-	190,015	-	190,015
Change in derivative instrument fair value	-	-	-	-	-	-	-	87,107	87,107
Reclassification to earnings	-	-	-	-	-	-	-	(18,129)	(18,129)
Minimum pension liability adjustment	-	-	-	-	-	-	-	(180)	(180)
Total comprehensive income									258,813
SFAS No. 158 transition amount	-	-	-	-	-	-	-	(1,270)	(1,270)
Cash dividends, $ 0.10 per share	-	-	-	-	-	-	(5,603)	-	(5,603)
Treasury stock purchases	-	-	-	(3,319,300)	(123,108)	-	-	-	(123,108)
Retirement of treasury stock	(3,275,689)	(33)	(122,598)	3,275,689	122,631	-	-	-	-
Issuance of common stock under Employee Stock Purchase Plan	26,046	-	814	-	-	-	-	-	814
Sale of common stock, including income tax benefit of stock option exercises	1,489,636	16	32,970	-	-	-	-	-	32,986

Adoption of Statement of Financial Accounting Standards No. 123(R)	-	-	(5,593)	-	-	5,593	-	-	-
Stock-based compensation expense	-	-	10,069	43,611	1,353	-	-	-	11,422
Balances, December 31, 2006	55,251,733	$ 553	$ 38,940	(250,000)	$ (4,272)	$ -	$ 695,224	$ 12,929	$ 743,374
Comprehensive income, net of tax:									
Net income	-	-	-	-	-	-	189,712	-	189,712
Change in derivative instrument fair value	-	-	-	-	-	-	-	(154,497)	(154,497)
Reclassification to earnings	-	-	-	-	-	-	-	(15,470)	(15,470)
Minimum pension liability adjustment	-	-	-	-	-	-	-	70	70
Total comprehensive income									19,815
Cash dividends, $ 0.10 per share	-	-	-	-	-	-	(6,284)	-	(6,284)
Treasury stock purchases	-	-	-	(792,216)	(25,957)	-	-	-	(25,957)
Issuance of common stock under Employee Stock Purchase Plan	29,534	-	919	-	-	-	-	-	919
Conversion of 5.75% Senior Convertible Notes due 2022 to common stock, including income tax benefit of conversion	7,692,295	77	106,854	-	-	-	-	-	106,931
Issuance of common stock upon settlement of RSUs following expiration of restriction period, net of shares used for tax withholdings	302,370	3	(4,569)	-	-	-	-	-	(4,566)

Sale of common stock, including income tax benefit of stock option exercises	733,650	7	19,011	-	-	-	-	-	19,018
Stock-based compensation expense	1,250	-	8,915	32,504	1,180	-	-	-	10,095
Balances, December 31, 2007	64,010,832	$ 640	$ 170,070	(1,009,712)	$ (29,049)	$ -	$ 878,652	$ (156,968)	$ 863,345
Comprehensive income, net of tax:									
Net income	-	-	-	-	-	-	91,553	-	91,553
Change in derivative instrument fair value	-	-	-	-	-	-	-	177,005	177,005
Reclassification to earnings	-	-	-	-	-	-	-	46,463	46,463
Minimum pension liability adjustment	-	-	-	-	-	-	-	(1,207)	(1,207)
Total comprehensive income									313,814
Cash dividends, $ 0.10 per share	-	-	-	-	-	-	(6,186)	-	(6,186)
Treasury stock purchases	-	-	-	(2,135,600)	(77,150)	-	-	-	(77,150)
Retirement of treasury stock	(2,945,212)	(29)	(103,237)	2,945,212	103,266	-	-	-	-
Issuance of common stock under Employee Stock Purchase Plan	45,228	-	1,055	-	-	-	-	-	1,055
Issuance of common stock upon settlement of RSUs following expiration of restriction period, net of shares used for tax withholdings	482,602	5	(6,910)	-	-	-	-	-	(6,905)
Sale of common stock, including income tax benefit of stock option exercises	868,372	9	24,691	-	-	-	-	-	24,700

Stock-based compensation expense	3,750	-	13,771	23,113	1,041	-	-	-	14,812
Balances, December 31, 2008	62,465,572	$ 625	$ 99,440	(176,987)	$ (1,892)	$ -	$ 964,019	$ 65,293	$ 1,127,485

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

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

	For the Years Ended December 31,		
	2008	2007	2006
Cash flows from operating activities:			
Reconciliation of net income to net cash provided by operating activities:			
Net income	$ 91,553	$ 189,712	$ 190,015
Adjustments to reconcile net income to net cash provided by operating activities:			
Loss related to hurricanes	6,980	-	-
(Gain) loss on insurance settlement	2,296	(5,243)	-
(Gain) loss on sale of proved properties	(63,557)	367	(6,910)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	314,330	227,596	154,522
Bad debt expense	16,735	-	-
Exploratory dry hole expense	6,823	14,365	10,191
Impairment of proved properties	302,230	-	7,232
Impairment of goodwill	9,452	-	-
Abandonment and impairment of unproved properties	39,049	4,756	4,301
Unrealized derivative (gain) loss	(11,209)	5,458	7,094
Change in Net Profits Plan liability	(34,040)	50,823	23,759
Stock-based compensation expense*	14,812	10,095	11,422
Deferred income taxes	40,634	92,955	74,832
Other	(3,593)	(10,497)	(2,479)
Changes in current assets and liabilities:			
Accounts receivable	(14,327)	(6,557)	22,476
Refundable income taxes	(12,228)	6,751	-
Prepaid expenses and other	(1,504)	19,375	(17,886)
Accounts payable and accrued expenses	(12,348)	40,769	5,215
	(13,867)	(9,933)	(16,084)

Excess income tax benefit from the exercise of stock options			
Net cash provided by operating activities	678,221	630,792	467,700
Cash flows from investing activities:			
Proceeds from insurance settlement	-	5,948	-
Proceeds from sale of oil and gas properties	178,867	495	860
Capital expenditures	(745,617)	(637,748)	(455,056)
Acquisition of oil and gas properties	(81,823)	(182,883)	(270,639)
Deposits to restricted cash	(14,398)	-	-
Other	(9,814)	10,316	116
Net cash used in investing activities	(672,785)	(803,872)	(724,719)
Cash flows from financing activities:			
Proceeds from credit facility	2,571,500	822,000	935,137
Repayment of credit facility	(2,556,500)	(871,000)	(601,137)
Excess income tax benefit from the exercise of stock options	13,867	9,933	16,084
Net proceeds from issuance of senior convertible debt	-	280,657	-
Proceeds from sale of common stock	11,888	10,007	17,716
Repurchase of common stock	(77,202)	(25,904)	(123,108)
Dividends paid	(6,186)	(6,284)	(5,603)
Other	(182)	(4,283)	4,469
Net cash provided by (used in) financing activities	(42,815)	215,126	243,558
Net change in cash and cash equivalents	(37,379)	42,046	(13,461)
Cash and cash equivalents at beginning of period	43,510	1,464	14,925
Cash and cash equivalents at end of period	$ 6,131	$ 43,510	$ 1,464

* Stock-based compensation expense is a component of exploration expense and general and administrative expense
on the consolidated statements of operations. During 2008, 2007, and 2006, respectively, approximately $5.8 million,
$3.2 million, and $3.1 million of stock-based compensation expense was included in exploration expense.
During 2008, 2007, and 2006, respectively, approximately $9.0 million, $6.9 million, and $8.3 million of stock-based

compensation expense was included in general and administrative expense.

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

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

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

	For the Years Ended December 31,		
	2008	2007	2006
	(In thousands)		
Cash paid for interest	$ 21,976	$ 22,816	$ 9,826
Net cash paid or (refunded) for income taxes	$ 17,326	$ (1,156)	$ 25,505

In December 2008 the Company closed a transaction whereby it exchanged non-core oil and gas properties
located in Coupee Parish, Louisiana fair valued at $30.4 million for an increased interest in properties
located in Upton and Midland Counties, Texas and $17.6 million in cash.

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

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

For the years ended December 31, 2008, 2007, and 2006, the Company issued 428,407, 102,634, and 492,851
restricted stock units, respectively, to employees as equity-based compensation pursuant to the Company's 2006
Equity Incentive Compensation Plan. The total fair values of the issuances were $23.4 million, $3.3 million, and
$16.7 million, respectively.

As of December 31, 2008, 2007, and 2006, $116.5 million, $116.9 million, and $73.5 million, respectively, are included as additions to oil and gas properties and accounts payable and accrued expenses. These oil and gas property additions are reflected in cash used in investing activities in the periods that the payables are settled.

For the years ended December 31, 2008, 2007, and 2006, the Company issued 23,113, 32,504, and 29,827 shares, respectively, of common stock from treasury to its non-employee directors pursuant to the Company's 2006 Equity Incentive Compensation Plan. The Company recorded compensation expense related to these issuances of approximately $1,041,000, $983,500, and $976,000 for the years ended December 31, 2008, 2007, and 2006, respectively.

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

In June 2006 the Company hired a new senior executive. In doing so, the Company issued 13,784 shares of stock. The fair value of this issuance was $727,600. In February 2008 and 2007, the Company issued 3,750 and 1,250 shares of stock, respectively, to the senior executive, as the Company achieved certain performance metrics under an agreement with the executive. The total fair values of these issuances were $141,900, and $45,012, respectively.

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

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2008

Note 1 – Summary of Significant Accounting Policies

Description of Operations

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

Basis of Presentation

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

Use of Estimates in the Preparation of Financial Statements

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

Revenue Recognition

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

Cash and Cash Equivalents

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

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Short-term Investments

As of December 31, 2008, and 2007, the Company's short-term investment consists of a certificate of deposit. Securities categorized as held-to-maturity are stated at amortized cost whereas available-for-sale securities are marked-to-market. As of December 31, 2008, and 2007, the Company held $1.0 million and $1.2 million, respectively, of short-term investments.

Concentration of Credit Risk

Substantially all of the Company's receivables are within the oil and gas industry, primarily from purchasers of oil and gas and from partners with interests in common properties operated by the Company. Although diversified among many companies, collectability is dependent upon the financial wherewithal of each individual company as well as the general economic conditions of the industry. The receivables are not collateralized. The Company currently has $16.8 million recorded as allowance for doubtful accounts. For additional discussion on allowance for doubtful accounts, please see Note 14 – SemGroup Bankruptcy.

The Company has accounts with separate banks in Denver, Colorado; Shreveport, Louisiana; Franklin, Louisiana; Tulsa, Oklahoma; and Billings, Montana. At December 31, 2008, and 2007, the Company had $4.8 million and $42.8 million, respectively, invested in money market funds and overnight investment sweep accounts. The difference between the investment amount and the cash and cash equivalents amount on the accompanying consolidated balance sheets represents uncleared disbursements and non-interest bearing checking accounts. The Company's policy is to invest in highly-rated instruments and to limit the amount of credit exposure at each individual institution.

The Company currently uses eight separate counterparties for its oil and gas commodity and interest rate derivatives. The counterparties to the Company's derivative instruments are highly-rated entities with corporate credit ratings at or exceeding A- or A2 classified by Standard & Poor's and Moody's, respectively.

Oil and Gas Producing Activities

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

Geological and geophysical costs and the costs of carrying and retaining unproved properties are expensed as incurred. DD&A of capitalized costs related to proved oil and gas properties is calculated on a pool-by-pool basis using the units-of-production method based upon proved reserves. The computation of DD&A takes into consideration restoration, dismantlement, and abandonment costs as well as the anticipated proceeds from salvaging equipment. As of December 31, 2008, the Company's capitalized proved oil and gas properties included $102.3 million of estimated salvage value.

The Company follows Financial Accounting Standards Board ("FASB") Staff Position ("FSP") FAS 19-1, "Accounting for Suspended Well Costs," ("FSP FAS 19-1"). For additional discussion, please see Note 16 –Oil and Gas Activities under the heading Suspended Well Costs.

Impairment of Proved and Unproved Properties

Producing oil and gas property costs are evaluated for impairment and reduced to fair value if the sum of expected undiscounted future cash flows is less than net book value pursuant to Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets", (“SFAS No. 144”). Expected future cash flows are calculated on all proved reserves using a discount rate and price forecasts selected by the Company’s management. The discount rate is a rate that management believes is representative of current market conditions. The price forecast is based on NYMEX strip pricing, adjusted for basis differentials, for the first five years. At the end of the first five years a flat terminal price is used. Future operating costs are also adjusted as deemed appropriate for these estimates. An impairment write down is provided on unproved property when the Company determines that either the property will not be developed or the carrying value is not realizable.

For the years ended December 31, 2008, and 2006, the Company recorded expense of $302.2 million and $7.2 million, respectively, related to proved property impairment write-downs. The Company did not incur any proved property impairment write-downs during 2007. Approximately $154 million of the 2008 impairment write-down relates to the South Texas assets that were acquired as part of the 2007 Rockford and Catarina acquisitions.

For the years ended December 31, 2008, 2007, and 2006, the Company recorded expense related to the abandonment and impairment of unproved properties of $39.0 million, $4.8 million, and $4.3 million, respectively.

Sales of Proved and Unproved Properties

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

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

Assets Held for Sale

In accordance with SFAS No. 144, any properties held for sale as of the date of presentation of a balance sheet have been classified as assets held for sale and are separately presented on the accompanying consolidated balance sheets at the lower of net book value or fair value less the cost to sell. The asset retirement obligation liabilities related to such properties have been reclassified to asset retirement obligations associated with oil and gas properties held for sale. For additional discussion of assets held for sale, please see Note 3 – Acquisitions, Divestitures, and Assets Held for Sale.

Other Property and Equipment

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

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Restricted Cash

Proceeds from certain sales of oil and gas properties are held in escrow and restricted for future acquisitions under a tax-free exchange agreement. These funds are invested in money market funds consisting of corporate commercial paper, repurchase agreements, and U.S. Treasury obligations and are carried at cost, which approximates fair market value.

Gas Balancing

The Company uses the sales method of accounting for gas revenue whereby sales revenue is recognized on all gas sold to purchasers, regardless of whether the sales are proportionate to the Company's ownership in the property. An asset or liability is recognized to the extent that there is an imbalance in excess of the remaining gas reserves on the underlying properties. The Company's gas imbalance position at December 31, 2008, and 2007, resulted in the recording of $1.8 million and $1.9 million, respectively, to accounts receivable, and $1.1 million and $1.1 million, respectively, to accounts payable.

Derivative Financial Instruments

The Company seeks to manage or reduce commodity price risk on acquisitions of producing properties and other production by hedging cash flows. The Company intends for derivative instruments used for this purpose to be designated as, and to qualify as, cash flow hedging instruments under Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," ("SFAS No. 133") and related pronouncements. The Company seeks to minimize its basis risk and indexes the majority of its oil hedges to NYMEX prices and the majority of its gas hedges to various regional index prices associated with pipelines in proximity to the Company's areas of gas production. For additional discussion of derivatives, please see Note 10 – Derivative Financial Instruments.

Fair Value of Financial Instruments

The Company's financial instruments including cash and cash equivalents, accounts receivable, and accounts payable are carried at cost, which approximates fair value due to the short-term maturity of these instruments. The recorded value of the Company's credit facility approximates its fair value as it bears interest at a floating rate. The Company had $300.0 million and $285.0 million in loans outstanding under its revolving credit agreement as of December 31, 2008, and 2007, respectively. The Company's interest rate swaps are recorded at fair value as discussed in Note 10 – Derivative Financial Instruments. The Company's 3.50% Senior Convertible Notes due 2027 (the "3.50% Senior Convertible Notes") are recorded at cost, and the fair value is disclosed in Note 5 – Long-Term Debt. The Company has derivative financial instruments that are marked-to-market for which changes in fair value are recorded in accumulated other comprehensive income in the accompanying consolidated balance sheets. Considerable judgment is required to develop estimates of fair value. The estimates provided are not necessarily indicative of the amounts the Company could realize upon the sale or refinancing of such instruments.

Net Profits Plan

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

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

Asset Retirement Obligations

The Company estimates future asset retirement obligations pursuant to the provisions of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," ("SFAS No. 143"). SFAS No. 143 requires the Company to recognize an estimated liability for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is completed or acquired.

Income Taxes

The Company accounts for deferred income taxes utilizing Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes," ("SFAS No. 109") as amended. SFAS No. 109 prescribes an asset and liability method whereby deferred tax assets and liabilities are recognized based on the tax effects of temporary differences between the carrying amount on the financial statements and the tax basis of assets and liabilities, as measured by current enacted tax rates. These differences will result in taxable income or deductions in future years when the reported amount of the asset or liability is recorded or settled, respectively. When appropriate, in accordance with SFAS No. 109, the Company evaluates the need for a valuation allowance to reduce deferred tax assets.

Earnings per Share

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

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

The treasury stock method is used to measure the dilutive impact of stock options, RSUs, and PSAs. The following table details the weighted-average dilutive and anti-dilutive securities related to stock options, RSUs, and PSAs for the years presented:

	For the Years Ended December 31,		
	2008	2007	2006
Dilutive	890,189	1,441,556	1,978,577
Anti-dilutive	330,231	-	-

Prior to the conversion of the Company’s 5.75% Senior Convertible Notes due 2022 (“5.75% Senior Convertible Notes”) on March 16, 2007, potentially dilutive shares associated with this instrument were accounted for using the if-converted method for the determination of diluted earnings per share. Adjusted net income used in the if-converted method was derived by adding interest expense paid on the 5.75% Senior Convertible Notes back to net income and then adjusting for nondiscretionary items that are based on net income and would have changed had the 5.75% Senior Convertible Notes been converted at the beginning of the respective periods. The 5.75% Senior Convertible Notes were called for redemption by the Company on March 16, 2007, and all of the note holders elected to convert the notes to shares of the Company's common stock. The Company issued 7.7 million common shares in connection with the conversion of the 5.75% Senior Convertible Notes. Upon conversion, these shares were included in the calculation of weighted-average common shares outstanding. The diluted earnings per share calculation for the year ended December 31, 2007, was adjusted for the conversion and included a time-weighted-average of approximately 1.6 million potentially dilutive shares related to the 5.75% Senior Convertible Notes. A total of 7.7 million potentially dilutive shares related to the 5.75% Senior Convertible Notes were included in the calculation of diluted earnings per share for the year ended December 31, 2006.

The Company's 3.50% Senior Convertible Notes, which were issued on April 4, 2007, have a net-share settlement right whereby each $1,000 principal amount of notes may be surrendered for conversion to cash in an amount equal to the principal amount and, if applicable, shares of common stock for the amount in excess of the principal amount. The treasury stock method is used to measure the potentially dilutive impact of shares associated with that conversion feature. The 3.50% Senior Convertible Notes have not been dilutive for any reporting period that they have been outstanding and therefore do not impact the diluted earnings per share calculation for the periods ended December 31, 2008, and 2007, respectively.

On August 1, 2008, the Company granted 465,751 PSAs for the three-year performance period ending June 30, 2011. At the end of each grant's three-year performance period, a multiplier will be applied to all vested PSAs to determine the number of common shares issued. The number of common shares issued is determined by the Company's absolute stock price performance and a comparison of the Company's stock price performance to that of its peers. The number of potentially dilutive shares related to the PSAs is based on the number of shares, if any, which would be issuable if the end of the reporting period was the end of the contingency period. There were no potentially dilutive shares related to the PSAs included in the diluted earnings per share calculation as of December 31, 2008. For additional discussion on PSAs, please see Note 7 – Compensation Plans under heading Performance Share Awards.

The following table sets forth the calculations of basic and diluted earnings per share.

	For the Years Ended December 31,		
	2008	2007	2006
	(In thousands, except per share amounts)		
Net income	$ 91,553	$ 189,712	$ 190,015
Adjustments to net income for dilution:			
Add: Interest expense not incurred if 5.75% Senior Convertible Notes converted	-	1,285	6,337
Less: Other adjustments	-	(13)	(63)
Less: Income tax effect of adjustment items	-	(469)	(2,237)
Net Income adjusted for the effect of dilution	$ 91,553	$ 190,515	$ 194,052
	62,243	61,852	56,291

Basic weighted-average common shares outstanding						
Add: Dilutive effect of stock options and unvested restricted stock units		890		1,441		1,979
Add: Dilutive effect of 5.75% Senior Convertible Notes using the if-converted method		-		1,557		7,692
Diluted weighted-average common shares outstanding		63,133		64,850		65,962
Basic earnings per common share	$	1.47	$	3.07	$	3.38
Diluted earnings per common share	$	1.45	$	2.94	$	2.94

Stock Based Compensation

At December 31, 2008, the Company had stock-based employee compensation plans that included RSUs, PSAs, and stock options issued to employees and non-employee directors as more fully described in Note 7- Compensation Plans. Stock options were last issued in December 2004. On January 1, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards No. 123 (R), "Share-Based Payment" ("SFAS No. 123 (R)"). This statement requires the Company to record expense associated with the fair value of stock-based compensation. The total unrecognized compensation expense associated with unvested stock options at the date of adoption of this standard totaled $2.4 million. The Company elected to use the modified-prospective adoption method for the standard and consequently recognized compensation expense of $1.9 million in 2006, $437,000 in 2007 and $17,000 in 2008, at which point all options were fully vested. The Company records compensation expense associated with the issuance of RSUs and PSAs. The Company records expense associated with these grants based on the estimated fair value of the RSUs and PSAs as determined at the time of grant.

Recently Issued Accounting Standards

The Company adopted FSP No.157-2 as of January 1, 2008, electing to partially adopt Statement of Financial Accounting Standards No. 157, "Fair Value Measurements" ("SFAS No. 157"). The Company did not apply SFAS No. 157 to nonrecurring fair value measurements of nonfinancial assets and nonfinancial liabilities, including nonfinancial long-lived assets measured at fair value for an impairment assessment under SFAS No. 144 and asset retirement obligations initially measured at fair value under SFAS No. 143. The partial adoption of SFAS No. 157 did not have a material impact on the Company's consolidated financial statements. Please refer to Note 11 – Fair Value Measurements. The adoption of SFAS No. 157 for all nonfinancial assets and nonfinancial liabilities is effective for the Company beginning January 1, 2009. The adoption of this pronouncement does not have a material impact on the Company's consolidated financial statements.

In December 2007 the FASB issued Statement of Financial Accounting Standards No. 141(R), "Business Combinations" ("SFAS No. 141(R)"), which requires the acquiring entity in a business combination to recognize and measure all assets and liabilities assumed in the transaction and any non-controlling interest in the acquiree at fair value as of the acquisition date. The statement also establishes guidance for the measurement of the acquirer shares issued in consideration for a business combination, the recognition of contingent consideration, the accounting treatment for pre-acquisition gain and loss contingencies, the treatment of acquisition related transaction costs, and the recognition of changes in the acquirer's income tax valuation allowance and deferred taxes. SFAS No. 141(R) changes the way the Company accounts for acquisitions of proved properties. Such acquisitions will now be treated as business combinations, which will require transaction costs to be expensed as incurred, may generate gains or losses due to changes between the effective and closing dates of acquisitions, and require possible recognition of goodwill given differences between the purchase price and assets received. SFAS No. 141(R) is effective for the Company beginning January 1, 2009. The impact of the adoption of SFAS No. 141(R) on the Company's consolidated financial statements will largely be dependent on the size and nature of the business combinations completed after the adoption of this statement.

In December 2007 the FASB issued Statement of Financial Accounting Standards No. 160, "Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51" ("SFAS No. 160"), which establishes accounting and reporting standards that require noncontrolling interests to be reported as a component of equity. SFAS No. 160 also requires that changes in a parent's ownership interest while the parent retains its controlling interest be accounted for as equity transactions and that any retained noncontrolling equity investment upon the deconsolidation of a subsidiary be initially measured at fair value. SFAS No. 160 is effective for the Company beginning January 1, 2009. The adoption of this pronouncement will not have a material impact on the Company's consolidated financial statements.

In March 2008 the FASB issued Statement of Financial Accounting Standard No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133" ("SFAS No. 161"), which requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. The statement requires fair value disclosures of derivative instruments and their gains and losses to be in tabular format, the potential effect on the entity's liquidity from the credit-risk-related contingent features to be disclosed, and cross-referencing within the footnotes. SFAS No. 161 is effective for the Company beginning January 1, 2009. The adoption of this pronouncement will not have an impact on the Company's consolidated financial statements, but it will require the Company to expand its disclosures about derivative instruments.

In May 2008 the FASB issued FSP APB 14-1, "Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement)" ("FSP APB 14-1"), which requires issuers of convertible debt that may be settled fully or partially in cash upon conversion to account separately for the liability and equity components of the convertible debt. The liability component is measured so that the effective interest expense associated with the convertible debt reflects the issuer's borrowing rate at the date of issuance for similar debt instruments without the conversion feature. FSP APB 14-1 applies to the Company's 3.50% Senior Convertible Notes and will be effective for the Company beginning on January 1, 2009. FSP APB 14-1 will be applied retrospectively to all periods that will be presented in the Company's consolidated financial statements beginning after January 1, 2009. Upon adoption, the Company will retrospectively record a decrease in the book value of its 3.50% Senior Convertible Notes of approximately $42 million at their inception on April 4, 2007, and a corresponding increase in additional paid-in capital. Further, the Company will record an additional $8.4 million and $6.3 million of interest expenses (net of applicable tax benefit of $3.1 million and $2.3 million) in its 2008 and 2007 consolidated financial statements, respectively. The Company will begin recording an additional non-cash interest expense of approximately $8 million per year in 2009.

On December 31, 2008, the Securities and Exchange Commission ("SEC") published the final rules and interpretations updating its oil and gas reporting requirements. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions include changes to the pricing used to estimate reserves, the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, and permitting disclosure of probable and possible reserves. The SEC will require companies to comply with the amended disclosure requirements for registration statements filed after January 1, 2010, and for annual reports for fiscal years ending on or after December 15, 2009. Early adoption is not permitted. The Company is currently assessing the impact that the adoption will have on the Company's disclosures, operating results, financial position, and cash flows.

Comprehensive Income

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

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

	Derivative Instruments	Pension Liability Adjustments	Other Comprehensive Income (Loss)
		(In thousands)	
For the year ended December 31, 2006			
Before tax income (loss)	$ 111,437	$ (290)	$ 111,147
Tax benefit (expense)	(42,459)	110	(42,349)
After deferred tax income (loss)	$ 68,978	$ (180)	$ 68,798
For the year ended December 31, 2007			
Before tax income (loss)	$ (272,655)	$ 119	$ (272,536)
Tax benefit (expense)	102,688	(49)	102,639
After deferred tax income (loss)	$ (169,967)	$ 70	$ (169,897)
For the year ended December 31, 2008			
Before tax income (loss)	$ 358,632	$ (1,941)	$ 356,691
Tax benefit (expense)	(135,164)	734	(134,430)
After deferred tax income (loss)	$ 223,468	$ (1,207)	$ 222,261

Major Customers

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

Industry Segment and Geographic Information

The Company operates exclusively in the exploration and production segment. All of the Company’s operations are conducted in the continental United States and in state and federal waters offshore in the Gulf of Mexico. Consequently, the Company currently reports as a single industry segment. The Company’s gas marketing department provides mostly internal services and acts as the first purchaser of natural gas and natural gas liquids produced by the Company in certain cases. We consider the Company’s marketing function as ancillary to the Company’s oil and gas producing activities. The amount of income these operations generate from marketing gas produced by third parties is not material to the Company’s financial position, and segmentation of such activity would not provide a better understanding of the Company’s performance. However, gross revenue and expense related to marketing activities for gas produced by third parties are presented discreetly in the accompanying consolidated statements of operations.

Intangible Assets

As of December 31, 2008, and 2007, the Company's accompanying consolidated balance sheets include $1.4 million and $2.4 million, respectively, of intangible assets. These assets arise from acquired oil and gas sale contracts with favorable pricing terms. They do not qualify as derivatives or hedges under SFAS No. 133. Intangible assets of the Company are amortized using the units-of-production method and are evaluated for impairment if such indicators arise. Intangible assets are included in other noncurrent assets on the Company's accompanying consolidated balance sheets.

Goodwill

Goodwill is measured as the excess of the acquisition costs over the sum of the amounts assigned to the identifiable assets acquired less liabilities assumed. Goodwill was recorded as a result of the acquisition of Agate

Petroleum, Inc. in January 2005. Goodwill is reviewed for impairment annually or more frequently if impairment indicators arise. The goodwill review was conducted at the reporting unit level. A reporting unit is defined as the oil and gas properties in a region. The Company fully impaired its goodwill at December 31, 2008.

Off-Balance Sheet Arrangements

As part of its ongoing business, the Company has not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities ("SPEs"), which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. As of and up to December 31, 2008, the Company has not been involved in any unconsolidated SPE transactions.

The Company evaluates its transactions to determine if any variable interest entities exist. If it is determined that St. Mary is the primary beneficiary of a variable interest entity, that entity is consolidated into St. Mary.

Note 2 – Accounts Receivable and Accounts Payable and Accrued Expenses

Accounts receivable are comprised of the following:

	As of December 31,	
	2008	2007
	(In thousands)	
Accrued oil and gas sales	$ 84,583	$ 115,534
Due from joint interest owners	56,493	37,860
Settled hedge receivable	8,829	-
Other	7,785	5,755
Total accounts receivable	$ 157,690	$ 159,149

Accounts payable and accrued expenses are comprised of the following:

	As of December 31,	
	2008	2007
	(In thousands)	
Accrued drilling costs	$ 111,397	$ 112,481
Revenue and severance tax payable	42,520	37,048
Accrued lease operating expense	20,328	14,604
Accrued property taxes	4,889	5,042
Accrued interest	2,794	3,590
Accrued compensation	18,613	17,887
Trade payables	25,629	28,187
Accrued payments to hedge contract counterparties	-	9,640
Plug and abandonment liability on offshore platform related to hurricanes	7,281	3,108
Accrued marketed gas system expense	8,892	13,520
Other	12,468	9,811

Total accounts payable and accrued expenses	$	254,811	$	254,918

Note 3 – Acquisitions, Divestitures, and Assets Held for Sale

Greater Green River Basin Divestiture

In June 2008 the Company completed the divestiture of certain non-strategic gas properties located in the Greater Green River Basin in the Rocky Mountain region. The cash received at closing, net of commission costs, was $21.7 million. The final sales price is subject to normal post-closing adjustments and is expected to be finalized during the first quarter of 2009. The estimated gain on sale of proved properties related to the divestiture is approximately $932,000 and may be impacted by the previously mentioned post-closing adjustments. The Company determined that this sale does not qualify for discontinued operations accounting under FASB Emerging Issues Task Force Issue No. 03-13, "Accounting for the Impairment or Disposal of Long-Lived Assets", ("EITF No. 03-13").

Abraxas Divestiture

On January 31, 2008, the Company completed the divestiture of certain non-strategic oil and gas properties located primarily in the Rocky Mountain and Mid-Continent regions to Abraxas Petroleum Corporation and Abraxas Operating, LLC. The cash received at closing, net of commission costs, was $129.6 million. The final sale price is subject to normal post-closing adjustments and is expected to be finalized during the first quarter of 2009. The estimated gain on sale of proved properties related to the divestiture is approximately $55.6 million and may be impacted by the previously mentioned post-closing adjustments. The Company determined that this sale does not qualify for discontinued operations accounting under EITF No. 03-13. These assets were classified as assets held for sale as of December 31, 2007.

Williston Basin Acquisition

On August 13, 2008, the Company acquired oil and gas properties located in the Bakken and Three Forks formations in the Williston Basin for $20.2 million of cash. After normal purchase price adjustments, the Company allocated $3.6 million to proved oil and gas properties and $16.6 million to unproved oil and gas properties. The acquisition was funded with cash on hand and borrowings under the Company's existing credit facility.

Carthage Acquisition

On March 21, 2008, the Company acquired oil and gas properties located primarily in the Carthage Field in Panola County, Texas for $49.2 million in cash. After normal purchase price adjustments, the Company allocated $29.0 million to proved oil and gas properties, $20.6 million to unproved oil and gas properties, and a net $215,000 to other liabilities. The Company also recorded a $165,000 asset retirement obligation liability associated with the acquired properties. The acquisition was funded with cash on hand and borrowings under the Company's existing credit facility. During the second quarter of 2008, the Company acquired additional interests in the majority of these properties for $8.1 million.

Rockford Acquisition

On October 4, 2007, the Company completed the purchase of certain oil and gas properties in the Gold River project area targeting the Olmos shallow gas formation located primarily in Webb and Dimmit Counties, Texas. The assets were purchased from Rockford Energy Partners II, LLC for $149.0 million. After normal purchase price adjustments, the Company allocated $127.3 million to proved oil and gas properties, $23.1 million to unproved oil and gas properties, and a net $292,000 to other assets. The Company also recorded a $1.7 million asset retirement obligation liability associated with the acquired properties. The acquisition was funded with cash on hand and borrowings under the Company's existing credit facility. The acquired properties are adjacent to the Catarina project area discussed below. In 2008 the Company recorded approximately $154 million of impairment write-downs for the properties acquired through this acquisition and the Catarina acquisition.

Catarina Acquisition

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

Like-Kind Exchanges and Variable Interest Entities

On December 31, 2008, the Company closed on a partial Section 1031 Internal Revenue Code of 1986, as amended (the "IRC") tax deferred exchange whereby it exchanged certain non-strategic, partner-operated oil and gas properties located in Pointe Coupee Parish, Louisiana for an increased interest in the Company-operated Sweetie Peck tight oil assets in Upton and Midland Counties, Texas and $17.6 million in cash. After normal purchase price adjustments, the Company allocated $11.0 million to proved oil and gas properties and $1.8 million to unproved oil and gas properties. Proceeds of $14.4 million were deposited to restricted cash to facilitate the acquisition of additional assets in tax deferred transactions. The exchange of proved properties resulted in the recognition of approximately $13.8 million of gain on sale of proved properties.

The Carthage acquisition described above was structured to qualify as the first step of a reverse like-kind exchange under Section 1031 of the IRC and Internal Revenue Service ("IRS") Revenue Procedure 2000-37. Prior to closing on the acquisition, the Company assigned all of its rights and duties under the purchase and sale agreement to NBF Reverse Exchange, LLC, an indirect wholly-owned subsidiary of Comerica Incorporated, which further assigned all of its rights and duties under the purchase and sale agreement to St. Mary Acquisition, LLC ("SMA, LLC"), a company unaffiliated with St. Mary. The Carthage Field assets were acquired by NBF Reverse Exchange, LLC as an exchange accommodation titleholder. In October 2008, SMA, LLC, was merged into St. Mary. Its existence with the Secretary of State of Texas was terminated.

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

In connection with the reverse like-kind exchange described above, St. Mary loaned an amount equal to the purchase price of the assets to SMA, LLC. Based on the provision of FASB Interpretation No. 46(R), "Consolidation of Variable Interest Entities" ("FIN 46(R)"), the Company determined that SMA, LLC was a variable interest entity for which St. Mary was the primary beneficiary. Accordingly, SMA, LLC was consolidated into St. Mary subsequent to SMA, LLC's completion of the purchase of oil and gas properties on March 21, 2008. As a result of the consolidation, St. Mary recognized all oil and gas reserves and production as well as all revenues and expenses attributed to the Carthage acquisition as of the March 21, 2008, acquisition date. St. Mary's loan to SMA, LLC was repaid on October 10, 2008.

The Rockford acquisition of the Gold River assets described above was also structured to qualify as the first step of a reverse like-kind exchange under Section 1031 of the IRC, and IRS Revenue Procedure 2000-37. Prior to closing on the Rockford acquisition, the Company assigned all of its rights and duties under the purchase and sale agreement to

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

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

Assets Held for Sale

As of December 31, 2008, the Company is engaged in marketing for sale certain non-core oil and gas properties located in the Rocky Mountain and Gulf Coast regions. In accordance with SFAS No. 144, these properties have been separately presented in the accompanying consolidated balance sheet at the lower of carrying value or fair value less the cost to sell. The accompanying consolidated balance sheets as of December 31, 2008, represents $1.8 million of assets held for sale, net of accumulated depletion, depreciation and amortization. Assets held for sale were measured at carrying value, which was less than fair value less cost to sell as of December 31, 2008. Any subsequent changes to fair value less the cost to sell will impact the measurement of assets held for sale if the fair value is determined to be less than the carrying value of the assets. Asset retirement obligation liabilities of $238,000 related to these properties have also been reclassified to liabilities associated with oil and gas properties held for sale on the consolidated balance sheet as of December 31, 2008. The Company determined that these sales do not qualify for discontinued operations accounting under EITF No. 03-13.

Note 4 – Income Taxes

The provision for income taxes consists of the following:

	For the Years Ended December 31,					
	2008		2007		2006	
	(In thousands)					
Current taxes						
Federal	$	17,863	$	15,136	$	28,557
State		1,361		2,459		1,917
Deferred taxes		40,634		92,955		74,832
Total income tax expense	$	59,858	$	110,550	$	105,306

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As a result of the exercise of stock options, the Company reduced its income tax payable in each year presented. The tax benefit to the Company of stock option exercises was $13.9 million in 2008, $9.9 million in 2007, and $16.1 million in 2006.

The components of the net deferred tax liability are as follows:

	December 31,			
	2008		2007	
	(In thousands)			
Deferred tax liabilities:				
Oil and gas properties	$	433,536	$	412,669
Unrealized derivative asset		42,407		-
Interest on Senior Convertible Notes		6,456		2,596
Other		3,635		1,429
Total deferred tax liabilities		486,034		416,694
Deferred tax assets:				
Net Profits Plan liability		66,800		79,552
Unrealized derivative liability		1,072		93,829
Stock compensation		7,291		8,849
State tax net operating loss carryforward or carryback		7,215		6,808
State and federal income tax benefit		3,285		2,939
Employee benefits and other		2,845		1,543
Other		1,049		614
Other long-term liabilities		-		1,724
Total deferred tax assets		89,557		195,858
Valuation allowance		(3,146)		(3,556)
Net deferred tax assets		86,411		192,302
Total net deferred tax liabilities		399,623		224,392
Less: current deferred income tax liabilities		(42,766)		(1,425)
Add: current deferred income tax assets		1,477		34,636
Non-current net deferred tax liabilities	$	358,334	$	257,603
Current federal income tax refundable	$	13,136	$	933
Current state income tax refundable (payable)	$	25	$	(105)

At December 31, 2008, the Company had estimated state net operating loss carryforwards of approximately $174 million expiring between 2009 and 2028 and tax credits of $288,000 expiring between 2008 and 2017. A portion of the Company's valuation allowance relates to state net operating loss carryforwards, state tax credits, and state and federal income tax benefit amounts which the Company anticipates will expire before they can be utilized. The Company has concluded that permanent items included in the calculation of income tax for certain states may impact its ability to deduct operating losses and realize federal income tax deduction benefits in certain states and has adjusted its valuation allowances accordingly. The remaining portion of the valuation allowance relates to the Net Profits Plan liability and reflects an estimate of future executive compensation that may not be deductible for income tax purposes when future cash payments occur under the plan.

Federal income tax expense differs from the amount that would be provided by applying the statutory U.S. Federal income tax rate to income before income taxes primarily due to the effect of state income taxes, percentage depletion, the estimated effect of the domestic production activities deduction, impairment of goodwill, and other permanent differences, as follows:

	For the Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Federal statutory taxes	$ 52,994	$ 105,092	$ 103,504
Increase (reduction) in taxes resulting from			
State taxes (net of federal benefit)	4,669	5,111	2,081
Goodwill	3,308	-	-
Change in valuation allowance	(409)	896	88
Statutory depletion	(294)	(407)	(315)
Domestic production activities deduction	(275)	(384)	(287)
Other	(135)	242	235
Income tax expense from operations	$ 59,858	$ 110,550	$ 105,306

At December 31, 2008, the Company recognized an impairment on Goodwill recorded in conjunction with the Agate acquisition (see Goodwill in Note 1). In accordance with the provisions of SFAS No. 109 tax benefit is not calculated upon the recognition of this expense. This resulted in a 2.2 percent increase in the Company's tax rate for the year ended December 31, 2008.

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

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction and in various states. With few exceptions, the Company is no longer subject to U.S. federal or state income tax examinations by these tax authorities for years before and including 2004. The Internal Revenue Service initiated an audit of the Company's 2005 tax year in 2008. The audit began on April 14th and is ongoing at year-end, but is expected to close in the first quarter of 2009 with no material impact to the Company.

In the third quarter of 2007 the Company received a refund of income tax and interest of $3.1 million from a carryback of net operating losses to the 2000 tax year. An additional $1.0 million due to the Company for income tax refunds and accrued interest resulting from a carryover of minimum tax credits to the 2003 tax year was received in January 2008. These amounts were previously recognized by the Company.

The Company adopted the provision of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" ("FIN No. 48"), on January 1, 2007. There was no financial statement adjustment required as a result of adoption. At adoption, the Company had a long-term liability for unrecognized tax benefit of $1.0 million and accumulated interest liability of $92,000. The entire amount of unrecognized tax benefit would affect the Company's effective tax rate if recognized. Interest expense in the 2008 accompanying consolidated statements of operation includes a nominal $12,000 associated with income tax. Penalties associated with income tax are recorded in general and administrative expense in the accompanying consolidated statements of operations. There were no penalties associated with income tax recorded for the year ended December 31, 2008.

The total amount recorded for unrecognized tax benefits is presented below:

	For the Years Ended December 31,			
	2008		2007	
	(In thousands)			
Beginning balance	$	957	$	1,112
Additions for tax positions of prior years		173		233
Reductions for lapse of statute of limitations		(136)		(388)
Ending balance	$	994	$	957

Note 5 – Long-term Debt

Revolving Credit Facility

The Company's revolving credit facility specifies a maximum loan amount of $500 million and has a maturity date of April 7, 2010. Borrowings under the facility are secured by a pledge, in favor of the lenders, of collateral that includes the majority of the Company's oil and gas properties and the common stock of the material subsidiaries of the Company. The borrowing base under the credit facility, as authorized by the bank group as of the date of this filing, is $1.4 billion and is subject to regular semi-annual redeterminations. The borrowing base redetermination process considers the value of St. Mary's oil and gas properties and other assets, as determined by the bank syndicate. The Company has elected an aggregate commitment amount of $500 million under the credit facility. The Company must comply with certain covenants under its existing credit facility agreement, including the limitation of the Company's annual dividend rate to no more than $0.25 per share. The Company is in compliance with all covenants under the credit facility. Interest and commitment fees are accrued based on the borrowing base utilization percentage table below. Euro-dollar loans accrue interest at London Interbank Offered Rate ("LIBOR") plus the applicable margin from the utilization table, and Alternative Base Rate ("ABR") loans accrue interest at Prime plus the applicable margin from the utilization table. Commitment fees are accrued on the unused portion of the $500 million aggregate commitment amount and are included in interest expense in the accompanying consolidated statements of operations.

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

The Company had $300.0 million, $285.0 million, and $318.5 million in outstanding loans under its revolving credit agreement on December 31, 2008, 2007, and February 17, 2009, respectively. The Company had $200.0 million, $215.0 million, and $181.5 million of available borrowing capacity under this facility as of December 31, 2008, 2007, and February 17, 2009, respectively.

5.75% Senior Convertible Notes Due 2022

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

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3.50% Senior Convertible Notes Due 2027

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

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

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

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

On or after April 6, 2012, the Company may redeem for cash all or a portion of the 3.50% Senior Convertible Notes at a redemption price equal to 100 percent of the principal amount of the notes to be redeemed plus accrued and unpaid interest, if any, up to but excluding the applicable redemption date. Holders of the 3.50% Senior Convertible Notes may require the Company to purchase all or a portion of their notes on each of April 1, 2012, April 1, 2017, and April 1, 2022, at a purchase price equal to 100 percent of the principal amount of the notes to be repurchased plus accrued and unpaid interest, if any, up to but excluding the applicable purchase date. On April 1, 2012, the Company may pay the purchase price in cash, in shares of common stock, or in any combination of cash and common stock. On April 1, 2017, and April 1, 2022, the Company must pay the purchase price in cash. Based on the market price of the 3.50% Senior Convertible Notes, the estimated fair value of the notes was approximately $204 million as of December 31, 2008.

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Weighted-Average Interest Rate Paid and Capitalized Interest

The weighted-average interest rate paid in 2008, 2007, and 2006 was 4.4 percent, 5.4 percent, and 7.6 percent, respectively, including commitment fees paid on the unused portion of the credit facility aggregate commitment, amortization of deferred financing costs, amortization of the contingent interest embedded derivative associated with the 5.75% Senior Convertible Notes for 2007 and 2006, and the effect of interest rate swaps. The average outstanding loan balance in 2008 increased in comparison to the average outstanding loan balance in 2007, while the rates associated with the balances decreased. The decrease is attributed to significantly lower LIBOR and Prime rates for the specified periods in 2008 compared to 2007. Capitalized interest costs for the Company for the years ended December 31, 2008, 2007, and 2006, were $3.7 million, $5.4 million, and $3.5 million, respectively.

Note 6 – Commitments and Contingencies

The Company has entered into various operating leases, which include drilling rig contracts of approximately $25.4 million, office space leases including maintenance of approximately $13.6 million, compressor contracts of approximately $3.8 million, and vehicle leases of approximately $3.1 million. The annual minimum lease payments for the next five years and thereafter are presented below:

Years Ending December 31,	(In thousands)
2009	$ 33,247
2010	6,066
2011	4,431
2012	1,647
2013	585
Thereafter	241
Total	$ 46,217

The Company leases office space under various operating leases with terms extending as far as May 31, 2014. Rent expense, net of sublease income, was $2.4 million, $1.9 million, and $1.5 million in 2008, 2007, and 2006, respectively. The Company also leases office equipment under various operating leases. The Company has a non-cancelable sublease through May 2012, worth approximately $632,000, with payments due to St. Mary of $185,000 per year through 2011 and $77,000 in 2012.

The Company is subject to litigation and claims that have arisen in the ordinary course of business. The company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of such litigation and claims will not have a material effect on the results of operations, the financial position, or cash flows of the Company.

Note 7 – Compensation Plans

Cash Bonus Plan

The Company has a cash bonus plan, under which the Company has established a performance measurement framework whereby selected employee participants may be awarded an annual cash bonus. As amended by the Board of Directors on March 28, 2008, the plan document provides that no participant may receive an annual bonus under the plan of more than 200 percent of his or her base salary. As the plan is currently administered, any awards under the plan are based on Company and regional performance, and are then further refined by individual performance. The Company accrues cash bonus expense based upon the current year’s performance. Included in the general and administrative and exploration expense line items in the accompanying consolidated statements of operations are $6.4 million, $3.6 million, and $1.9 million of cash bonus expense related to the specific performance year for the years ended December 31, 2008, 2007, and 2006, respectively.

Net Profits Plan

Under the Company's Net Profits Plan, all oil and gas wells that were completed or acquired during a year were designated within a specific pool. Key employees recommended by senior management and designated as participants by the Company's Compensation Committee of the Board of Directors and employed by the Company on the last day of that year became entitled to payments under the Net Profits Plan after the Company has received net cash flows returning 100 percent of all costs associated with that pool. Thereafter, ten percent of future net cash flows generated by the pool are allocated among the participants and distributed at least annually. The portion of net cash flows from the pool to be allocated among the participants increases to 20 percent after the Company has recovered 200 percent of the total costs for the pool, including payments made under the Net Profits Plan at the ten percent level. The Net Profits Plan has been in place since 1991. Pool years prior to and including 2006 are fully vested. The 2007 pool year carries a vesting period of three years, whereby one-third is vested at the end of the year for which participation is designated and one-third vests on each of the following two anniversary dates. The 2006 and 2007 Pool years include a cap whereby the maximum benefit to full participants from a particular year's pool is limited to 300 percent of a participating individual's adjusted base salary paid during the year to which the pool relates. In December 2007 the Board approved a restructuring of the Company's incentive compensation programs. The change in the incentive compensation structure is designed to replace the programs involving the grant of RSUs and the grant of participation interests in the Net Profits Plan with a single long-term incentive program utilizing performance share awards. As a result, the 2007 Net Profits Plan pool was the last pool established by the Company.

The Company records changes in the present value of estimated future payments under the Net Profits Plan as a separate item in the accompanying consolidated statements of operations. The change in the estimated liability is recorded as a non-cash expense or benefit in the current period. The amount recorded as an expense or benefit associated with the change in the estimated liability is not allocated to general and administrative expense or exploration expense because it is associated with the future net cash flows from oil and gas properties in the respective pools rather than results being realized through current period production. The table below presents the estimated allocation of the change in the liability if the Company did allocate the adjustment to these specific functional line items based on the current allocation of actual distributions being made by the Company. The change in allocation of costs to the functional classification relates to the current composition of employees as compared to those individuals that have terminated employment with the Company. Of the payments made under the Net Profits Plan, 13 percent, 22 percent, and 54 percent would have been classified as exploration expense in the accompanying consolidated statements of operations for the years ended December 31, 2008, 2007, and 2006, respectively. As time progresses, less of the distributions relate to prospective exploration efforts as more of the distributions are made to employees that have terminated employment and thereby do not provide ongoing exploration support.

	For the Years Ended December 31,		
	2008	2007	2006
	(In thousands)		
General and administrative expense (benefit)	$ (29,672)	$ 39,866	$ 10,820
Exploration expense (benefit)	(4,368)	10,957	12,939
Total	$ (34,040)	$ 50,823	$ 23,759

401(k) Plan

The Company has a defined contribution pension plan (the "401(k) Plan") that is subject to the Employee Retirement Income Security Act of 1974. The 401(k) Plan allows eligible employees to contribute up to 60 percent of their base salaries. The Company matches each employee's contribution up to six percent of the employee's base salary and may make additional contributions at its discretion. The Company's contributions to the 401(k) Plan were $2.0 million, $1.5 million, and $1.2 million for the years ended December 31, 2008, 2007, and 2006, respectively. No discretionary contributions were made by the Company to the 401(k) Plan for any of these years.

Employee Stock Purchase Plan

Under the St. Mary Land & Exploration Company Employee Stock Purchase Plan ("the ESPP"), eligible employees may purchase shares of the Company's common stock through payroll deductions of up to 15 percent of eligible compensation. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on the first or last day of the purchase period, and shares issued under the ESPP are restricted for a period of 18 months from the date issued. The ESPP is intended to qualify under Section 423 of the IRC. The Company had to set aside 2,000,000 shares of its common stock to be available for issuance under the ESPP, of which 1,554,583 shares are available for issuance as of December 31, 2008. Shares issued under the ESPP totaled 45,228 in 2008, 29,534 in 2007, and 26,046 in 2006. Total proceeds to the Company for the issuance of these shares were $1.1 million in 2008, $919,000 in 2007, and $814,000 in 2006.

The fair value of ESPP shares are measured at the date of grant using the Black-Scholes option-pricing model. The fair values of ESPP shares issued were estimated using the following weighted-average assumptions:

	For the Years Ended December 31,		
	2008	2007	2006
Risk free interest rate	1.2%	4.1%	5.1%
Dividend yield	0.2%	0.3%	0.3%
Volatility factor of the expected market			
price of the Company's common stock	81.5%	27.2%	36.7%
Expected life (in years)	0.5	0.5	0.5

For the ESPP offering periods during 2008, 2007, and 2006, the Company expensed $307,000, $260,000, and $243,000, respectively, based on the estimated fair value of grants on the respective grant dates.

Equity Incentive Compensation Plan

There are several components to the equity compensation plan that are described in this section. Various types of equity awards have been granted by the Company in different periods. These disclosures reflect the culmination of the disclosure requirements for all equity awards still outstanding.

In May 2006 the stockholders approved the 2006 Equity Incentive Compensation Plan (the "2006 Equity Plan") to authorize the issuance of restricted stock, RSUs, 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 the Predecessor Plans 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. An amendment and restatement of the 2006 Equity Plan was approved by the Company's stockholders at the 2008 annual stockholders' meeting held on May 21, 2008.

As of December 31, 2008, 1.5 million shares of common stock remained available for grant under the 2006 Equity Plan. For an issuance of a direct share benefit such as an outright grant of common stock, a grant of a restricted share, or a RSU grant, each direct share benefit issued counts as two shares against the number of shares available to be granted under the 2006 Equity Plan. The issuance of a PSA is considered a direct share benefit under the 2006

Equity Plan. At the end of each grant's three-year performance period a final multiplier ranging between zero and two is applied to each performance share so that each performance share granted has the potential to result in the issuance of two shares of common stock. Consequently, each performance share granted counts as four shares against the number of shares available to be granted under the 2006 Equity Plan.

Stock options granted count as one share for each instrument issued against the number of shares available to be granted under the 2006 Equity Plan.

The Company has outstanding stock option grants under the Predecessor Plans and RSU awards under the Predecessor Plans and the 2006 Equity Plan. The following sections describe the details of RSU grants and stock options outstanding as of December 31, 2008.

Effective January 1, 2006, the Company adopted SFAS No. 123(R) using the modified-prospective transition method. Under that transition method, compensation expense recognized in 2006, 2007, and 2008 includes: (a) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006 based on the grant date fair value estimated in accordance with the original provision of SFAS No. 123, and (b) compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123 (R).

Performance Share Awards

In late 2007, St. Mary decided to transition from RSUs and interests in the Net Profits Plan to PSAs as the primary form of long-term equity incentive compensation. On August 1, 2008, the Company granted 465,751 PSAs. PSAs represent the right to receive, upon settlement of the PSAs after the completion of a three-year performance period ending June 30, 2011, a number of shares of the Company's common stock that may be from zero to two times the number of PSAs granted on the award date, depending on the extent to which the Company's performance criteria have been achieved and the extent to which the PSAs have vested. The performance criteria for the PSAs are based on a combination of the Company's cumulative total shareholder return ("TSR") for the performance periods and the relative measure of the Company's TSR compared with the cumulative TSR of certain peer companies for the performance period. The PSAs will vest 1/7th on August 1, 2009, 2/7ths on August 1, 2010, and 4/7ths on August 1, 2011. Total stock-based compensation expense related to the PSAs granted in 2008 was $2.5 million.

In measuring compensation expense related to the grant of PSAs, SFAS No. 123(R) requires companies to estimate the fair value of the award on the grant date. The fair value of PSAs has been measured using a stochastic process method using the Geometric Brownian Motion Model ("GBM Model"). A stochastic process is a mathematically defined equation that can create a series of outcomes over time. These outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for those iterations. In the case of the Company's PSAs, the Company cannot predict with certainty the path its stock price or the stock price of its peers will take over the three-year performance period. By using a stochastic simulation the Company can create multiple prospective stock pathways, statistically analyze these simulations, and ultimately make inferences to the most likely path the stock price will take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the GBM Model is deemed an appropriate method by which to determine the fair value of the PSAs. The fair value of the Company's PSAs granted on August 1, 2008, was equal to $12.3 million.

A summary of the status and activity of PSAs for the year ended December 31, 2008, is presented in the following table.

	PSAs	Weighted-Average Grant-Date Fair Value
At January 1, 2008	-	$ -
Granted	465,751	$ 26.48
Vested	-	$ -
Forfeited	(1,418)	$ 26.48
At December 31, 2008	464,333	$ 26.48

Restricted Stock Incentive Program Under the Equity Incentive Compensation Plan

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

St. Mary issued 158,744 RSUs on February 28, 2008, related to 2007 performance, 78,657 RSUs on February 28, 2007, related to 2006 performance, and 484,351 RSUs on February 28, 2006, related to 2005 performance. The total fair value associated with these issuances was $6.0 million in 2008, $2.5 million in 2007, and $16.4 million in 2006 as measured on the respective grant dates. The granted RSUs vested 25 percent immediately upon grant and vest 25 percent on each of the first three anniversary dates of the grant.

In 2008, 2007, and 2006, the Company issued 4,290, 23,977, and 8,500 RSUs for various grants to certain employees. These grants have various vesting schedules. The total fair value associated with these issuances was $164,000, $803,000, and $319,000 for 2008, 2007, and 2006, respectively as measured on the respective grant dates.

In 2008, 2007, and 2006, the Company issued 23,113, 32,504, and 29,827 shares respectively, of common stock from treasury to its non-employee directors pursuant to the Company's 2006 Equity Plan. The Company recorded compensation expense related to the issuances of shares to non-employee directors of $1.0 million, $983,500, and $976,000 for the years ended December 31, 2008, 2007, and 2006, respectively.

St. Mary issued 265,373 RSUs on June 30, 2008, as a transitional award to employees when the Company moved from the old RSU program to the new PSA program. The total fair value associated with this issuance was $17.2 million as measured on the grant date. One third of the granted RSUs vest on December 15th in 2008, 2009, and 2010, respectively. Compensation expense is recorded monthly over the vesting period of the award. For RSUs awarded prior to 2006, vested shares of common stock underlying the RSU grants were issued on the third anniversary of the grant, at which time the shares carried no further restrictions. For all awards subsequent to the 2005 RSU grant, St. Mary eliminated the restriction period that extends beyond the vesting period so shares were issued without restriction upon vesting, rather than on the third anniversary of the award. This change was effected for existing awards in 2007 within the safe harbor adoption provisions of the newly enacted U.S. Treasury regulations interpreting IRC provisions governing deferred compensation. A mutual election of the employee and the Company was required to effect this change for each outstanding award. Essentially all of the awards were modified by mutual election, and as such, the incremental value associated with removal of this restriction period is being amortized over the remaining service period for these awards. For grants made beginning with the 2006 grant period, the Company is using the accelerated amortization method as described in FASB Interpretation No. 28, "Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans – an interpretation of APB Opinion No.'s 15 and 25," whereby approximately 48 percent of the total estimated compensation expense is recognized in the first year of the vesting period. As of December 31, 2008, a total of 409,388 RSUs were outstanding, of which 7,091 were vested. The total RSU compensation expense for the year ended December 31, 2008, 2007, and 2006 was $11.0 million, $8.4 million, and $8.5 million, respectively. As of December 31, 2008, there was $13.4 million of total unrecognized compensation expense related to unvested RSU awards. The unrecognized compensation expense is being amortized through 2011.

During 2008, the Company converted 678,197 RSUs, relating to awards granted in 2008, 2007, 2006, and 2005 into common stock based on the amended terms of the RSU awards. The Company and the majority of grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and award agreements. As a result, the Company issued net 482,602 shares of common stock associated with these grants. The remaining 195,595 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon the delivery of the shares underlying those RSUs.

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

In measuring compensation expense related to the grant of RSUs, SFAS No. 123(R) requires companies to estimate the fair value of the award on the grant date. For grants prior to January 1, 2008, the Company had a restriction period beyond vesting. Therefore, the fair value of the RSUs was inherently less than the market value of an unrestricted share of St. Mary's common stock. The fair value of RSUs had been measured using the Black-Sholes option-pricing model. The Company's computation of expected volatility was based on the historic volatility of St. Mary's common stock. The Company's computation of expected life was determined based on historical experience of similar awards, giving consideration to the contractual terms of the awards, vesting schedules, and expectations of future employee behavior. The interest rate for periods within the contractual life of the award was based on the U.S. Treasury constant maturity yield at the time of the grant.

The fair values of RSU awards granted were estimated using the following weighted-average assumptions:

	For the Years Ended December 31,	
	2007	2006
Risk free interest rate	4.5%	4.7%
Dividend yield	0.3%	0.3%
Volatility factor of the expected market price of the Company's common stock	32.0%	36.6%
Expected life of the awards (in years)	3	3

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

Upon the adoption of SFAS No. 123(R), the deferred compensation balance of $5.6 million related to outstanding RSU awards was reclassified to additional paid-in-capital within the shareholders' equity section of the balance sheet. This deferred compensation balance had been recorded in accordance with APB Opinion No. 25. The

Company had recorded compensation expense in periods prior to January 1, 2006, for restricted stock awards based on the intrinsic value on the date of grant. The intrinsic value was recorded as deferred compensation in a separate component of shareholders' equity and was amortized to compensation expense over the vesting period. SFAS No. 123(R) requires expense recognized subsequent to the adoption date to be based on fair value.

Stock Awards Under the Equity Incentive Compensation Plan

As part of hiring a new senior executive in the second quarter of 2006, St. Mary granted a special common stock award of 20,000 shares that vested immediately upon commencement of employment. The fair value associated with this award was $727,600. In addition to this award, the employee will earn an additional 5,000 shares over a four-year period and an additional 15,000 shares contingent on the Company meeting certain net asset growth performance conditions over a four-year period. In 2008 and 2007, the Company issued 3,750 and 1,250 worth of guaranteed and contingent shares with associated fair values of $141,900 and $45,012, respectively. The fair value of these awards will be recorded as compensation expense over the vesting period.

As part of hiring a new senior executive in the third quarter of 2008, St. Mary granted a special restricted stock award of 15,496 shares that vest one half on December 15, 2009, and one half on December 15, 2010. The fair value of this award was $600,005 and will be recorded as compensation expense over the vesting period. For the year ended December 31, 2008, the Company recorded compensation expense of $115,000 related to this award.

A summary of the status and activity of non-vested stock awards and RSUs for the year ended December 31, 2008, is presented below:

	Shares		Weighted-Average Grant-Date Fair Value
Non-vested, at December 31, 2007	289,385	$	32.26
Granted	443,903	$	53.81
Vested	(291,659)	$	22.92
Forfeited	(39,332)	$	37.82
Non-vested, at December 31, 2008	402,297	$	48.24

Stock Option Grants Under the Equity Incentive Compensation Plan

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

During the year ended December 31, 2008, the Company recognized stock-based compensation expense of approximately $17,000 related to stock options that were outstanding and unvested as of January 1, 2006. There was no cumulative effect adjustment from the adoption of SFAS No. 123 (R). As of December 31, 2008, there were no unvested stock options outstanding.

Prior to adopting SFAS No. 123(R), all tax benefits resulting from the exercise of stock options were presented as operating cash flows in the accompanying consolidated statements of cash flows. SFAS No. 123 (R) requires cash flows resulting from excess tax benefits to be classified as part of cash flows from financing activities. Excess tax benefits are realized tax benefits from tax deductions for exercised options in excess of the deferred tax asset attributable to stock compensation costs for such options. The Company has recorded $13.9 million, $9.9 million, and $16.1 million of excess tax benefits for the years ended December 31 2008, 2007, and 2006, respectively, as cash inflows from financing activities. Cash received from option exercises under all share-based payment arrangements for the years ended December 31, 2008, 2007, and 2006 was $10.8 million, $9.1 million, and $16.9 million, respectively.

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

	Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value
For the period ended December 31, 2006			
Outstanding, start of year	4,698,243	$ 12.21	
Granted	-	-	
Exercised	(1,489,636)	$ 11.35	
Forfeited	(87,005)	$ 14.33	
Outstanding, end of year	3,121,602	$ 12.56	$ 75,800,322
Vested, or expected to vest, end of year	3,121,602	$ 12.56	$ 75,800,322
Exercisable, end of year	2,966,944	$ 12.56	$ 72,049,258
For the period ended December 31, 2007			
Outstanding, start of year	3,121,602	$ 12.56	
Granted	-	-	
Exercised	(733,650)	$ 12.38	
Forfeited	(2,452)	$ 7.34	
Outstanding, end of year	2,385,500	$ 12.62	$ 62,007,749
Vested, or expected to vest, end of year	2,385,500	$ 12.62	$ 62,007,749
Exercisable, end of year	2,378,000	$ 12.62	$ 61,814,737
For the period ended December 31, 2008			
Outstanding, start of year	2,385,500	$ 12.62	
Granted	-	-	
Exercised	(868,372)	$ 12.47	
Forfeited	(7,418)	$ 13.39	
Outstanding, end of year	1,509,710	$ 12.69	$ 11,529,600
Vested, or expected to vest, end of year	1,509,710	$ 12.69	$ 11,529,600
Exercisable, end of year	1,509,710	$ 12.69	$ 11,529,600

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A summary of additional information related to options outstanding as of December 31, 2008, follows:

	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Number Outstanding	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise price
\$ 6.19 - \$ 7.97	174,346	1.5 years	\$ 6.69	174,346	1.5 years	\$ 6.69
10.60 - 10.86	155,428	3.1 years	10.72	155,428	3.1 years	10.72
11.58 - 12.03	223,381	3.6 years	11.92	223,381	3.6 years	11.92
12.08 - 12.50	161,268	4.0 years	12.47	161,268	4.0 years	12.47
12.53 - 12.66	213,754	4.5 years	12.59	213,754	4.5 years	12.59
13.39 - 13.39	31,723	4.8 years	13.39	31,723	4.8 years	13.39
13.65 - 13.65	130,585	4.5 years	13.65	130,585	4.5 years	13.65
14.25 - 14.25	194,119	5.0 years	14.25	194,119	5.0 years	14.25
16.66 - 16.66	166,474	2.0 years	16.66	166,474	2.0 years	16.66
20.87 - 20.87	58,632	6.0 years	20.87	58,632	6.0 years	20.87
Total	1,509,710			1,509,710		

The fair value of options was measured at the date of grant using the Black-Scholes option-pricing model.

Note 8 – Pension Benefits

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

On December 31, 2006, the Company adopted the recognition and disclosures provisions of Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an Amendment of the FASB Statements No. 87, 88, 106, and 132(R)" ("SFAS No. 158"). This standard requires the Company to recognize the funded status (i.e., the difference between the fair value of plan assets and the projected benefit obligation) of its pension plan in the consolidated balance sheets as either an asset or a liability, with the corresponding adjustment to accumulated other comprehensive income, net of tax. The adjustment to accumulated other comprehensive income at adoption represented the net unrecognized actuarial losses and unrecognized prior service costs, both of which were previously netted against the plan's funded status in the Company's consolidated balance sheets pursuant to the provisions of Statement of Financial Accounting Standards No. 87, "Employers' Accounting for Pension" ("SFAS No. 87"). These amounts will be subsequently recognized as net periodic pension cost pursuant to the Company's accounting policy for amortizing such amounts. Further actuarial gains and losses that arise in subsequent periods and are not recognized as net periodic pension cost in the same periods will be recognized as a component of other comprehensive income. Those amounts will be subsequently recognized as a component of net period pension cost on the same basis as the amounts recognized in accumulated other comprehensive income at adoption of SFAS No. 158.

The incremental effects of adopting the provisions of SFAS No. 158 on the Company's consolidated balance sheet at December 31, 2006, are presented in the following table. The adoption of SFAS No. 158 had no effect on the Company's accompanying consolidated statements of operations for the year ended December 31, 2006, or for any prior period presented, and it will not affect the Company's operating results in future periods. The effect of recognizing this additional liability is included in the table below in the column labeled "Prior to Adopting SFAS No. 158."

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

Actuarial gains and losses are comprised of experience changes and effects of changes in actuarial assumption. Experience changes are the effects of differences between previous actuarial assumptions and what actually occurred. Included in accumulated other comprehensive income at December 31, 2008, are the following amounts that have not yet been recognized in net periodic pension cost:

	As of December 31, 2008
	(In thousands)
Unrecognized actuarial losses	$ 4,441
Unrecognized prior service costs	-
Accumulated other comprehensive income	$ 4,441

The estimated net loss for the Qualified Pension Plan and the Nonqualified Pension Plan (the "Pension Plans") that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year is $312,000.

Obligations and Funded Status for Both Pension Plans

	For the Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Change in benefit obligations			
Projected benefit obligation at beginning of year	$ 14,744	$ 13,763	$ 11,900
Service cost	2,229	1,911	1,684
Interest cost	889	793	652
Actuarial (gain) loss	(166)	95	7
Benefits paid	(2,910)	(1,818)	(480)
Projected benefit obligation at end of year	$ 14,786	$ 14,744	$ 13,763
Change in plan assets			
Fair value of plan assets at beginning of year	$ 8,755	$ 7,789	$ 5,955
Actual return on plan assets	(1,782)	536	968
Employer contribution	2,489	2,248	1,346
Benefits paid	(2,910)	(1,818)	(480)
Fair value of plan assets at end of year	$ 6,552	$ 8,755	$ 7,789
Funded status	$ (8,234)	$ (5,989)	$ (5,974)
Accumulated Benefit Obligation	$ 9,922	$ 10,416	$ 9,922

The combined underfunded status for the Pension Plans of $8.2 million at December 31, 2008, is recognized in the accompanying consolidated balance sheets as a portion of other noncurrent liabilities. No plan assets of the Qualified Pension Plan are expected to be returned to the Company during the fiscal year ended December 31, 2008. There are no plan assets in the Nonqualified Pension Plan.

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

	As of December 31,	
	2008	2007
	(In thousands)	
Projected benefit obligation	$ 14,786	$ 14,744
Accumulated benefit obligation	$ 9,922	$ 10,416
Fair value of plan assets	$ 6,552	$ 8,755

Components of Net Periodic Benefit Cost for Both Pension Plans

	For the Year Ended December 31,		
	2008	2007	2006
	(In thousands)		
Components of net periodic benefit cost			
Service cost	$ 2,229	$ 1,911	$ 1,684
Interest cost	889	793	652
Expected return on plan assets that reduces periodic pension cost	(565)	(540)	(427)
Amortization of prior service cost	-	-	-
Amortization of net actuarial loss	248	218	296
Net periodic benefit cost	$ 2,801	$ 2,382	$ 2,205

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

Assumptions

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

	As of December 31,	
	2008	2007
Projected benefit obligation		
Discount rate	6.6%	6.1%
Rate of compensation increase	6.2%	6.2%
Net periodic benefit cost		
Discount rate	6.1%	5.9%
Expected return on plan assets	7.5%	7.5%
Rate of compensation increase	6.2%	6.2%

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

	Target	As of December 31,	
Asset Category	2009	2008	2007
Equity securities	60.0%	52.0%	57.5%
Debt securities	40.0%	48.0%	42.5%
Other	-%	-%	-%
Total	100.0%	100.0%	100.0%

Equity securities do not include any shares of the Company's common stock for any period presented. There is no asset allocation of the Nonqualified Pension Plan since that plan does not have its own assets. An expected return on plan assets of 7.5 percent was used to calculate the Company's obligation under the Qualified Pension Plan for 2008 and 2007. Factors considered in determining the expected return include the 60 percent equity and 40 percent debt securities mix of investment of plan assets and the long-term historical rate of return provided by the equity and debt securities markets. The difference in investment income using the projected rate of return compared to the actual rates of return for the past two years was not material and will not have a material effect on the statements of operations or cash flows from operating activities in future years.

Contributions

The Company contributed $2.5 million, $2.2 million, and $1.3 million, to the Pension Plans in the years ended December 31, 2008, 2007, and 2006, respectively. Under the Pension Protection Act of 2006 St. Mary is required to make a minimum contribution of $395,000 to the Pension Plans in 2009.

Benefit Payments

The Pension Plans made actual benefit payments of $2.9 million, $1.8 million, and $480,000 in the years ended December 31, 2008, 2007, and 2006, respectively. Expected benefit payments over the next ten years are as follows:

Years Ended December 31,		(In thousands)
2009	$	415
2010		722
2011		1,274
2012		1,605
2013		2,460
2014 through 2018	$	14,437

Note 9 – Asset Retirement Obligations

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

The Company's estimated asset retirement obligation liability is based on historical experience in abandoning wells, estimated economic lives, estimates as to the cost to abandon the wells in the future, and federal and state regulatory requirements. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. The credit-adjusted risk-free rates used to discount the Company's abandonment liabilities range from 6.5 percent to 12.0 percent. Revisions to the liability could occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells.

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

	As of December 31,	
	2008	2007
	(In thousands)	
Beginning asset retirement obligation	$ 108,284	$ 77,242
Liabilities incurred	11,684	10,851
Liabilities settled	(24,154)	(12,276)
Accretion expense	7,486	5,458
Revision to estimated cash flows	12,974	27,009
Ending asset retirement obligation	$ 116,274	$ 108,284

Accounts payable and accrued expenses as of December 31, 2008, contain $7.3 million related to the Company's asset retirement obligation. The amount relates to the estimated plugging and abandonment costs associated with one offshore platform that was destroyed during Hurricane Ike. Please refer to Note 15 – Hurricanes Gustav and Ike for additional details. Accounts payable and accrued expenses contained $3.1 million related to the Company's asset retirement obligation as of December 31, 2007. The amount relates to the estimated plugging and abandonment costs associated with one offshore platform that was destroyed during Hurricane Rita. Plugging and abandonment of the platform has been completed as of December 31, 2008. Please refer to Note 13 – Insurance Settlement for additional details.

Note 10 – Derivative Financial Instruments

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

	For the Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Derivative contract settlements included in realized oil and gas hedge gain (loss)	$ (101,096)	$ 24,484	$ 28,176
Ineffective portion of hedges qualifying for hedge accounting included in unrealized derivative (gain) loss	11,209	(4,123)	(8,087)
Non-qualifying derivative contracts included in unrealized derivative gain (loss)	-	(1,335)	993
Interest rate derivative contract settlements	(1,017)	226	(550)
Total recognized gain (loss) on derivative instruments	$ (90,904)	$ 19,252	$ 20,532

Oil and Gas Commodity Hedges

To mitigate a portion of the potential exposure to adverse market changes, the Company has entered into various derivative contracts. The Company's derivative contracts in place include swap and collar arrangements for the sale of oil, natural gas, and natural gas liquids. As of December 31, 2008, the Company has hedge contracts in place through 2011 for a total of approximately 8 million Bbls of anticipated crude oil production, 54 million MMBtu of anticipated natural gas production, and 1 million Bbls of anticipated natural gas liquids production.

The Company attempts to qualify its oil and gas derivative instruments as cash flow hedges for accounting purposes under SFAS No. 133 and related pronouncements. The Company formally documents all relationships between the derivative instruments and the hedged production, as well as the Company's risk management objective and strategy for the particular derivative contracts. This process includes linking all

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derivatives that are designated as cash flow hedges to the specific forecasted sale of oil or gas at its physical location. The Company also formally assesses (both at the derivative's inception and on an ongoing basis) whether the derivatives being utilized have been highly effective in offsetting changes in the cash flows of hedged production and whether those derivatives may be expected to remain highly effective in future periods. If it is determined that a derivative has ceased to be highly effective as a hedge, the Company will discontinue hedge accounting prospectively. If hedge accounting is discontinued and the derivative remains outstanding, the Company will recognize all subsequent changes in its fair value on the Company's consolidated statements of operations for the period in which the change occurs. As of December 31, 2008, all oil and natural gas derivative instruments qualified as cash flow hedges for accounting purposes. The Company anticipates that all forecasted transactions will occur by the end of their originally specified periods. All contracts are entered into for other than trading purposes.

The Company's oil and gas hedges are measured at fair value and are included in the accompanying consolidated balance sheets as assets and liabilities. The Company derives internal valuation estimates taking into consideration the counterparties' credit ratings, the Company's credit rating, and the time value of money and then compares that to the counterparties' mark-to-market statements. The considered factors result in an estimated exit-price for each asset or liability under a market place participant's view. Management believes that this approach provides a reasonable, non-biased, verifiable, and consistent methodology for valuing derivative instruments. The derivative instruments utilized by the Company are not considered by management to be complex, structured, or illiquid. The oil and gas derivative markets are highly active. The fair value of oil and natural gas derivative contracts designated and qualifying as cash flow hedges under SFAS No. 133 was a net asset of $105.3 million at December 31, 2008.

The Company recognized a net loss of $90.9 million, a net gain of $19.3 million, and a net gain of $20.5 million from its oil and natural gas and interest rate derivative contracts for the years ended December 31, 2008, 2007, and 2006, respectively.

After-tax changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributed to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings upon the sale of the hedged production. As of December 31, 2008, the amount of unrealized gain net of deferred income taxes to be reclassified from accumulated other comprehensive income to oil and gas production operating revenues in the next twelve months was $64.5 million.

Any change in fair value resulting from ineffectiveness is recognized currently in unrealized derivative (gain) loss in the accompanying consolidated statements of operations. Unrealized derivative (gain) loss for the years ended December 31, 2008, 2007, and 2006, includes a net gain of $11.2 million, a net loss of $4.1 million, and a net loss of $8.1 million, respectively, from ineffectiveness related to oil and natural gas derivative contracts.

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

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

Interest Rate Derivative Contracts

In September 2007, the Company entered into a one year floating-to-fixed interest rate derivative contract for a notional amount of $75 million. Under the agreement, the Company paid a fixed rate of 4.90 percent and received a variable rate based on the one-month LIBOR rates. The interest rate derivative contract was measured at fair value using quoted prices in active markets. The interest rate swap was a straightforward, non-complex, non-structured instrument that was highly liquid. This derivative qualified for cash flow hedge treatment under

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SFAS No. 133 and related pronouncements. The Company recorded a net derivative loss of $1.0 million in the accompanying consolidated statements of operations for the year ended December 31, 2008, related to this interest rate derivative contract. This contract was settled in the third quarter of 2008.

Convertible Note Derivative Instrument

In relation the Company's 5.75% Senior Convertible Notes converted in March 2007, the Company entered into fixed-to-floating interest rate swaps of $50 million of principal in October 2003. Due to the continued increases in interest rates, the Company entered into a floating-to-fixed interest rate swap in April 2005 through March 20, 2007, for this same notional amount of $50 million in order to effectively offset our fixed-to-floating interest rate swaps. The impact of this instrument, when combined with the other interest rate swaps, was that the Company fixed the net liability related to the interest rate swaps, and paid a 1.1 percent interest rate on $50 million of notional debt through March 2007.

The contingent interest provision of the 3.50% Senior Convertible Notes is a derivative instrument. However, the value of the derivative was determined to be deminimis at the inception of the instrument.

Note 11 – Fair Value Measurements

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

- Level 1 – Quoted prices in active markets for identical assets or liabilities
- Level 2 – Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable
- Level 3 – Significant inputs to the valuation model are unobservable

The following is a listing of the Company's assets and liabilities required to be measured at fair value on a recurring basis and where they are classified within the hierarchy as of December 31, 2008:

	Level 1	Level 2	Level 3
		(In thousands)	
Assets:			
Accrued derivative	$ -	$ 133,190	$ -
Liabilities:			
Accrued derivative	$ -	$ 27,920	$ -
Net Profits Plan	$ -	$ -	$ 177,366

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

Derivatives

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

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

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

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

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

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

Net Profits Plan

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

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

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

As noted above, the calculation of the estimated liability for the Net Profits Plan is highly sensitive to price estimates and discount rate assumptions. For example, if the commodity prices used in the calculation changed by five percent, the liability recorded at December 31, 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. Actual cash payments to be made to participants in future periods are dependent on realized actual production, prices, and costs associated with the properties in each individual pool of the Net Profits Plan. Consequently, actual cash payments are inherently different from the amounts estimated.

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

	For the Years Ended December 31,		
	2008	2007	2006
	(In thousands)		
Beginning balance	$ 211,406	$ 160,583	$ 136,824
Net increase in liability (a)	17,421	82,734	49,900
Net settlements (a) (b)	(51,461)	(31,911)	(26,141)
Transfers in (out) of Level 3	-	-	-

Ending balance	$	177,366	$	211,406	$	160,583

(a) Net changes in the Net Profits Plan liability are shown in the Change in Net Profits Plan liability line item of the accompanying consolidated statements of operations.

(b) Settlements represent cash payments made or accrued for under the Net Profits Plan.

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In February 2007 the FASB issued SFAS No. 159, which allows entities to choose, at specified election dates, to use fair value to measure eligible financial assets and liabilities that are not otherwise required to be measured at fair value. SFAS No. 159 was effective for the Company on January 1, 2008, at which point the Company elected not to implement the fair value option.

Refer to Note 10 – Derivative Financial Instruments, and Note 7 – Compensation Plans, for more information regarding the Company's hedging instruments and the Net Profits Plan, respectively. Additionally, refer to Note 5 – Long-term Debt for the disclosure of the December 31, 2008, fair value of the 3.50% Senior Convertible Notes Due 2027.

Note 12 – Repurchase and Retirement of Common Stock

Stock Repurchase Program

In July 2006 the Company's Board of Directors approved an increase of 5,473,182 shares to the remaining authorized number of shares that can be repurchased under the Company's original authorization approved in August 1998, for a total number of shares to be repurchased under the plan of 6 million. As of the date of this filing, the Company has Board authorization to repurchase up to 3,072,184 shares of common stock. The shares may be repurchased from time to time in open market transactions or in privately negotiated transactions, subject to market conditions and other factors, including certain provisions of St. Mary's existing credit facility agreement and compliance with securities law. Stock repurchases may be funded with existing cash balances, internal cash flow, and borrowings under the credit facility. The details for shares repurchased and retired are summarized as follows:

	For the Years Ended December 31,		
	2008	2007	2006
Number of shares repurchased	2,135,600	792,216	3,319,300
Total purchase price, including commissions	$ 77,149,451	$ 25,956,847	$ 123,106,775
Weighted-average price, including commissions	$ 36.13	$ 32.76	$ 37.09
Number of shares retired	2,945,212	-	3,275,689
Remaining shares authorized to be repurchased	3,072,184	5,207,784	6,000,000

Note 13 – Insurance Settlement

In April 2007 the Company reached a global insurance settlement for reimbursement of damages sustained during Hurricane Rita in 2005. St. Mary's net cash received in the final settlement was approximately $33 million. As a result of this settlement, the Company recorded a gain of $5.2 million in other revenue in the accompanying consolidated statements of operations for the year ended December 31, 2007. The Company experienced significant weather-related and other delays in its retirement efforts and consequently incurred additional retirement costs for the offshore platform. For the year ended December 31, 2008, the Company has recorded a gain of $2.9 million associated with the insurance settlement, which is included in other revenue on the Company's consolidated statements of operations. The Company's retirement efforts are complete as of December 31, 2008.

Note 14 – SemGroup Bankruptcy

On July 22, 2008, SemGroup, L.P. and certain of its North American subsidiaries (collectively referred to herein as "SemGroup") filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code in the

United States Bankruptcy Court for the District of Delaware. Certain SemGroup entities purchase a portion of the Company's crude oil production. As a result of the SemGroup bankruptcy filing the Company recorded an allowance for doubtful accounts and bad debt expense of $16.6 million as of December 31, 2008. The Company believes that it has fully allowed for all potentially uncollectible amounts and believes that it has no remaining exposure resulting from this bankruptcy. In an effort to maximize its recovery, the Company has filed the appropriate pleadings and is participating in certain adversary proceedings in the SemGroup bankruptcy case to establish the Company's secured and priority claims. The matter does not have a material adverse effect on the Company's liquidity or overall financial position.

Note 15 – Hurricanes Gustav and Ike

During the third quarter of 2008, assets in which the Company has an interest were impacted by Hurricanes Gustav and Ike. The Company incurred damage to two wells and to its production facilities located at Goat Island in Galveston Bay and minor damages to several other properties. The Vermilion 281 production platform was lost in Hurricane Ike.

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

Note 16 – Oil and Gas Activities

Costs Incurred in Oil and Gas Producing Activities

Costs incurred in oil and gas property acquisition, exploration and development activities, whether capitalized or expensed, are summarized as follows:

	For the Years Ended December 31,		
	2008	2007	2006
	(In thousands)		
Development costs (1)	$ 586,579	$ 591,013	$ 367,546
Exploration costs	92,199	111,470	126,220
Acquisitions			
Proved properties	51,567	161,665	238,400
Unproved properties – acquisitions of proved properties (2)	43,274	23,495	44,472
Unproved properties - other	83,078	38,436	28,816
Total, including asset retirement obligation (3)	$ 856,697	$ 926,079	$ 805,454

(1) Includes capitalized interest of $3.7 million, $5.4 million, and $3.5 million in 2008, 2007, and 2006, respectively.
(2) Represents a portion of the allocated purchase price of unproved properties acquired as part of the acquisition of proved properties. Refer to Note 3 – Acquisitions, Divestitures, and Assets Held for Sale in Part IV, Item 15 of this report for additional information.
(3) Includes amounts relating to estimated asset retirement obligations of $15.4 million, $27.6 million, and $7.8 million in 2008, 2007, and 2006, respectively.

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Suspended Well Costs

The following table reflects the net changes in capitalized exploratory well costs during 2008, 2007, and 2006. The table does not include amounts that were capitalized and either subsequently expensed or reclassified to producing well costs in the same period:

	For the Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Beginning balance on January 1,	$ 42,930	$ 22,799	$ 7,994
Additions to capitalized exploratory well costs pending the determination of proved reserves	9,437	29,551	17,693
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	(36,842)	(9,237)	(2,888)
Capitalized exploratory well costs charged to expense	(6,088)	(183)	-
Ending balance at December 31,	$ 9,437	$ 42,930	$ 22,799

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

	For the Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Exploratory well costs capitalized for one year or less	$ 9,437	$ 29,368	$ 17,958
Exploratory well costs capitalized for more than one year	-	13,562	4,841
Ending balance at December 31,	$ 9,437	$ 42,930	$ 22,799
Number of projects with exploratory well costs that have been capitalized more than a year	-	3	1

Note 17 – Disclosures about Oil and Gas Producing Activities (Unaudited)

Oil and Gas Reserve Quantities

For all years presented, Netherland, Sewell and Associates, Inc ("NSAI") prepared the reserve information for the Company's coalbed methane projects at Hanging Woman Basin in the northern Powder River Basin as well as the Company's non-operated coalbed methane interests in the Green River Basin. The Company engaged Ryder Scott Company, L.P. to review internal engineering estimates for 80 percent of the PV-10 value of its proved conventional oil and gas reserves in 2008, 2007 and 2006. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

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

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

	For the Years Ended December 31,					
	2008		2007		2006	
	Oil or Condensate (MBbl)	Gas (MMcf)	Oil or Condensate (MBbl)	Gas (MMcf)	Oil or Condensate (MBbl)	Gas (MMcf)
Developed and undeveloped						
Beginning of year	78,847	613,450	74,195	482,475	62,903	417,075
Revisions of previous estimate(a)	(22,667)	(108,163)	5,238	9,489	524	10,946
Discoveries and extensions	677	41,077	1,166	28,483	857	36,723
Infill reserves in an existing proved field	5,424	92,389	4,592	69,090	4,131	49,107
Purchases of minerals in place	356	26,956	567	91,374	11,857	28,030
Sales of reserves	(4,659)	(33,433)	(4)	(1,400)	(20)	(2,958)
Production	(6,615)	(74,910)	(6,907)	(66,061)	(6,057)	(56,448)
End of year (b)	51,363	557,366	78,847	613,450	74,195	482,475
Proved developed reserves						
Beginning of year	68,277	426,627	61,519	358,477	55,971	313,125
End of year	47,106	433,210	68,277	426,627	61,519	358,477

(a) For the year ended December 31, 2008, of the 244.2 BCFE downward revision of previous estimate 199.7 BCFE and 44.5 BCFE relate to price and performance revisions, respectively. For the year ended December 31, 2007, of the 40.9 BCFE upward revision of previous estimate 34.5 BCFE and 6.4 BCFE relate to price and performance revisions, respectively. For the year ended December 31, 2006, of the 14.1 BCFE upward revision of previous estimate (52.2) BCFE and 66.3 BCFE relate to price and performance revisions, respectively.

(b) For the years ended December 31, 2008, 2007, and 2006 amounts included approximately 659, 316, and 523 MMcf respectively, representing the Company's net underproduced gas balancing position.

Standardized Measure of Discounted Future Net Cash Flows

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

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

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

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

	2008	2007	2006
Gas (per Mcf)	$ 4.88	$ 7.56	$ 5.54
Oil (per Bbl)	$ 33.91	$ 88.71	$ 53.65

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

	As of December 31,		
	2008	2007	2006
	(In thousands)		
Future cash inflows	$ 4,463,894	$ 11,629,679	$ 6,653,455
Future production costs	(1,866,821)	(3,672,857)	(2,283,452)
Future development costs	(393,620)	(611,288)	(429,303)
Future income taxes	(419,544)	(2,316,637)	(1,125,955)
Future net cash flows	1,783,909	5,028,897	2,814,745
10 percent annual discount	(724,840)	(2,321,983)	(1,238,308)
Standardized measure of discounted future net cash flows	$ 1,059,069	$ 2,706,914	$ 1,576,437

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

	For the Years Ended December 31,		
	2008	2007	2006
	(In thousands)		
Standard measure, beginning of year	$ 2,706,914	$ 1,576,436	$ 1,712,298
Sales of oil and gas produced, net of production costs	(988,045)	(693,885)	(554,147)
Net changes in prices and production costs	(2,033,674)	1,320,994	(661,074)
Extensions, discoveries and other including infill reserves in an existing proved field, net of production costs	288,162	462,952	280,822
Purchase of minerals in place	33,215	265,285	263,762
Development costs incurred during the year	105,031	123,630	67,864
Changes in estimated future development costs	213,554	(32,566)	114,007
Revisions of previous quantity estimates	(363,908)	166,428	34,940

Accretion of discount		386,118		215,745		249,417
Sales of reserves in place		(198,514)		(1,915)		(8,991)
Net change in income taxes		947,955		(573,259)		200,858
Changes in timing and other		(37,739)		(122,931)		(123,319)
Standardized measure, end of year	$	1,059,069	$	2,706,914	$	1,576,437

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Note 18 – Quarterly Financial Information (Unaudited)

The Company's quarterly financial information for fiscal 2008 and 2007 is as follows (in thousands, except per share amounts):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year Ended December 31, 2008				
Total operating revenues	$ 362,102	$ 356,942	$ 324,088	$ 258,169
Total operating expenses	204,762	298,691	179,762	446,885
Income (loss) from operations	$ 157,340	$ 58,251	$ 144,326	$ (188,716)
Income (loss) before income taxes	$ 152,466	$ 52,782	$ 139,206	$ (193,043)
Net income (loss)	$ 95,996	$ 33,550	$ 88,047	$ (126,040)
Basic net income (loss) per common share	$ 1.53	$ 0.54	$ 1.42	$ (2.03)
Diluted net income (loss) per common share	$ 1.50	$ 0.53	$ 1.40	$ (2.01)
Dividends declared per common share	$ 0.05	$ -	$ 0.05	$ -
Year Ended December 31, 2007				
Total operating revenues	$ 221,006	$ 247,154	$ 246,687	$ 275,247
Total operating expenses	151,494	149,171	151,336	218,682
Income from operations	$ 69,512	$ 97,983	$ 95,351	$ 56,565
Income before income taxes	$ 63,562	$ 94,387	$ 91,624	$ 50,689
Net income	$ 39,950	$ 59,235	$ 57,653	$ 32,874
Basic net income per common share	$ 0.70	$ 0.93	$ 0.91	$ 0.52
Diluted net income per common share	$ 0.63	$ 0.91	$ 0.89	$ 0.51
Dividends declared per common share	$ 0.05	$ -	$ 0.05	$ -

SIGNATURES

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

ST. MARY LAND & EXPLORATION COMPANY
(Registrant)

Date: February 23, 2009	By:	/s/ ANTHONY J. BEST Anthony J. Best President, Chief Executive Officer, and Director

GENERAL POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints each of Anthony J. Best and A. Wade Pursell his or her true and lawful attorney-in-fact and agent with full power of substitution and resubstitution, and each with full power to act alone, for the undersigned and in his or her name, place and stead, in any and all capacities, to sign any amendments to this Annual Report on Form 10-K for the fiscal year ended December 31, 2008, and to file the same, with exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, hereby ratifying and confirming all that each of said attorney-in-fact, or his substitute or substitutes, may do or cause to be done by virtue hereof.

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

Signature	Title	Date
/s/ ANTHONY J. BEST Anthony J. Best	President, Chief Executive Officer, and Director	February 23, 2009
/s/ A. WADE PURSELL A. Wade Pursell	Executive Vice President and Chief Financial Officer	February 23, 2009
/s/ MARK T. SOLOMON Mark T. Solomon	Controller	February 23, 2009

Signature	Title	Date
/s/ MARK A. HELLERSTEIN Mark A. Hellerstein	Chairman of the Board of Directors	February 23, 2009
/s/ BARBARA M. BAUMANN Barbara M. Baumann	Director	February 23, 2009
/s/ LARRY W. BICKLE Larry W. Bickle	Director	February 23, 2009
/s/ WILLIAM J. GARDINER William J. Gardiner	Director	February 23, 2009
/s/ JULIO M. QUINTANA Julio M. Quintana	Director	February 23, 2009
/s/ JOHN M. SEIDL John. M. Seidl	Director	February 23, 2009
/s/ WILLIAM D. SULLIVAN William D. Sullivan	Director	February 23, 2009