1908 – 2008

ST. MARY LAND & EXPLORATION COMPANY

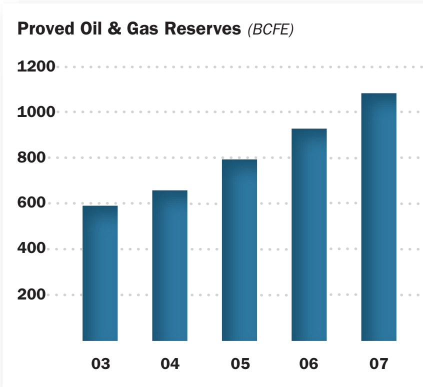
ENERGIZED FOR 100 Years

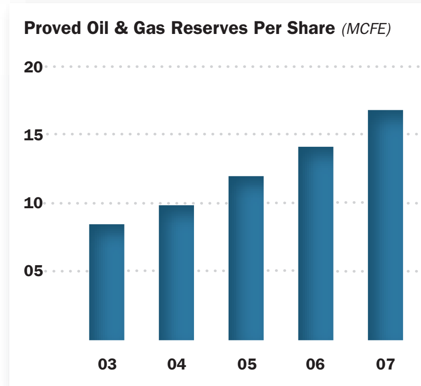
...and moving forward

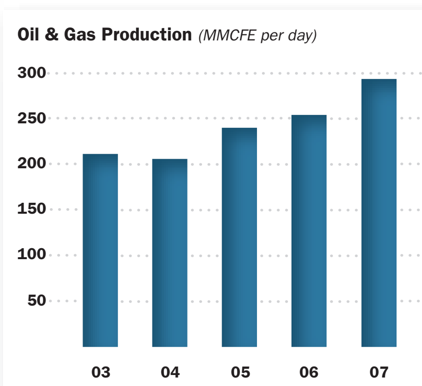
ANNUAL REPORT 2007

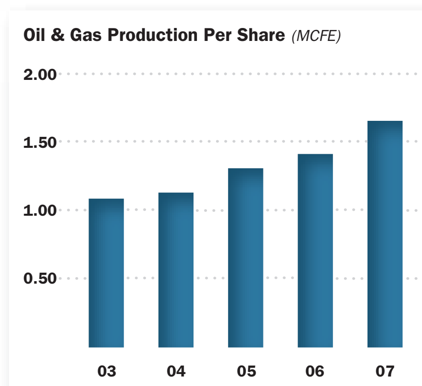
Our Mission

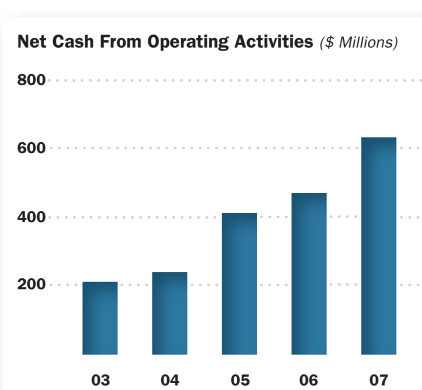
To deliver top tier stock
price performance
to our investors
through growth
of Net Asset Value per share.

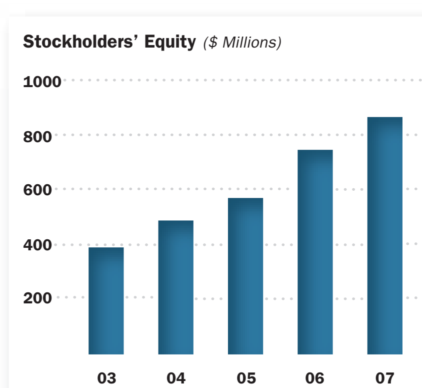

Proved Oil & Gas Reserves (BCFE)
1200
1000
800
600
400
200
03
04
05
06
07


Proved Oil & Gas Reserves Per Share (MCFE)
20
15
10
05
03
04
05
06
07


Oil & Gas Production (MMCFE per day)
300
250
200
150
100
50
03
04
05
06
07


Oil & Gas Production Per Share (MCFE)
2.00
1.50
1.00
0.50
03
04
05
06
07


Net Cash From Operating Activities ($ Millions)
800
600
400
200
03
04
05
06
07


Stockholders' Equity ($ Millions)
1000
800
600
400
200
03
04
05
06
07

FinancialHighlights

	2007	2006	2005	2004	2003
In thousands except production, proved reserves, price data, and per share amounts, as adjusted for 2 for 1 split on March 31, 2005					
Income Statement Data					
Oil and gas production revenues	**$ 936,577**	$ 758,913	$ 711,005	$ 413,318	$ 365,114
Gains on sales and other	**53,517**	28,788	28,585	19,781	28,594
Total operating revenues	**$ 990,094**	$ 787,701	$ 739,590	$ 433,099	$ 393,708
Net income	**$ 189,712**	$ 190,015	$ 151,936	$ 92,479	$ 95,575
Diluted earnings per share	**$ 2.94**	$ 2.94	$ 2.33	$ 1.44	$ 1.40
Cash dividends declared and paid per share	**$ 0.10**	$ 0.10	$ 0.10	$ 0.05	$ 0.05
Diluted weighted average common shares outstanding	**64,850**	65,962	66,894	66,894	71,069
Balance Sheet Data					
Working capital	**$ (92,604)**	$ 22,870	$ 4,937	$ 12,035	$ 3,101
Total assets	**2,571,680**	1,899,097	1,268,747	945,460	735,854
Long-term debt	**572,500**	433,980	99,885	136,791	110,696
Stockholders' equity	**863,345**	743,374	569,320	484,455	390,653
Average Net Daily Production					
Gas (MMcf)	**181.0**	154.7	141.9	127.3	136.1
Oil (MBbl)	**18.9**	16.6	16.2	13.1	12.4
MMCFE (6:1)	**294.5**	254.2	239.4	206.0	210.7
Average Realized Sales Price					
Gas (per Mcf)	**$ 7.63**	$ 7.37	$ 7.90	$ 5.52	$ 4.89
Oil (per Bbl)	**$ 62.60**	$ 56.60	$ 50.93	$ 32.53	$ 26.96
Proved Reserves					
Gas (Bcf)	**613.5**	482.5	417.1	319.2	307.0
Oil (MMBbl)	**78.8**	74.2	62.9	56.6	47.8
BCFE (6:1)	**1,086.5**	927.6	794.5	658.6	593.7

Letter To Stockholders

The theme to last year's 2006 annual report was "Transitions." In that report we described the various transitions St. Mary has made over its 100 year history — from passive oil and gas royalty owner to a fully functioning multi-billion dollar exploration and production company. In 2007, the "Transitions" theme continued. I was named CEO early in the year when Mark Hellerstein retired after leading the Company for 15 years. We continued the transition of our asset base toward more concentrated asset groups comprised of low risk, repeatable resource plays. One way we did this was with two acquisitions in South Texas targeting the Olmos shallow gas formation. Another way was our initiation of a marketed divestiture package of non-core assets during the year. This sale closed in January of 2008 for $131 million. Management also continued to transition during 2007 as we saw new leaders appointed to head four of our five regional offices.

This brings us to the theme of this year's annual report: "Energized for 100 years… ***and moving forward.*****" In early 2008, we celebrate our 100th anniversary. This is a tremendous accomplishment for any business, particularly in an industry that sees as much consolidation as the exploration and production industry. Our longevity is proof that St. Mary has been successful at delivering value to its owners for a very long period of time. We plan to celebrate this anniversary with gatherings at each of our offices early in the year, capped off with a special event at the New York Stock Exchange where we will ring the closing bell. Our 100 years of success has been achieved with a focus on creating value for our stockholders. We intend to continue this tradition.**

2007 Performance and Highlights

The Company's operational and financial highlights for 2007 include the following:

- ***Proved reserves grew 17% year over year to 1,087 BCFE, which is a record for the Company both in absolute terms and on a per share basis.***
- ***Record average daily production of 294.5 MMCFE per day, up 16% year over year. This was a record on a per diluted share basis as well.***
- ***Record net cash provided by operating activities of $630.8 million, up 35% year over year.***
- ***Net income of $189.7 million and diluted earnings per share of $2.94 per share.***
- ***All-in reserve replacement percentage of 248%, an improvement from 244% in the prior year.***
- ***All-in finding costs of $3.48 per MCFE, down from $3.56 per MCFE in 2006.***

These 2007 results were driven by an active acquisition and capital development plan whereby St. Mary invested $926 million in acquisition, development, and leasing activities. The Company deployed $741 million on exploration and development projects during the year, which was an increase from the $523 million spent in 2006. Highlights of our 2007 regional programs include the following:

MID-CONTINENT — In 2007, we invested $186 million in the Mid-Continent region on exploration, development, and acquisition activities. Throughout 2007, we maintained a consistent level of activity in the Arkoma Basin in order to advance our horizontal Woodford shale program where we continued to refine our understanding of the play. Our results for this program were significantly better in the second half of the year as we gained experience in the overall completion and design methodology for these wells together with an increased understanding of the underlying geology, all of which translated into enhanced performance. We decreased our activity in the Atoka/Granite Wash development program while working to develop and implement a more cost efficient completion design for these wells. Several exploration wells were also drilled by this regional office in 2007. The most exciting of these tested deeper sections of the Anadarko Basin, which we believe validated a geologic idea that we plan to test further in 2008.

ARKLATEX — The ArkLaTex region invested $150 million in 2007. This is 70% more than the $88 million spent in 2006. The primary drivers of this increase in capital investment were increased activity levels in our James Lime and Cotton Valley programs. In the St. Mary operated horizontal James Lime program, we operated one rig continuously throughout 2007. We continued to see solid results in proven development areas and had two successful test wells during the year that extended the play westward by a number of miles. We believe that we have identified a trend that is roughly 75 miles in length that could be prospective for the James Lime. During 2007, we increased our acreage position along that trend to approximately 50,000 net acres. Our team in Shreveport has been successfully drilling and completing horizontal James Lime wells for a number of years, and we believe we are one of the better operators in the play. The partner operated Cotton Valley programs at Elm Grove and Terryville fields were areas of significant investment in 2007. At Elm Grove Field, advancements such as 20-acre increased density drilling and

In 2007, the Company's proved reserves exceeded 1,000 BCFE, or 1 TCFE, marking a major milestone in our history.

1 TCFE

1,000,000,000,000

commingling of production from the Cotton Valley and Hosston formations have benefited us, particularly as development has moved into areas where we have larger working interests. There is an old adage in the exploration and production business that "good fields get better"—this is certainly the case with Elm Grove. At Terryville Field, despite more difficult operating conditions resulting from the Cotton Valley formation being deeper and more highly pressured compared to Elm Grove Field, operations there were highly successful in 2007 and allowed for sustained activity during the year.

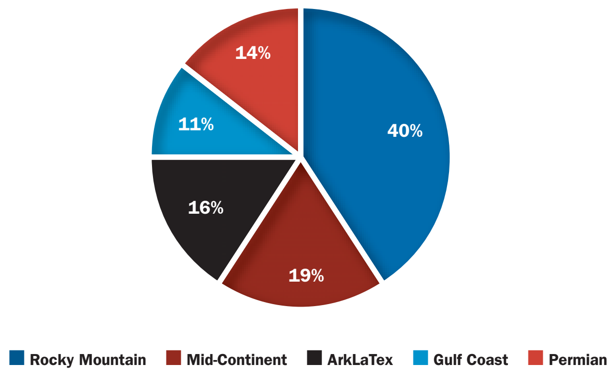
GULF COAST—Our capital expenditures in the Gulf Coast region grew significantly from $66 million in 2006 to $279 million in 2007, primarily driven by two significant acquisitions totaling $179 million. These were the $149 million Rockford acquisition that closed in October 2007 and the $30 million Catarina acquisition, which closed in April 2007. Both of these target the Olmos shallow gas formation and are located in the greater Maverick Basin in South Texas. St. Mary had been interested in the Olmos formation for some time, and we are pleased that we were able to enter the play in a meaningful way in 2007. We are the operator of these recently acquired assets and our emphasis in 2007 was the integration of these properties into our operations. While the core focus of the region shifted toward onshore projects, we continued to be active offshore in 2007. The previously discovered Zloty intermediate deepwater project began production late in the year, and other intermediate deepwater projects in which we are a partner continued to advance. We were also active closer to shore with a program that included the successful Reno, Clement, and Amber Jack wells. We have benefited from the meaningful production associated with some of these longer lead time projects.

PERMIAN — St. Mary began 2007 with no regional office in the Permian Basin. That changed in February when we opened a regional office in Midland, Texas to manage the Sweetie Peck properties acquired in December 2006. Throughout 2007, we continued to build our Midland staff and as of the date of this letter we are now fully staffed in this regional office. During 2007, this region invested $135 million. The majority of this investment was deployed to develop projects that target the Wolfcamp and Spraberry formations, commonly referred to as the "Wolfberry." We participated in two substantial Wolfberry programs during the year — the operated Sweetie Peck program and the outside operated program at Halff East. We operated between two and five drilling rigs at Sweetie Peck throughout 2007. Our efforts in the Sweetie Peck program have focused on improving our operating efficiencies. Throughout 2007, we significantly improved our rig fleet and transitioned the drilling operations in-house once the Midland office was fully staffed. We anticipate that these improvements will benefit our program here in the years to come. At Halff East, our operating partner had two drilling rigs running continuously throughout the year. During the year, we also invested capital in the Parkway and East Shugart Delaware waterflood projects.

ROCKY MOUNTAIN — In 2007, St. Mary invested $178 million in the Rocky Mountain region, compared to $161 million in 2006. The 2007 amount included $36 million of capital invested in the Hanging Woman Basin coalbed methane project. The 2007 conventional program focused on a horizontal development in the Mississippian formations of the Williston Basin and the drilling of Bakken formation infill locations in Montana.

2007 Proved Reserve Base by Region

1,087 BCFE • 56% Gas • 23% PUD



As a result of our active 2007 program, the Company reached a significant milestone in 2007 as its proved reserves surpassed 1 TCFE. As of December 31, 2007, St. Mary had proved reserves of 1,087 BCFE, of which 77% were proved developed and 56% were natural gas. This is a significant threshold for any independent E&P company since every day its assets are depleting as they are produced. The ability to economically grow reserves is critical for the ongoing success of any company in our industry. At St. Mary, our long-standing goal is to annually replace 200% of that year's production. In 2007, we met this goal by replacing 248% of our reserves produced in 2007 on an all sources basis. Our 3 year and 5 year average reserve replacement percentages were 249% and 235%, respectively. What is particularly important for stockholders is that St. Mary has consistently grown proved reserves on a per share basis while incurring moderate levels of debt. We replaced 88% of our 2007 produced reserves through acquisitions in 2007, which is in-line with our historic average for acquisition reserve replacement. Acquisitions have historically been a significant part of the St. Mary business plan, and we believe they will continue to play an important role in our future strategy.

Our 2007 all-in finding cost for proved reserves was $3.48 per MCFE, down from $3.56 per MCFE in 2006. We believe that it is important to look at longer time periods when analyzing this metric due to the differences in timing as to when capital is invested and when proved reserves are booked. Our 3 and 5 year averages for all-in finding costs on a per MCFE basis were $3.01 and $2.61, respectively. Finding costs in the industry have generally increased in recent years as costs to acquire or develop proved reserves have increased in correlation to commodity prices. Although finding costs only tell part of the story with respect to the economics of a company's investments, we realize that finding costs are an important metric used to evaluate and compare

Years

100

St. Mary has grown value for its owners for 100 years, and is focused on building value as it enters its second century.

the costs at which companies are adding reserves. Accordingly, we are very focused on reducing costs and making portfolio changes that will allow us to improve on this metric.

Production in 2007 set a new record for St. Mary, both in absolute terms and on a per share basis. Total production for the year was 107.5 BCFE, or an average daily rate of 294.5 MMCFE per day. For the full year, approximately 60% of the Company's production was natural gas and roughly 40% was oil. This record production combined with strong commodity prices during the year, particularly for oil, resulted in solid net income and cash flow from operating activities. Production growth in 2007 was driven primarily by strong contributions from the Permian, ArkLaTex, and Mid-Continent regions. The strong cash flows that we enjoyed during the year allowed us to maintain the strong balance sheet for which St. Mary is known.

Plans for 2008

We are entering 2008 on solid footing both financially and operationally. We have a business plan that we believe will deliver growth and value for our stockholders. Our debt-to-book capitalization ratio as of the end of 2007 was 40%. When adjusted for the proceeds received from the divestiture of non-core properties that closed on January 31, 2008, our pro forma debt-to-book capitalization ratio stands at 34%. Currently, we are generating strong cash flows. We enjoy the benefits of having oil as a significant portion of our production profile. Opportunistic natural gas hedges have helped our realized natural gas revenues stay strong. Operationally, 2008 offers the strongest inventory of projects that we have had since I joined St. Mary in 2006. We have a multi-year drilling program in nearly every region that when taken together make clearly visible the Company's path for continued growth. The foundation of our property base was strengthened by

the divestiture of non-core assets referred to earlier — not only have we removed lower growth properties from our portfolio, but now our employees can focus more of their efforts on the assets that offer more upside potential for the Company.

Our initial 2008 exploration and development budget is $626 million. We believe that this budget level will improve the capital efficiency of our investments and enhance the strength of our balance sheet to maintain financial flexibility in the future. This budget level also provides solid organic production growth for the Company. Programs that failed to meet our return criteria in 2007 were either omitted or substantially reduced if they warranted further study. Accordingly, we anticipate operating cash flows will exceed our drilling capital budget during the year. This will provide us the financial flexibility to accelerate successful drilling programs, pursue potential acquisition opportunities, consider repurchases of outstanding shares of common stock, or repay bank borrowings with excess cash flows. Highlights of the Company's 2008 exploration and development plan are as follows:

ARKLATEX — The largest regional capital program in 2008 will be in the ArkLaTex region, which will focus on Cotton Valley and James Lime programs. Of the capital allocated for Cotton Valley programs in 2008, a little over half will be invested at Elm Grove Field in northern Louisiana where development continues to be highly successful. Further development of the field on 20-acre spacing and highly economic uphole recompletions continue to drive activity in this play, which becomes more meaningful to St. Mary as activity moves onto acreage where we have a larger working interest. A successful horizontal Cotton Valley well completed at the end of 2007 has raised the prospect that the field could be further developed with horizontal wells. Our operating partner is currently drilling an offset to the initial horizontal test which, if successful, could

20%

St. Mary has provided a compound return of 20% to stockholders since its IPO in 1992.

substantiate a horizontal development plan at Elm Grove Field. The remaining Cotton Valley allocation for 2008 will be split between the program at Terryville Field and the St. Mary operated program in East Texas. Subsequent to year end, St. Mary acquired additional producing and non-producing properties in Panola County, Texas, which are adjacent to existing St. Mary leasehold. These assets target the Cotton Valley formation, a formation in which we are increasingly interested. As operator, we plan to drill several horizontal and vertical wells in the area in 2008. We believe that our experience in the region, particularly in drilling horizontal James Lime wells, will be an advantage that we can exploit as we pursue a more active operated Cotton Valley program in the future. In the operated horizontal James Lime program, we plan to have a more aggressive program in 2008 with two operated rigs budgeted to run continuously throughout the year. We continue to be active acquirers of leasehold in the play. We have been involved with this program for a number of years and believe we are a leader in the play.

MID-CONTINENT — The largest component of our 2008 Mid-Continent plan is the horizontal Woodford shale program in the Arkoma Basin. Our budget anticipates that we will drill ten horizontal Woodford wells with two operated rigs in the first half of 2008, and continue to participate with our partners in outside operated wells. As I mentioned earlier, we have seen results improve recently in the horizontal Woodford program. With continued success in the play, we have the ability to increase our capital investment in the program in the second half of 2008. We also plan to continue with an exploration program in the Anadarko Basin that yielded encouraging results in 2007. This exploration program targets some of the deeper formations of the basin. In our Western Oklahoma Washes program in the Anadarko Basin, previously referred to as the Mayfield development area, we plan to invest capital in wells that target the Atoka and Granite Wash formations.

The area is a known hydrocarbon province. Our development efforts in 2008 will feature enhanced geotechnical efforts and revised drilling and completion techniques, both of which should improve the economic performance of this program.

GULF COAST — Our development and exploration budget in the Gulf Coast region for 2008 is focused on the evaluation and exploitation of the two Olmos shallow gas projects that we acquired in South Texas during 2007. Our technical team in Houston is in the process of reinterpreting seismic data that covers a large portion of our acreage. Approximately half of the budgeted capital will be deployed to drill new Olmos wells, with additional capital being invested in a number of recompletion opportunities. We anticipate that the addition of this resource play will provide focus and a visible inventory of projects for our Gulf Coast team. We will also invest capital in production facilities for an intermediate deepwater discovery from 2005 that is expected to be brought online in early 2009.

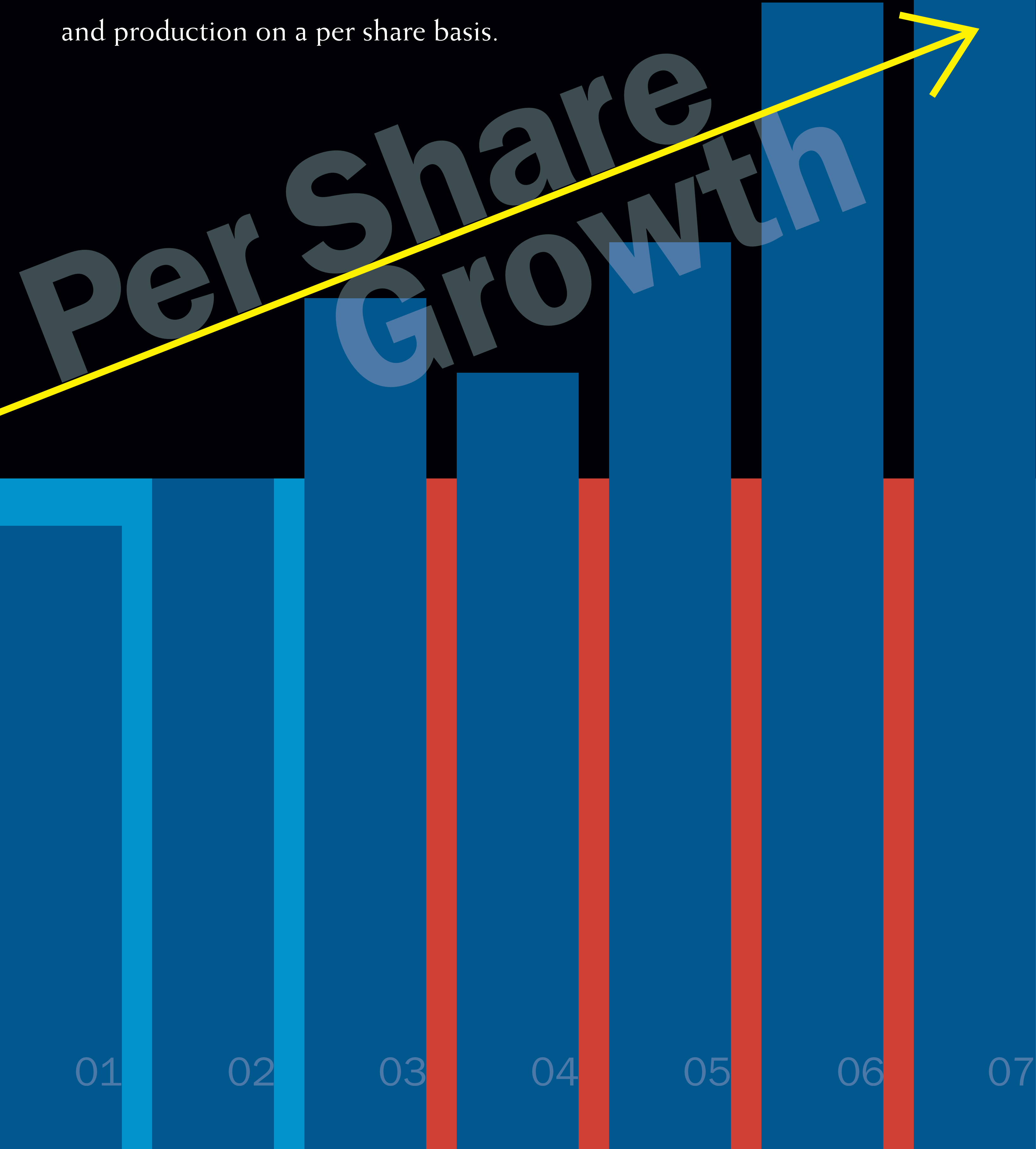
PERMIAN — The majority of capital investment made in the Permian in 2008 will be in properties targeting the Wolfberry interval. At Sweetie Peck, we plan to operate three drilling rigs continuously throughout the year. Included in the budget are investment dollars to test several 40-acre pilot areas that could add meaningful proved reserves if successful. We expect to see increased operating efficiency on the investments we made in 2007 related to high-grading our rig fleet and bringing the drilling operations in-house. At the Halff East Wolfberry development area, we will continue to invest with our operating partner. We will also be investing in several smaller programs, including our Delaware waterfloods.

ROCKY MOUNTAIN — The 2008 plan for the Rockies is smaller than in years past. In the conventional Rockies program, six vertical wells and two recompletions in the Red River are planned for 2008. We also plan to drill a small number of horizontal Bakken wells in and around our historic Bakken development areas in Montana. We expect to participate in a handful of wells in the North Dakota Bakken play that has received so much attention in the past year. Our plan also includes workover and recompletion operations in our Wind River Basin and Big Horn Basin oil properties. At the outside operated Atlantic Rim coalbed methane play in the Green River Basin, we expect to see activity ramp up since regulatory and environmental delays appear to have been resolved. At Hanging Woman Basin, we plan to moderate our drilling activity in 2008 focusing on completing the in-fill program in the shallow coals, monitoring the intermediate depth wells, and testing several horizontal completion techniques in the deeper coals. We plan to continue concentrating our property base in the Rocky Mountain region, and are conducting a thorough review of our Rockies acreage position. Divestitures of non-core assets are anticipated in the region in the future.

Moving Forward

As mentioned earlier, the theme of this year's annual report is "Energized for 100 years… *and moving forward*." As we move forward into our second century, we must embrace the challenge of adapting to new competitive and market realities. One challenge that St. Mary has worked to address over the past two years is the state of its drilling portfolio by actively working to increase its inventory of repeatable, multi-year drilling projects. These types of programs are advantageous because they allow for more predictable production and reserve growth, and have the potential for improved economics as operational efficiencies develop. Transactions such as the Sweetie

St. Mary has a consistent record of building value for stockholders by growing proved reserves and production on a per share basis.



Peck acquisition in 2006 and the Olmos acquisitions in 2007 have added to our inventory. The inventory has also grown through an increased emphasis on grassroots resource programs such as the horizontal James Lime and Woodford shale. As with any exploration and production company, we need to continue adding to our project portfolio. To that end, we have been busy in 2007 and early 2008 adding business development professionals in our Denver headquarters and in our regional offices. The goal is simple — build the team that will economically grow the project inventory for the Company. As we capture more of these high quality projects in our inventory pipeline, we will need more technical personnel to execute the development of those resources. Accordingly, we have hired and are continuing to actively hire engineers and geologists in all of our regional offices. As of this letter, our total number of employees is 438, an increase of roughly 80 employees from a year ago. This talented group will drive our long-term growth in value.

With the changes outlined above, there are also certain standards that will remain unchanged. Values such as integrity, reliability, and a sense of stewardship for our owners and our communities will always be prominent characteristics of St. Mary. We remain committed to being a preferred partner, employer, and customer in the industry. We believe that this foundation of values and the commitment of our employees will result in value creation for our stockholders.

March 10, 2008

Anthony J. Best

President and Chief Executive Officer

DIRECTORS

Barbara M. Baumann (1),(4)
Denver, Colorado
President
Cross Creek Energy Corporation

Anthony J. Best (1)
Denver, Colorado
President and Chief Executive Officer
St. Mary Land & Exploration Company

Larry W. Bickle (2),(4)
Houston, Texas
Private Investor

William J. Gardiner (1),(3)
Houston, Texas
Chief Financial Officer and Vice President
King Ranch Inc.

Mark A. Hellerstein (1)
Denver, Colorado
Chairman and
Former Chief Executive Officer
St. Mary Land & Exploration Company

Julio Quintana (3)
Houston, Texas
President and Chief Executive Officer
TESCO Corporation

John M. Seidl (2),(3)
Houston, Texas
Chairman
EnviroFuels, LLC

William D. Sullivan (2),(4)
The Woodlands, Texas
Former Executive Vice President,
Exploration and Production
Anadarko Petroleum Corporation

(1) Executive Committee
(2) Nominating and Corporate
Governance Committee
(3) Audit Committee
(4) Compensation Committee

OFFICERS

Anthony J. Best
President and Chief Executive Officer

Javan D. Ottoson
Executive Vice President and
Chief Operating Officer

Mark D. Mueller
Senior Vice President and
Regional Manager

Stephen C. Pugh
Senior Vice President and
Regional Manager

Paul M. Veatch
Senior Vice President and
Regional Manager

Jerry Hertzler
Vice President – Business Development

Gregory T. Leyendecker
Vice President and Regional Manager

Lehman E. Newton, III
Vice President and Regional Manager

Milam Randolph Pharo
Vice President – Land and Legal
and Assistant Secretary

Garry A. Wilkening
Vice President – Human Resources
and Administration

Mark T. Solomon
Controller

Linda A. Ditsworth
Assistant Vice President –
Land and Assistant Secretary

Michael F. Roach
Assistant Vice President –
Director of Taxation

David J. Whitcomb
Assistant Vice President –
Director of Marketing

Matthew J. Purchase
Treasurer and Budget & Planning Director

INFORMATION ABOUT FORWARD LOOKING STATEMENTS

This annual report contains forward looking statements within the meaning of securities laws, including forecasts and projections for future periods. The words “will,” “believe,” “anticipate,” “budget,” “intend,” “estimate,” “forecast,” “plan,” and “expect” and similar expressions are intended to identify forward looking statements. These statements involve known and unknown risks, which may cause St. Mary’s actual results to differ materially from results expressed or implied by the forward looking statements. These risks include such factors as discussed in the “Risk Factors” and “Cautionary Information about Forward Looking Statements” sections of the accompanying 2007 Annual Report on Form 10-K/A. Although St. Mary may from time to time voluntarily update its prior forward looking statements, it disclaims any commitment to do so except as required by securities laws.

GLOSSARY

Finding cost. Expressed in dollars per BOE or MCFE. Finding costs are 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 previous estimates during the same period.

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

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

FORM 10-K/A

☑ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2007
or
☐ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Commission file number 001-31539

ST. MARY LAND & EXPLORATION COMPANY

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

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

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

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

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

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

The aggregate market value of 62,317,450 shares of voting stock held by non-affiliates of the registrant, based upon the closing sale price of the common stock on June 29, 2007, the last business day of the registrant's most recently completed second fiscal quarter, of $36.62 per share as reported on the New York Stock Exchange was $2,282,065,019. Shares of common stock held by each director and executive officer and by each person who owns 10 percent or more of the outstanding common stock or who is otherwise believed by the Company to be in a control position have been excluded. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of February 15, 2008, the registrant had 63,020,524 shares of common stock outstanding, which is net of 1,009,712 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 2008 annual meeting of stockholders to be filed within 120 days after December 31, 2007.

EXPLANATORY NOTE:

This Amendment on Form 10-K/A to the Annual Report on Form 10-K for the fiscal year ended December 31, 2007, by St. Mary Land & Exploration Company (the "Company") is being filed to (i) include typed conformed signatures of Deloitte & Touche LLP in the Report of Independent Registered Public Accounting Firm appearing on page 72 and the Report of Independent Registered Public Accounting Firm appearing on page F-1 (collectively, the "Reports"), the corresponding manual signatures for which were obtained by the Company prior to the filing of the original Annual Report on Form 10-K (the "Original Form 10-K") on February 22, 2008, but the typed conformed signatures for which were inadvertently omitted from the electronic versions of the Reports filed with the Original Form 10-K, (ii) file a consent of Deloitte & Touche LLP which refers to the correct date of the Reports of February 21, 2008, and thereby corrects an inadvertent typographical error in the consent of Deloitte & Touche LLP filed with the Original Form 10-K, which consent incorrectly referred to the date of the Reports as February 20, 2008, and (iii) furnish a certification of the Company's Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 which refers to the correct title of the Company's Chief Financial Officer as Senior Vice President - Chief Financial Officer and Secretary and thereby corrects an inadvertent error in the corresponding certification furnished with the Original Form 10-K, which certification incorrectly referred to the title of the Company's Chief Financial Officer as Senior Vice President - Chief Financial Officer and Treasurer.

Pursuant to the rules of the Securities and Exchange Commission, Item 15 of the Original Form 10-K has been amended to contain currently dated certifications of the Company's Chief Executive Officer and Chief Financial Officer, as required by Sections 302 and 906 of the Sarbanes-Oxley Act of 2002.

All other information contained in the Original Form 10-K remains unchanged, and the entire report with all Items is included in this Form 10-K/A for the convenience of the reader. The Company has not updated the disclosures contained herein to reflect events that occurred after the date of the Original Form 10-K.

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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. We were founded in 1908 and incorporated in Delaware in 1915. Our initial public offering of common stock took place in December of 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 objective is to build stockholder value through consistent economic growth in reserves and production that increases net asset value per share. We seek to invest in oil and gas producing assets that result in a superior return on equity while preserving underlying capital, resulting in a return on equity to stockholders that reflects capital appreciation as well as the payment of cash dividends.

The majority of our current senior technical managers in each region possess between 20 and 30 years of industry experience and lead fully-staffed regional technical offices that are supported by centralized administration from our corporate office in Denver. We use our comprehensive base of geological, geophysical, land, engineering, and production experience in each of our core operating areas to source prospects for our ongoing low-to-medium-risk development and exploitation programs. We conduct detailed geologic studies and use an array of technologies and tools including 2-D and 3-D seismic imaging, hydraulic fracturing and other reservoir stimulation techniques, horizontal drilling, secondary recovery, and specialized logging tools to enhance the potential of our existing properties. We believe that having fully-staffed technical teams based in each of our operating regions is an advantage in that our regional offices are staffed with personnel that have a deep knowledge of the basins in which they work, participate in the regional deal flow and prefer to live in regional areas, which minimizes personnel attrition.

Acquisitions have been a key element of our business strategy. Historically, we have been most successful in acquiring properties on a negotiated basis, as opposed to participating in widely marketed auctions for properties. In the last two years we have made several large acquisitions. In 2007, we paid $178.9 million for two acquisitions in South Texas for properties targeting the Olmos shallow gas formation. In 2006, we paid $243.1 million to acquire assets that target the Wolfberry section in the Permian Basin.

We divest selected non-core assets when market conditions and prices are attractive. We will continue to evaluate such opportunities in the future when we believe it to be appropriate. During 2007, we sold properties with estimated proved reserves of 1.4 BCFE. We actively marketed and contracted to sell a package of non-core assets in 2007. This sale closed on January 31, 2008, for a total adjusted sales price of $131.1 million before commissions; this sale represented 40.4 BCFE of our year-end 2007 proved reserves. We utilized a 1031 reverse exchange structure to defer the recognition of income tax on the gain from this sale.

Conservative use of financial leverage has long been a critical element of our strategy. We believe that maintaining a strong balance sheet is a significant competitive advantage that enables us to pursue acquisitions and other opportunities, particularly in weaker price environments. It also provides us with the financial resources to weather periods of volatile commodity prices or escalating costs. Our debt to book capitalization ratio was 40 percent at the end of December 2007. The proceeds from the aforementioned property sale in January 2008 were applied to reducing bank borrowings.

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

Significant Developments in 2007

- *Increase in 2007 Year-End Reserves.* Proved reserves increased 17 percent to 1,086.5 BCFE at December 31, 2007, from 927.6 BCFE at December 31, 2006. We added 132.1 BCFE from our drilling program and 94.8 BCFE from acquisitions. We had a positive revision of 40.9 BCFE which consisted of a 6.4 BCFE upward performance revision and an upward revision of 34.5 BCFE due primarily to increased oil prices at the end of 2007. The 2007 acquisition volumes are lower than the initial estimates previously disclosed as a result of the final year-end reservoir engineering estimation. We sold properties with reserves of 1.4 BCFE in 2007.

- *Drilling Results.* Reserve additions from drilling activities of 132.1 BCFE were driven by results in the Mid-Continent, Rocky Mountain, ArkLaTex, and Permian regions, with those regions contributing 37 percent, 21 percent, 20 percent, and 18 percent, respectively. Additions in the Mid-Continent were driven principally by successful drilling by us and others in the horizontal Woodford shale formation in the Arkoma Basin, as well as positive results in two programs in the Anadarko Basin. In the Rocky Mountain region, the largest contribution came from the Hanging Woman Basin where we added 9.9 BCFE of proved reserves. The ArkLaTex region added 26.2 BCFE from successful drilling operations in the James Lime carbonate program and Elm Grove Field. Successful results in the Wolfberry program in 2007 were the principal driver of drilling additions in the Permian Basin.

- *New Basin Entry in 2007.* In 2007 we spent $182.9 million for acquisitions of proved and unproved oil and gas properties. We entered the greater Maverick Basin with two acquisitions in South Texas totaling $178.9 million that target the Olmos shallow gas formation. The first was the $30.0 million Catarina acquisition that closed in June 2007. The more significant transaction was the $148.9 million Rockford acquisition that closed in October 2007. These properties added a sizeable inventory of lower risk drilling locations to our portfolio. Consistent with prior acquisitions, we hedged several years of the risked production related to these acquisitions at the time of acquisition. The remaining acquisitions in 2007 were small niche transactions throughout the year in the Mid-Continent, ArkLaTex, and Rocky Mountain regions.

- *Senior and Regional Management Changes.* During 2007, the Company underwent or announced personnel changes in the chief executive position and in several regional manager positions. On February 23, 2007, Mark Hellerstein retired as Chief Executive Officer after serving in that role since 1995. Tony Best, President of the Company, was appointed as Chief Executive Officer on that date. Mr. Hellerstein continues to serve as the Chairman of the Board. In June of 2007, Jerry Schuyler, the Senior Vice President responsible for the Gulf Coast and Permian regions, left St. Mary to pursue another professional opportunity. Greg Leyendecker, then Operations Manager for the Gulf Coast region, assumed responsibility for the Gulf Coast and is now Vice President - Regional Manager of the Gulf Coast region. We also made the Midland office a stand-alone regional office headed by Lehman Newton III, Vice President - Regional Manager of our Permian region. Mr. Leyendecker and Mr. Newton joined St. Mary in 2006 and each have over 25 years of management and operational experience in the oil and gas industry. In July 2007, Stephen Pugh joined the Company as Senior Vice President and Regional Manager of the ArkLaTex region. Mr. Pugh succeeded David Hart, who retired from St. Mary after 15 years in various roles at the Company. Mr. Pugh came to St. Mary with over

25 years of engineering, operations, and business development experience in the oil and gas industry. In August of this year, Robert Nance, Senior Vice President - Regional Manager of the Rocky Mountain region, announced his decision to retire in the first quarter of 2008 after more than 40 years in the oil and gas industry. Mark Mueller joined us as Senior Vice President in August and now leads our Rocky Mountain region. Mr. Mueller has over 20 years of management and technical experience in the oil and gas industry. Effective January 1, 2008 Mark Mueller was appointed Senior Vice President - Regional Manager. Subsequent to year end, David Honeyfield, Senior Vice President - Chief Financial Officer, announced that he will resign as an officer of St. Mary on March 21, 2008, in order to pursue an opportunity in an unrelated industry. An external search for his successor is underway at the time of this filing.

- *2007 Capital Markets Activity.* In March of 2007 we called for redemption of the then outstanding $100.0 million 5.75% Senior Convertible Notes. The notes had a conversion price of $13.00 per share. One hundred percent of the holders of the notes elected to convert their notes into shares of common stock. As a result of the conversion, 7.7 million shares of stock were issued to the note holders. This resulted in a decrease to long-term debt of $100.0 million, and an increase to common stock associated with the conversion together with the recognition of the excess tax benefit associated with the contingent interest feature associated with the notes.

  In April of 2007, we completed the sale of $287.5 million of 3.50% Senior Convertible Notes. The net proceeds from the 3.50% Senior Convertible Notes were used to repay outstanding borrowings under our revolving credit facility.

- *Significant Volatility in Commodity Prices.* During 2007, the exploration and production sector was impacted by volatility in the prices for crude oil and natural gas. Our operations and financial conditions were 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. NYMEX crude oil began 2007 with an average January price of $54.67 per barrel and increased steadily throughout the year, reaching an average monthly high for the year of $94.63 per barrel in November. The average NYMEX price for the year was $72.34 per barrel. Geopolitical unrest in various producing regions overseas and concerns domestically related to refinery utilization and petroleum product inventories were the principal drivers of the increase in oil prices in 2007.

  We sell the majority of our natural gas on contracts which 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 $6.86 per MMBtu in 2007, which was five percent lower than the average for 2006. High levels of natural gas in storage had an impact on pricing during 2007 as inventory levels exceeded the five year average for all of 2007. Concerns about supply overhang peaked for the year around September of 2007, leading to the lowest Henry Hub price for the year of $5.43 per MMBtu. The impact was more acute in the Rocky Mountain region where bid week prices were driven down to $2.13 per MMBtu and $1.11 per MMBtu for September and October, respectively, on the Colorado Interstate Gas (CIG) index. A significant portion of our production in the Rockies is oil and we had limited exposure to the CIG hub. Additionally, recent acquisitions have added a richer gas stream to our overall production mix. The value received associated with natural gas liquids (NGLs) from this rich gas stream align more closely with crude oil prices. The increase in crude prices has had a similar impact on prices for NGLs, and as a result we have enjoyed higher realized natural gas prices. We hedge a portion of our oil and gas production using swaps and collars. A gain of $58.7 million was realized on our natural gas hedges for the year and a loss of $34.3 million was realized on our oil hedges for the year.

- *Repurchase of Common Stock.* In 2007, we repurchased a total of 792,216 shares of our common stock in the open market for a weighted-average price of $32.76 per share, including commissions, under this program. At the time we repurchased our shares, we entered into hedges for a commensurate amount of our production that was represented by the share repurchase in order to lock in the discounted price at which our shares were trading. As of the date of this filing, we are authorized by the Board to repurchase 5,207,784 additional shares under this 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 borrowings under the credit facility.

Assets

As of December 31, 2007, we had estimated proved reserves of 78.8 MMBbl of oil and 613.5 Bcf of natural gas. Prices in effect on December 31, 2007, used to estimate proved reserves were $6.80 per MMBtu of gas and $95.98 per barrel of oil. On an equivalent basis, our proved reserves were 1,086.5 BCFE as of December 31, 2007, an increase of 17 percent from 927.6 BCFE at the end of the prior year. The increase in proved reserves in 2007 was the result of development activities and acquisitions. On an equivalent basis, 77 percent of our proved reserves are classified as proved developed as of year-end. Total proved oil and gas reserves have a before income tax PV-10 value of $3.9 billion and a standardized measure value, which includes the effect of income taxes, of $2.7 billion (a reconciliation between these two amounts is shown under Reserves in Part I, Items 1 and 2). During 2007, our average daily production was 181.0 MMcf of gas and 18.9 MBbl of oil, for an average equivalent production rate of 294.5 MMCFE per day, which is a new annual record for us. We sold certain non-core oil and gas properties subsequent to year end; all production and reserve information presented is before the impact of this sale unless otherwise noted.

Our reserve replacement percentage – including sales for 2007 was 248 percent, which includes 1.4 BCFE of asset sales that occurred during the year. Our reserve replacement percentage – excluding sales was 249 percent. We acquired 94.8 BCFE of proved reserves through acquisitions in 2007, the majority of which relate to the two Olmos shallow gas acquisitions in South Texas. We believe the use of the phrase “reserve replacement percentage” is widely understood by those who make investment decisions related to the oil and gas exploration business. We believe that this measure is useful in evaluating and comparing exploration and production companies and provides a measure of the growth of a company. The Glossary includes a definition of “reserve replacement percentage” and description of how it is calculated.

In 2007, we invested a total of $926.1 million on drilling activities and acquisitions. This was 15 percent higher than the $805.5 million invested in 2006. Drilling investments, including leasing activity, in 2007 of $740.9 million comprised 80 percent of our total capital investment budget for the year and compares to $522.6 million in 2006. The increase in drilling activity was driven primarily by development of the Sweetie Peck asset in the Permian Basin that was acquired in late 2006 as well as increases in activity in our ArkLaTex region. We invested $185.2 million on acquisitions in 2007, the majority of which related to the two acquisitions in South Texas targeting the Olmos shallow gas play.

We have $626 million budgeted for development and exploration investments in 2008, which is a decrease of 16 percent from the $740.9 million invested in drilling activities in 2007. The decrease in investment year over year is a reflection of our goal to improve our capital efficiency and to invest within our cash flow from operations in order to maintain financial flexibility so that we can deploy additional capital where warranted in order to make accretive acquisitions, repurchase stock, or repay debt.

Our operations are currently concentrated in five core operating areas in the United States. The following table summarizes the production and proved reserves and PV-10 value of our core operating areas as of December 31, 2007.

	ArkLaTex	Mid-Continent	Gulf Coast	Permian	Rocky Mountain	Total
2007 Proved Reserves:						
Oil (MMBbl)	1.0	1.5	0.9	20.0	55.4	78.8
Gas (Bcf)	163.9	192.4	111.3	34.7	111.2	613.5
Equivalents (BCFE)	170.1	201.3	116.8	154.7	443.6	1,086.5
Relative percentage	15%	19%	11%	14%	41%	100%
Proved Developed %	52%	88%	48%	69%	92%	77%
PV-10 Value (in millions)	$380.3	$585.5	$361.6	$824.2	$1,709.6	$3,861.2
Relative percentage	10%	15%	9%	21%	45%	100%
2007 Production:						
Oil (MMBbl)	0.1	0.5	0.2	1.4	4.7	6.9
Gas (Bcf)	13.0	30.9	9.0	2.4	10.8	66.1
Equivalent (BCFE)	13.8	34.0	10.3	10.7	38.7	107.5
Avg. Daily Equivalents (MMCFE/d)	37.8	93.2	28.2	29.3	106.0	294.5
Relative percentage	13%	31%	10%	10%	36%	100%

Note: The table above includes production and proved reserves related to non-core assets that were divested on January 31, 2008. The properties divested were primarily in the Mid-Continent and Rocky Mountain regions. These non-core properties contributed 5.0 BCFE of production during 2007 and represented 40.4 BCFE of proved reserves at December 31, 2007.

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 and Travis Peak formations in the region. In recent years, we have utilized horizontal wells in the development of limestone carbonates found in the region, particularly the James Lime formation.

The ArkLaTex region invested $149.8 million in 2007 on exploration, development, and acquisition activities, which is 70 percent higher than the $88.0 million spent in 2006. The primary drivers of this increase in capital were increased activity levels in our James Lime and Cotton Valley programs during the year. In the St. Mary operated horizontal James Lime program, we operated one rig continuously throughout 2007. We continued to see solid results in proven development areas and had two successful wells that extended the play westward by approximately 75 miles. The Cotton Valley programs at Elm Grove and Terryville fields were areas of significant investment in 2007, although these are operated by other companies. At Elm Grove Field, advancements such as 20-acre increased density drilling, commingling of production of the Cotton Valley and Hosston formations, and horizontal drilling have benefited us, particularly as development has moved into areas where we have larger working interests. Even though operations at Terryville Field are more difficult due to the formation being deeper and more highly pressured than the Cotton Valley formation at Elm Grove Field, operations in the field were highly successful in 2007 and allowed for sustained activity during the year. The region's 2007 production increased 31 percent to 13.8 BCFE. Our proved reserves at year-end 2007 were 170.1 BCFE, a seven percent increase over 2006 year-end proved reserves of 159.5 BCFE. On a forward looking basis, we expect that proved reserves in this area will be booked on 20-acre spacing as the in-fill program at Elm Grove Field continues and additional locations become permitted. We have not however booked these locations as proved reserves at year end due to the Securities and Exchange Commission technical requirement of needing to have an "alternate unit" permitting process completed prior to booking such items as proved reserves.

The Elm Grove Field is the highest value field in the ArkLaTex region at year-end 2007, with proved reserves of 85.3 BCFE and a PV-10 value of $161.3 million. Elm Grove comprises roughly 42 percent of the region's PV-10 value and approximately four percent of our entire PV-10 value. We own interests in 382 producing wells in the field with many of those wells having uphole recompletion potential in the future. 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 capital budget for the ArkLaTex region in 2008 is $161 million, 51 percent of which will be operated by us. The largest portion of this year's budget relates to Cotton Valley programs, where 50 percent of the region's capital will be deployed. Of the capital allocated for Cotton Valley programs, 60 percent will be invested at Elm Grove Field where development continues to be highly successful. Development of the field on 20-acre spacing continues to drive activity levels, and a successful horizontal well completed at the end of 2007 could set the stage for horizontal development at Elm Grove Field. The remaining Cotton Valley allocation for 2008 will be split roughly evenly between the program at Terryville Field and the St. Mary operated program at Carthage. Our operated horizontal James Lime program will represent 34 percent of the region's 2008 budget. We plan to operate two drilling rigs throughout the year, with plans to drill more than 20 horizontal James Lime wells in 2008.

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 and our primary focus in the region is currently on the Atoka and Granite Wash formations. 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, although the Wapanucka limestone and Cromwell sandstone also appear to have commercial potential. The Mid-Continent region oversees our assets in Constitution South Field in Jefferson County, Texas. Our long history of operations and proprietary geologic knowledge in the region enables us to sustain economic development and exploration programs despite periods of adverse industry conditions. We apply current technology through the use of hydraulic fracturing, innovative well completion techniques, and horizontal drilling to accelerate production and associated cash flow from the region's tight gas reservoirs and developing plays.

In 2007, we invested $185.7 million in the Mid-Continent region on exploration, development, and acquisition activity, which is 13 percent less than the $214.3 million deployed in 2006. Throughout 2007, we maintained a consistent level of activity in the Arkoma Basin working on the Woodford shale program as we continued to refine our understanding of the play. We decreased our activity in the Atoka/Granite Wash development program as we developed more cost efficient completion designs for these wells. Mid-Continent production in 2007 was 34.0 BCFE, an increase of 14 percent from the 29.8 BCFE produced in 2006. Proved reserves at the end of 2007 were 201.3 BCFE, an increase of 18 percent from the 170.7 BCFE report for the prior year.

The Constitution South Field is the highest value field in the Mid-Continent region with reserves of 15.2 BCFE and a PV-10 value of $115.1 million. This field also contributed 8.6 BCFE of production in 2007, which represents approximately eight percent of our total production. Three wells, the Paggi Broussard #1, the Paggi Broussard # 2, and the Loretta B. Casey #1, comprise the majority of reserves, PV-10 value, and production in the Constitution South Field. These wells historically have performed better than anticipated and we have a history, including at year-end 2007, of recognizing upward performance revisions in our proved reserves at this field.

The 2008 capital expenditure budget for the Mid-Continent region is $135.0 million, 69 percent of which we will operate. The largest component of the budget is our program targeting the Woodford shale using horizontal wells in the Arkoma basin, where roughly 30 percent of the region's budget will be invested. After mixed results in the horizontal Woodford shale program in the first half of 2007, we had a series of successful wells in the latter part of the year which we believe validates our understanding of the well and completion design being used currently in this program. Our budget anticipates that we will drill ten horizontal Woodford wells with two operated rigs in the first half of 2008, and continue to participate with our partners in outside operated wells. With continued success in the play, we have the ability to increase activity and our capital investment in the program in the latter part of 2008. In 2008, we plan to continue with an exploration program in the Anadarko

Basin that yielded encouraging results in 2007. This exploration program targets deeper formations of the basin. We also plan to deploy approximately 27 percent of the region's 2008 capital budget to drill six exploratory test wells in this program. In the Western Oklahoma Washes program in the Anadarko Basin, which we have referred to previously as the Mayfield development area, we plan to invest roughly 17 percent of the year's budget in this program that targets the Atoka and Granite Wash formations. The area is a known hydrocarbon province, and efforts in 2008 will be directed toward improving the geotechnical effort applied to the program and revising drilling and completion techniques.

Gulf Coast Region. St. Mary's presence in south Louisiana dates to the early 1900s when our founders acquired our namesake property in St. Mary Parish, Louisiana abutting the Gulf of Mexico. These 24,914 acres of fee lands yielded $3.7 million of gross oil and gas royalty revenue in 2007. Our Gulf Coast regional presence expanded as a result of the acquisition of King Ranch Energy, Inc. in 1999. During 2007 we reached a significant inflection point in this region as it shifted from an office centered on geotechnically driven exploration to one focused on repeatable development and exploitation with our acquisition of two Olmos shallow gas assets in South Texas. The Gulf Coast region is run from our office in Houston, Texas.

Our capital expenditures for exploration, development, and acquisition activity in the Gulf Coast region grew significantly from $65.5 million in 2006 to $278.5 million in 2007, primarily driven by two significant acquisitions. The majority of our 94.8 BCFE of acquisitions, classified as purchases of minerals in place, were in the Gulf Coast region. These were the $150.3 million Rockford acquisition that closed in October 2007 and the $30.4 million Catarina acquisition which closed in April 2007, both of which target the Olmos shallow gas formation and are located in the greater Maverick Basin in Southwestern Texas. Final year-end reserve estimates related to these acquisitions are lower than the initial estimates we previously disclosed, partly due to the fact that our presentation of reserves at the time of the acquisition was on a dry gas basis whereas our annual report on Form 10-K disclosures utilize a wet gas presentation. This accounted for approximately ten BCFE of the difference in volumes, without any impact to value. The remaining difference was based on our final year-end assessment of proved non-producing reserves and our proved undeveloped reserves, which were each lower than the amounts estimated at the time of acquisition. Our emphasis in 2007 was on the successful integration of our newly acquired properties. While the core focus of the region shifted toward onshore projects, we continued to be active offshore in 2007. A previously discovered intermediate deepwater project, Zloty, began production late in 2007 and we continue to work to advance other intermediate deepwater projects in which we are a partner. We were also active closer to shore with a mixed program that included the successful Reno, Clement, and Amber Jack wells. Gulf Coast production in 2007 was 10.3 BCFE, an increase of six percent from the 9.7 BCFE produced in 2006. Proved reserves at the end of 2007 were 116.8 BCFE, an increase of 263 percent from the 32.2 BCFE reported for the prior year. The disparity between the production growth and reserve growth for the Gulf Coast region in 2007 is attributable to the acquisitions previously discussed.

The most significant asset in the Gulf Coast region is the Gold River project area that was acquired in October of 2007 as part of the Rockford acquisition. The Gold River project area has 104 producing wells as of year end. At December 31, 2007, this project area had a PV-10 value of $136.9 million with 53.6 BCFE of proved reserves and accounts for approximately four percent of our entire PV-10 value. The acquisition of these assets, together with the Catarina assets, represents the most recent resource play entry for the Company.

Our development and exploration budget in the Gulf Coast region for 2008 is $80 million and is focused primarily on the development of the Olmos assets acquired in 2007. St. Mary will operate 75 percent of the planned capital investment next year. Roughly $38 million, or 47 percent, of the budget will be dedicated to grass roots Olmos wells and approximately $10 million, or 12 percent, of the budget will be spent on Olmos recompletions.

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 the 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 early February 2007.

In 2007, we spent $135.1 million in the region. The majority of this capital was deployed to develop projects that target 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 2007 – the operated Sweetie Peck program and the outside operated program at Halff East. We operated between two and five drilling rigs at Sweetie Peck throughout 2007. At Halff East, our operating partner had two drilling rigs running throughout the year. We also invested capital in the Parkway and East Shugart Delaware waterflood projects. Production in the region increased 234 percent over the prior year, from 3.2 BCFE in 2006 to 10.7 BCFE in 2007. Proved reserves as of the end of 2007 were 154.7 BCFE, which is an increase of nine percent from 2006 year-end reserves of 142.2 BCFE.

As of the end of December 2007, the Sweetie Peck assets in the Permian Basin represented a PV-10 value of $438.0 million with 77.7 BCFE of proved reserves. This accounts for approximately 11 percent of our entire PV-10 value. The Sweetie Peck assets had 106 producing wells and 47 proved undeveloped reserve locations as of the end of 2007.

The capital budget for 2008 in the region is $120 million, of which 74 percent will be operated by us. Of this amount, roughly $103 million, or 86 percent, will be invested in Wolfberry projects. At Sweetie Peck, we plan to spend approximately $77 million operating three drilling rigs continuously throughout the year. Included in this amount are investment dollars to test several 40-acre pilot areas, which if successful could add meaningful proved reserves. At Halff East, we will invest approximately $25 million with our operating partner. We will also invest a small amount of capital in several smaller programs, including our Delaware waterfloods.

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 tremendous acreage position that has precipitated additional growth in this region.

Including the Hanging Woman Basin coalbed methane project, we invested $178.3 million in 2007 on exploration, development, and acquisitions in the Rocky Mountain region, compared to $161.3 million in 2006. The 2007 program was focused on a horizontal development in the Mississippian formations of the Williston Basin, and the drilling of Bakken formation infill locations in Montana and Red River locations. Additionally, 2007 saw an acceleration of drilling at Hanging Woman Basin. Proved reserves for the Rocky Mountain region were 443.6 BCFE at year-end, up five percent from 422.9 BCFE as of year end 2006. Production in the Rocky Mountain region for 2007 was 38.7 BCFE. Total regional production was down two percent from 39.5 BCFE in 2006.

Included in the Rocky Mountain region is the coalbed methane project at Hanging Woman Basin. This program is of particular interest because of the large resource potential on our leasehold. In 2007, we invested $35.7 million at Hanging Woman Basin compared to $30.4 million in 2006. Proved reserves in this project grew 20 percent in 2007 to 40.2 BCFE, 75 percent of which were proved developed. Hanging Woman Basin had 33.4 BCFE in proved reserves at December 31, 2006, 91 percent of which were proved developed. Production was 3.0 BCFE for the year ended 2007, up 49 percent from production in 2006.

The Elm Coulee Field is the highest value field in the region at year-end 2007, with 92 producing wells and proved reserves of 42.4 BCFE and a PV-10 value of $236.5 million. The reserves in this field are predominately oil and the Bakken is the formation of primary interest. This field comprises approximately six percent of our entire PV-10 value.

Our capital budget for the Rocky Mountain region is $130 million for 2008, with roughly $24 million budgeted for activities for Hanging Woman Basin coalbed methane. We will operate roughly 65 percent of our planned regional investment in 2008. In the conventional Rockies program, several vertical wells and two recompletions in the Red River are planned for the year. We also plan to drill a small number of horizontal Bakken wells in and around our historic Bakken development areas in Montana. Workover and recompletion operations are planned in our Wind River Basin and Big Horn Basin oil properties. At the outside operated Atlantic Rim coalbed methane play in the Green River Basin, we expect to see activity ramp up since regulatory and environmental delays appear to have been resolved. At Hanging Woman Basin, we plan to moderate our drilling activity in 2008 and monitor and evaluate the results of the shallow and intermediate pods and deep horizontal programs from previous year's drilling efforts.

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, 2007. 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 2007 and 2006. In 2005, Ryder Scott Company, L.P. prepared the reserve estimates for at least 80 percent of the PV-10 value of our conventional oil and gas assets. St. Mary personnel prepared the reserve estimates for the remainder of all properties. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available. The PV-10 values shown in the following table are not intended to represent the current market value of the estimated proved oil and gas reserves owned by St. Mary. Neither prices nor costs have been escalated. You should read the following table along with the section entitled "Risk Factors – Risks Related to Our Business – 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 authority or agency, other than the Securities and Exchange Commission, since the beginning of the last fiscal year.

	As of December 31,		
Proved Reserves Data:	2007	2006	2005
Oil (MMBbl)	78.8	74.2	62.9
Gas (Bcf)	613.5	482.5	417.1
BCFE	1,086.5	927.6	794.5
Standardized measure of discounted future net cash flows (in thousands)	$ 2,706,914	$ 1,576,437	$ 1,712,298
PV-10 value (in thousands)	$ 3,861,187	$ 2,157,449	$ 2,494,169
Proved developed reserves	77%	78%	82%
Reserve replacement – including sales of reserves	248%	244%	256%
Reserve replacement – excluding sales of reserves	249%	247%	256%
Reserve life (years) (1)	10.1	10.0	9.1

(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,		
	2007	2006	2005
		(In thousands)	
Standardized measure of discounted future net cash flows	$ 2,706,914	$ 1,576,437	$ 1,712,298
Add: 10 percent annual discount, net of income taxes	2,321,983	1,238,308	1,286,568
Add: Future income taxes	2,316,637	1,125,955	1,448,444
Undiscounted future net cash flows	$ 7,345,534	$ 3,940,700	$ 4,447,310
Less: 10 percent annual discount without tax effect	(3,484,347)	(1,783,251)	(1,953,141)
PV-10 value	$ 3,861,187	$ 2,157,449	$ 2,494,169

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,		
	2007	2006	2005
Net production:			
Oil (MMBbl)	6.9	6.1	5.9
Gas (Bcf)	66.1	56.4	51.8
BCFE	107.5	92.8	87.4
Average net daily production:			
Oil (MBbl)	18.9	16.6	16.2
Gas (MMcf)	181.0	154.7	141.9
MMCFE	294.5	254.2	239.4
Average realized sales price, excluding the effects of hedging:			
Oil (per Bbl)	$ 67.56	$ 59.33	$ 53.18
Gas (per Mcf)	$ 6.74	$ 6.58	$ 8.08
Per MCFE	$ 8.48	$ 7.88	$ 8.40
Average realized sales price, including the effects of hedging:			
Oil (per Bbl)	$ 62.60	$ 56.60	$ 50.93
Gas (per Mcf)	$ 7.63	$ 7.37	$ 7.90
Per MCFE	$ 8.71	$ 8.18	$ 8.14
Production costs per MCFE:			
Lease operating expense	$ 1.31	$ 1.25	$ 0.99
Transportation expense	$ 0.14	$ 0.12	$ 0.09
Production taxes	$ 0.58	$ 0.54	$ 0.56

Productive Wells

As of December 31, 2007, St. Mary had working interests in 2,365 gross (1,125 net) productive oil wells and 4,199 gross (1,405 net) productive gas wells. Productive wells are either producing wells or wells capable of commercial production although currently shut-in. One or more completions in the same wellbore are counted as one well. A well is categorized under state reporting regulations as an oil well or a gas well based upon the ratio of gas to oil produced when it first commenced production, and such designation may not be indicative of current production.

Drilling Activity

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

	Years Ended December 31,					
	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	164	77.91	81	35.32	83	38.09
Gas	518	204.62	446	178.97	379	152.69
Non-productive	30	13.18	31	10.65	29	9.12
	712	295.71	558	224.94	491	199.90
Exploratory:						
Oil	3	1.92	10	5.53	8	1.91
Gas	9	4.01	15	3.68	5	0.86
Non-productive	5	2.58	8	1.81	5	2.32
	17	8.51	33	11.02	18	5.09
Farmout or non-consent	1	-	2	-	18	-
Total (1)	730	304.22	593	235.96	527	204.99

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

Acreage

The following table sets forth the gross and net acres of developed and undeveloped oil and gas leases, fee properties, mineral servitudes, and lease options held by St. Mary as of December 31, 2007. Undeveloped acreage includes leasehold interests that may already have been classified as containing proved undeveloped reserves.

	Developed Acres (1)		Undeveloped Acres (2)		Total	
	Gross	Net	Gross	Net	Gross	Net
Arkansas	2,917	408	207	68	3,124	476
Colorado	3,098	2,496	20,269	12,530	23,367	15,026
Louisiana	136,606	45,913	52,349	15,081	188,955	60,994
Mississippi	6,646	727	59,907	21,435	66,553	22,162
Montana	70,462	45,523	426,161	286,841	496,623	332,364
New Mexico	5,440	2,608	1,480	1,187	6,920	3,795
North Dakota	150,968	97,691	198,104	110,786	349,072	208,477
Oklahoma	302,820	91,523	107,018	56,735	409,838	148,258
Texas	215,056	78,310	163,849	97,019	378,905	175,329
Utah (3)	480	115	3,574	831	4,054	946
Wyoming	152,209	97,129	395,083	226,410	547,292	323,539
Other (4)	2,201	873	3,836	1,090	6,037	1,963
	1,048,903	463,316	1,431,837	830,013	2,480,740	1,293,329
Louisiana Fee Properties	10,818	10,818	14,096	14,096	24,914	24,914
Louisiana Mineral Servitudes	10,173	5,740	4,411	4,048	14,584	9,788
	20,991	16,558	18,507	18,144	39,498	34,702
Total (5)	1,069,894	479,874	1,450,344	848,157	2,520,238	1,328,031

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

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

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

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

(5) Subsequent to December 31, 2007, St. Mary divested certain non-core properties, which included leases covering approximately 155,400 and 53,900 developed gross and net acres, respectively, and 67,100 and 38,400 undeveloped gross and net acres, respectively. Additionally, St. Mary also divested its overriding royalty interest in 36,000 gross acres in Utah.

Major Customers

During 2007 and 2006, no customer individually accounted for ten percent or more of the Company’s total oil and gas production revenue. During 2005, sales to Tesoro Refining and Marketing individually accounted for 13 percent of the Company’s total oil and gas production revenue.

Employees and Office Space

As of February 15, 2008, we had 438 full-time employees. None of our employees are subject to a collective bargaining agreement, and we consider our relations with our employees to be good. We lease approximately 77,000 square feet of office space in Denver, Colorado for our executive and administrative offices, of which approximately 10,000 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; and approximately 2,000 square feet in Casper, Wyoming.

Title to Properties

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

Seasonality

Generally, but not always, the demand and price levels for natural gas increase during the colder winter months and decrease during the warmer summer months. To lessen seasonal demand fluctuations, pipelines, utilities, local distribution companies, and industrial users utilize natural gas storage facilities and forward purchase some of their anticipated winter requirements during the summer. However, increased summertime demand for electricity is beginning to place an increasing demand on storage volumes. Crude oil and the demand for heating oil are also impacted by generally higher prices in the winter – 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, at this time, anticipated to have any material negative impact on our ability to deploy our drilling capital budget for 2008. 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 have to be willing to compete in this market in order to be successful.

Government Regulations

Our business is subject to various federal, state, and local laws and governmental regulations that may be changed from time to time in response to economic or political conditions. Matters subject to regulation include the issuance of drilling permits, discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties, taxation, and environmental protection. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and gas wells below actual production capacity in order to conserve supplies of oil and gas.

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

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

- Engineering and construction specifications for offshore production facilities
- Safety procedures
- Flaring of production
- Plugging and abandonment of Outer Continental Shelf (OCS) wells
- Calculation of royalty payments and the valuation of production for this purpose
- Removal of facilities.

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

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

Environmental Regulations. Our operations are subject to numerous existing federal, state, and local laws and regulations governing environmental quality and pollution control. These laws and regulations may require that permits be obtained before drilling commences, restrict the types, quantities, and concentration of various substances that can be released into the environment in connection with drilling and production activities, and limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, and other protected areas, including areas containing endangered animal species. As a result, these laws and regulations may substantially increase the costs of exploring 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 such laws and regulations.

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

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

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

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

Cautionary Information about Forward-Looking Statements

This Form 10-K contains “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this Form 10-K that address activities, events or developments 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 expressions are intended to identify forward-looking statements. Forward-looking statements appear in a number of places in this Form 10-K, and include statements about such matters as:

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

- The drilling of wells and other exploration and development activities, 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 implied by those reserve estimates

- Future oil and natural gas production estimates

- Our outlook on future oil and natural gas prices

- Cash flows, anticipated liquidity, and the future repayment of debt

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

- Other similar matters such as those discussed in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" 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" in Item 1A of this Form 10-K, and include such factors as:

- The volatility and level of realized oil and natural gas prices

- Our ability to replace reserves and sustain production

- Unexpected drilling conditions and results

- Unsuccessful exploration and development drilling

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

- The risks of hedging strategies

- Lower prices realized on oil and natural gas sales resulting from our commodity price risk management activities

- 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

- Drilling and operating service availability

- Uncertainties in cash flow

- The financial strength of hedge contract counterparties

- The negative impact that lower oil and natural gas prices could have on our ability to borrow

- 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 you that forward-looking statements are not guarantees of future performance and that actual results or developments 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 www.stmaryland.com. Within our website's financial information section we make available free of charge our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC under applicable securities laws. These materials are made available as soon as reasonably practical after we electronically file such materials with or furnish such materials to the SEC.

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

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

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.

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

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

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

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

BCFE. Billion cubic feet of 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 beyond its known horizon.

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

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

Finding cost. Expressed in dollars per BOE or MCFE. Finding costs are calculated by dividing the amount of total capital expenditures for oil and 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 previous estimates during the same period. The information for this calculation is included in Note 13 of Part IV, Item 15 of this Form 10-K.

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

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

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

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

Hydraulic fracturing. A procedure to stimulate production by forcing a mixture of fluid and proppant (usually sand) into the formation under high pressure. This increases the permeability and porosity of the targeted formation.

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.

OCS. Outer Continental Shelf in the Gulf of Mexico.

PV-10 value. The present value of estimated future gross revenue to be generated from the production of estimated net proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date indicated (unless such prices or costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion, and amortization, discounted using an annual discount rate of 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 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 percentage – 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. This is believed to be a useful non-GAAP measure that is widely utilized within the exploration and production industry as well as by investors. It is an easily calculable number and is representative of the relative success a company is having in replacing its production from its declining asset base as well as its ability to grow the overall company.

Reserve replacement percentage – including sales 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. This is believed to be a useful non-GAAP measure that is widely utilized within the exploration and production industry as well as by investors. It is an easily calculable number and is representative of the relative success a company is having in replacing its production from its declining asset base as well as its ability to grow the overall company.

Royalty. The 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.

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 and natural gas, regardless of whether such acreage contains estimated net proved reserves.

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

ITEM 1A. RISK FACTORS

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

Risks Related to Our Business

Oil and natural gas prices are volatile and a decline in prices could hurt 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 and borrowing capacity, as well as the amount and value of our oil and natural gas reserves.

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:

- Worldwide and domestic supplies of oil and natural gas
- The ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls
- Pipeline, transportation, or refining capacity constraints in a regional or localized area may impact the realized price for oil or natural gas
- Political instability or armed conflict in oil or natural gas producing regions
- The price and level of foreign imports of crude oil, refined petroleum products, and liquefied natural gas
- Worldwide and domestic economic conditions
- The level of consumer demand for hydrocarbons
- Productive capacity of the industry as a whole
- The availability of transportation facilities
- Weather conditions

- The price and availability of alternative fuels

- Governmental regulations and taxes.

These factors and the volatility of oil and natural gas markets make it very 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 material adverse effect on us.

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

Our future operations depend on our ability to find, develop, and acquire oil and 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.

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 are actively seeking oil and natural gas properties 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 and technical 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 or 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 people. The need for talented people across all disciplines in the industry has grown at a time when the number of people available is 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. Reserve 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 reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering, and economic data for each reservoir. These estimates are dependent on many variables and therefore changes often occur as these variables evolve. 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, 2007, approximately 23 percent, or 250.2 BCFE, of our estimated proved reserves were proved undeveloped and approximately 11 percent or 116.0 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 recover our proved undeveloped reserves, an estimated $234 million of capital expenditures will be spent during 2008. Production revenues from proved developed non-producing reserves will not be realized until some time in the future. In order to bring production on-line for our proved developed non-producing reserves, we estimate capital expenditures of $12 million for 2008. 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 capital expenditure budget for 2008 is directed towards projects that are not yet classified within the construct of proved reserves as defined by Regulation S-X of the Securities and Exchange Commission.

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 SEC requirements, whereas actual future prices and costs may be materially higher or lower. For example, values of our reserves as of December 31, 2007, were estimated using a calculated sales price of $6.80 per MMBtu of natural gas (NYMEX Henry Hub spot price) and $95.98 per Bbl of oil (NYMEX West Texas Intermediate spot price). We then adjust this base price to ensure we consider the appropriate basis and location differentials as of that date in estimating our proved reserves. During 2007, our monthly average realized natural gas prices, excluding the effect of hedging, were as high as $7.83 per Mcf and as low as $5.42 per Mcf. For the same period our monthly average realized oil prices before hedging were as high as $91.53 per Bbl and as low as $48.88 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 governmental regulations or taxes.

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

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

Successful property acquisitions require an assessment of a number of factors beyond our control. These factors include exploration potential, future oil and 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 and 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. The availability of drilling rigs can vary significantly from region to region at any particular time. Although land drilling rigs can be moved from one region to another in response to changes in levels of demand, an undersupply of rigs in any region may result in drilling delays and higher drilling costs for the rigs that are available in that region.

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

The wells we drill may not be productive and we may not recover all or any portion of our investment in such wells. The seismic data and other technologies 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.

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

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

To manage our exposure to price risks in the sale of our oil and natural gas, we enter into commodity price risk management arrangements 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. 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. In addition, these transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

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

Some of our hedging agreements may also require us to furnish cash collateral, letters of credit, or other forms of performance assurance in the event that mark-to-market calculations result in settlement obligations by us to the counterparties, which 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.

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 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. Accordingly, a significant decline in oil or natural gas prices or unsuccessful exploration efforts could cause a future write-down of capitalized costs.

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

Substantial capital is required to replace our reserves.

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

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

The markets for raising public debt are quite constrained at the current time, given the overall liquidity concerns arising from the widely reported difficulties in the sub-prime and leveraged loan markets. While we continue to believe that our secured revolving credit facility will be sufficient for the foreseeable future, we must continually monitor the overall condition of the markets as a whole and remain cognizant that an overall pressure on the credit markets has the risk of increasing the cost of borrowings or decreasing the availability of new capital or the capacity of existing debt instruments.

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

Our revolving credit facility currently has a maximum commitment amount of $500 million, subject to a borrowing base of $1.25 billion that the lenders periodically redetermine based on the bank groups' assessment of the value of our oil and natural gas properties, which in turn is based in part on oil and natural gas prices. Lower 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, 2007, we had $287.5 million of total long-term senior unsecured debt outstanding under our 3.50 % Senior Convertible Notes due 2027 and $285.0 million of secured debt outstanding under our revolving credit facility. As of February 15, 2008, we had an outstanding balance of $180.0 million drawn against our revolving credit facility resulting in $320.0 million of available debt capacity under our revolving credit facility, assuming the borrowing conditions of this facility were met. Our long-term debt represented 40 percent of our total book capitalization as of December 31, 2007. The decrease in the borrowings subsequent to year end is a result of using the net proceeds from the sale of non-core properties on January 31, 2008. Our revolving credit facility has a maximum loan amount of $500 million, a current borrowing base of $1.25 billion, and we have elected a current commitment amount of $500 million.

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 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 to 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, 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.

Our debt instruments, including our revolving credit 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.

In addition, 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 and 2005, the insurance markets suffered significant losses. As a result, the availability of coverage and the cost at which such coverage will be available in the future is uncertain, and such coverage has become substantially more expensive.

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

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

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

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.

In addition, recent studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases,” may be contributing to 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. In response to these studies, the U.S. Congress is considering legislation to reduce emissions of greenhouse gases. In addition, at least nine states in the Northeast and five states in the West have separately taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emissions inventories and/or regional greenhouse gas cap and trade programs. Also, as a result of the U.S. Supreme Court’s decision on April 2, 2007 in *Massachusetts et al. v. Environmental Protection Agency et al.*, the U.S. Environmental Protection Agency must reconsider whether it is required to regulate greenhouse gas emissions from motor vehicles even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court’s holding in *Massachusetts* that greenhouse gases fall under the Federal Clean Air Act’s definition of “air pollutant” may also result in future regulation of greenhouse gas emissions from stationary sources under certain Clean Air Act programs. 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 restrict emissions of greenhouse gases, including methane or carbon dioxide, in areas in which we conduct business could adversely affect our operations and the demand for our products.

We depend on transportation facilities owned by others.

The marketability of our oil and 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, 2007 to February 15, 2008, the closing daily sales price of our common stock as reported by the New York Stock Exchange ranged from a low of $31.80 per share to a high of $44.07 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 bylaws have provisions that discourage corporate takeovers and could prevent stockholders from receiving a takeover premium on their investment.

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

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

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 material adverse effect on our stock price. As of February 15, 2008, 62,915,531 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 2,367,914 shares of our common stock were outstanding, of which 2,360,414 were exercisable. These options are exercisable at prices ranging from $4.63 to $20.87 per share. In addition, restricted stock units providing for the issuance of up to a total of 682,446 shares of our common stock were outstanding. As of February 15, 2008, there were 63,020,524 shares of common stock outstanding, which is net of 1,009,712 treasury shares.

We may not always pay dividends on our common stock.

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

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 2007.

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth the names, ages and positions held by St. Mary's executive officers. The age of the executive officers is as of February 15, 2008.

Name	Age	Position
Anthony J. Best	58	Chief Executive Officer and President
Javan D. Ottoson	49	Executive Vice President and Chief Operating Officer
David W. Honeyfield*	41	Senior Vice President - Chief Financial Officer and Secretary
Mark D. Mueller	43	Senior Vice President and Regional Manager
Stephen C. Pugh	49	Senior Vice President and Regional Manager
Paul M. Veatch	41	Senior Vice President and Regional Manager
Jerold M. Hertzler	50	Vice President - Business Development
Gregory T. Leyendecker	50	Vice President - Regional Manager
Lehman E. Newton, III	52	Vice President - Regional Manager
Milam Randolph Pharo	55	Vice President - Land and Legal and Assistant Secretary
Garry A. Wilkening	57	Vice President - Human Resources and Administration
Mark T. Solomon	39	Controller

*Mr. Honeyfield has announced that he will resign from his position of Senior Vice President - Chief Financial Officer and Secretary effective March 21, 2008, in order to pursue an opportunity in an unrelated industry.

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. From November 2005 to June 2006, Mr. Best was developing a business plan and attempting to raise 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., a subsidiary of Unocal Corporation, 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 public, private, and small startup exploration and production 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 20 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. Mr. Ottoson managed the Permian Basin assets for Pure Resources, Inc., a subsidiary of Unocal Corporation, 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 - ARCO China, Commercial Director of ARCO British, and Vice President of Operations and Development - ARCO Permian.

David W. Honeyfield was appointed as Chief Financial Officer in May 2005 and Senior Vice President in March 2007. Mr. Honeyfield joined St. Mary in May 2003 as Vice President - Finance, Treasurer and Secretary. Prior to joining St. Mary, Mr. Honeyfield was Controller and Chief Accounting Officer of Cimarex Energy from September 2002 to May 2003 and Controller and Chief Accounting Officer of Key Production Company, Inc., which was acquired by Cimarex in September 2002. Prior to joining Key Production Company in April 2002, Mr. Honeyfield was a senior audit manager with Arthur Andersen LLP in Denver. Mr. Honeyfield had been with Arthur Andersen since January 1991.

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 21 years and was Vice President and General Manager at Samson Exploration Ltd. in Calgary, Canada from September 2006 to September 2007. Mr. Mueller was Vice President and General Manager for Samson Canada Ltd. from April 2005 until its sale in August 2006. 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 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.

Stephen C. Pugh joined St. Mary as Senior Vice President and Regional Manager of the ArkLaTex region in July 2007. Stephen Pugh has over 26 years of experience in the oil and gas industry. He was a Managing Director for Scotia Waterous in the Houston office from July 2006 to July 2007. Prior to joining Scotia Waterous, Mr. Pugh had over 17 years of experience in acquisition and divestiture, operations and engineering with Burlington Resources (subsequently ConocoPhillips). His most recent title there 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.

Paul M. Veatch was appointed Senior Vice President and Regional Manager of the Mid-Continent region in March 2006. Mr. Veatch joined St. Mary in April 2001 as Regional Acquisition and Divestiture Engineer of the ArkLaTex region. He was Manager of Engineering from April 2003 to August 2004 and Vice President – General Manager, ArkLaTex from August 2004 to March 2006. Prior to joining St. Mary, Mr. Veatch worked in various engineering and supervisory roles at Burlington Resources from November 1994 to April 2001. Prior to joining Burlington Resources, Mr. Veatch held various engineering and operations positions for Arco Oil & Gas Company (subsequently Vastar Resources) in Louisiana and Texas from July 1989 until November 1994.

Jerold M. Hertzler was appointed Vice President - Business Development in March 2007. Mr. Hertzler joined St. Mary in October 1998 as Manager of Reservoir Engineering. He assumed the role of Acquisitions Manager in July 2003 and was promoted to Director and Business Development in March 2005. Mr. Hertzler entered the petroleum industry in December of 1979 and has served in various operations and reservoir engineering roles since then, including nine years with Tenneco Oil Company and seven years with Meridian Oil Company.

Gregory T. Leyendecker was appointed Vice President - Regional Manager of the Gulf Coast region 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 27 years in the energy industry and held various positions with the Unocal Corporation 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 Chevron’s San Joaquin Valley business unit 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, a position he held from February 2006 to November 2006.

Lehman E. Newton III joined St. Mary in December 2006 as General Manager for the Midland office and was appointed Vice President - Regional Manager of the Permian region in June 2007. Mr. Newton has over 27 years of exploration and production 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 projects in the continental United States. 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 exploration and production company in the Permian Basin, 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.

Garry A. Wilkening was appointed Vice President - Human Resources and Administration in November 2007 and served as Vice President of Administration from January 2007 to November 2007. Mr. Wilkening relinquished his position as Controller in January 2007 when Mark T. Solomon was elected to that office. Mr. Wilkening was Vice President - Administration and Controller from 1999 to 2007.

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

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

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

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

PART II

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

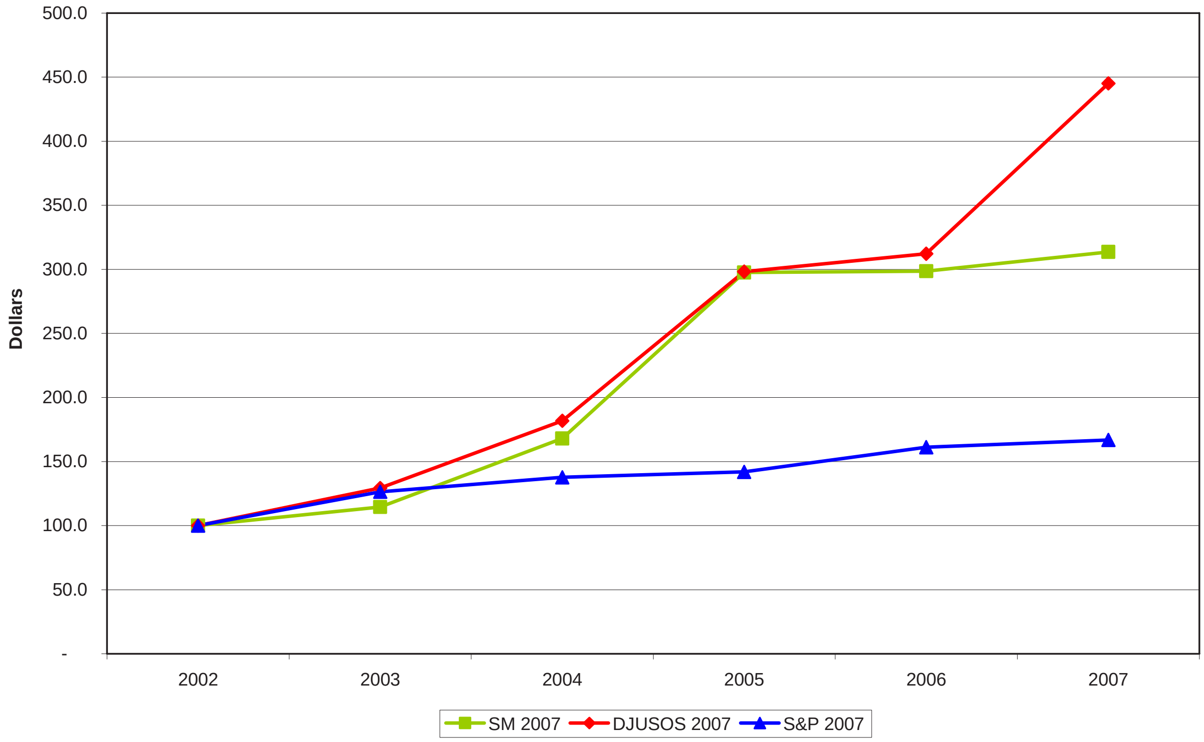
Market Information. St. Mary's common stock is currently traded on the New York Stock Exchange under the symbol SM. The range of high and low sales prices for the quarterly periods in 2007 and 2006, as reported by the New York Stock Exchange.

Quarter Ended	High	Low
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
December 31, 2006	$ 40.85	$ 33.43
September 30, 2006	43.92	34.77
June 30, 2006	45.59	34.38
March 31, 2006	44.69	34.70

PERFORMANCE GRAPH

The following performance graph compares the cumulative total stockholder return on St. Mary's common stock for the period December 31, 2002, to December 31, 2007, with the cumulative total return of the Dow Jones U.S. Exploration and Production Broad Index, and the Standard & Poor's 500 Stock Index.

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



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

Holders. As of February 15, 2008, the number of record holders of St. Mary's common stock was 116. Based on inquiry, management believes that the number of beneficial owners of our common stock is approximately 21,700.

Dividends. St. Mary has paid cash dividends to stockholders every year since 1940. Semi-annual dividends of $0.025 per share were paid in each of the years 1998 through 2004. Semi-annual dividends of $0.05 per share were paid in 2005, 2006 and 2007. 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 $6.3 million in 2007.

Restricted Shares. Aside from Rule 144 restrictions on shares for insiders, shares subject to transfer restrictions under the provisions of the Employee Stock Purchase Plan, restricted shares issued to directors under the Non-Employee Director Stock Compensation Plan, and restricted shares issued to directors under the 2006 Equity Incentive Compensation Plan (the "2006 Equity Plan"), St. Mary has no restricted shares outstanding as of December 31, 2007.

Equity Compensation Plans. St. Mary has the 2006 Equity Plan under which options and shares of St. Mary common stock are authorized for grant or issuance as compensation to eligible employees, consultants, and members of the Board of Directors. Our stockholders have approved this plan. See Note 7 - Compensation Plans in the Notes to Consolidated Financial Statements included in Part IV, Item 15 of this report for further information about the material terms of these plans. The following table is a summary of the shares of common stock authorized for issuance under our equity compensation plans as of December 31, 2007:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))	
2006 Equity Incentive Compensation Plan				
Stock Options and Incentive Stock Options	2,385,500	$ 12.62	-	(1)
Restricted Stock Plan	684,264	N/A	2,560,224	(1)
Employee Stock Purchase Plan	-	-	1,599,811	(2)
Equity compensation plans not approved by security holders	-	-	-	
Total	3,069,764	$ 12.62	4,160,035	

(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, 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. Awards granted in 2007, 2006, and 2005 under the 2006 Equity Plan and the Predecessor Plans were 135,138, 527,678, and 209,238, respectively.

(2) Under the St. Mary Land & Exploration Company Employee Stock Purchase Plan, 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 Employee Stock Purchase Plan are restricted for a period of 18 months from the date issued. The Employee Stock Purchase Plan is intended to qualify under Section 423 of the Internal Revenue Code. There have been 29,534, 26,046, and 28,447 shares issued under this plan in 2007, 2006, and 2005, respectively.

The following table provides information about purchases by the Company or "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the quarters and year ended December 31, 2007, of shares of the Company's common stock, which is the sole class of equity securities registered by the Company pursuant to Section 12 of the Exchange Act.

PURCHASES OF EQUITY SECURITIES BY ISSUER AND AFFILIATED PURCHASERS

	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares that May Yet be Purchased Under the Program[2]
January 1, 2007 – March 31, 2007	-	$ -	-	6,000,000
April 1, 2007 - June 30, 2007	-	$ -	-	6,000,000
July 1, 2007 - September 30, 2007	791,816 (1)	$ 32.76	790,816	5,209,184
October 1, 2007 - October 31, 2007	-	$ -	-	5,209,184
November 1, 2007 - November 30, 2007	-	$ -	-	5,209,184
December 1, 2007 - December 31, 2007	1,400	$ 37.52	1,400	5,207,784
Total October 1, 2007 - December 31, 2007	1,400	$ 37.52	1,400	5,207,784
Total	793,216	$ 32.76	792,216	5,207,784

(1) Includes a total of 1,000shares purchased by Anthony J. Best, St. Mary's President and Chief Executive Officer, in open market transactions that were not made pursuant to our stock repurchase program. The table does not include the 678 shares purchased by Mr. Best under the Company's employee stock purchase plan.

(2) In July 2006 the Company's Board of Directors approved an increase in the number of shares that may be repurchased under the original August 1998 authorization to 6,000,000 as of the effective date of the resolution. Accordingly, as of the date of this filing, the Company has Board authorization to repurchase 5,207,784 shares of common stock on a prospective basis. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of St. Mary's existing bank credit facility agreement and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow, and borrowings under St. Mary's bank credit facility. The stock repurchase program may be suspended or discontinued at any time.

The stock repurchases are subject to covenants in our bank credit facility, including the requirement that we maintain certain levels of stockholders' equity.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth supplemental selected financial and operating data for St. Mary as of the dates and for the periods indicated. The financial data for each of the five years presented were derived from the consolidated financial statements of St. Mary. The following data should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations," which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with St. Mary's consolidated financial statements included in this report. 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,				
	2007	2006	2005	2004	2003
	(In thousands, except per share data)				
Total operating revenues	$ 990,094	$ 787,701	$ 739,590	$ 433,099	$ 393,708
Income before cumulative effect of change in accounting principle	$ 189,712	$ 190,015	$ 151,936	$ 92,479	$ 90,140
Net income per share:					
Basic	$ 3.07	$ 3.38	$ 2.67	$ 1.60	$ 1.53
Diluted	$ 2.94	$ 2.94	$ 2.33	$ 1.44	$ 1.40
Total assets at year end	$ 2,571,680	$ 1,899,097	$ 1,268,747	$ 945,460	$ 735,854
Long-term obligations:					
Line of credit	$ 285,000	$ 334,000	$ -	$ 37,000	$ 11,000
Senior convertible notes	$ 287,500	$ 99,980	$ 99,885	$ 99,791	$ 99,696
Cash dividends declared and paid per common share	$ 0.10	$ 0.10	$ 0.10	$ 0.05	$ 0.05

Supplemental Selected Financial and Operational Data:

	Years Ended December 31,				
	2007	2006	2005	2004	2003
	(In thousands, except per share data)				
Balance Sheet Data:					
Total working capital (deficit)	$ (92,604)	$ 22,870	$ 4,937	$ 12,035	$ 3,101
Total stockholders' equity	$ 863,345	$ 743,374	$ 569,320	$ 484,455	$ 390,653
Weighted-average shares outstanding:					
Basic	61,852	56,291	56,907	57,702	62,467
Diluted	64,850	65,962	66,894	66,894	71,069
Reserves:					
Oil (MMBbl)	78.8	74.2	62.9	56.6	47.8
Gas (Mcf)	613.5	482.5	417.1	319.2	307.0
MCFE	1,086.5	927.6	794.5	658.6	593.7
Production and Operational:					
Oil and gas production revenues, including hedging	$ 936,577	$ 758,913	$ 711,005	$ 413,318	$ 365,114
Oil and gas production expenses	$ 218,208	$ 176,590	$ 142,873	$ 95,518	$ 88,509
DD&A	$ 227,596	$ 154,522	$ 132,758	$ 92,223	$ 81,960
General and administrative	$ 60,149	$ 38,873	$ 32,756	$ 22,004	$ 21,197
Production Volumes:					
Oil (MMBbl)	6.9	6.1	5.9	4.8	4.5
Gas (Bcf)	66.1	56.4	51.8	46.6	49.7
BCFE	107.5	92.8	87.4	75.4	76.9
Realized Price – pre hedging:					
Per Bbl	$ 67.56	$ 59.33	$ 53.18	$ 39.77	$ 29.40
Per Mcf	$ 6.74	$ 6.58	$ 8.08	$ 5.85	$ 5.12
Realized Price – net of hedging:					
Per Bbl	$ 62.60	$ 56.60	$ 50.93	$ 32.53	$ 26.96
Per Mcf	$ 7.63	$ 7.37	$ 7.90	$ 5.52	$ 4.89
Expense per MCFE:					
LOE	$ 1.31	$ 1.25	$ 0.99	$ 0.81	$ 0.77
Transportation	$ 0.14	$ 0.12	$ 0.09	$ 0.10	$ 0.09
Production taxes	$ 0.58	$ 0.54	$ 0.56	$ 0.36	$ 0.29
DD&A	$ 2.12	$ 1.67	$ 1.52	$ 1.22	$ 1.07
General and administrative	$ 0.56	$ 0.42	$ 0.37	$ 0.29	$ 0.28
Cash Flow:					
From operations	$ 630,792	$ 467,700	$ 409,379	$ 237,162	$ 204,319
Used in investing	$ (803,872)	$ (724,719)	$ (339,779)	$ (247,006)	$ (196,939)
From (used in) financing	$ 215,126	$ 243,558	$ (61,093)	$ 1,435	$ (3,707)

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 the United States. We earn 95 percent of our revenues and generate our cash flows from operations primarily from the sale of produced natural gas and crude oil. Our oil and gas reserves and operations are concentrated primarily in various Rocky Mountain basins, including the Williston, Big Horn, Wind River, Powder River and Greater Green River basins; the Mid-Continent Anadarko and Arkoma basins; the Permian Basin; the tight sandstone reservoirs of East Texas and North Louisiana; South Texas assets targeting the Olmos shallow gas formation; 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.

In 2007, we achieved the following financial and operational results:

- Average daily gas production of 181.0 MMcf per day, up 17 percent from 2006. Average daily oil production of 18.9 MBbl per day, up 14 percent from 2006. Average total equivalent daily production was 294.5 MMCFE which was an annual record for the Company.

- Estimated proved reserves of 78.8 MMBbls of oil and 613.5 Bcf of natural gas, or 1,086.5 BCFE, as of December 31, 2007. This was an increase of 17 percent from year-end 2006 proved reserves of 927.6 BCFE.

- Diluted earnings per share for 2007 were $2.94 on net income of $189.7 million. This reflects a slight decrease in net income when compared to 2006. The earnings per share benefited from the 0.8 million shares acquired by the Company during 2007.

- Cash flow from operating activities of $630.8 million, an increase of 35 percent from 2006.

- Debt to capitalization ratio is 40 percent. The 2007 amount does not consider proceeds from our divestiture of non-core assets that closed on January 31, 2008, described in Note 3 of Part IV, Item 15 of this report, which were used to pay down outstanding bank borrowings.

Our business objective is to economically grow our production and proved reserves through development, exploitation, and exploration activities, as well as through acquisitions of developed and undeveloped properties. Our operations are generally funded first through cash flows from operating activities, and then 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 credit facility, and cash flow from operating activities. In 2007, we deployed $740.9 million for development and exploration and invested $185.2 million for acquisitions of oil and gas properties.

A major determinant of the value of our Company is the value of our proved reserves. At year-end 2007, we had proved reserves of 1,086.5 BCFE of which 56 percent were natural gas and 77 percent were characterized as proved developed. Based on our year-end oil and gas reserve estimation process, we determined that we added 94.8 BCFE of proved reserves through acquisitions in 2007, 96 percent of which was natural gas and 42 percent of which was proved developed. Upward price revisions resulted in an increase of 34.5 BCFE which were driven primarily by higher oil prices at December 31, 2007, compared to the prior year. We experienced positive performance revisions of 6.4 BCFE and divested 1.4 BCFE of proved reserves. The before income tax PV-10 value of our proved reserves was $3.9 billion as of December 31, 2007. The after tax value of $2.7 billion as represented by the standardized measure calculation is presented in Note 13 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. This value is based on adjusted year-end pricing of $7.56 per Mcf and $88.71 per Bbl, which are up 36 percent and 65 percent, respectively, from the prior year.

Chief Executive Officer, Chief Financial Officer and Senior and Regional Management Transitions

During 2007, the Company underwent or announced personnel changes in the chief executive position and several regional manager positions. On February 23, 2007, Mark Hellerstein, retired as Chief Executive Officer after serving in that role since 1995. Tony Best, President of the Company, was appointed as Chief Executive Officer on that date. Mr. Hellerstein continues to serve as the Chairman of the Board. In June 2007, Jerry Schuyler, the Senior Vice President responsible for the Gulf Coast and Permian regions, left St. Mary to pursue other professional opportunities. Greg Leyendecker, then Operations Manager for the Gulf Coast region, assumed responsibility for the Gulf Coast and is now Vice President - Regional Manager of the Gulf Coast region. We also made the Midland office a stand-alone regional office which is headed by Lehman Newton III, as Vce President - Regional Manager of the Permian region. Mr. Leyendecker and Mr. Newton both joined St. Mary in 2006 and each have over 25 years of management and operational experience in the oil and gas industry. In July 2007, Stephen Pugh joined the Company as Senior Vice President - Regional Manager of the ArkLaTex region. Mr. Pugh succeeded David Hart, who retired from St. Mary after 15 years in various roles at the Company. Mr. Pugh came to St. Mary with over 25 years of engineering, operations, and business development experience in the oil and gas industry. In August of this year, Robert Nance, Senior Vice President - Regional Manager of the Rocky Mountain region announced his decision to retire in the first quarter of 2008 after more than 40 years in the oil and gas industry. Mark Mueller joined the Company as Senior Vice President in September and is now responsible for the Rocky Mountain region. Mr. Mueller has 20 years of management and technical experience in the oil and gas industry. Effective January 1, 2008, Mark Mueller became the Senior Vice President and Regional Manager. Subsequent to year end, David Honeyfield, Senior Vice President - Chief Financial Officer, announced he will resign effective March 21, 2008, to accept an executive position in an unrelated industry.

2007 Acquisition of South Texas Oil and Natural Gas Assets

We entered the greater Maverick Basin with two acquisitions in South Texas that target the Olmos shallow gas formation. These two acquisitions comprised the majority of the 94.8 BCFE of reserves classified as purchases of minerals in place. These properties added a sizable inventory of lower risk drilling locations to our portfolio. The first was the $30.0 million Catarina acquisition that closed in June 2007, in which we acquired 14.0 BCFE of proved reserves that were 99 percent gas and 65 percent proved developed. The average working interest in these assets is 30 percent; however we are the operator of the project area. The more significant transaction was the $148.9 million Rockford acquisition that closed in October 2007, where we have a nearly 100 percent working interest and are the operator. As mentioned elsewhere in this report, the final year-end reserve estimates we recorded were lower than the initial estimates we previously disclosed at the time of acquisition. We initially estimated reserves on a dry gas basis in our previous disclosure at the time of the acquisition whereas our annual report on Form 10-K disclosures utilize a wet gas presentation convention. This accounted for approximately ten BCFE of the difference in volumes, without any impact on value. The remaining difference was a result of our final year end assessment of proved non-producing reserves and our proved undeveloped reserves which were each lower than the amounts preliminarily estimated at the time of acquisition. The Rockford properties are adjacent to the Catarina assets. Consistent with prior acquisitions, we hedged several years of risked production related to these assets at the time of acquisition. These assets will be managed by our Gulf Coast region based in Houston, Texas.

2007 Capital Markets Activity

In March of 2007 we called for redemption of the then outstanding $100.0 million 5.75% Senior Convertible Notes. The notes had a conversion price of $13.00 per share. One hundred percent of the holders of the notes elected to convert their notes into shares of common stock. As a result of the conversion, 7.7 million shares of stock were issued to the note holders. This resulted in a decrease to long-term debt of $100.0 million, and an increase to common stock associated with the conversion together with the recognition of the excess tax benefit associated with the contingent interest feature associated with the notes. In April of 2007, we completed the private placement of $287.5 million of 3.50% Senior Convertible Notes. The net proceeds from the 3.50% Senior Convertible Notes were used to repay outstanding borrowings under our revolving credit facility.

Reserve Replacement, Finding Costs and Growth

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

We believe growth in net asset value per share drives appreciation in our stock price over the long term. Our challenge is to grow net asset value per share. To accomplish this, our goal is to economically replace at least 200 percent of annual production with new reserves and to grow production by ten to 15 percent per year. In 2007, we replaced 248 percent of our production at a finding cost of $3.48 per MCFE. The reserve replacement percentages and finding cost terms are defined in the glossary at the end of Part I, Items 1 and 2 of this report. Excluding acquisitions, we replaced 161 percent of our production at a cost of $4.42 per MCFE. Through acquisition activities we replaced 88 percent of production at an acquisition cost of $1.71 per MCFE. We sold reserves representing 1.4 BCFE of our proved reserves during 2007. 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 evaluating these items over an extended period of time is a better indication of performance. We note that aberrations, causing both relatively good and bad results, will occur over short intervals of time. Our three-year average reserve replacement ratio – including sales is 249 percent and our three-year average all-in finding cost is $3.01 per MCFE. Our finding cost numbers, particularly those related to drilling activities, have been notably higher in recent years. Part of this is explained by increases in completed well costs that have occurred in recent years which have affected all exploration and production companies. A significant part has related to the performance of our capital investments being less than anticipated. We will need to see an improvement in the types of projects we are pursuing and/or see an improvement in our operating abilities to meaningfully bring our finding cost numbers down. We believe that we have taken steps through recent acquisitions and portfolio screenings to improve the projects in which we are investing. Our operating teams are also performing technological reviews to see where we can improve our operations.

Sustainability in our business is dependent on the ability to create new ideas and new value year-after-year. The challenges we face are increasingly more difficult each year as North American oil and gas production continues to decline and other exploration and production companies compete for available reserves. We believe we have a formula for meeting these challenges. We have placed talented geoscientists, engineers, and landmen in each of our regional offices where their experience and knowledge of the local area can be fully utilized. We provide a compensation package that aligns their goals with those of the Company and in turn with those of our stockholders. We support our personnel with a strong balance sheet and fiscal and operating discipline. Even so, we are subject to similar constraints as other companies in the exploration and production industry. Limitations to future growth will be based on overall availability of additional qualified personnel and the generation of new ideas and the utilization of appropriate technology to improve the economics of our operations. We believe that we have sufficient capital resources for the foreseeable future, that we have the ability to grow our workforce, and that we have the necessary access to drilling rigs and services to execute our drilling budget for 2008 in a successful and profitable manner.

Oil and Gas Prices

Results of our operations and financial condition are significantly affected by oil and natural gas commodity prices, which fluctuate dramatically. In 2007, we saw a net increase in oil prices throughout the year. Geopolitical unrest in various producing regions overseas and concerns domestically related to refinery utilization and petroleum product inventories were the principal drivers of the increase in oil prices in 2007. Natural gas prices were moderated throughout 2007 by high levels of natural gas in storage and a lack of significant disruptive hurricane activity during year.

Repurchase of Common Stock

We evaluate the market price of our common stock relative to our internal assessment of net asset value per share. To the extent that the market price per share is below what we believe to be the net asset value per share and when the trading window for the Company and executive management is open, we may repurchase shares under the program. In 2007, we repurchased 792,216 shares of our common stock in the open market for a weighted-average price of $32.76 per share, including commissions. These shares were purchased under a share repurchase program approved by the Board. At the time we repurchased our shares, we entered into hedges for a commensurate amount of our production that was represented by the share repurchase in order to lock in the discounted price at which our shares were trading. As of the date of this filing, we are authorized to repurchase an additional 5,207,784 million shares under this program.

Hedging Activities

We have an active hedging program in which we hedge the first two to five years of an acquisition's risked production. We will also on occasion enter into derivative transactions to hedge a portion of our existing forecasted production. In October 2005, we hedged a significant portion of anticipated future production from our current producing properties using zero-cost collars. We also hedged a portion of specific forecasted natural gas production for 2006, 2007, and 2008 using swap contracts. Taking into account all oil and gas production hedge contracts in place through February 15, 2008, we have hedged anticipated future production of approximately 11 million Bbls of oil, 70 million MMBtu of natural gas, and 1 million Bbls of natural gas liquids through the year 2011. We believe we have established an economic base for our future operations, and the spread between the price floors and ceilings on our collars allows us to continue to participate in a higher oil and gas price environment. Please see Note 10 of Part IV, Item 15 of this report for additional information regarding our oil and gas hedges, and see the caption, *Summary of Oil and Gas Production Hedges in Place,* later in this section.

Net Profits Plan

Payments made for distributions from the Net Profits Plan have been expensed as compensation costs in the amounts of $31.9 million, $26.1 million, and $20.8 million for the years ended December 31, 2007, 2006, and 2005, respectively. Although increasing each year, these payments for 2007 were lower than originally budgeted due to the effects of increased oil and gas production expense and additional capital expenditures, both of which decreased the current impact of and delayed the timing of payout for the 2004 pool. 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. 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 our past exploration efforts. We have 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.

With respect to the accounting estimate of the liability associated with future estimated payments from our Net Profits Plan, we have recorded $50.8 million of net expense for the year ended December 31, 2007, thereby increasing the long-term liability associated with this item. This increase is related to an increase in the estimated future prices used to calculate the liability driven by overall commodity price increases, the accretion of the discount used for the calculation, and the addition of the 2007 pool. Additionally, we adjusted our discount rate used to calculate the present value of future payments during the fourth quarter of 2007 from a base rate of 15 percent to 12 percent. The single largest item was the impact from the change in discount rate, which drove an increase in the liability of $29 million as of December 31, 2007. As a result of these factors the liability increased to $211.4 million at December 31, 2007. While we have forecast that this liability will again increase in 2008, it is not possible to predict this with certainty due to the impact of commodity prices and reserve estimates on the valuation of this estimated liability. The Company will not be adding new Net Profits Plan pools prospectively as this benefit has been replaced with a different program, which is described in Footnote 7 of Part IV, Item 15 of this Form 10-K. The Company will continue to make payments from the established Net Profits Plan pools, as well as make prospective adjustments to the long-term liability, as necessary for current conditions. We expect general and administrative expense to increase due to changes in our incentive compensation program. Beginning in 2008, grants from the restricted stock units program and the Net Profits Plan are being replaced with grants of market-based performance shares under our 2006 Equity Plan. Although the total value of the compensation package to employees is essentially unchanged, we do expect general and administrative expense to increase as the cost of the grants of performance shares under the 2006 Equity Plan will be amortized over a much shorter time than the functional expense recorded under the Net Profits Plan.

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

The calculation of the estimated liability for the Net Profits Plan is highly sensitive to our price estimates and discount rate assumptions. For example, if we changed the commodity prices in our calculation by five percent, the liability recorded on the balance sheet at December 31, 2007, would differ by approximately $19 million. A one percentage point decrease in the discount rate would result in an increase to the liability of approximately $12 million, while a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $10 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, 2007, 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, 2007	September 30, 2007	June 30, 2007	March 31, 2007
	(In millions, except production sales data)			
Production (BCFE)	28.5	27.5	26.0	25.5
Oil and gas production revenue, excluding the effects of hedging	$ 273.7	$ 228.5	$ 216.2	$ 193.7
Lease operating expense	$ 37.8	$ 36.9	$ 31.6	$ 34.1
Transportation costs	$ 3.8	$ 3.2	$ 4.2	$ 4.4
Production taxes	$ 19.1	$ 14.9	$ 14.5	$ 13.7
DD&A	$ 64.8	$ 59.1	$ 54.7	$ 49.0
Exploration*	$ 16.0	$ 12.6	$ 11.1	$ 19.0
General and administrative expense*	$ 15.1	$ 15.8	$ 16.3	$ 12.9
Net income	$ 32.8	$ 57.7	$ 59.2	$ 40.0
Percentage change from previous quarter:				
Production (BCFE)	4%	6%	2%	2%
Oil and gas production revenues, excluding the effects of hedging	20%	6%	12%	7%
Lease operating expense	2%	17%	(7)%	9%
Transportation costs	19%	(24)%	(5)%	47%
Production taxes	28%	3%	6%	6%
DD&A	10%	8%	12%	10%
Exploration*	27%	14%	(42)%	19%
General and administrative expense*	(4)%	(3)%	26%	63%
Net income	(43)%	(3)%	48%	(8)%

*As a result of a change in circumstances in 2007, we have begun classifying payments made under the Net Profits Plan to exploration overhead only for those individuals who are currently employed by us and who continue to be involved in our exploration efforts. Therefore, the quarterly financial information presented in the above table reflects that Net Profits Plan payments associated with the distributions under the Net Profits Plan for ex-employees were recorded to general and administrative expense since there is no longer any functional link to exploration expense as there is by definition no periodic costs associated with geologic and geophysical, exploration related work by those ex-employees. The impact to any prior comparative quarter was not material.

2007 Financial Highlights

In 2007, we experienced record production and strong earnings. Our record production is the realization of operational and investment decisions made in prior years as well as the current period. Our solid earnings reflect our balanced production profile and high oil prices throughout the year. Our hedging program contributed to our earnings as we received meaningful cash flows from the realization of in-the-money natural gas hedges. Our operating margins remained strong in 2007 despite increasing operating costs. Our 2007 operating margin was $6.68 per MCFE compared to $6.27 per MCFE in 2006.

Net income for 2007 was $189.7 million or $2.94 per diluted share compared to $190.0 million or $2.94 per diluted share for the prior year. Net cash provided by operating activities was $630.8 million, up 35 percent from 2006. Average daily production for the year increased 16 percent to a record 294.5 MMCFE. Our average net realized price increased $0.53 to $8.71 per MCFE. Unit costs increased for the period as lease operating expenses increased $0.06 to $1.31 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 to 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 also have been actively incurring workover expense to restore or increase production in the Gulf Coast and Rocky Mountain regions. Per MCFE transportation costs increased $0.02 per MCFE, or 17 percent, to $0.14 per MCFE as compared to a year ago. The increase is due to newly drilled wells with higher transportation costs. Production taxes increased $0.04 per MCFE to $0.58 per MCFE and are a reflection of higher commodity prices.

Depletion, depreciation, and amortization, including asset retirement obligation accretion expense, per MCFE increased $0.45 to $2.12 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 per MCFE cost of oil and gas properties. General and administrative expense increased $0.14 per MCFE to $0.56 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 2007 was $58.7 million, which was $6.8 million higher than the $51.9 million incurred during 2006 due to an increase in exploratory dry hole expense as well as the overall increase in the level of exploration activity during 2007. We discuss these financial results and trends in more detail below.

Outlook for 2008

Our anticipated exploration and development drilling budget is $626 million for 2008, which is 16 percent smaller than the $740.9 million we spent on development and exploration in 2007. The decrease in our development and exploration budget reflects our desire to improve the capital efficiency of our investments and to manage the balance sheet to improve financial flexibility in the future. Planned expenditures for programs that failed to meet our expectations in 2007 were either omitted or substantially reduced in 2008. The reduced budget for 2008 is also expected to allow for cash flow in excess of our capital investments for the year. We believe that this will provide us the financial flexibility to accelerate successful drilling programs, pursue potential acquisition opportunities, repurchase outstanding shares of common stock, or repay bank borrowings when the opportunity arises. We have not budgeted any capital for acquisitions in 2008, however we believe our solid financial condition provides us the ability to execute significant transactions we believe will be accretive to the Company. We anticipate production for the first half of 2008 to be slightly lower than the last quarter of 2007 due to the divestiture of non-core properties that closed subsequent to year-end. We project production will ramp up in the second half of 2008 as many of our exploration and development projects are scheduled to come on-line in the second half of the year.

Our 2008 capital budget was built using a NYMEX price deck of $7.00 per Mcf and $60.00 per barrel. Current strip prices for oil and natural gas support our plans for the year. However, we are keenly aware of how volatile oil and natural gas prices are and how quickly they can move. The cost environment related to drilling and completing wells appears to have leveled out in the past year after several years of significant cost escalation. Day rates for land-based drilling rigs have held flat or declined throughout the year, and the increasing number of drilling rigs entering the market bodes well for this trend. Prices for completion services continue to be firm, but we note new capacity is being added by incumbent providers as well as new entrants to the service sector. Availability of drilling and completion services is not the potentially limiting condition that existed the last two years. Prices for these services are highly dynamic, vary greatly region to region, and are influenced greatly by commodity prices. We will continue to evaluate the economics of each well prior to the onset of drilling using the most current commodity price and cost information available to ensure it meets our economic and operational thresholds.

The information below provides some detail of our capital investment plans for 2008:

- We believe that we have the necessary capital, personnel, and service availability to execute this program. The $626 million budgeted for drilling activities in 2008 is allocated among our core areas as described below. Included in the discussion are highlights of the program in each region this year.

  ArkLaTex - $161 million – Half of our budgeted capital investment for this region in 2008 is for projects targeting the Cotton Valley sandstone formation. The largest component relates to activity planned at Elm Grove Field, where 20-acre increased density drilling and Hosston and Cotton Valley formation commingling are improving results and enhancing reserve recovery. Importantly, there has been a successful horizontal test well at Elm Grove Field that could lead to additional upside. Also in the Cotton Valley program, we plan to participate in twice the number of wells in Terryville Field in 2008 compared to 2007. Lastly, we will operate a small Cotton Valley program in 2008 where we have plans to drill two vertical and three horizontal wells. The other major program in the ArkLaTex region is our operated horizontal James Lime program. We plan to operate two drilling rigs continuously and drill more than 20 wells throughout 2008.

  Mid-Continent - $135 million – The largest part of our 2008 program in the Mid-Continent relates to the horizontal Woodford program in the Arkoma Basin. After mixed results in the horizontal Woodford program in the first half of 2007, we had a series of successful wells in the latter part of the year which we believe validates our understanding of the well and completion design. We currently plan to drill ten horizontal Woodford wells using two operated rigs in the first half of 2008, as well as continuing to participate with our partners in outside operated wells. With continued success in the play, we anticipate increasing our activity and our capital investment in the program in the latter part of 2008. In the Western Oklahoma Washes program in the Anadarko Basin, which we have referred to previously as the Mayfield development area, we plan to invest in projects in the Atoka and Granite Wash formations. The area is a known hydrocarbon province, and efforts in 2008 will center around refining our assessments of geotechnical aspects of the program and revising drilling and completion techniques with an intent to lower the completion costs. We also plan to deploy approximately one quarter of the region's 2008 capital budget to drill six exploratory test wells which focus on a geologic concept that was developed in 2007 which targets deeper formations in the Anadarko Basin.

  Rocky Mountain - $130 million – In the conventional Rockies program, six vertical wells and two recompletions in the Red River are planned for 2008. We also plan to drill a small number of horizontal Bakken wells in and around our historic Bakken development areas in Montana. We have planned workover and recompletion operations in our Wind River Basin and Big Horn Basin oil properties. At the outside operated Atlantic Rim coalbed methane play in the Green River Basin, we expect to see activity ramp up since regulatory and environmental delays appear to have been resolved. At Hanging Woman Basin, we plan to moderate our drilling activity in 2008 focusing on completing the in-fill program in the shallow coals, monitoring the intermediate depth wells and testing several horizontal completion techniques in the deeper coal horizontal programs.

  Permian - $120 million – The vast majority of capital investment made in the Permian in 2008 will be in properties targeting the Wolfberry section. At Sweetie Peck, we plan to operate three drilling rigs continuously throughout the year. Included in the budget are investment dollars to test several 40-acre pilot areas which, if successful, could add meaningful proved reserves. At the Halff East Wolfberry development area, we will invest approximately $25 million with our operating partner. We will also be investing a small amount of capital in several smaller programs, including the Delaware waterfloods.

  Gulf Coast - $80 million – Our development and exploration budget in the Gulf Coast region for 2008 is focused on the integration and development of the two Olmos shallow gas projects that we acquired in South Texas in 2007. Approximately half of the budgeted capital will be deployed to drill new

Olmos wells, with additional capital being invested in a number of recompletion opportunities. We anticipate that the addition of this resource play will provide focus and a visible inventory of projects for our Gulf Coast team. We will also invest capital in production facilities for an intermediate deepwater discovery from 2005 that is expected to be brought online in early 2009.

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

	As of and for the Years Ended			Percent Change Between	
	2007	2006	2005	2007/2006	2006/2005
Selected Operations Data (In Thousands, Except Price, Volume, and Per MCFE Amounts):					
Total proved reserves					
Oil (MMBbl)	78.8	74.2	62.9		
Natural gas (Bcf)	613.5	482.5	417.1		
BCFE	1,086.5	927.6	794.5	17%	17%
Net production volumes					
Oil (MMBbl)	6.9	6.1	5.9		
Natural gas (Bcf)	66.1	56.4	51.8		
BCFE	107.5	92.8	87.4	16%	6%
Average daily production					
Oil (MBbl)	18.9	16.6	16.2		
Natural gas (MMcf)	181.0	154.7	141.9		
MMCFE	294.5	254.2	239.4	16%	6%
Oil & gas production revenues					
Oil production, including hedging	$ 432,375	$ 342,810	$ 301,860		
Gas production, including hedging	504,202	416,103	409,145		
Total	$ 936,577	$ 758,913	$ 711,005	23%	7%
Oil & gas production costs					
Lease operating expenses	$ 140,389	$ 115,896	$ 86,130		
Transportation costs	15,529	10,999	8,010		
Production taxes	62,290	49,695	48,733		
Total	$ 218,208	$ 176,590	$ 142,873	24%	24%
Average net realized sales price (1)					
Oil (per Bbl)	$ 62.60	$ 56.60	$ 50.93	11%	11%
Natural gas (per Mcf)	$ 7.63	$ 7.37	$ 7.90	4%	(7)%
Per MCFE data					
Average net realized price (1)	$ 8.71	$ 8.18	$ 8.14	6%	-%
Lease operating expense	(1.31)	(1.25)	(0.99)	5%	26%
Transportation costs	(0.14)	(0.12)	(0.09)	17%	33%
Production taxes	(0.58)	(0.54)	(0.56)	7%	(4)%
General and administrative	(0.56)	(0.42)	(0.37)	33%	14%
Operating profit	$ 6.12	$ 5.85	$ 6.13	5%	(5)%
Depletion, depreciation and amortization	$ 2.12	$ 1.67	$ 1.52	27%	10%
Financial Information (In Thousands, Except Per Share Amounts):					
Working capital (deficit)	$ (92,604)	$ 22,870	$ 4,937	(505)%	363%
Long-term debt	$ 572,500	$ 433,980	$ 99,885	32%	334%
Stockholders' equity	$ 863,345	$ 743,374	$ 569,320	16%	31%
Net income	$ 189,712	$ 190,015	$ 151,936	-%	25%
Basic net income per common share	$ 3.07	$ 3.38	$ 2.67	(9)%	27%
Diluted net income per common share	$ 2.94	$ 2.94	$ 2.33	-%	26%
Basic weighted-average shares outstanding	61,852	56,291	56,907	10%	(1)%
Diluted weighted-average shares outstanding	64,850	65,962	66,894	(2)%	(1)%
Net cash provided by operating activities	$ 630,792	$ 467,700	$ 409,379	35%	14%
Net cash used in investing activities	$ (803,872)	$ (724,719)	$ (339,779)	11%	113%
Net cash provided by (used in) financing Activities	$ 215,126	$ 243,558	$ (61,093)	(12)%	(499)%

(1) Includes the effects of our hedging activities.

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

The increase in our proved reserves reflects our drilling results and acquisition activity. Please see Note 13 of Part IV, Item 15 for additional details. Over time, our ability to economically replace at least 200 percent of the total volumes produced annually has proven to be a key factor that determines whether we are successful in achieving our goal of increasing net asset value per share. We anticipate that we must continue our successful drilling program and average one or more relatively significant acquisitions per year in the current price environment to achieve this level of ongoing growth. The measure of our success will vary year-to-year due to changes in these factors.

Rapid changes in production volumes, oil and gas sales revenues, and costs reflect the cyclical and highly volatile prices our industry receives for production, as well as the impact of the timing of acquisitions. The comparison of changes in production from 2006 to 2007 reflects the positive results from our drilling programs in 2007 and the full year impact of a significant acquisition made in the fourth quarter of 2006. Production volumes in 2007 were also affected by production from oil and gas properties acquired in 2007 and from production from new drilling activity.

We present per MCFE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends that we believe require analysis. Our year-to-year comparison of financial results presented later provides additional details for the analysis of changes between years in selected line items. Oil and gas production expenses increased in 2007 as a result of a higher percentage of oil production and ongoing upward pressure for oil and gas sector services related to the ongoing operation of our oil and gas properties. Depreciation, depletion, and amortization will continue to significantly increase due to higher costs associated with finding and acquiring crude oil and natural gas reserves. General and administrative expense increased as a result of $41 million in expense associated with payments under our Net Profits Plan, costs associated with office space and overall upward pressure on compensation in the exploration and production industry.

We have in-the-money stock options, unvested restricted stock units, and Senior Convertible Notes that are considered potentially dilutive securities. At times these dilutive securities can affect our earnings per share. Consequently, both basic and diluted earnings per share are presented in the table above. A detailed explanation is presented in Note 1 of Part IV, Item 15 of this report. Basic and diluted weighted-average common shares outstanding used in our 2007, 2006 and 2005 earnings per share calculations reflect our stock repurchases, offset by an increase in outstanding shares related to stock option exercises. Basic and diluted weighted-average shares outstanding in 2007 were affected by similar factors as 2006 and 2005, as well as an increase in shares that is related to the issuance of common stock upon settlement of RSU's following the expiration of the restriction period. We issued 733,650 shares of common stock in 2007, 1,489,636 shares in 2006, and 936,403 shares in 2005 as a result of stock option exercises. These share issuances were offset by the repurchase of 792,216 shares of common stock in 2007, 3,319,300 shares in 2006, and 1,175,282 shares in 2005 through our stock repurchase plan.

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

Overview of Liquidity and Capital Resources

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

Sources of cash

Based on our current forecast, we project that our 2008 cash flows from operations will exceed our planned capital investment budget for exploration and development resulting in free cash flow that will be available for additional drilling opportunities, acquisitions, share repurchases, or repayment of debt. Accordingly, we do not expect to access the capital markets in 2008. On January 31, 2008, we closed on the sale of our previously announced divestiture of non-core oil and gas properties. Net proceeds from this transaction, before commission costs, was $131.6 million. These proceeds were used to repay debt under our revolving credit facility. We do anticipate that we will continue to evaluate our property base for the divestiture of properties that we consider non-core and we will likely utilize such proceeds to fund our capital programs. Although our working capital is a negative amount, it is important to note that a significant portion of this relates to hedge contracts that are in a liability position. We classify those expected settlements that are anticipated to be settled over the year of 2008 as a current item in our balance sheet.

Our primary sources of liquidity are the cash provided by operating activities, debt financing, sales of non-core properties, and access to capital markets. All of these sources can be impacted by the general condition of our industry and by significant fluctuations in oil and gas prices, operating costs, and volumes produced. We have no control over the market prices for oil and natural gas, although we are able to influence the amount of our net realized revenues related to oil and gas sales through the use of derivative contracts. A decrease in 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 continue to be available to us, although they are significantly less favorable than this time a year earlier. Credit spreads have increased materially and the volume of transactions being placed in the market is down dramatically. The overall credit markets have seen a significant contraction as a result of credit tightening caused by widely reported sub-prime and leveraged loan market issues. Equity and convertible debt financings are still an available alternative and are somewhat favorable to energy companies that operate in the exploration and production industry. This is a result of strong commodity prices and the general strength reflected in the balance sheets of the companies in this industry as well as the historically low credit defaults of energy companies. We do not, however, anticipate any need to raise either public debt or equity related capital in the foreseeable future. We intend to rely on our current credit facility for borrowings. However, a significant transaction could necessitate the need to raise additional public debt or equity financing.

Our current credit facility. We have a five-year, $500 million credit facility agreement with Wachovia Bank, Wells Fargo Bank and nine other participating banks. This credit facility has a borrowing base of $1.25 billion. We have elected a commitment amount of $500 million. We believe this commitment level is adequate for our near-term liquidity requirements. The credit agreement has a maturity date of April 7, 2010. We must comply with certain financial and non-financial covenants under our existing credit facility. The Company is in compliance with all covenants associated with the credit facility. As of February 15, 2008, we had $320.0 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 new facility are secured by mortgages on the majority of our oil and gas properties and a pledge of the common stock of our material subsidiary companies.

Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the consolidated statements of operations. We had an outstanding loan balance of $285.0 million as of December 31, 2007. As of December 31, 2007, we had a cash and short-term investment balance of $44.7 million.

We decreased our net borrowings from the previous year by $49.0 million when comparing the ending balance sheet amounts. A substantial increase in the average outstanding credit facility balance throughout 2007, offset by a decrease in interest rates and an increase in the amount of capitalized interest of $1.9 million, resulted in a higher interest expense of $19.9 million in 2007 compared with $8.5 million in 2006. Our weighted-average interest rate paid in 2007 was 5.4 percent and included fees paid on the unused portion of the credit facility aggregate commitment amount, amortization of deferred financing costs, amortization of the contingent interest embedded derivative associated with the 5.75% Senior Convertible Notes, and the effects of interest rate swaps.

Uses of cash

We use cash for the acquisition, exploration, and development of oil and gas properties, and for the payment of debt obligations, trade payables, income taxes, common stock repurchases, and stockholder dividends. During 2007 we spent $637.7 million of cash on capital development and $182.9 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 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 anticipate spending approximately $626 million for capital and exploration expenditures in 2008. The capital expenditures budget was described in more detail earlier in the *Outlook for 2008* section. 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 16 percent of our total income tax expense for 2007. We make estimated payments during the calendar year and as of December 31, 2007, we anticipate that we have an income tax refund with accrued interest due the Company of $1.0 million.

During 2007 we purchased 792,216 shares of our common stock in the open market at a weighted-average price of $32.76, including commissions, for a total of $26.0 million. As of this filing date we have Board authorization to repurchase up to an additional 5,207,784 million 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 2007, we paid $6.3 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 Change Between		Percent of Change Between	
	2007/2006	2006/2005	2007/2006	2006/2005
Net Cash Provided By Operating Activities	$ 163,092	$ 58,321	35%	14%
Net Cash Used In Investing Activities	$ (79,153)	$ (384,940)	11%	113%
Net Cash Provided By (Used In) Financing Activities	$ (28,432)	$ 304,651	(12)%	499%

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 amount 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 for income taxes decreased $26.7 million relative to the prior year as the Company was able to deduct for tax purposes 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 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 issuance 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.

Analysis of cash flow changes between 2006 and 2005

Operating activities. Cash received from oil and gas production revenue, net of the realized effects of hedging, increased $152.5 million to $802.1 million for the year ended December 31, 2006. Included in the oil and gas production revenue amount is $28.2 million of realized hedging gains. This increase was the result of a six percent increase in production offset by lower realized prices. Net cash payments made for income taxes decreased $40.2 million as the Company was able to deduct a larger amount of intangible drilling costs due to the expanded capital program.

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

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

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

Capital Expenditures

The following table sets forth certain historical information regarding the costs incurred by us in our oil and gas activities. The below amounts for 2007, 2006, and 2005 include capitalized costs associated with asset retirement obligations of $27.6 million, $7.8 million, and $22.8 million, respectively.

	Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
Development costs	$ 591,013	$ 367,546	$ 249,518
Exploration costs	111,470	126,220	69,817
Acquisitions:			
Proved	161,665	238,400	84,981
Unproved	23,495	44,472	2,853
Leasing activity	38,436	28,816	14,330
Total	$ 926,079	$ 805,454	$ 421,499

The costs we incurred for capital and exploration activities in 2007 increased $120.6 million or 15 percent compared to 2006. This increase was a result of planned increases in drilling activity offset by an $88.1 million decrease in acquisitions relative to the prior year. Increased activity in our drilling program was the primary driver of this increase, particularly since cost inflation moderated in 2007.

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 income taxes. General and administrative expenses have not been adjusted. To fund the capital expenditures we incurred in those years we would have been required to utilize different amounts under our credit facility as a source of funds. In each of these years we would have had sufficient borrowing base available under our credit facility to meet this contingency without reducing or eliminating expenditures 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,		
	2007	2006	2005
		(In thousands)	
Oil	$ 25,248	$ 20,496	$ 18,098
Natural Gas	29,998	25,117	24,502
Total	$ 55,246	$ 45,613	$ 42,600

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

Summary of Oil and Gas Production Hedges in Place

Our oil and natural gas derivative contracts include swap and 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 also hedge a portion of our forecasted production on a discretionary basis. As of year end our hedged positions of anticipated production through 2011 totaled approximately 11 million Bbls of oil, 70 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 tables describe the volumes, average contract prices, and fair value of contracts we have in place as of December 31, 2007. We seek to minimize basis risk and index the majority of our oil contracts to NYMEX prices and our gas contracts to various regional index prices associated with pipelines in proximity to our areas of gas production.

Oil Contracts

Oil Swaps

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at December 31, 2007 Asset/(Liability)
	(Bbl)	(per Bbl)	(in thousands)
First quarter 2008 -			
NYMEX WTI	493,000	$ 69.52	$ (12,707)
WCS	45,000	$ 51.63	(464)
Second quarter 2008 -			
NYMEX WTI	459,000	$ 69.10	(11,157)
WCS	45,000	$ 53.69	(296)
Third quarter 2008 -			
NYMEX WTI	438,000	$ 69.22	(9,814)
WCS	45,000	$ 54.03	(206)
Fourth quarter 2008 -			
NYMEX WTI	405,000	$ 68.79	(8,645)
WCS	15,000	$ 50.42	(107)
2009 -			
NYMEX WTI	1,363,000	$ 67.74	(26,439)
2010 -			
NYMEX WTI	1,239,000	$ 66.47	(22,068)
2011 -			
NYMEX WTI	1,032,000	$ 65.36	(18,312)
All oil swap contracts			$ (110,215)

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at December 31, 2007 Asset/(Liability)
	(Bbl)	(per Bbl)	(per Bbl)	(in thousands)
First quarter 2008	415,000	$ 50.00	$ 69.83	$ (10,580)
Second quarter 2008	415,000	$ 50.00	$ 69.83	(9,876)
Third quarter 2008	419,000	$ 50.00	$ 69.82	(9,385)
Fourth quarter 2008	419,000	$ 50.00	$ 69.82	(9,012)
2009	1,526,000	$ 50.00	$ 67.31	(32,858)
2010	1,367,500	$ 50.00	$ 64.91	(29,056)
2011	1,236,000	$ 50.00	$ 63.70	(26,176)
All oil collars				$ (126,943)

Gas Contracts

Gas Swaps

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at December 31, 2007 Asset/(Liability)
	(MMBtu)	(per MMBtu)	(in thousands)
First quarter 2008 -			
IF CIG	780,000	$ 8.94	$ 2,104
IF PEPL	1,410,000	$ 9.28	3,990
IF NGPL	330,000	$ 7.53	366
IF ANR OK	330,000	$ 7.68	408
IF EL PASO	220,000	$ 7.94	284
IF HSC	1,120,000	$ 8.64	1,726
Second quarter 2008 -			
IF CIG	780,000	$ 7.00	561
IF PEPL	1,420,000	$ 7.22	1,077
IF NGPL	240,000	$ 6.41	(18)
IF ANR OK	240,000	$ 6.66	(17)
IF EL PASO	260,000	$ 6.72	1
IF HSC	1,180,000	$ 7.66	276
Third quarter 2008 -			
IF CIG	780,000	$ 6.70	148
IF PEPL	1,460,000	$ 7.48	1,046
IF NGPL	190,000	$ 6.69	(26)
IF ANR OK	190,000	$ 6.82	31
IF EL PASO	280,000	$ 7.16	2
IF HSC	1,200,000	$ 7.95	241
Fourth quarter 2008 -			
IF CIG	780,000	$ 7.30	400
IF PEPL	1,490,000	$ 8.32	1,849
IF NGPL	160,000	$ 7.10	2
IF ANR OK	160,000	$ 7.18	19
IF EL PASO	300,000	$ 7.20	(29)
IF HSC	1,400,000	$ 8.44	562
2009 -			
IF CIG	1,710,000	$ 7.79	998
IF PEPL	3,360,000	$ 8.06	2,189
IF NGPL	440,000	$ 7.11	(176)
IF ANR OK	440,000	$ 7.38	(59)
IF EL PASO	1,200,000	$ 7.11	(646)
IF HSC	6,320,000	$ 8.35	447

Gas Swaps (continued)

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at December 31, 2007 Asset/(Liability)
	(MMBtu)	(per MMBtu)	(in thousands)
2010 -			
IF ANR OK	60,000	$ 7.98	(18)
IF NGPL	60,000	$ 7.60	(37)
IF EL PASO	1,090,000	$ 6.79	(1,065)
IF HSC	3,460,000	$ 8.25	(421)
2011 -			
IF EL PASO	880,000	$ 6.34	(1,220)
All gas swap contracts			$ 14,995

Gas Collars

Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at December 31, 2007 Asset/(Liability)
	(MMBtu)	(per MMBtu)	(per MMBtu)	(in thousands)
First quarter 2008 -				
IF CIG	720,000	$ 5.60	$ 8.72	$ 35
IF PEPL	1,642,500	$ 6.28	$ 9.42	329
IF HSC	240,000	$ 6.57	$ 9.70	19
NYMEX Henry Hub	120,000	$ 7.00	$ 10.57	14
Second quarter 2008 -				
IF CIG	720,000	$ 5.60	$ 8.72	115
IF PEPL	1,642,500	$ 6.28	$ 9.42	662
IF HSC	240,000	$ 6.57	$ 9.70	30
NYMEX Henry Hub	120,000	$ 7.00	$ 10.57	31
Third quarter 2008 -				
IF CIG	720,000	$ 5.60	$ 8.72	71
IF PEPL	1,657,500	$ 6.28	$ 9.42	549
IF HSC	240,00	$ 6.57	$ 9.70	(1)
NYMEX Henry Hub	120,000	$ 7.00	$ 10.57	25
Fourth quarter 2008 -				
IF CIG	720,000	$ 5.60	$ 8.72	(35)
IF PEPL	1,657,500	$ 6.28	$ 9.42	314
IF HSC	240,000	$ 6.57	$ 9.70	(47)
NYMEX Henry Hub	120,000	$ 7.00	$ 10.57	(8)

Gas Collars (continued)

Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at December 31, 2007 Asset/(Liability)
	(MMBtu)	(per MMBtu)	(per MMBtu)	(in thousands)
2009 -				
IF CIG	2,400,000	$ 4.75	$ 8.82	(1,036)
IF PEPL	5,510,000	$ 5.30	$ 9.25	(2,036)
IF HSC	840,000	$ 5.57	$ 9.49	(516)
NYMEX Henry Hub	360,000	$ 6.00	$ 10.35	(164)
2010 -				
IF CIG	2,040,000	$ 4.85	$ 7.08	(1,940)
IF PEPL	4,945,000	$ 5.31	$ 7.61	(4,740)
IF HSC	600,000	$ 5.57	$ 7.88	(712)
NYMEX Henry Hub	240,000	$ 6.00	$ 8.38	(252)
2011 -				
IF CIG	1,800,000	$ 5.00	$ 6.32	(2,350)
IF PEPL	4,225,000	$ 5.31	$ 6.51	(6,066)
IF HSC	480,000	$ 5.57	$ 6.77	(816)
NYMEX Henry Hub	120,000	$ 6.00	$ 7.25	(181)
All gas collars				$ (18,706)

Natural Gas Liquid Contracts

Natural Gas Liquid Swaps

	Volumes	Weighted-Average Contract Price	Fair Value at December 31, 2007 Asset/(Liability)
	(Bbls)	(per Bbl)	(in thousands)
First quarter 2008	151,000	$ 39.54	$ (3,581)
Second quarter 2008	170,000	$ 39.49	(3,190)
Third quarter 2008	194,000	$ 39.25	(3,403)
Fourth quarter 2008	217,000	$ 38.63	(4,026)
2009	627,000	$ 38.61	(9,053)
All natural gas liquid swaps			$ (23,253)

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 will pay a fixed rate of 4.90 percent and will be paid a variable rate of the one-month LIBOR rate.

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 our net liability related to the interest rate swaps, and paid a 1.1 percent interest factor 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.

Market risk is estimated as the potential change in fair value resulting from an immediate hypothetical one percentage point parallel shift in the yield curve. For fixed-rate debt, interest rate changes affect the fair market value but do not impact results of operations or cash flows. Conversely, interest rate changes for floating-rate debt generally do not affect the fair market value but do impact future results of operations and cash flows, assuming other factors are held constant. The carrying amount of our floating-rate debt typically approximates its fair value. We had $285.0 million of floating rate debt outstanding as of December 31, 2007. Our fixed rate debt outstanding at this same date was $287.5 million associated with the 3.50% Senior Convertible Notes.

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

Schedule of contractual obligations

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

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-Term Debt	$ 615.3	$ 10.1	$ 315.2	$ 290.0	$ -
Operating Leases	44.2	29.1	13.0	1.9	0.2
Other Long-Term Liabilities	511.8	141.8	238.5	130.6	0.9
Total	$ 1,171.3	$ 181.0	$ 566.7	$ 422.5	$ 1.1

This table includes our 2007 estimated pension liability payment of approximately $1.9 million expected to be paid in the second quarter of 2008. The table also includes the remaining unfunded portion of our estimated pension liability of $4.2 million even though we recognize that we cannot determine with accuracy the timing of future payments. We have made payments of $2.2 million, $1.3 million, and $1.1 million in 2007, 2006, and 2005, respectively, towards the pension liability. We have included $216.7 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 value recorded on the balance sheet reflects the impact of discounting and therefore differs from the amounts disclosed in this table. The variability in the amount of the payments will be a direct reflection of commodity prices, capital expenditures, and operating costs in future periods. Predicting the timing of payments associated with this liability is contingent upon estimates of appropriate discount factors, adjusting for risk and time value, and upon a number of factors that we cannot control.

The scheduled repayment of the long-term credit facility is in 2010. Accordingly, it has been disclosed in the table as such. Since this is a revolving credit facility, the actual payments will vary significantly. We anticipate refinancing this obligation. For purposes of this table, we assume that we will net share settle the 3.50% Senior Convertible Notes. Additionally, $42.8 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 for these amounts. Pension liabilities and asset retirement obligations are discussed in Note 8 and Note 9 of Part IV, Item 15, respectively, and the Net Profits Plan is discussed in Note 7 of Part IV, Item 15 of this report.

This table also includes estimated oil and natural gas derivative payments of $282.9 million based on futures market prices as of December 31, 2007. This amount represents only the cash outflows; it does not include oil and gas receipts of $20.6 million that would be paid based on December 31, 2007, market prices. The net of $262.3 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, 2007, was a net liability of $264.1 million. The fair value considers time value and volatility that affect the ultimate fair value. Both the intrinsic value and fair value will change as oil and natural gas commodity prices change. Please refer to the discussion above under the caption Summary of Oil and Gas Production Hedges in Place in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and to Note 10 – Derivative Financial Instruments in Part IV, Item 15 of this report for additional information regarding our oil and gas hedges.

We believe that we will continue to pay annual dividends of $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 and up to December 31, 2007, 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 changing business conditions or unexpected circumstances. Policies we believe are critical to understanding our business operations and results of operations are detailed below. For additional information on our significant accounting policies you should see Note 1 – Summary of Significant Accounting Policies, Note 9 – Asset Retirement Obligations, and Note 12 – Disclosures About Oil and Gas Producing Activities in Part IV, Item 15 of this report.

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

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

	Years Ended December 31,					
	2007		2006		2005	
	BCFE Change	Percent of total Additions	BCFE Change	Percent of total Additions	BCFE Change	Percent of total Additions
Revisions resulting from price changes	34.5	13%	(52.2)	(23)%	23.1	10%
Revisions resulting from performance	6.4	2%	66.3	29%	10.8	5%
Total	40.9	15%	14.1	6%	33.9	15%

Over the three-year period, we added 720.7 BCFE of reserves. Of these, 83.5 BCFE, or 12 percent, was a result of changes in estimates based on the performance of our oil and gas properties. A 5.4 BCFE increase 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:

	Years Ended December 31,					
	2007		2006		2005	
	BCFE Change	Percent Change	BCFE Change	Percent Change	BCFE Change	Percent Change
A 10% decrease in pricing	(16.3)	(2)%	(28.2)	(3)%	(28.9)	(4)%
A 10% decrease in proved undeveloped reserves	(25.0)	(2)%	(20.0)	(2)%	(14.6)	(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 analyses of liquidity and capital resources. We derive our revenue primarily from the sale of produced natural gas and crude oil. We report revenue as the gross amounts we receive before taking into account production taxes and transportation costs, which are reported as separate expenses. Revenue is recorded in the month our production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to a purchaser. At the end of each month we make estimates of the amount of production delivered to the purchaser and the price we will receive. We use our knowledge of our properties, their historical performance, 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 $11.6 million in 2007.

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 the actual settlements with the counterparty. If our natural gas and crude oil hedge contracts did not qualify for hedge accounting treatment or we chose not to use this hedge accounting methodology, our periodic 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 for oil and gas hedge loss in our statements of operations. These fluctuations could be especially significant in a volatile pricing environment such as what we have encountered over the last three years. The amounts recorded to accumulated other comprehensive income (loss) of $(170.0) million, $69.0 million, and $(57.2) million, for 2007, 2006, and 2005, 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 Profit Plan. The estimated liability is calculated based on a number of assumptions, including estimates of oil and gas reserves, recurring and workover lease operating expense, product and ad valorem tax rates, present value discount factors, and pricing assumptions. Additional discussion is included in the analysis in the above section titled *Overview of the Company*, under the heading *Net Profits Plan*.

Asset retirement obligations. We are required to recognize an estimated liability for future costs associated with the abandonment of our oil and gas properties. We base our estimate of the liability on our historical experience in abandoning oil and gas wells projected into the future based on our current understanding of federal and state regulatory requirements. Our present value calculations require us to estimate the economic lives of our properties, assume what future inflation rates apply to external estimates, and determine what credit adjusted risk-free rate to use. The 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 is recorded at cost. An impairment allowance is provided on unproved property when we determine that the property will not be developed or the carrying value will not be realized. We evaluate the realizability of our proved properties and other long-lived assets whenever events or changes in circumstances indicate that impairment may be appropriate. Our impairment test compares the expected undiscounted future net revenues from a property, using escalated pricing, with the related net capitalized costs of the property at the end of each period. When the net capitalized costs exceed the undiscounted future net revenue of a property, the cost of the property is written down to our estimate of fair value, which is determined by applying a discount rate that we believe is indicative of the current market. Our criteria for an acceptable internal rate of return are subject to change over time. Different pricing assumptions or discount rates could result in a different calculated impairment.

Income taxes. We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements in accordance with SFAS No. 109, "Accounting for Income Taxes." This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Additionally, our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared, therefore we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits, and net operating and capital loss carryforwards and carrybacks. Adjustments related to differences between the estimates we used and actual amounts we reported are recorded in the period in which we file our income tax returns. These adjustments and changes in our estimates of asset recovery could have an impact on our results of operations. A one percent change in our effective tax rate would have affected our calculated income tax expense by $2.9 million for the year ended December 31, 2007.

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

Additional Comparative Data in Tabular Format:

	Change Between Years	
Oil and Gas Production Revenues:	2007 and 2006	2006 and 2005
Increase in oil and gas production Revenues, net of hedging (in thousands)	$ 177,664	$ 47,908
Components of Revenue Increases (Decreases):		
Oil		
Realized price change per Bbl, net of hedging	$ 6.00	$ 5.67
Realized price percentage change	11%	11%
Production change (MBbl)	851	130
Production percentage change	14%	2%
Natural Gas		
Realized price change per Mcf, net of hedging	$ 0.26	$ (0.53)
Realized price percentage change	4%	(7)%
Production change (MMcf)	9,613	4,646
Production percentage change	17%	9%

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

	Years Ended December 31,		
Revenue	2007	2006	2005
Oil	46%	45%	42%
Natural Gas	54%	55%	58%
Production			
Oil	39%	39%	41%
Natural Gas	61%	61%	59%

Information regarding the effects of oil and gas hedging activity:

	Years Ended December 31,		
	2007	2006	2005
Oil Hedging			
Percentage of oil production hedged	66%	66%	24%
Oil volumes hedged (MBbl)	4,565	4,021	1,419
Decrease in oil revenue	$ (34.3 million)	$ (16.6 million)	$ (13.3 million)
Average realized oil price per Bbl before hedging	$ 67.56	$ 59.33	$ 53.18
Average realized oil price per Bbl after hedging	$ 62.60	$ 56.60	$ 50.93
Natural Gas Hedging			
Percentage of gas production hedged	46%	40%	25%
Natural gas volumes hedged (MMBtu)	32.5 million	24.2 million	14.0 million
Increase (decrease) in gas revenue	$ 58.7 million	$ 44.7 million	$ (9.2 million)
Average realized gas price per Mcf before hedging	$ 6.74	$ 6.58	$ 8.08
Average realized gas price per Mcf after hedging	$ 7.63	$ 7.37	$ 7.90

Information regarding the components of exploration expense:

	Years Ended December 31,		
Summary of Exploration Expense (in millions)	2007	2006	2005
Geological and geophysical expenses	$ 17.0	$ 9.5	$ 7.9
Exploratory dry holes	14.4	10.2	8.1
Overhead and other expenses	27.3	32.2	28.9
Total	$ 58.7	$ 51.9	$ 44.9

Comparison of Financial Results and Trends between 2007 and 2006

Oil and gas production revenues. Average net daily production increased 16 percent to a record 294.5 MMCFE for 2007 compared with 254.2 MMCFE in 2006. The following table presents specific components that contributed to the increase in revenue between the two periods:

	Average Net Daily Production Added	Oil and Gas Revenue Added	Production Costs Added
	(MMCFE)	(In millions)	(In millions)
Sweetie Peck acquisition and drilling, Permian Basin region	15.8	65.2	9.3
Rockford acquisition and drilling	1.6	4.6	1.0
Williston Basin Middle Bakken Play	2.2	11.4	1.9
Elm Grove Field	6.3	16.2	2.0
James Lime formation	3.4	8.9	1.0
Anadarko Basin fields	8.5	22.1	3.4
Woodford shale formation – horizontal wells	5.7	11.5	1.1
Other wells completed in 2007 and 2006	54.4	85.1	13.7
Other acquisitions	4.1	12.1	3.3
Total	102.0	237.1	36.7

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

Oil and gas realized hedge gain (loss). The 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 attributed 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. We continue to closely monitor the activities associated with these properties. Any significant variation between actual and estimated plugging and abandonment and outside-operated damage repair costs will impact the final determination of the insurance settlement gain. We assume that all work will be completed and expect adjustments to the gain will be finalized during the second quarter of 2008.

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 current year and prior year 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
- A $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 increase production in the Permian region.

Depletion, Depreciation, and Amortization. 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. This 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 a general lowering of DD&A as compared to what DD&A would have been with the upward revisions of 40.9 BCFE of proved reserves.

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 the current year 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 costs 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 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 current period realized expense associated with the Net Profits Plan increasing 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 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 Future 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 the 12 percent resulted from our divestiture marketing process and our assessment that the overall market for proved oil and gas reserves is ever more competitive. This liability is a significant management estimate. Adjustments to the liability are subject to estimation and may change dramatically from period-to-period based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, production tax rates, and production costs.

Interest expense. Interest expense increased by $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 in 2006, resulting in effective tax rates 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 is $17.6 million compared to $30.5 million in 2006. These amounts are 16 percent and 29 percent of total income tax expense for the respective periods. The decrease resulted from significant increased drilling activity reflecting the deduction of intangible drilling costs in the year incurred, thereby reducing current taxable income. We project that the current portion of taxable income will be similar in 2008.

Comparison of Financial Results and Trends between 2006 and 2005

Oil and gas production revenues. Average net daily production increased six percent to a record 254.2 MMCFE for 2006 compared with 239.4 MMCFE in 2005. The following table presents specific components that contributed to the increase in revenue between the two periods:

	Average Net Daily Production Added	Oil and Gas Revenue Added	Production Costs Added
	(MMCFE)	(In millions)	(In millions)
Williston Basin Middle Bakken Play	6.2	23.5	2.5
Wold acquisition	3.1	9.2	5.2
Other wells completed in 2006 and 2005	47.2	80.8	15.3
Other acquisitions	2.9	9.7	1.4
Total	59.4	123.2	24.4

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

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

Oil and gas production expenses. Total production costs increased $33.7 million or 24 percent to $176.6 million for 2006, from $142.9 million in 2005. The acquisition of properties added $1.4 million of incremental production costs, prior year acquisitions of properties added $5.2 million of incremental production costs, and other wells completed in 2005 and 2006 added $15.3 million of incremental production costs in 2006 that were not reflected in 2005. We experienced an increase in production taxes consistent with the increase in revenue from higher realized prices.

Total oil and gas production costs per MCFE increased $0.27 to $1.91 for 2006, compared with $1.64 for 2005. This increase was comprised of the following:

- A $0.02 decrease in production taxes, due to a $0.04 decrease in our Rocky Mountain region resulting from an increase in new production, which qualifies for incentive tax rates, that was partially offset by a minor increase in our Mid-Continent region resulting from higher natural gas revenues
- A $0.03 increase in overall transportation cost, due to an increase in the Rocky Mountain region resulting from a change in the sale measurement point, as well as newly drilled wells with higher transportation costs
- A $0.20 increase in recurring LOE related to continued increases in costs for oil and gas service sector resources
- A $0.06 overall increase in LOE relating to workover charges, mainly due to activity in the Rockies.

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

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

Exploration expense. Exploration expense increased $7.0 million or 15 percent to $51.9 million in 2006 compared with $44.9 million for 2005. This increase was due to a $3.3 million increase in exploration overhead related to increases in payments made under the Net Profits Plan and increases in the size of our geologic and exploration staff. Additionally, the increase in exploration expense was partially related to an approximate $2.1 million increase in exploratory dry hole expense and a $1.6 million increase in geologic and geophysical expense to support a larger overall program.

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

A 16 percent increase in employee count contributed to an increase in base employee compensation of approximately 18 percent, or $3.5 million, between the year ended December 31, 2006, and the same period of 2005. Oil and gas price increases triggered additional Net Profits Plan payouts and increased the amounts payable to plan participants. Consequently, the realized expense associated with the Net Profits Plan increased by $5.4 million in 2006 compared with the same period in 2005. A decrease in the bonus percentage resulted in a decrease in the accrued cash bonus expense of $5.0 million to $2.8 million for the year ended December 31, 2006, compared with $7.8 million for the year ended December 31, 2005.

RSU bonus expense was $1.5 million higher for the year ended December 31, 2006, as compared to the year ended December 31, 2005, which was due to the increase in amortization of stock-based compensation expense. In 2006, we recorded expense for four periods of RSU grants while there were only three grants recorded in 2005. Also in 2006, we included the grant made in 2006 for 2005 performance and the additional accrual of the expense estimated for the 2006 plan year. This increase was partially offset by a decrease in RSU bonus expense for the year ended December 31, 2006, compared with the same period in 2005. This decrease correlated to the decrease in cash bonus expense and reflected an evaluation of our overall performance for 2006 including reserve replacement, production, and net asset value per share growth factors.

As a result of the implementation of SFAS No. 123(R) on January 1, 2006, we recorded $2.2 million of compensation expense in 2006 related to stock options and the ESPP. The above amounts combined with a net $5.1 million increase in other G&A expense, including payroll tax and 401(k) contribution expense, were offset by a $3.2 million increase in the amount of G&A that was allocated to exploration expense due to the aforementioned incentive plan increases as well as increases in the size of our technical exploration staff and a $3.4 million increase in COPAS overhead reimbursements. COPAS overhead reimbursements from operations increased due to an increase in our operated well count from our drilling program.

Change in Future Net Profits Plan Liability. For the year ended December 31, 2006, this expense decreased $82.5 million to $23.8 million from $106.3 million for 2005. This decrease reflects a smaller change in future oil and gas prices as compared to 2005 when we experienced significant increases in prices. Since the prices used in the calculation were much more comparable in the year-end 2006 calculation to that of the 2005 calculation, the degree of increase was much less in 2006. This liability is a significant management estimate. Adjustments to the liability are subject to estimation and may change dramatically from period-to-period based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, production tax rates, and production costs.

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

Income tax expense. Income tax expense totaled $105.3 million for 2006 and $86.3 million in 2005, resulting in effective tax rates of 35.7 percent and 36.3 percent, respectively. The effective rate change from 2005 reflected changes in the mix of the highest marginal state tax rates as a result of enacted Texas margin tax legislation, the benefit of estimated percentage depletion for both federal and state income taxes, acquisition and drilling activity, and also reflected other permanent differences including differing estimated effects between years of the domestic production activities deduction.

The current portion of income tax expense in 2006 was $30.5 million compared to $80.8 million in 2005. These amounts comprised 29 percent and 94 percent of total income tax expense for the respective periods. The decrease resulted from a significant increase in drilling activity, whereby we deducted intangible drilling costs in the year it was incurred and reduced our current taxable income.

Other Liquidity and Capital Resource Information

Pension Benefits

Substantially all of our employees who meet age and service requirements participate in a non-contributory defined benefit pension plan. On December 31, 2006, the Company adopted the recognition and disclosure provisions of Statement of Financial Accounting Standards No. 158, "Employers' Accounting for

Defined Benefit Pension and Other Postretirement Plans, an amendment of Statement of Financial Accounting Standards No 87, 88, 106 and 132(R)". Statement of Financial Accounting Standards No. 158 requires the Company to recognize the funded status (i.e., the difference between the fair value of plan assets and the projected benefit obligation) of its pension plan in the December 31, 2006 consolidated balance sheet as either an asset or a liability, with a corresponding adjustment to accumulated other comprehensive income, net of tax. At December 31, 2007, and December 31, 2006, we had a recorded balance of $2.5 million and $2.6 million, respectively, of pre-tax loss in accumulated other comprehensive income as a result of this new pronouncement. We believe this obligation will be funded from future cash flow from operating activities. For purposes of calculating our obligation under the plan, we have used an expected return on plan assets of 7.5 percent. We think this rate of return is appropriate over the long-term given the 60 percent equity and 40 percent debt securities mix of investment of plan assets and the historical rate of return provided by equity and debt securities since the 1920s. Our actual rate of return was 6.5 percent for 2007 and was 14.1 percent for 2006. The difference in investment income using our projected rate of return compared to our actual rates of return for the past two years was not material and will not have a material effect on the results of operation or cash flow from operating activities in future years.

For the 2007 plan year, a 0.20 percentage point increase in the discount rate and a 0.50 percentage point increase in the lump sum interest rate, netted with a larger than expected increase in base salaries and an increase in new participants, caused a $161,000 increase in the projected benefit obligation of the plan. We do not believe this change was material and project that it will not have a material effect on the results of operations or on cash 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 2007 plan year, a 0.20 percentage point increase in the discount rate and a 0.50 percentage point increase in the lump sum interest rate caused a $62,000 decrease in the projected benefit obligation for this plan. This plan's accumulated benefit obligation was $1.0 million at December 31, 2007, and $1.5 million at December 31, 2006. We believe this obligation will be funded from future cash flow from operating activities.

Accounting Matters

We refer you to Note 4 – Income Taxes and Note 5 – Long-term Debt in Part IV, Item 15 of this report for information regarding accounting matters related to FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – An Interpretation of FASB Statement No. 109" and FASB Staff Position APB 14-a, "Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)".

In September 2006 the FASB issued Statement of Financial Accounting Standards No. 157, "Fair Value Measurements", which defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. The provisions of SFAS No. 157 will be effective as of the beginning of the Company's 2008 fiscal year. The adoption of SFAS No. 157 has no impact on the Company's consolidated financial statements, however, it will require changes in certain disclosures.

In February 2007 the FASB issued Statement of Financial Accounting Standards No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities", which expands the use of fair value accounting but does not affect existing standards which require assets or liabilities to be carried at fair value. SFAS No. 159 allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item's fair value in subsequent reporting periods must be recognized in current earnings. SFAS No. 159 also establishes presentation and disclosure requirements designed to draw comparisons between entities that elect different measurement attributes for similar assets and liabilities. If elected, SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. SFAS No. 159 will be effective for the Company beginning with the 2008 fiscal year. The Company did not elect the fair value option. There is no impact on the Company's consolidated financial statements.

Environmental

St. Mary’s compliance with applicable environmental regulations has not resulted in any significant capital expenditures or materially adverse effects to our liquidity or results of operations. We believe we are in substantial compliance with environmental regulations and 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 timely decisions regarding required disclosure.

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

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

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

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

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2007. 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, 2007.

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
Anthony J. Best
President and Chief Executive Officer
February 21, 2008

/s/ DAVID W. HONEYFIELD
David W. Honeyfield
Senior Vice President – Chief Financial Officer and Secretary
February 21, 2008

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, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on 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 financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, 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, 2007, of the Company, and our report dated February 21, 2008, expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 21, 2008

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item concerning St. Mary's Directors and corporate governance is incorporated by reference to the information provided under the captions "Election of Directors," "Nominees for Election of Directors," "Corporate Governance" and "Board and Committee Meetings" in St. Mary's definitive proxy statement for the 2008 annual meeting of stockholders to be filed within 120 days from December 31, 2007. The information required by this Item concerning St. Mary's executive officers is incorporated by reference to the information provided in Part I—Item 4A—EXECUTIVE OFFICERS OF THE REGISTRANT, included in this Form 10-K.

The information required by this Item concerning compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated by reference to the information provided under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" in St. Mary's definitive proxy statement for the 2008 annual meeting of stockholders to be filed within 120 days from December 31, 2007.

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," "Grants of Plan-Based Awards," "Outstanding Equity Awards at Fiscal Year-End," "Nonqualified Deferred Compensation," "Option Exercises and Stock Vested," "Retirement Plans," "Pension Benefits," "Equity Compensation Plans," "Compensation Committee Interlocks and Insider Participation," "Compensation Committee Report," "Employee Agreements and Termination of Employment," and "Change-of-Control Arrangements" in St. Mary's definitive proxy statement for the 2008 annual meeting of stockholders to be filed within 120 days from December 31, 2007.

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 2008 annual meeting of stockholders to be filed within 120 days from December 31, 2007.

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

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

The information required by this Item is incorporated by reference to the information provided under the caption "Certain Relationships and Related Transactions," "Election of Directors," "Corporate Governance," and "Board and Committee Meetings" in St. Mary's definitive proxy statement for the 2008 annual meeting of stockholders to be filed within 120 days from December 31, 2007.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item is incorporated by reference to the information provided under the caption “Independent Accountants” and “Audit Committee Preapproval Policy and Procedures” in St. Mary’s definitive proxy statement for the 2008 annual meeting of stockholders to be filed within 120 days from December 31, 2007.

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, 2007 (filed as Exhibit 3.1 to the registrant’s Current Report on Form 8-K filed on December 21, 2007, 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 as 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 registrant's Registration Statement on Form S-8 (Registration No. 333-106438) and incorporated herein by reference)
10.3†	Cash Bonus Plan (filed as Exhibit 10.5 to the registrant's Registration Statement on Form S-1 (Registration No. 33-53512) and incorporated herein by reference)
10.4†	Summary Plan Description/Pension Plan dated December 30, 1994 (filed as Exhibit 10.35 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1994 and incorporated herein by reference)
10.5†	Non-qualified Unfunded Supplemental Retirement Plan, as amended (filed as Exhibit 10.8 to the registrant's Registration Statement on Form S-1 (Registration No. 33-53512) and incorporated herein by reference)
10.6†	Employee Stock Purchase Plan (filed as Exhibit 10.48 filed to the registrant's Annual Report on Form 10-K for the year ended December 31, 1997 and incorporated herein by reference)
10.7†	First Amendment to Employee Stock Purchase Plan dated February 27, 2001 (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001 and incorporated herein by reference)
10.8†	Second Amendment to the Employee Stock Purchase Plan dated February 18, 2005 (filed as Exhibit 10.48 to the registrants Annual Report on Form 10-K for the year ended December 31, 2004 and incorporated herein by reference)
10.9†	Form of Change of Control Severance Agreements (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001 and incorporated herein by reference)
10.10†	Amendment to Form of Change of Control Severance Agreement (filed as Exhibit 10.9 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 and incorporated herein by reference)
10.11	5.75% Senior Convertible Notes due 2022 Indenture dated March 13, 2002 (filed as Exhibit 10.26 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2001 and incorporated herein by reference)
10.12	Amendment to and Extension of Office Lease dated as of December 14, 2001 (filed as Exhibit 10.45 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference)

Exhibit Number	Description
10.13†	Non-Employee Director Stock Compensation Plan as adopted on March 27, 2003 (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 and incorporated herein by reference)
10.14†	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)
10.15†	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)
10.16†	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)
10.17	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)
10.18	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)
10.19	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)
10.20	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)
10.21	Guaranty Agreement by Nance Petroleum Corporation in favor of Wachovia Bank, National Association, as Administrative Agent, dated April 7, 2005 (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference)
10.22	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)
10.23	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)
10.24	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)
10.25	First Supplement and Amendment to Deed of Trust, Mortgage, Line of Credit Mortgage, Assignment, Security Agreement, Fixture Filing and Financing Statement for the benefit of Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 7, 2005 (filed as Exhibit 10.7 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference)
10.26	Deed of Trust – St. Mary Land & Exploration to Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 7, 2005 (filed as Exhibit 10.8 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference)

Exhibit Number	Description
10.27†	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)
10.28	Summary of Charitable Contributions in Honor of Thomas E. Congdon (filed as Exhibit 10.4 to the registrant's Current Report on Form 8-K filed on December 19, 2005 and incorporated herein by reference)
10.29†	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)
10.30	Employment Agreement of A.J. Best dated May 1, 2006 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on May 4, 2006 and incorporated herein by reference)
10.31***†	Summary of 2008 Compensation Arrangements for Non-Employee Directors
10.32	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)
10.33	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)
10.34	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)
12.1***	Computation of Ratio of Earnings to Fixed Charges
14.1	Code of Business Conduct and Ethics (filed as Exhibit 14.1 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference)
21.1***	Subsidiaries of Registrant
23.1*	Consent of Deloitte & Touche LLP
23.2*	Consent of Ryder Scott Company L.P.
23.3*	Consent of Netherland, Sewell & Associates, Inc.
24.1***	Power of Attorney
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
32.1**	Certification pursuant to U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes – Oxley Act of 2002

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* Filed with this Form 10-K/A.
** Furnished with this Form 10-K/A.
*** Previously filed.
† Exhibit constitutes a management contract or compensatory plan or arrangement.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of St. Mary Land & Exploration Company and subsidiaries (the "Company") as of December 31, 2007 and 2006, 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, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of St. Mary Land & Exploration Company and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, 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, 2007, 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 21, 2008, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 21, 2008

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)

ASSETS	December 31, 2007	December 31, 2006
Current assets:		
Cash and cash equivalents	$ 43,510	$ 1,464
Short-term investments	1,173	1,450
Accounts receivable	159,149	142,721
Refundable income taxes	933	7,684
Prepaid expenses and other	14,129	17,485
Accrued derivative asset	17,836	56,136
Deferred income taxes	33,211	-
Total current assets	269,941	226,940
Property and equipment (successful efforts method), at cost:		
Proved oil and gas properties	2,721,229	2,063,911
Less - accumulated depletion, depreciation, and amortization	(804,785)	(630,051)
Unproved oil and gas properties, net of impairment allowance of $10,319 in 2007 and $9,425 in 2006	134,386	100,118
Wells in progress	137,417	97,498
Oil and gas properties held for sale less accumulated depletion, depreciation, and amortization	76,921	-
Other property and equipment, net of accumulated depreciation of $11,549 in 2007 and $9,740 in 2006	9,230	6,988
	2,274,398	1,638,464
Noncurrent assets:		
Goodwill	9,452	9,452
Accrued derivative asset	5,483	16,939
Other noncurrent assets	12,406	7,302
Total noncurrent assets	27,341	33,693
Total Assets	**$ 2,571,680**	**$ 1,899,097**
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 254,918	$ 171,834
Short-term note payable	-	4,469
Accrued derivative liability	97,627	13,100
Deferred income taxes	-	14,667
Deposit associated with oil and gas properties held for sale	10,000	-
Total current liabilities	362,545	204,070
Noncurrent liabilities:		
Long-term credit facility	285,000	334,000
Senior convertible notes	287,500	99,980
Asset retirement obligation	96,432	77,242
Asset retirement obligation associated with oil and gas properties held for sale	8,744	-
Net Profits Plan liability	211,406	160,583
Deferred income taxes	257,603	224,518
Accrued derivative liability	190,262	46,432
Other noncurrent liabilities	8,843	8,898
Total noncurrent liabilities	1,345,790	951,653
Commitments and contingencies		
Stockholders' equity:		
Common stock, $0.01 par value: authorized - 200,000,000 shares; issued: 64,010,832 shares in 2007 and 55,251,733 shares in 2006; outstanding, net of treasury shares: 63,001,120 shares in 2007 and 55,001,733 shares in 2006	640	553
Additional paid-in capital	170,070	38,940
Treasury stock, at cost: 1,009,712 shares in 2007 and 250,000 shares in 2006	(29,049)	(4,272)
Retained earnings	878,652	695,224
Accumulated other comprehensive income (loss)	(156,968)	12,929
Total stockholders' equity	863,345	743,374
Total Liabilities and Stockholders' Equity	**$ 2,571,680**	**$ 1,899,097**

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

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

	For the Years Ended December 31,		
	2007	2006	2005
Operating revenues:			
Oil and gas production revenue	$ 912,093	$ 730,737	$ 733,544
Realized oil and gas hedge gain (loss)	24,484	28,176	(22,539)
Marketed gas system revenue	45,149	20,936	25,269
Gain (loss) on sale of proved properties	(367)	6,910	222
Other revenue	8,735	942	3,094
Total operating revenues	990,094	787,701	739,590
Operating expenses:			
Oil and gas production expense	218,208	176,590	142,873
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	227,596	154,522	132,758
Exploration	58,686	51,889	44,931
Impairment of proved properties	-	7,232	-
Abandonment and impairment of unproved properties	4,756	4,301	5,780
General and administrative	60,149	38,873	32,756
Change in Net Profits Plan liability	50,823	23,759	106,263
Marketed gas system expense	42,485	18,526	24,164
Unrealized derivative loss	5,458	7,094	1,615
Other expense	2,522	2,649	2,456
Total operating expenses	670,683	485,435	493,596
Income from operations	319,411	302,266	245,994
Nonoperating income (expense):			
Interest income	746	1,576	456
Interest expense	(19,895)	(8,521)	(8,213)
Income before income taxes	300,262	295,321	238,237
Income tax expense	(110,550)	(105,306)	(86,301)
Net income	**$ 189,712**	**$ 190,015**	**$ 151,936**
Basic weighted-average common shares outstanding	61,852	56,291	56,907
Diluted weighted-average common shares outstanding	64,850	65,962	66,894
Basic net income per common share	**$ 3.07**	**$ 3.38**	**$ 2.67**
Diluted net income per common share	**$ 2.94**	**$ 2.94**	**$ 2.33**

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

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

	Common Stock		Additional Paid-in	Treasury Stock		Deferred Stock-Based	Retained	Accumulated Other Comprehensive	Total Stockholders'
	Shares	Amount	Capital	Shares	Amount	Compensation	Earnings	Income (Loss)	Equity
Balances, December 31, 2004	**57,458,246**	**$ 574**	**$ 127,374**	**(500,000)**	**$ (5,295)**	**$ (5,039)**	**$ 364,567**	**$ 2,274**	**$ 484,455**
Comprehensive income, net of tax:									
Net income	-	-	-	-	-	-	151,936	-	151,936
Change in derivative instrument fair value	-	-	-	-	-	-	-	(71,522)	(71,522)
Reclassification to earnings	-	-	-	-	-	-	-	14,366	14,366
Minimum pension liability adjustment	-	-	-	-	-	-	-	283	283
Total comprehensive income									95,063
Cash dividends, $ 0.10 per share	-	-	-	-	-	-	(5,691)	-	(5,691)
Treasury stock purchases	-	-	-	(1,175,282)	(28,902)	-	-	-	(28,902)
Retirement of treasury stock	(1,411,356)	(14)	(28,729)	1,411,356	28,743	-	-	-	-
Issuance of common stock under Employee Stock Purchase Plan	28,447	-	601	-	-	-	-	-	601
Sale of common stock, including income tax benefit of stock option exercises	936,403	10	16,619	-	-	-	-	-	16,629
Deferred compensation related to issued restricted stock unit awards, net of forfeitures	-	-	3,404		-	(3,404)	-	-	-
Directors' stock compensation	-	-	-	13,926	306	(306)	-	-	-
Accrued stock-based compensation	-	-	4,009	-	-	-	-	-	4,009
Amortization of deferred stock-based compensation	-	-	-	-	-	3,156	-	-	3,156
Balances, December 31, 2005	**57,011,740**	**$ 570**	**$ 123,278**	**(250,000)**	**$ (5,148)**	**$ (5,593)**	**$ 510,812**	**$ (54,599)**	**$ 569,320**
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)
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**

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,		
	2007	2006	2005
Reconciliation of net income to net cash provided by operating activities:			
Net income	$ 189,712	$ 190,015	$ 151,936
Adjustments to reconcile net income to net cash provided by operating activities:			
Gain on insurance settlement	(5,243)	-	-
(Gain) loss on sale of proved properties	367	(6,910)	(222)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	227,596	154,522	132,758
Exploratory dry hole expense	14,365	10,191	8,104
Impairment of proved properties	-	7,232	-
Abandonment and impairment of unproved properties	4,756	4,301	5,780
Unrealized derivative loss	5,458	7,094	1,615
Change in Net Profits Plan liability	50,823	23,759	106,263
Stock-based compensation expense*	10,095	11,422	7,165
Deferred income taxes	92,955	74,832	5,547
Other	(10,497)	(2,479)	281
Changes in current assets and liabilities:			
Accounts receivable	(6,557)	22,476	(57,113)
Refundable income taxes	6,751	-	-
Prepaid expenses and other	19,375	(17,886)	(1,210)
Accounts payable and accrued expenses	40,769	5,215	42,438
Income tax benefit from the exercise of stock options**	(9,933)	(16,084)	6,037
Net cash provided by operating activities	**630,792**	**467,700**	**409,379**
Cash flows from investing activities:			
Proceeds from insurance settlement	5,948	-	-
Proceeds from sale of oil and gas properties	495	860	1,213
Capital expenditures	(637,748)	(455,056)	(270,881)
Acquisition of oil and gas properties	(182,883)	(270,639)	(73,905)
Deposits to short-term investments	(1,168)	-	(1,502)
Receipts from short-term investments	1,450	25	1,427
Other	10,034	91	3,869
Net cash used in investing activities	**(803,872)**	**(724,719)**	**(339,779)**
Cash flows from financing activities:			
Proceeds from credit facility	822,000	935,137	284,090
Repayment of credit facility	(871,000)	(601,137)	(321,090)
Repayment of short-term note payable	(4,469)	-	-
Proceeds from short-term note payable	-	4,469	-
Income tax benefit from the exercise of stock options**	9,933	16,084	-
Proceeds from issuance of senior convertible debt, net of deferred financing costs	280,657	-	-
Proceeds from sale of common stock	10,007	17,716	11,193
Repurchase of common stock	(25,904)	(123,108)	(28,902)
Dividends paid	(6,284)	(5,603)	(5,691)
Other	186	-	(693)
Net cash provided by (used in) financing activities	**215,126**	**243,558**	**(61,093)**
Net change in cash and cash equivalents	42,046	(13,461)	8,507
Cash and cash equivalents at beginning of period	1,464	14,925	6,418
Cash and cash equivalents at end of period	**$ 43,510**	**$ 1,464**	**$ 14,925**

* Stock-based compensation expense is a component of Exploration expense and General and administrative expense on the Consolidated Statements of Operations. During 2007, 2006, and 2005, respectively, approximately $3.2 million, $3.1 million, and $3.3 million, of stock-based compensation expense was included in Exploration expense. During 2007, 2006, and 2005, respectively, approximately $6.9 million, $8.3 million, and $3.9 million of stock-based compensation expense was included in General and administrative expense.

** SFAS 123(R) requires presentation of the income tax benefit from the exercise of stock options to be presented in financing activities subsequent to adoption. The prior period classification is to remain unchanged under SFAS 123(R).

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,		
	2007	2006	2005
		(in thousands)	
Cash paid for interest, net of capitalized interest	$ 22,816	$ 9,826	$ 8,458
Cash paid (refunded) for income taxes	$ (1,156)	$ 25,505	$ 65,752

As of December 31, 2007, 2006, and 2005, $116.9 million, $73.5 million, and $51.0 million, respectively, are included as additions to oil and gas properties and as increases to accounts payable and accrued expenses. These oil and gas property additions are reflected in cash used in investing activities in the periods that the payables are settled.

In May 2007 and 2006, July 2007 and 2006, and May 2005, the Company issued 26,292, 26,076, 6,212, 3,751 and 13,926 shares, respectively, of common stock from treasury to its non-employee directors pursuant to the Company's non-employee director stock compensation plan. The Company recorded compensation expense related to the issuances of shares to non-employee directors of $983,500, $976,000 and $178,000 for the years ended December 31, 2007, 2006 and 2005, respectively.

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

In June 2006 the Company hired a new senior executive. In doing so, the Company issued 13,784 shares of stock and recorded compensation expense of approximately $728,000. Additionally, in March 2007 the Company issued 1,250 shares of stock to the senior executive as the Company reached certain performance levels. The Company has recognized approximately $136,000 of expense related to this issuance as of December 31, 2007.

In February 2007, February 2006, and March 2005, the Company issued 78,657, 484,351, and 195,312 restricted stock units, respectively, pursuant to the Company's restricted stock plan. The total value of the issuances were $2.5 million, $16.4 million, and $4.5 million, 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.

Note 1 – Summary of Significant Accounting Policies

Description of Operations

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

Basis of Presentation

The 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 method as appropriate. Equity method investments are included in other noncurrent assets, and minority interest is included in other noncurrent liabilities in the accompanying consolidated balance sheets. All significant intercompany accounts and transactions have been eliminated.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Estimates of oil and gas reserve quantities provide the basis for calculations of depletion, depreciation, and amortization ("DD&A"), impairment, goodwill, and the Net Profits Interest Bonus Plan (the "Net Profits Plan") liability, each of which represents a significant component of the 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 a purchaser. At the end of each month, the Company estimates the amount of production delivered to the purchaser and the price the Company will receive. The Company uses its knowledge of its properties, their historical performance, the anticipated effect of weather conditions during the month of production, New York Mercantile Exchange ("NYMEX") and local spot market prices, and other factors as the basis for these estimates.

Cash and Cash Equivalents

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

Short-term Investments

As of December 31, 2007, the Company's short-term investments consist of a certificate of deposit. As of December 31, 2006, the Company's short-term investments consist of investment-grade marketable debt that is classified as held-to-maturity or available-for-sale. Securities categorized as held-to-maturity are stated at amortized cost whereas available-for-sale securities are marked-to-market. As of December 31, 2007, and 2006, the Company held $1.2 million and $1.5 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. To date the Company has had minimal bad debts.

The Company has accounts with separate banks in Denver, Colorado; Shreveport, Louisiana; Franklin, Louisiana; Tulsa, Oklahoma; and Billings, Montana. At December 31, 2007, 2006, and 2005, the Company had $42.8 million, $1.6 million, and $36.8 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 nine separate counterparties for its oil and gas commodity and interest rate derivatives. The counterparties to the Company's derivative instruments are all highly-rated entities with corporate credit ratings at or exceeding A- or A2 as 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 or not proved reserves are found.

Geological and geophysical costs and the costs of carrying and retaining unproved properties are expensed as incurred. DD&A of capitalized costs related to proved oil and gas properties is calculated on a field-by-field basis using the units-of-production method based upon proved reserves. The computation of DD&A takes into consideration restoration, dismantlement, and abandonment costs and the anticipated proceeds from salvaging equipment. As of December 31, 2007, the Company's capitalized proved oil and gas properties included $95.9 million of estimated salvage value, which is excluded from the depletable property costs when calculating DD&A.

The Company follows Statement of Financial Accounting Standards Staff Position No. FAS 19-1, "Accounting for Suspended Well Costs," ("FSP FAS 19-1"). For additional discussion, please see Note 13 – Disclosures about Oil and Gas Producing Activities under the heading *Suspended Well Costs*.

The Company reviews its long-lived assets for impairments when events or changes in circumstances indicate that an impairment may have occurred. The impairment test for proved properties compares the expected undiscounted future net cash flows on a field-by-field basis with the related net capitalized costs, including costs associated with asset retirement obligations, at the end of each period. Expected future cash flows are calculated on all proved reserves using a discount rate and price forecasts selected by the Company's management. The discount rate is a rate that management believes is representative of current market conditions. The price forecast is based on NYMEX strip pricing, 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. When the net capitalized costs exceed the undiscounted future net revenues of a field, the cost of the field is reduced to fair value, which is determined using discounted future net revenues. An impairment 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.

Sales of Proved and Unproved Properties

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

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

Assets Held for Sale

In accordance with Statement of Financial Accounting Standards No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets”, 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 obligation 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, and computer hardware and software are recorded at cost. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs are expensed when incurred. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets from three to eight years. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts.

Gas Balancing

The Company uses the sales method of accounting for gas revenue whereby sales revenue is recognized on all gas sold to purchasers, regardless of whether the sales are proportionate to the Company’s ownership in the property. An asset or a liability is recognized to the extent that there is an imbalance in excess of the remaining gas reserves on the underlying properties. The Company’s gas imbalance position at December 31, 2007, and 2006, resulted in the recording of $1.9 million and $1.4 million, respectively, to accounts receivable, and $1.1 million and $791,000, respectively, to accounts payable.

Derivative Financial Instruments

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

Fair Value of Financial Instruments

The Company's financial instruments including cash and cash equivalents, accounts receivable, and accounts payable are carried at cost, which approximates fair value due to the short-term maturity of these instruments. The recorded value of the Company's credit facility approximates its fair value as it bears interest at a floating rate. The Company had $285.0 million in loans outstanding under its revolving credit agreement as of December 31, 2007, and $334.0 million in loans outstanding under its revolving credit agreement as of December 31, 2006. 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 other financial instruments and investments in available-for-sale securities that are marked-to-market for which changes in fair value are recorded in accumulated other comprehensive income in the accompanying consolidated balance sheets. Since considerable judgment is required to develop estimates of fair value, the estimates provided are not necessarily indicative of the amounts the Company could realize upon the sale or refinancing of such instruments.

Net Profits Plan

The Company records the estimated 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.*

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 bases 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 recovered 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 of stock is calculated by dividing net income available to common stockholders by the weighted-average basic common shares outstanding for the respective period. The shares represented by vested restricted stock units ("RSUs") are included in the calculation of the weighted-average basic common shares outstanding. The 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 calculations consist of unvested RSUs, in-the-money outstanding stock options to purchase the Company's common stock, shares into which the 5.75% Senior Convertible Notes due 2022 (the "5.75% Senior Convertible Notes") were convertible for the periods those notes were outstanding, and shares into which the 3.50% Senior Convertible Notes due 2027 are convertible.

The shares underlying the unvested grants of RSUs are included in the diluted earnings per share calculation beginning on the grant date of the RSUs. Following the lapse of restriction periods, the shares underlying the units are issued and therefore are included in the number of issued and outstanding shares.

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

	For the Years Ended December 31,		
	2007	2006	2005
Dilutive	1,441,556	1,978,577	2,293,768
Anti-dilutive	-	-	-

Prior to the conversion of the Company's 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 period. The 5.75% Senior Convertible Notes were called for redemption by the Company on March 16, 2007, and all of the note holders elected to convert the notes to shares of the Company's common stock. The Company issued 7.7 million common shares in connection with the conversion of the 5.75% Senior Convertible Notes. Upon conversion, these shares were included in the calculation of weighted-average common shares outstanding. 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 years ended December 31, 2006, and 2005.

The Company's 3.50% Senior Convertible Notes have a net-share settlement right, and 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 issued April 4, 2007 have not been dilutive for the entire time they have been outstanding and therefore do not impact the diluted earnings per share calculation for the period ended December 31, 2007.

The dilutive impact of unvested RSUs and stock options is considered in the detailed calculations below. There were no anti-dilutive securities related to stock options or RSUs for the years ended December 31, 2005, 2006, and 2007.

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

	For the Years Ended December 31,		
	2007	2006	2005
	(In thousands, except per share amounts)		
Net income	$ 189,712	$ 190,015	$ 151,936
Adjustments to net income for dilution:			
Add: Interest expense not incurred if 5.75% Senior Convertible Notes converted	1,285	6,337	6,337
Less: Other adjustments	(13)	(63)	(64)
Less: Income tax effect of adjustment items	(469)	(2,237)	(2,275)
Net income adjusted for the effect of dilution	$ 190,515	$ 194,052	$ 155,934
Basic weighted-average common shares outstanding	61,852	56,291	56,907
Add: Dilutive effect of stock options and unvested restricted stock units	1,441	1,979	2,295
Add: Dilutive effect of 5.75% Senior Convertible Notes using the if-converted method	1,557	7,692	7,692
Diluted weighted-average common shares outstanding	64,850	65,962	66,894
Basic earnings per common share:	$ 3.07	$ 3.38	$ 2.67
Diluted earnings per common share:	$ 2.94	$ 2.94	$ 2.33

Stock-Based Compensation

At December 31, 2007, the Company had stock-based employee compensation plans that included RSUs and stock options issued to employees and non-employee directors as more fully described in Note 7 – Compensation Plans. Stock options were last issued in December 2004. Prior to 2006, the Company had accounted for stock-based compensation using the intrinsic value recognition and measurement principles detailed in Accounting Principles Board Opinion No. 25, “Accounting for Stock Issued to Employees” ("APB Opinion No. 25") and related interpretations. No stock-based employee compensation expense relating to stock options has been reflected in the Company’s accompanying consolidated statements of operations for any period presented prior to 2006 since all options granted under the plans had an exercise price equal to the market value of the underlying common stock on the date of grant. The Company used the Black-Scholes option valuation model to calculate the disclosures required under Statement of Financial Accounting Standards No. 123, “Accounting for Stock-Based Compensation” (“SFAS No. 123”). Beginning January 1, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards No. 123(R), “Share-Based Payment” (“SFAS No. 123(R)”). This statement requires the Company to record expense associated with the fair value of stock-based compensation. The total 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 additional compensation expense of $1.9 million in 2006 and $437,000 in 2007, and expects to recognize expense of $17,000 in 2008 related to the vesting of these stock options. The Company has recorded compensation expense associated with the issuance of RSUs since the plan was adopted in 2004 and units were first granted. The Company recognizes costs associated with these grants based on the estimated fair value of the RSUs as determined at the time of the grant.

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

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

For purposes of pro forma disclosures, the estimated fair values of the options and employee stock purchase plan grants are amortized to expense over the options' vesting periods. The effects of applying SFAS No. 123 in the pro forma disclosure are not necessarily indicative of actual future amounts.

Recently Issued Accounting Standards

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. SFAS No. 141(R) also establishes guidance for the measurement of the acquirer shares issued in consideration for a business combination, the recognition of contingent consideration, the accounting treatment for pre-acquisition gain and loss contingencies, the treatment of acquisition related transaction costs, and the recognition of changes in the acquirer's income tax valuation allowance and deferred taxes. SFAS No. 141(R) is effective for fiscal years beginning after December 15, 2008, and is to be applied prospectively as of the beginning of the fiscal year in which the statement is applied. Early adoption is not permitted. SFAS No. 141(R) will be effective for the Company beginning with the 2009 fiscal year. The Company is currently evaluating the impact of SFAS No. 141(R) on its accompanying consolidated financial statements when effective, but the nature and magnitude of the specific effects will depend upon the nature, terms, and size of the acquisitions the Company consummates after the effective date.

In December 2007 the FASB issued Statement of Financial Accounting Standards No. 160, "Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB 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 fiscal years beginning after December 15, 2008, and is to be applied prospectively as of the beginning of the fiscal year in which the statement is applied. The Company is required to adopt SFAS No. 160 beginning with the 2009 fiscal year. The Company is currently evaluating the potential impact, if any, of the adoption of SFAS No. 160 on its accompanying consolidated financial statements when effective.

In February 2007 the FASB issued Statement of Financial Accounting Standards No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" ("SFAS No. 159"), which expands the use of fair value accounting but does not affect existing standards that require assets or liabilities to be carried at fair value. SFAS No. 159 allows entities to choose, at specified election dates, to use fair value to measure eligible financial assets and liabilities that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item's fair value in subsequent reporting periods must be recognized in current earnings. SFAS No. 159 also establishes presentation and disclosure requirements designed to draw comparisons between entities that elect different measurement attributes for similar assets and liabilities. If elected, SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. SFAS No. 159 will be effective for the Company beginning with the 2008 fiscal year. The Company did not elect the fair value option. There is no impact on the Company's consolidated financial statements.

In September 2006 the FASB issued Statement of Financial Accounting Standards No. 157, "Fair Value Measurements" ("SFAS No. 157"), which defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. The provisions of SFAS No. 157 will be effective as of the beginning of the Company's 2008 fiscal year. The adoption of SFAS No. 157 has no impact on the Company's consolidated financial statements, however, it will require changes in certain disclosures.

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 Adjustment	Other Comprehensive Income (Loss)
		(In thousands)	
For the period ending December 31, 2005			
Before tax income (loss)	$ (92,097)	$ 455	$ (91,642)
Tax benefit (expense)	34,941	(172)	34,769
After deferred tax income (loss)	$ (57,156)	$ 283	$ (56,873)
For the period ending 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 period ending 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)

Major Customers

During 2007 and 2006 no customer individually accounted for more than ten percent of the Company's total oil and gas production revenue. During 2005 one customer individually accounted for 13 percent of the Company's total oil and gas production revenue.

Industry Segment and Geographic Information

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

Intangible Assets

As of December 31, 2007, and 2006, the Company's accompanying consolidated balance sheets include $2.4 million and $3.4 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 is conducted at the reporting unit level. A reporting unit is defined as the oil and gas properties in a region.

Off – Balance Sheet Arrangements

As part of its ongoing business, the Company has not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities ("SPEs"), which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. As of and up to December 31, 2007, 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,	
	2007	2006
	(In thousands)	
Accrued oil and gas sales	$ 115,534	$ 95,036
Due from joint interest owners	37,860	33,309
Other	5,755	14,376
Total accounts receivable	$ 159,149	$ 142,721

Accounts payable and accrued expenses are comprised of the following:

	As of December 31,	
	2007	2006
	(In thousands)	
Accrued drilling costs	$ 112,481	$ 68,326
Revenue payable	37,048	27,591
Accrued lease operating expense	14,604	11,153
Accrued taxes	5,042	2,358
Accrued interest	3,590	2,846
Accrued compensation	17,887	10,323
Trade payables	28,187	37,152
Accrued payments to hedge contract counterparties	9,640	665
Plug and abandonment liability on offshore platform related to Hurricane Rita	3,108	-
Accrued marketed gas system expense	13,520	6,396
Other	9,811	5,024
Total account payable and accrued expenses	$ 254,918	$ 171,834

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

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 $148.9 million of cash, which is net of normal purchase price adjustments of $2.1 million. The acquisition was funded with cash on hand and borrowings under the Company's existing revolving credit facility. The Company allocated $127.2 million to proved oil and gas properties, $23.1 million to unproved oil and gas properties, and a net $292,000 to other assets. The Company also recorded $1.7 million in asset retirement obligation liability associated with the acquired properties. This property acquisition is adjacent to the recently acquired Catarina project area discussed below. The Company has hedged the equivalent of the first three years of natural gas production and the first two years of associated natural gas liquids production related to this acquisition.

Variable Interest Entity

The acquisition of the properties in the Gold River project area was structured to qualify as the first step of a reverse like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended ("the IRC"), and I.R.S. 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 the second step of the like-kind exchange was completed in conjunction with the divestiture of certain non-core oil and gas properties discussed below under *Assets Held for Sale*. As of the date of closing on October 4, 2007, 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.

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 provisions of FASB Interpretation No. 46(R), "Consolidation of Variable Interest Entities", the Company determined that SMLEA, LLC is a variable interest entity for which St. Mary is the primary beneficiary. Accordingly, SMLEA, LLC was consolidated into St. Mary subsequent to the completion of the purchase of oil and gas properties on October 4, 2007. As a result of the consolidation, St. Mary recognized all oil and gas reserves and production as well as all revenues and expenses attributed to the Rockford acquisition beginning on October 4, 2007.

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. The Company allocated $29.9 million to proved oil and gas properties, $535,000 to unproved oil and gas properties, and a net $215,000 to other assets. The Company also recorded $623,000 in asset retirement obligation liability associated with the acquired properties. The acquisition was funded with cash on hand and borrowings under the Company's existing credit facility.

Permian Basin Acquisition

On December 14, 2006, the Company acquired oil and gas properties in the Permian Basin in West Texas from private parties in exchange for $243.1 million of cash, which is net of normal purchase price adjustments of approximately $4.3 million. The Company recorded $199.1 million to proved oil and gas properties, $41.5 million to unproved oil and gas properties, $3.0 million to intangible assets, a net $326,000 to other assets, and $859,000 to asset retirement obligation liability. The Company allocated the purchase price based on the estimated fair value of the assets and liabilities acquired. The acquisition was accounted for using the purchase method and was funded with cash on hand and borrowings under the Company's credit facility.

Richland County, Montana Acquisition

On May 15, 2006, the Company closed on a transaction whereby it exchanged oil and gas properties located in the Uinta Basin of Utah for oil and gas properties located in Richland County, Montana. The transaction was structured to qualify as a like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended, and I.R.S. Revenue Procedure 2000-37. For financial reporting purposes, the transaction is considered a non-monetary exchange and was accounted for at estimated fair value. The exchange of properties resulted in recognition of approximately $6.4 million of gain.

Assets Held for Sale

In December 2007 St. Mary reached an agreement for the sale of its previously announced divestiture package, and 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 before commission costs was $131.1 million. The final sale price is subject to normal post-closing adjustments and settlements and is expected to be finalized during the second quarter of 2008. The transaction has an effective date of December 1, 2007. The accompanying consolidated balance sheet as of December 31, 2007, presents the $76.9 million assets held for sale, net of accumulated depletion, depreciation and amortization. The corresponding asset retirement obligation of $8.7 million and a $10.0 million deposit associated with oil and gas properties held for sale are also separately presented. Under FASB Emerging Issues Task Force Issue No. 03-13, the Company determined that these sales do not qualify for discontinued operations accounting.

Note 4 – Income Taxes

The provision for income taxes consists of the following:

	For the Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
Current taxes:			
Federal	$ 15,136	$ 28,557	$ 75,848
State	2,459	1,917	4,906
Deferred taxes	92,955	74,832	5,547
Total income tax expense	$ 110,550	$ 105,306	$ 86,301

As a result of the exercise of stock options, the Company was able to reduce its income tax payable in each year presented. The tax benefit to the Company of stock option exercises was $9.9 million in 2007, $16.1 million in 2006, and $6.0 million in 2005.

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

	December 31, 2007	December 31, 2006
	(In thousands)	
Deferred tax liabilities:		
Oil and gas properties	$ 412,669	$ 299,082
Unrealized derivative asset	-	17,184
Interest on Senior Convertible Notes	2,596	6,925
Other	1,429	59
Total deferred tax liabilities	416,694	323,250
Deferred tax assets:		
Net Profits Plan liability	79,552	59,537
Unrealized derivative liability	93,829	8,174
Stock compensation	8,849	8,104
State tax net operating loss carryforward or carryback	6,808	4,589
State and federal income tax benefit	2,939	2,285
Other long-term liabilities	1,724	2,026
Employee benefits and other	1,543	1,391
Deferred capital loss	-	619
Other	614	-
Total deferred tax assets	195,858	86,725
Valuation allowance	(3,556)	(2,660)
Net deferred tax assets	192,302	84,065
Total net deferred tax liabilities	224,392	239,185
Less: current deferred income tax liabilities	(1,425)	(17,188)
Add: current deferred income tax assets	34,636	2,521
Non-current net deferred tax liabilities	$ 257,603	$ 224,518
Current federal income tax refundable	$ 933	$ 7,293
Current state income tax refundable (payable)	$ (105)	$ 391

At December 31, 2007, the Company had estimated state net operating loss carryforwards of approximately $162.5 million that expire between 2008 and 2027 and state tax credits of $145,000 that expire between 2008 and 2016. A portion of the Company's valuation allowance relates to state net operating loss carryforwards, state tax credits, and state and federal income tax benefit amounts that the Company anticipates will expire before they can be utilized. The Company has concluded that permanent items included in the calculation of income tax for certain states may impact its ability to deduct net operating losses and realize federal income tax deduction benefits of those states and has adjusted its valuation allowances accordingly. The remaining portion of the valuation allowance relates to the Net Profits Plan liability and reflects an estimate of future executive compensation that may not be deductible for income tax purposes when future cash payments occur under the plan.

Federal income tax expense 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, and other permanent differences, as follows:

	For the Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
Federal statutory taxes	$ 105,092	$ 103,504	$ 83,307
Increase (reduction) in taxes resulting from:			
State taxes (net of federal benefit)	5,111	2,081	4,185
Statutory depletion	(407)	(315)	(224)
Domestic production activities deduction	(384)	(287)	(1,717)
Other	242	235	(108)
Change in valuation allowance	896	88	858
Income tax expense from operations	$ 110,550	$ 105,306	$ 86,301

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

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 2003. The Internal Revenue Service completed audits for the 2000, 2002, and 2003 tax years during the quarter ended March 31, 2007. There was no change to the provision for income tax as a result of these examinations.

In 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 carry over of minimum tax credits to the 2003 tax year was received in January 2008. These amounts have been previously recognized by the Company.

The Company adopted the provisions 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 2007 accompanying consolidated statements of operations includes a nominal $4,000 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, 2007.

The total amount recorded for unrecognized tax benefits for the year ended December 31, 2007, is presented below (in thousands):

Balance at January 1, 2007	$ 1,112
Additions for tax positions of prior years	233
Reductions for lapse of statute of limitations	(388)
Balance at December 31, 2007	$ 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 $1.25 billion and is subject to regular semi-annual redeterminations. The borrowing base redetermination process considers the value of St. Mary's oil and gas properties and other assets, as determined by the bank syndicate. The Company has elected an aggregate commitment amount of $500 million under the credit facility. The Company must comply with certain financial and non-financial covenants under its existing credit facility. The Company is in compliance with all covenants associated with the credit facility. The payment of dividends is subject to covenants under the Company's existing credit facility, including the requirement that the Company maintain certain levels of stockholders' equity and the limitation of the Company's annual dividend rate to no more than $0.25 per share per year. 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 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 $285.0 million and $180.0 million in outstanding loans under its revolving credit agreement on December 31, 2007, and February 15, 2008, respectively.

5.75% Senior Convertible Notes Due 2022

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

3.50% Senior Convertible Notes Due 2027

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

Holders may convert their notes based on a conversion rate of 18.3757 shares of the Company's common stock per $1,000 principal amount of the 3.50% Senior Convertible Notes (which is equal to an initial conversion price of approximately $54.42 per share), subject to adjustment, contingent upon and only under the following circumstances: (1) if the closing price of the Company's common stock reaches specified thresholds or the trading price of the notes falls below specified thresholds, (2) if the notes are called for redemption, (3) if specified distributions to holders of the Company's common stock are made or specified corporate transactions occur, (4) if a fundamental change occurs, or (5) during the ten trading days prior to, but excluding, the maturity date. The notes and underlying shares have been registered under a shelf registration statement. If the Company becomes involved in a material transaction or corporate development, it may suspend trading of the 3.50% Senior Convertible Notes 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 settle its obligations upon conversion of the notes in cash and, if applicable, shares of common stock. If the Company makes this election, then, for each $1,000 principal amount of notes converted, the Company will pay the following to holders in lieu of shares of common stock: (1) an amount in cash equal to the lesser of (i) $1,000 or (ii) the conversion value determined in the manner set forth in the indenture for the 3.50% Senior Convertible Notes, and (2) if the conversion value exceeds $1,000, the Company will also deliver, at its election, cash or common stock or a combination of cash and common stock with respect to the remaining value deliverable upon conversion. Currently, it is the Company's intention to net share settle the 3.50% Senior Convertible Notes. However, the Company has not made this a formal legal irrevocable election and thereby reserves the right to settle the 3.50% Senior Convertible Notes in any manner allowed under the offering memorandum as business conditions warrant.

If a holder elects to convert 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 $296 million as of December 31, 2007.

In August 2007 the FASB proposed FASB Staff Position APB 14-a, "Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (including Partial Cash Settlement)" ("FSP APB 14-a"). FSP APB 14-a proposes that the accounting treatment for certain convertible debt instruments that may be settled in cash, shares of common stock, or any portion thereof at the election of the issuing company be accounted for utilizing a bifurcation model under which the value of the debt instrument would be determined without regard to the conversion feature. As of the date of this filing, FSP APB 14-a remains a proposed FASB staff position under redeliberation.

Weighted-Average Interest Rate Paid and Capitalized Interest

The weighted-average interest rate paid in 2007, 2006, and 2005 was 5.4 percent, 7.6 percent, and 7.1 percent, respectively, including commitment fees paid on the unused portion of the credit facility aggregate commitment, amortization of deferred financing costs, amortization of the contingent interest embedded derivative associated with the 5.75% Senior Convertible Notes, and the effect of interest rate swaps. The average outstanding loan balance in 2007 grew at a faster rate than the aforementioned items resulting in a lower weighted-average interest rate. Capitalized interest costs for the Company for the years ended December 31, 2007, 2006, and 2005, were $5.4 million, $3.5 million, and $1.9 million, respectively.

Note 6 – Commitments and Contingencies

The Company has entered into various operating leases, some of which include drilling rig contracts of, approximately $25.5 million, office space leases of approximately $14.1 million, and compressor contracts of approximately $2.0 million. The annual minimum lease payments for the next five years and thereafter are presented below:

Years Ending December 31,	(In thousands)
2008	$ 29,119
2009	5,882
2010	3,747
2011	3,352
2012	1,335
Thereafter	814
Total	$ 44,249

The Company leases office space under various operating leases with terms extending as far as May 31, 2014. Rent expense, net of sublease income, was $1.9 million, $1.5 million, and $1.3 million in 2007, 2006, and 2005, respectively. The Company also leases office equipment under various operating leases. The Company has a non-cancelable sublease through May 2012, of approximately $816,000, with payments 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. Management believes it has sufficiently provided for such items to the extent necessary in the consolidated balance sheets.

Note 7 – Compensation Plans

Cash Bonus Plan

The Company has a cash bonus plan under which the Company can award participants a cash bonus of up to 50 percent of their aggregate base salary. Any awards under the cash bonus plan are based on Company and regional performance, and then are further refined by individual performance. The Company accrues cash bonus expense related to the current year's performance. Included in the general and administrative and exploration expense line items in the accompanying consolidated statements of operations are $3.6 million, $1.9 million, and $7.4 million of cash bonus expense related to the specific performance year for the years ended December 31, 2007, 2006, and 2005, respectively.

Net Profits Plan

Under the Company's Net Profits Plan, all oil and gas wells that are completed or acquired during a year are designated within a specific pool. Key employees recommended by senior management and designated as participants by the Company's Compensation Committee of the Board of Directors and employed by the Company on the last day of that year become entitled to payments under the Net 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 2005 are fully vested. The 2006 and 2007 Pool years carry a vesting period of three years, whereby one-third is vested at the end of the year for which participation is designated and one-third vests 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 current 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 shares. As a result, the 2007 Net Profits Plan pool will be the last pool established by the Company.

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. Historically and for a predominate number of the pools, a discount rate of 15 percent was used to calculate this liability and is intended to represent the best estimate of the present value of expected future payments under the Net Profits Plan. During the fourth quarter of 2007, the Company adjusted 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 was based on experience gained from the divestiture marketing process, an overall sense of the valuation of oil and gas assets and an assessment of the current market for proved oil and gas reserves.

The Company's estimate of its liability is highly dependent on the price and cost assumptions, as well as the discount rates used in the calculations. The commodity price assumptions are formulated by applying a price that is derived from a rolling average of actual prices realized over the prior 24 months together with adjusted NYMEX strip prices for the ensuing 12 months for a total of 36 months of data. This average is adjusted to include the effect of hedge prices for the percentage of forecasted production hedged in the relevant period. The forecasted 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 include the current market environment for oil and gas prices, costs, discount rates, and overall market conditions.

No published market quotes exist on which to base the Company's estimate of fair value of the Net Profits Plan. As such, it is entirely based on management estimates which are described within this footnote. While some inputs to the Company's calculation to estimate the fair value of the Net Profits Plan's future payments are from published sources, others are derived from the Company's own calculations and estimates, such as the approximated discount rate and the expected future cash flows.

The following table presents the changes in the estimated future liability attributable to the Net Profits Plan. These amounts relate to the realized results for the years presented from oil and gas operations for the properties associated with the respective pools that have achieved payout status.

	As of December 31,	
	2007	2006
	(In thousands)	
Liability balance for Net Profits Plan as of the beginning of the period	$ 160,583	$ 136,824
Increase in liability	82,734	49,900
Reduction in liability for cash payments made or accrued and recognized as compensation expense	(31,911)	(26,141)
Liability balance for Net Profits Plan as of the end of the period	$ 211,406	$ 160,583

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, 2007, would differ by approximately $19 million. A one percentage point decrease in the discount rate would result in an increase to the liability of approximately $12 million. While a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $10 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 will be inherently different from the amounts estimated.

The Company records changes in the present value of estimated future payments under the Net Profits Plan as a separate item in the 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 realized in the current period. 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. For the years ended December 31, 2007, 2006, and 2005, 22 percent, 54 percent, and 51 percent, respectively, of payments made under the Net Profits Plan were classified as exploration expense in the accompanying consolidated statements of operations. As time progresses, less of the distribution relates to prospective exploration efforts as more of the distributions are made to employees that have terminated employment and thereby do not provide any period exploration support.

	For the Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
General and administrative expense	$ 41,803	$ 10,342	$ 51,419
Exploration expense	9,020	13,417	54,844
Total	$ 50,823	$ 23,759	$ 106,263

401(k) Plan

The Company has a defined contribution pension plan (the "401(k) Plan") that is subject to the Employee Retirement Income Security Act of 1974. The 401(k) Plan allows eligible employees to contribute up to 60 percent of their base salaries. The Company matches each employee's contributions up to six percent of the employee's base salary and may make additional contributions at its discretion. The Company's contributions to the 401(k) Plan were $1.5 million, $1.2 million, and $966,000 for the years ended December 31, 2007, 2006, and 2005, respectively. No discretionary contributions were made by the Company to the 401(k) Plan in any of these years.

Employee Stock Purchase Plan

Under the St. Mary Land & Exploration Company Employee Stock Purchase Plan ("the ESPP"), eligible employees may purchase shares of the Company's common stock through payroll deductions of up to 15 percent of eligible compensation. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on the first or last day of the purchase period, and shares issued under the ESPP are restricted for a period of 18 months from the date issued. The ESPP is intended to qualify under Section 423 of the IRC. The Company has set aside 2,000,000 shares of its common stock to be available for issuance under the ESPP, of which 1,599,811 shares are available for issuance as of December 31, 2007. Shares issued under the ESPP totaled 29,534 in 2007, 26,046 in 2006, and 28,447 in 2005. Total proceeds to the Company for the issuance of these shares were $919,000 in 2007, $814,000 in 2006, and $601,000 in 2005.

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,		
	2007	2006	2005
Risk free interest rate	4.1%	5.1%	2.5%
Dividend yield	0.3%	0.3%	0.4%
Volatility factor of the expected market price of the Company's common stock	27.19%	36.7%	36.3%
Expected life (in years)	0.5	0.5	0.5

For the ESPP offering periods during 2007 and 2006, the Company expensed $260,000 and $243,000, respectively, based on the estimated fair values of grants on the respective grant dates. There was no expense related to ESPP shares recorded in 2005.

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. For example, the Company ceased issuing stock options and began issuing restricted stock or RSUs to employees and directors in 2004. 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 a Predecessor Plan prior to the effective date of the 2006 Equity Plan continues to be governed solely by the terms and conditions of the instruments evidencing such grants or issuances.

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

(b) compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123(R).

As of December 31, 2007, 2.6 million shares of common stock remained available for grant under the 2006 Equity Plan. Any issuance of a direct share benefit such as an outright grant of common stock, a grant of a restricted share, or a RSU counts as two shares for each share issued against the amount eligible to be granted under the 2006 Equity Plan. Each stock option and similar instrument granted counts as one share for each share issued against the eligible shares authorized to be issued under the 2006 Equity Plan.

St. Mary anticipates granting Performance Share Plan (“PSP”) awards in lieu of RSUs beginning in 2008. The performance shares are expected to be subject to vesting periods and pre-established performance criteria. PSP awards will result in tradable shares of St. Mary common stock being issued immediately upon final vesting at the end of the planned three-year performance measurement period. The Company expects that awards granted under the PSP will be granted under the existing stockholder approved 2006 Equity Plan. The Company does have outstanding stock option grants under the Predecessor Plans and RSU grants 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, 2007.

Restricted Stock Incentive Program Under the Equity Incentive Compensation Plan

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

St. Mary issued 78,657 RSUs on February 28, 2007, related to 2006 performance, 484,351 RSUs on February 28, 2006, related to 2005 performance and 195,312 RSUs on March 15, 2005 related to 2004 performance. The total fair value associated with these issuances was $2.5 million in 2007, $16.4 million in 2006, and $4.5 million in 2005 as measured on the respective grant dates. The granted RSUs vest 25 percent immediately upon grant and 25 percent on each of the next three anniversary dates of the grant. Compensation expense is recorded monthly over the vesting period of the award. Vested shares of common stock underlying the 2005 RSU grant will be issued on the third anniversary of the grant, at which time the shares carry no further restrictions. For all awards subsequent to the 2005 RSU grant, St. Mary has eliminated the restriction period that extends beyond the vesting period so that shares will be issued without restriction upon vesting, rather than on the third anniversary of the award. This change was effected within the safe harbor adoption provisions of the newly enacted U.S. Treasury regulations interpreting IRC laws governing deferred compensation. The mutual election of the employee and the Company were required to effect this change. Essentially all of the awards were modified for this mutual election and as such the incremental value associated with removing this restriction period will be amortized over the remaining service period for these awards. For grants made beginning with the 2006 grant period, the Company is using the accelerated amortization method as described in FASB Interpretation No. 28, “Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans – an interpretation of APB Opinions No. 15 and 25,” whereby approximately 48 percent of the total estimated compensation expense is recognized in the first year of the vesting period. Expense for grants made for plan years prior to 2006 is being amortized under the straight-line method since this method was allowed prior to the adoption of SFAS No. 123(R). As of December 31, 2007, a total of 684,264 RSUs were outstanding, of which 394,879 were vested. Total compensation expense related to the RSUs recognized in the year ended December 31, 2007, was $8.4 million. This amount includes $2.8 million of compensation expense related to the 2007 equity plan year for vesting of the estimated value of grants expected to be issued in 2008.

St. Mary also issued 23,977 RSUs and 13,500 RSUs for various grants to specific employees during 2007 and 2006, respectively. No special grants were issued during 2005. These grants have various vesting schedules. The fair value of these awards will be recorded to compensation expense over the respective vesting periods using the same basic framework as described above.

In 2007, 2006, and 2005, the Company issued 32,504, 29,827, and 13,926 shares, respectively, of common stock from treasury to its non-employee directors pursuant to the Company's non-employee director stock compensation plan. The Company recorded compensation expense related to the issuances of shares to non-employee directors of $983,500, $976,000 and $178,000 for the years ended December 31, 2007, 2006 and 2005, respectively.

On June 30, 2007, the Company converted 427,059 RSUs, which were granted on June 30, 2004, into common stock based on the original terms of the RSU award. The Company and the majority of the grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and original award agreements. As a result, the Company issued a net 302,370 shares of common stock associated with this grant. 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 from the grant of RSUs, SFAS No. 123(R) requires companies to estimate the fair value of the award on the grant date. The fair value of the RSUs is inherently less than the market value of an unrestricted security. The fair value of RSUs has been measured using the Black-Scholes option-pricing model. The Company's computation of expected volatility was based on the historic volatility of St. Mary's common stock. The Company's computation of expected life was determined based on historical experience of similar awards, giving consideration to the contractual terms of the awards, vesting schedules, and expectations of future employee behavior. The interest rate for periods within the contractual life of the award was based on the U.S. Treasury constant maturity yield at the time of grant. The fair values of granted RSUs were estimated using the following weighted-average assumptions:

	For the Years Ended December 31,		
	2007	2006	2005
Risk free interest rate	4.5%	4.7%	4.0%
Dividend yield	0.3%	0.3%	0.4%
Volatility factor of the expected market price of the Company's common stock	32.0%	36.6%	26.7%
Expected life of the awards (in years)	3	3	3

Upon the adoption of SFAS No. 123(R), the deferred compensation balance of $5.6 million related to outstanding RSU awards was reclassified to additional paid-in-capital within the shareholders' equity section of the balance sheet. This deferred compensation balance had been recorded in accordance with APB Opinion No. 25. The Company had recorded compensation expense in periods prior to January 1, 2006, for restricted stock awards based on the intrinsic value on the date of grant. The intrinsic value was recorded as deferred compensation in a separate component of shareholders' equity and was amortized to compensation expense over the vesting period. SFAS No. 123(R) requires expense recognized subsequent to the adoption date to be based on fair value.

Stock Awards Under the Equity Incentive Compensation Plan

As part of hiring a new senior executive in the second quarter of 2006, St. Mary granted a special common stock award of 20,000 shares that vested immediately upon commencement of employment. Approximately $728,000 of compensation expense was recorded related to this award in 2006. In addition to this award, the employee may earn an additional 5,000 shares over a four-year period and an additional 15,000 shares contingent on the Company meeting certain net asset growth performance conditions over a four-year period. The fair value of this award will be recorded as compensation expense over the vesting period. For the years ended December 31, 2007 and 2006 the Company recorded compensation expense of $136,000 and $27,000 respectively, related to the contingent award.

A summary of the status and activity of non-vested stock awards and RSUs for the year ended December 31, 2007, is presented below:

	Shares	Weighted-Average Grant-Date Fair Value
Non-vested, at December 31, 2006	506,161	$ 28.92
Granted	102,634	$ 32.45
Vested	(268,123)	$ 25.94
Forfeited	(51,287)	$ 31.77
Non-vested, at December 31, 2007	289,385	$ 32.26

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 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, 2007, the Company recognized stock-based compensation expense of approximately $437,000 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).

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 a part of cash flows from financing activities. Excess tax benefits are realized tax benefits from tax deductions for exercised options in excess of the deferred tax asset attributable to stock compensation costs for such options. The Company has recorded $9.9 million and $16.1 million of excess tax benefits for the years ended December 31, 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, 2007, 2006, and 2005, was $9.1 million, $16.9 million, and $10.6 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, 2005			
Outstanding, start of year	5,651,350	$12.06	
Granted	-	-	
Exercised	(936,403)	11.31	
Forfeited	(16,704)	13.24	
Outstanding, end of year	4,698,243	$12.21	$ 115,595,735
Vested or expected to vest, end of year	4,698,243	$12.21	$ 115,595,735
Exercisable, end of year	4,121,424	$12.07	$ 101,972,732
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

A summary of additional information related to options outstanding as of December 31, 2007, 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
$ 4.62 - $ 10.60	464,747	2.9 years	$ 7.77	464,747	2.9 years	$ 7.77
10.86 - 12.03	469,156	4.5 years	11.65	469,156	4.5 years	11.65
12.08 - 12.53	388,139	5.1 years	12.50	388,139	5.1 years	12.50
12.66 - 13.65	368,847	5.6 years	13.25	361,347	5.6 years	13.25
14.25 - 14.25	239,129	6.0 years	14.25	239,129	6.0 years	14.25
16.66 - 16.66	387,078	3.0 years	16.66	387,078	3.0 years	16.66
20.87 - 20.87	68,404	7.0 years	20.87	68,404	7.0 years	20.87
Total	2,385,500			2,378,000		

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 disclosure provisions of Statements of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an Amendment of FASB Statements No. 87, 88, 106, and 132(R)" ("SFAS No. 158"). 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 a 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 Statements of Financial Accounting Standards No. 87, "Employers' Accounting for Pensions" ("SFAS No. 87"). These amounts will be subsequently recognized as net periodic pension cost pursuant to the Company's accounting policy for amortizing such amounts. Further actuarial gains and losses that arise in subsequent periods and are not recognized as net periodic pension cost in the same periods will be recognized as a component of other comprehensive income. Those amounts will be subsequently recognized as a component of net periodic pension cost on the same basis as the amounts recognized in accumulated other comprehensive income at adoption of SFAS No. 158.

The incremental effects of adopting the provisions of SFAS No. 158 on the Company's statement of financial position at December 31, 2006, are presented in the following table. The adoption of SFAS No. 158 had no effect on the Company's 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 assumptions. Experience changes are the effects of differences between previous actuarial assumptions and what actually occurred. Included in accumulated other comprehensive income at December 31, 2007, are the following amounts that have not yet been recognized in net periodic pension cost:

	As of December 31, 2007
	(In thousands)
Unrecognized actuarial losses	$ 2,500
Unrecognized prior service costs	-
Accumulated other comprehensive income	$ 2,500

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 $112,000.

Obligations and Funded Status for Both Pension Plans

	For the Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
Change in benefit obligations:			
Projected benefit obligation at beginning of year	$ 13,763	$ 11,900	$ 10,174
Service cost	1,911	1,684	1,385
Interest cost	793	652	535
Actuarial (gain) loss	95	7	(4)
Benefits paid	(1,818)	(480)	(190)
Projected benefit obligation at end of year	$ 14,744	$ 13,763	$ 11,900
Change in plan assets:			
Fair value of plan assets at beginning of year	$ 7,789	$ 5,955	$ 4,675
Actual return on plan assets	536	968	412
Employer contribution	2,248	1,346	1,058
Benefits paid	(1,818)	(480)	(190)
Fair value of plan assets at end of year	$ 8,755	$ 7,789	$ 5,955
Funded status:	$ (5,989)	$ (5,974)	$ (5,945)
Accumulated Benefit Obligation	$ 10,416	$ 9,922	$ 8,429

The combined underfunded status for the Pension Plans of $6.0 million at December 31, 2007, is recognized in the accompanying statement of financial position as long-term accrued pension liability. 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 Plans with an Accumulated Benefit Obligation in Excess of Plan Assets for Both Plans

	As of December 31,	
	2007	2006
	(In thousands)	
Projected benefit obligation	$ 14,744	$ 13,763
Accumulated benefit obligation	$ 10,416	$ 9,922
Fair value of plan assets	$ 8,755	$ 7,789

Components of Net Periodic Benefit Cost for Both Pension Plans

	For the Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
Components of net periodic benefit cost:			
Service cost	$ 1,911	$ 1,684	$ 1,385
Interest cost	793	652	535
Expected return on plan assets that reduces periodic pension cost	(540)	(427)	(354)
Amortization of prior service cost	-	-	-
Amortization of net actuarial loss	218	296	241
Net periodic benefit cost	$ 2,382	$ 2,205	$ 1,807

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,	
	2007	2006
Projected benefit obligation		
Discount rate	6.1%	5.9%
Rate of compensation increase	6.2%	6.2%
Net periodic benefit cost		
Discount rate	5.9%	5.5%
Expected return on plan assets	7.5%	7.5%
Rate of compensation increase	6.2%	6.2%

Plan Assets

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

	Target	As of December 31,	
Asset Category	2008	2007	2006
Equity securities	60.0%	57.5%	64.8%
Debt securities	40.0%	42.5%	35.2%
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 for the Nonqualified Pension Plan since that plan does not have its own assets. An expected return on plan assets of 7.5 percent was used to calculate the Company's obligation under the Qualified Pension Plan. Factors considered in determining the expected return include the 60 percent equity and 40 percent debt securities mix of investment for plan assets and the long-term historical rate of return provided by the equity and debt securities markets. The estimated rate of return on plan assets was 7.5 percent for 2007 and 2006. The difference in investment income using the projected rate of return compared to the actual rates of return for the past two years was not material and will not have a material effect on the statements of operation or on cash flows from operating activities in future years.

Contributions

The Company contributed \$2.2 million, \$1.3 million, and \$1.1 million, to the Pension Plans in the years ended December 31, 2007, 2006, and 2005, respectively. St. Mary expects to contribute approximately \$2.9 million to the Pension Plans in 2008.

Benefit Payments

The Pension Plans made actual benefit payments of \$1.8 million, \$480,000, and \$190,000 in the years ended December 31, 2007, 2006, and 2005, respectively. Expected benefit payments over the next ten years follows:

Years Ended December 31,	(in thousands)
2008	$ 1,612
2009	479
2010	734
2011	1,254
2012	1,529
2013 through 2017	$ 13,793

Note 9 – Asset Retirement Obligations

The Company recognizes an estimated liability for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and a corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is completed or acquired. The increase in carrying value is included in proved oil and gas properties in the 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 a credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. The credit-adjusted risk-free rates used to discount the Company’s abandonment liabilities range from 6.50 percent to 7.25 percent. Revisions to the liability could occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells.

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

	As of December 31,	
	2007	2006
	(In thousands)	
Beginning asset retirement obligation	$ 77,242	$ 66,078
Liabilities incurred	10,851	7,555
Liabilities settled	(12,276)	(1,484)
Accretion expense	5,458	4,926
Revision to estimated cash flows	27,009	167
Ending asset retirement obligation	$ 108,284	$ 77,242

Accounts payable and accrued expenses as of December 31, 2007, contain $3.1 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 Rita. Plugging and abandonment of the platform is expected to be completed during the second quarter of 2008. Please refer to Note 12 – Insurance Settlement for additional details. Accounts payable and accrued expenses did not contain any amount related to the Company's asset retirement obligation as of December 31, 2006.

Note 10 – Derivative Financial Instruments

Oil and Gas Commodity Hedges

To mitigate a portion of the potential exposure to adverse market changes, the Company has entered into various derivative contracts. The Company's derivative contracts in place include swap and collar arrangements for the sale of oil, natural gas, and natural gas liquids. Please refer to the tables under *Summary of Oil and Gas Production Hedges in Place* in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, for details regarding the Company's hedged volumes and associated prices. As of December 31, 2007, the Company has hedge contracts in place through 2011 for a total of approximately 11.4 million Bbls of anticipated crude oil production, 70.2 million MMBtu of anticipated natural gas production, and 1.4 million Bbls of anticipated natural gas liquids production.

The Company attempts to qualify its oil and natural 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 derivatives that are designated as cash flow hedges to the specific forecasted sale of oil or gas at its physical location. The Company also formally assesses (both at the derivative's inception and on an ongoing basis) whether the derivatives being utilized have been highly effective at offsetting changes in the cash flows of hedged production and whether those 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, 2007, 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 or liabilities. The Company evaluates market prices in active markets to establish the valuation of derivative instruments. The Company compares valuation estimates against mark-to-market statements from counterparties for reasonableness. 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 liability of $264.1 million at December 31, 2007.

The Company realized a net gain of $19.3 million, a net gain of $20.5 million, and a net loss of $24.4 million from its oil and gas derivative contracts for the years ended December 31, 2007, 2006, and 2005, 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 attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings upon the sale of the hedged production. As of December 31, 2007, the amount of unrealized loss net of deferred income taxes to be reclassified from accumulated other comprehensive income to oil and gas production operating revenues in the next twelve months was $48.0 million.

Any change in fair value resulting from ineffectiveness is recognized currently in unrealized derivative loss in the accompanying consolidated statements of operations. Unrealized derivative loss for the years ended December 31, 2007, 2006, and 2005, includes net losses of $4.1 million, $8.1 million, and $1.8 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.

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

	For the Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
Derivative contract settlements included in realized oil and gas hedge gain (loss)	$ 24,484	$ 28,176	$ (22,539)
Ineffective portion of hedges qualifying for hedge accounting included in unrealized derivative loss	(4,123)	(8,087)	(1,754)
Non-qualified derivative contracts included in unrealized derivative loss	(1,335)	993	139
Interest rate derivative contract settlements	226	(550)	(247)
Total realized gain (loss)	$ 19,252	$ 20,532	$ (24,401)

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 will pay a fixed rate of 4.90 percent and will be paid a variable rate based on the one-month LIBOR rate. The interest rate derivative contract is measured at fair value using quoted prices in active markets. The liability in the accompanying consolidated balance sheet at December 31, 2007, was $447,000. The interest rate swap is a straightforward, non-complex, non-structured instrument that is highly liquid This derivative qualifies for cash flow hedge treatment under SFAS No. 133 and related pronouncements. The Company recorded a net derivative gain of $57,000 in the accompanying consolidated statements of operations for the year ended December 31, 2007, related to this interest rate derivative contract.

Convertible Note Derivative Instrument

In relation to the Company's 5.75% Senior Convertible Notes converted in March 2007, the Company entered into fixed-to-floating interest rate swaps on $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 factor 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 de minimis at the inception of the instrument.

Note 11 – Repurchase 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 5,207,784 shares of common stock. The shares may be repurchased from time to time in open market transactions or in privately negotiated transactions, subject to market conditions and other factors, including certain provisions of St. Mary's existing credit facility agreement and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow, and borrowings under the credit facility. During 2007 the Company repurchased 792,216 shares of its outstanding common stock in the open market at a weighted-average price of $32.76 per share, including commissions, for a total of $26.0 million. During 2006 the Company repurchased 3,319,300 shares of its outstanding common stock in the open market at a weighted-average price of $37.09 per share, including commissions, for a total of $123.1 million. During 2005 the Company repurchased 1,175,282 shares of its outstanding common stock in the open market at a weighted-average price of $24.59 per share, including commissions, for a total of $28.9 million. The Company did not retire any shares in 2007. The Company retired 3,275,689 shares in 2006 and 1,411,356 shares in 2005.

Note 12 – Insurance Settlement

In April of 2007 the Company reached a global insurance settlement for reimbursement of damages sustained during Hurricane Rita. St. Mary's net amount of the final settlement was approximately $33 million. As a result of this settlement, the Company recorded a gain of $5.2 million in other revenue in the accompanying statement of operations for the year ended December 31, 2007. The Company experienced significant weather-related delays in its plug and abandonment efforts during 2007 and consequently accrued an additional $2.1 million of plug and abandonment costs for one offshore platform during the fourth quarter of 2007. The gain calculation takes into consideration a total of approximately $12.1 million of costs associated with the plugging and abandonment of the above-mentioned offshore platform. Any significant variation between actual and estimated plugging and abandonment and outside-operated damage repair costs will impact the final determination of the gain associated with the insurance settlement. The Company expects adjustments to the gain to be completed by the second quarter of 2008.

Note 13 – Disclosures about Oil and Gas Producing Activities

Costs Incurred in Oil and Gas Producing Activities

Costs incurred in oil and gas property acquisition, exploration and development activities, whether capitalized or expensed, are summarized as follows. The 2007, 2006, and 2005 amounts include $27.6 million, $7.8 million, and $22.8 million, respectively, of capitalized costs associated with asset retirement obligations.

	For the Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
Development costs	$ 591,013	$ 367,546	$ 249,518
Exploration	111,470	126,220	69,817
Acquisitions:			
Proved	161,665	238,400	84,981
Unproved	23,495	44,472	2,853
Leasing activity	38,436	28,816	14,330
Total	$ 926,079	$ 805,454	$ 421,499

Suspended Well Costs

The following table reflects the net changes in capitalized exploratory well costs during 2007, 2006, and 2005. 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,		
	2007	2006	2005
		(In thousands)	
Beginning balance at January 1,	$ 22,799	$ 7,994	$ 189
Capitalized exploratory well costs charged to expense upon adoption of FSP FAS 19-1	-	-	-
Additions to capitalized exploratory well costs pending the determination of proved reserves	29,551	17,693	7,994
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	(9,237)	(2,888)	(189)
Capitalized exploratory well costs charged to expense	(183)	-	-
Ending balance at December 31,	$ 42,930	$22,799	$ 7,994

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,		
	2007	2006	2005
		(In thousands)	
Exploratory well costs capitalized for one year or less	$ 29,368	$ 17,958	$ 7,994
Exploratory well costs capitalized for more than one year	13,562	4,841	-
Ending balance at December 31,	$ 42,930	$ 22,799	$ 7,994
Number of projects with exploratory well costs that have been capitalized more than a year	3	1	-

The exploratory well costs capitalized for more than one year includes $4.8 million for a well that was drilled in 2005 and 2006 and is located offshore in the Gulf of Mexico. A Reserve Analysis and Reservoir Simulation Study has been completed for this well. Construction of a long lead-time infrastructure began in 2007 and is expected to be completed during the fourth quarter of 2008. Production from this well is expected to commence in 2009. The operational plan is to build the connection and process facilities in support of the already recognized costs. The Company believes these costs are realizable.

The exploratory well costs capitalized for more than one year also includes $5.7 million and $3.1 million of costs related to two additional wells located offshore in the Gulf of Mexico that were drilled in 2006. Reserve Analysis and Reservoir Simulation Studies have been completed for these wells to support the ongoing project economics. The wells were both waiting on the construction of production facilities, which were completed in late 2007. Production from both of these wells is expected to commence during the first quarter of 2008. Based on the operational plan and project economics for these wells, the Company believes these costs are realizable.

Oil and Gas Reserve Quantities (Unaudited)

For all years presented, Netherland, Sewell and Associates, Inc. (“NSAI”) prepared the reserve information for the Company’s coalbed methane projects at Hanging Woman Basin in the northern Powder River Basin as well as the Company’s non-operated coalbed methane 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 proven conventional oil and gas reserves in 2007 and 2006. In 2005, Ryder Scott Company, L.P. prepared the reserve estimates for at least 80 percent of the PV-10 value of the Company's conventional oil and gas assets. St. Mary personnel prepared the reserve estimates for the remainder of all properties. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established 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,					
	2007		2006		2005	
	Oil or Condensate (MBbl)	Gas (MMcf)	Oil or Condensate (MBbl)	Gas (MMcf)	Oil or Condensate (MBbl)	Gas (MMcf)
Developed and undeveloped:						
Beginning of year	74,195	482,475	62,903	417,075	56,574	319,196
Revisions of previous estimate	5,238	9,489	524	10,946	1,593	24,354
Discoveries and extensions	1,166	28,483	857	36,723	2,553	21,998
Infill reserves in an existing proved field	4,592	69,090	4,131	49,107	3,286	83,093
Purchases of minerals in place	567	91,374	11,857	28,030	4,831	20,823
Sales of reserves	(4)	(1,400)	(20)	(2,958)	(7)	(588)
Production	(6,907)	(66,061)	(6,057)	(56,448)	(5,927)	(51,801)
End of year [(a)] [(b)]	78,847	613,450	74,195	482,475	62,903	417,075
Proved developed reserves:						
Beginning of year	61,519	358,477	55,971	313,125	47,992	272,295
End of year	68,277	426,627	61,519	358,477	55,971	313,125

(a) At December 31, 2007, 2006, and 2005 amounts include approximately 316, 523, and 435 MMcf, respectively, representing the Company's net underproduced gas balancing position.

(b) Subsequent to the year ended December 31, 2007, the Company divested of certain non-core properties, which included 40.4 BCFE of reserves that were owned by the Company as of December 31, 2007.

Standardized Measure of Discounted Future Net Cash Flows (Unaudited)

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 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:

	2007	2006	2005
Gas (per Mcf)	$ 7.56	$ 5.54	$ 8.34
Oil (per Bbl)	$ 88.71	$ 53.65	$ 55.63

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,		
	2007	2006	2005
		(In thousands)	
Future cash inflows	$ 11,629,679	$ 6,653,455	$ 6,979,279
Future production costs	(3,672,857)	(2,283,452)	(2,146,590)
Future development costs	(611,288)	(429,303)	(385,379)
Future income taxes	(2,316,637)	(1,125,955)	(1,448,444)
Future net cash flows	5,028,897	2,814,745	2,998,866
10 percent annual discount	(2,321,983)	(1,238,308)	(1,286,568)
Standardized measure of discounted future net cash flows	$ 2,706,914	$ 1,576,437	$ 1,712,298

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

	For the Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
Standard measure, beginning of year	$ 1,576,436	$ 1,712,298	$ 1,033,938
Sales of oil and gas produced, net of production costs	(693,885)	(554,147)	(590,671)
Net changes in prices and production costs	1,320,994	(661,074)	725,154
Extensions, discoveries and other including infill reserves in an existing proved field, net of production costs	462,952	280,822	422,481
Purchase of minerals in place	265,285	263,762	132,185
Development costs incurred during the year	123,630	67,864	55,324
Changes in estimated future development costs	(32,566)	114,007	(42,710)
Revisions of previous quantity estimates	166,428	34,940	117,763
Accretion of discount	215,745	249,417	150,112
Sales of reserves in place	(1,915)	(8,991)	(1,000)
Net change in income taxes	(573,259)	200,858	(314,685)
Changes in timing and other	(122,931)	(123,319)	24,407
Standardized measure, end of year	$ 2,706,914	$ 1,576,437	$ 1,712,298

Note 14 – Quarterly Financial Information (Unaudited)

The Company's quarterly financial information for fiscal 2007 and 2006 is as follows (in thousands, except per share amounts):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year Ended December 31, 2007				
Total operating revenues	$ 221,006	$ 247,154	$ 246,687	$ 275,247
Total operating expenses (1)	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	$ -
Year Ended December 31, 2006				
Total operating revenues	$ 193,588	$ 193,381	$ 198,040	$ 202,692
Total operating expenses	112,902	128,296	110,818	133,419
Income from operations	$ 80,686	$ 65,085	$ 87,222	$ 69,273
Income before income taxes	$ 80,131	$ 64,076	$ 85,142	$ 65,972
Net income	$ 50,526	$ 40,080	$ 55,877	$ 43,532
Basic net income per common share	$ 0.88	$ 0.70	$ 1.01	$ 0.78
Diluted net income per common share	$ 0.76	$ 0.61	$ 0.88	$ 0.69
Dividends declared per common share	$ 0.05	$ -	$ 0.05	$ -

(1) General and administrative and exploration expense are components of total operating expenses. As a result of a change in circumstances in 2007, the Company began classifying all payments made under the Net Profits Plan to exploration overhead only for those individuals who are currently employed by St. Mary and who continue to be involved in the Company's exploration efforts. Therefore, the quarterly financial information presented in the following table reflects a reconciliation from what was previously reported in the quarterly reports on Form 10-Q, to the reclassified balances, which reflect current distributions being made and accrued for under the Net Profits Plan for former employees as being fully allocated to general and administrative expense since there is no longer any functional link to geologic and geophysical or exploration related work by those former employees. The reclassification was determined in the fourth quarter, therefore, no reclassification was necessary as the amounts reported for the fourth quarter were accounted for consistent with the current presentation. The change had no impact on total operating expenses, income from operations, income before income taxes, net income, basic net income per share, or diluted net income per share as it was simply a reclassification between two line items within the accompanying consolidated statements of operations as shown below.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands)			
General and administrative:				
As previously reported	$ 11,141	$ 13,697	$ 13,110	$ 15,187
Net Profits Plan Adjustment	1,750	2,569	2,695	-
Adjusted general and administrative	$ 12,891	$ 16,266	$ 15,805	$ 15,187
Exploration:				
As previously reported	$ 20,769	$ 13,643	$ 15,257	$ 16,030
Net Profits Plan Adjustment	(1,749)	(2,569)	(2,695)	-
Adjusted exploration	$ 19,020	$ 11,074	$ 12,562	$ 16,030

SIGNATURES

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

ST. MARY LAND & EXPLORATION COMPANY
(Registrant)

Date: March 4, 2008

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

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

Signature	Title	Date
/s/ ANTHONY J. BEST Anthony J. Best	President, Chief Executive Officer, and Director	March 4, 2008
* David W. Honeyfield	Senior Vice President-Chief Financial Officer and Secretary	March 4, 2008
* Mark T. Solomon	Controller	March 4, 2008
* Mark A. Hellerstein	Chairman of the Board of Directors	March 4, 2008

Signature	Title	Date
*__________________________ Barbara M. Baumann	Director	March 4, 2008
*__________________________ Larry W. Bickle	Director	March 4, 2008
*__________________________ William J. Gardiner	Director	March 4, 2008
*__________________________ Julio M. Quintana	Director	March 4, 2008
*__________________________ John M. Seidl	Director	March 4, 2008
*__________________________ William D. Sullivan	Director	March 4, 2008
* By: /s/ ANTHONY J. BEST Anthony J. Best (as attorney-in-fact for each of the persons indicated)		March 4, 2008

STOCKHOLDER INFORMATION

INVESTOR SERVICES

You can reach our corporate office at:
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Denver, CO 80203
303-861-8140
Fax: 303-861-0934

We also have offices in Tulsa, Oklahoma; Shreveport, Louisiana; Billings, Montana; Houston, Texas; and Midland, Texas

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PHOTOGRAPHY BY: RON COPPOCK-KING (DENVER, COLORADO)

INVESTOR RELATIONS CONTACT

Stockholders, securities analysts, or portfolio managers who have questions or need information concerning St. Mary may contact Brent Collins, Director of Investor Relations at 303-861-8140.
E-mail: bcollins@stmaryland.com

Annual Reports, 10Ks, 10Qs
To receive an information packet on St. Mary or to be added to our mailing list, contact Pam Sweet at 303-861-8140.
E-mail: information@stmaryland.com

Please visit our web site at: www.stmaryland.com

Stock Transfer Agent
Any stockholder with questions or inquiries regarding stock certificate holdings, changes in registration address, lost certificates, dividend payments, and other stockholder account matters should be directed to St. Mary Land & Exploration Company's transfer agent at the following address or phone number:

> **Computershare Trust Company NA**
> 350 Indiana Street, Suite 800
> Golden, CO 80401
> 303-262-0600

NYSE: SM
The Company's common stock is listed for trading on the New York Stock Exchange under the symbol SM.

The price ranges of the Company's common stock by quarter for the last two years are provided below. As of February 15, 2008 the Company had 63,020,524 shares of common stock outstanding, net of 1,009,712 treasury shares owned by the Company.

Market Prices	2007—Quarter Ended		2006—Quarter Ended	
	high	low	high	low
March 31	$38.20	$33.55	$44.69	$34.70
June 30	40.19	34.91	45.59	34.38
September 30	37.15	31.20	43.92	34.77
December 31	44.50	35.40	40.85	33.43

OTHER INFORMATION
In 2007, St. Mary submitted to the New York Stock Exchange a certificate of the Chief Executive Officer of St. Mary certifying that he was not aware of any violation by St. Mary of the New York Stock Exchange corporate governance listing standards. St. Mary has filed with the SEC certifications of the Chief Executive Officer and the Chief Financial Officer required under Section 302 of the Sarbanes-Oxley Act as exhibits to the Annual Report on Form 10-K/A for the year ended December 31, 2007.