GULFPORT
ENERGY CORPORATION
2006 ANNUAL REPORT

GULFPORT ENERGY CORPORATION
SUPPLEMENTAL FINANCIAL AND OPERATING STATISTICS

	Year End		
Financial Highlights	**2006**	**2005**	**% Improvement**
Revenues	$60,390,000	$27,559,000	119%
Income from Operations	$25,855,000	$9,417,000	175%
Net Income	$27,808,000	$10,895,000	155%
Earnings per Diluted Share	$0.82	$0.34	141%
Oil & Natural Gas Properties	$250,838,000	$173,135,000	45%
Production			
Oil (M Bbls)	870	517	68%
Natural Gas (MMCF)	677	575	18%
Total Oil Equivalent (M BOE)	983	613	60%
Realized Price			
Oil (per M Bbls)	$64.43	$46.39	39%
Natural Gas (per MMCF)	$6.20	$5.98	4%
Total Oil Equivalent (M BOE)	$61.30	$44.75	37%
Drilling Activity			**Success Rate**
Wells Drilled	28		89%
Recompletions Performed	19		

Letter to the Shareholders

Dear Fellow Shareholders,

2006 was a year of expansion and record results for Gulfport as we positioned the company for future growth. We successfully executed the most active drilling program in our ten-year history and made selected, strategic capital investments. Our development drilling in our West Cote Blanche Bay ("WCBB") field along the Louisiana Gulf Coast continued to provide production growth that resulted in record earnings and cash flow.

NASDAQ MarketSite welcomes Gulfport Energy

Our primary goal is to enhance shareholder value through the achievement of superior returns. In addition, we continue to pursue investment and acquisition opportunities outside our core WCBB field area, and have several exciting exploratory and development prospects, including the Hackberry field in southern Louisiana and our Canadian oil sands project. Put simply, we seek opportunities that enable value creation both in our core areas, as well as outside Louisiana.

For the full-year 2006, Gulfport shares gained 12.8% compared to 2005. This compares to the S&P oil and gas exploration and production index gain of 4.7% for 2006. Over the same period, crude oil (West Texas Intermediate) gained less than 1% and natural gas (Henry Hub) decreased by 43.9%.

Gulfport reached yet another milestone in 2006 by transitioning from the over-the-counter equity market to the NASDAQ Global Select market. We value the added exposure and liquidity that a major exchange brings to GPOR shares.

A closer look at our 2006 performance:

Operational Performance:

- Increased total net production 60% to 982,000 barrels of oil equivalent ("BOE")
- Drilled 28 wells and performed 19 successful recompletions
- Replaced production through the drillbit, maintaining 23.2 million BOE of proved reserves

Financial Performance:

- Reported record net income of $27.8 million, or $0.82 per diluted share
- Generated record cash flow from operations of $41.9 million
- 12.8% total shareholder return

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In southern Louisiana, our WCBB field remains our foundation asset and again delivered production growth year-over-year. Last year marked our highest drilling activity ever in this field with 27 wells and 19 recompletions of existing wells which provided record production. Drilling at this pace also increased our overall inventory of behind-pipe recompletion targets, thus increasing the overall value of our field.

Production barge facility and well head at Hackberry Field

At the Hackberry field, also along the Gulf Coast of southern Louisiana, our three dimensional (3-D) seismic shoot from 2005 has provided critical data for pre-drill analysis and mapping. Our staff identified seven well locations for an initial assessment drilling program and we drilled our first exploratory well late in 2006. The remaining wells will be drilled in the first half of 2007 and could fuel future field development. It is our belief that the Hackberry field has the potential for sizable production and reserve growth for Gulfport and could ultimately evolve into a core asset similar to our WCBB field.

Throughout 2006, we successfully improved our facilities at both our southern Louisiana fields. In WCBB, we upgraded our compressor capacity in preparation for our planned production growth from the field. These compressors are an essential part of our field operations, as they provide gas lift for our crude production. In addition, we made several improvements to our production platforms and living quarters in the field. In the Hackberry field, a majority of the fabrication for a new production barge facility was completed in 2006. As of April 2007, the barge facility is on location and commissioning activities are under way.

Just as important and valuable as the natural resources in our field are the human resources it takes to study, drill, produce, market and account for our oil and gas activities. Over the course of 2006, we made enormous strides to grow and broaden our workforce and our company. Within our technical teams, we added a senior reserve engineer, a geophysicist, two geologists, two production engineers and a drilling foreman. We are thrilled to expand our human talent in lockstep with our planned operational growth. On the corporate side, we strengthened our financial team, including adding a director of investor relations to respond to the increased interest from institutional shareholders.


Core hole drilling activity in Canada

In August 2006, we announced the acquisition of a 25% interest in 115,000 acres in the Alberta, Canada oil sands play. This acquisition afforded us the opportunity to secure acreage in a proven producing long-term crude oil play with significant upside potential. Since August, the total gross acreage position increased to nearly 320,000 acres, and we drilled 62 core holes on select locations to assess the bitumen saturation and development potential. The analysis of the core samples and electric logs is expected to be completed by a third-party engineering firm in the summer of 2007, at which time we will begin planning our winter 2007-2008 core hole drilling program. If successful, we estimate submitting governmental approval in 2008 for an initial 10,000 barrel a day steam assisted gravity drainage (SAGD) facility. Sizable capital requirements would be estimated to begin in 2009.

In Thailand, our small interest in a world-class gas field reached first gas sales in late 2006 and additional developmental drilling is planned in 2007.

2007 is already shaping up to be more active than 2006 given our activity in WCBB and Hackberry. We have a similar drilling program planned for WCBB and our exploratory activity at East Hackberry provides significant production and reserve growth potential. Our project in Canada continues to progress as expected and the analysis of our core program is ongoing.

We project total 2007 net production in the range of 1.7 to 1.9 million BOE, a 73% to 93% increase compared net 2006 production. This production forecast excludes any incremental production that may be produced from our exploratory program at East Hackberry. We expect operating costs on a per barrel basis to decline as well.

With the combination of our cash flow generation from our WCBB field, and the near-term upside exploratory potential at our East Hackberry field and the long-lived potential of our Canadian oil sands project, we believe Gulfport has an oil-leveraged portfolio to generate superior returns for many years to come.

Thank you for your continued support and interest in Gulfport.

Respectfully,

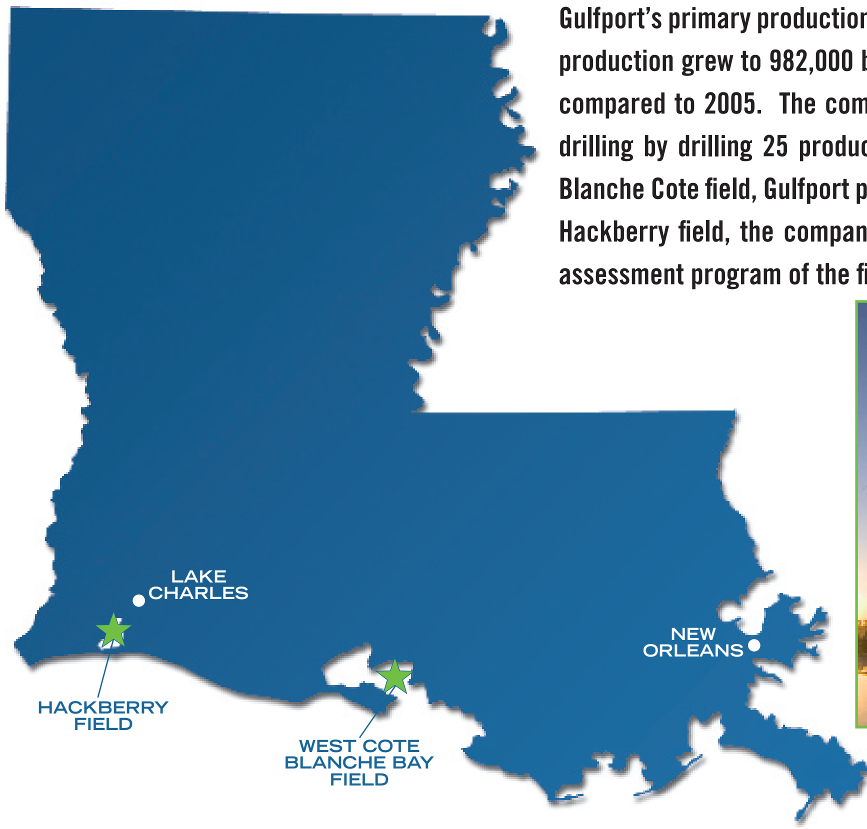
Mike Liddell
Chairman of the Board

James D. Palm
Chief Executive Officer


Drilling activity at Hackberry Field

Operational Highlights

Southern Louisiana



Gulfport's primary production is based in southern Louisiana. In 2006, production grew to 982,000 barrels of oil equivalent, a 60% increase compared to 2005. The company continues its record of successful drilling by drilling 25 productive wells out of 28. At the West Cote Blanche Cote field, Gulfport plans to drill 26 to 28 wells in 2007. At the Hackberry field, the company plans to complete a seven well initial assessment program of the field in 2007.

Canada

Gulfport has acquired 317,000 acreages in Alberta, Canada. This acreage is located in the Athabasca oil sands play. Gulfport commenced a 62-well drilling program in late 2006. Core samples from the drilling activity are being evaluated for assessment of estimated resource in place and possible developmental potential.

Thailand

Gulfport owns an indirect 0.7% interest in a world-class natural gas field in north-east Thailand. The field has initial proved reserves of 516 BCF and is operated by Hess Corporation. Additional development wells are being drilled at the field in 2007. Current estimated production from the field is approximately 100 MMcf per day. The upside case for potential resources (3P) totals 9 Tcf, which is 10.7 million BOE net to Gulfport.

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

Form 10-KSB

(Mark One)

☒ **ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2006

OR

☐ **TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number: 000-19514

Gulfport Energy Corporation
(Name of Small Business Issuer in Its Charter)

Delaware	**73-1521290**
(State or Other Jurisdiction of Incorporation or Organization)	**(I.R.S. Employer Identification No.)**
14313 North May Avenue, Suite 100 **Oklahoma City, Oklahoma**	**73134**
(Address of Principal Executive Offices)	**(Zip code)**

(405) 848-8807
(Issuer'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 per Share	**The Nasdaq Stock Market LLC**

Securities Registered Pursuant to Section 12(g) of the Act: **None**

Check whether the issuer is not required to file reports pursuant to Section 13 or 15(d) of the Exchange Act. ☐

Check whether the issuer: (1) filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the past 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 ☐

Check if there is no disclosure of delinquent filers in response to Item 405 of Regulation S-B contained in this form, and no disclosure will 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-KSB or any amendment to this Form 10-KSB. ☐

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

Registrant's revenues for its most recent fiscal year: $60,390,000

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of March 20, 2007 was $237,249,924.

As of March 20, 2007, 35,096,768 shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Certain information called for by Part III is incorporated by reference to certain sections of the Company's 2007 Proxy Statement that will be filed with the Securities and Exchange Commission not later than 120 days after December 31, 2006.

Transitional Small Business Disclosure Format (check one): Yes ☐ No ☒

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FORWARD-LOOKING STATEMENTS

Our disclosure and analysis in this Form 10-KSB may include forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act, and the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. These statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In some cases, you can identify forward-looking statements by terms such as "may," "will," "should," "could," would," "expects," "plans," "anticipates," "intends," "believes," "estimates," "projects," "predicts," "potential" and similar expressions intended to identify forward-looking statements. All statements, other than statements of historical facts, included in this Form 10-KSB that address activities, events or developments that we expect or anticipate will or may occur in the future, including such things as estimated future net revenues from oil and gas reserves and the present value thereof, future capital expenditures (including the amount and nature thereof), business strategy and measures to implement strategy, competitive strength, goals, expansion and growth of our business and operations, plans, references to future success, reference to intentions as to future matters and other such matters are forward-looking statements.

These forward-looking statements are largely based on our expectations and beliefs concerning future events, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors relating to our operations and business environment, all of which are difficult to predict and many of which are beyond our control.

Although we believe our estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this Form 10-KSB are not guarantees of future performance, and we cannot assure any reader that those statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to the factors listed in the "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" sections and elsewhere in this Form 10-KSB. All forward-looking statements speak only as of the date of this Form 10-KSB. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise, except as required by law. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

PART I

ITEM 1. DESCRIPTION OF BUSINESS

General

We are an independent oil and natural gas exploration and production company with our principal properties located along the Louisiana Gulf Coast. Our operations are concentrated in two fields: West Cote Blanche Bay, or WCBB, and the Hackberry fields. We also hold ownership interests in entities that operate in Southeast Asia, Canada and the Williston Basin area of western North Dakota and eastern Montana. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

In 2006, at our WCBB field, we drilled 27 wells and recompleted 19 existing wells for a total cost of $45.3 million as of December 31, 2006. Of our 27 new wells drilled at WCBB in 2006, 23 were completed as producing wells, one was waiting to be completed at year end and three were non-productive. During 2007, we intend to drill 26 to 28 wells and recomplete 18 existing wells at our WCBB field for an estimated aggregate cost of $50 million. During the first quarter of 2007, we have drilled four new wells at WCBB, of which one is producing, one is waiting on completion and two were non-productive.

During 2005, we completed a 3-D seismic program at our East Hackberry field to enhance our drilling program at that field. In 2006, we drilled one well in Lake Calcasieu in East Hackberry and, at year end, it was waiting to be completed. Year to date 2007 at East Hackberry, we have drilled two additional wells in Lake Calcasieu and are currently drilling two more wells, one on land and the other in Lake Calcasieu. The wells in Lake Calcasieu will be completed once we have the new production barge facility operational, which is currently scheduled for early in the second quarter of 2007. We also intend to drill two additional exploratory wells in East Hackberry during the second quarter of 2007. Once we have evaluated the results of our initial wells, we will be in a position to finalize our 2007 East Hackberry drilling activity.

As of December 31, 2006, we had 23.2 million barrels of oil equivalent (“MMBOE”) of proved reserves with a present value of estimated future net revenues, discounted at 10%, or PV-10, of approximately $399.4 million and associated standardized measure of discounted future net cash flows of approximately $352.6 million. See Item 2. “Properties—Proved Oil and Natural Gas Reserves” for our definition of PV-10, a non-GAAP financial measure, and a reconciliation of our standardized measure of discounted future net cash flows to PV-10.

Principal Oil and Natural Gas Properties

We own interests in producing oil and natural gas properties located along the Louisiana Gulf Coast. The following table presents certain information as of December 31, 2006 reflecting our net interest in our principal producing oil and natural gas properties in Louisiana.

								Proved Reserves		
	NRI/WI (1)	Producing Wells (2)		Non-Producing Wells		Developed Acreage (3)		Gas	Oil	Total
Field	Percentages	Gross	Net	Gross	Net	Gross	Net	Mboe	Mboe	Mboe
West Cote Blanche Bay (4)	79.443/100	78	78	195	195	5,668	5,668	2,908	16,605	19,513
E. Hackberry (5)	78.7/100	6	6	84	84	3,147	3,147	558	2,935	3,493
W. Hackberry	87.5/100	3	3	24	24	592	592	—	148	148
Overrides/Royalty Non-operated	Various	18	0.8	16	.7	4,956	586	—	4	4
Total		105	87.8	319	303.7	14,363	9,993	3,466	19,692	23,158

(1) Net Revenue Interest (NRI)/Working Interest (WI).

(2) Includes 30 gross and net wells at WCBB that are producing intermittently.

(3) Developed acres are acres spaced or assigned to productive wells. All of our acreage is developed acreage. All of the oil and natural gas leases in which we own an interest have been perpetuated by production. The operator may surrender the leases at any time by notice to the lessors, or by the cessation of production.

(4) We have a 100% working interest (79.443% average NRI) from the surface to the base of the 13,900 Sand which is located at 11,320 feet. Below the base of the 13,900 Sand, we have a 40.40% non-operated working interest (29.95% NRI).
(5) We have exercised an option with the State of Louisiana to acquire an additional 3,280 gross and net acres in the East Hackberry field. Final documentation and approval by the State of Louisiana is in progress.

West Cote Blanche Bay Field

Location and Land

The WCBB field lies approximately five miles off the coast of Louisiana in a shallow bay with water depths averaging eight to ten feet. We own a 100% working interest (79.4% net revenue interest, or NRI), and are the operator, in depths above the base of the 13900 Sand which is located at 11,320 feet. In addition, we own a 40.4% non-operated working interest (30.0% NRI) in depths below the base of the 13900 Sand, which is operated by Chevron Corporation. Our leasehold interests at WCBB contain 5,668 gross acres.

Area History and Production

Texaco, now Chevron Corporation, drilled the discovery well in this field in 1940 based on a seismic and gravitational anomaly. WCBB was subsequently developed on an even 160-acre pattern for much of the remainder of the decade. Developmental drilling continued and reached its peak in the 1970s when over 300 wells were drilled in the field. Of the 874 wells drilled as of December 31, 2006, 787 were completed as producing wells. As a result, the field has a historic success rate of 90% for all wells drilled. From the date of our acquisition of WCBB in 1997 through December 31, 2006, we drilled 94 new wells, 10 of which were non-productive, for an 89% success rate. As of December 31, 2006, estimated field cumulative gross production was 186 million barrel of oil equivalent, or MMboe, and 235 billion cubic feet, or Bcf, of gas. Of the 874 wells drilled in WCBB as of December 31, 2006, 48 were producing, 195 were shut-in, 30 were producing intermittently and five were being used as salt water disposal wells. The other 596 wells have been plugged and abandoned.

In 1991, Texaco conducted a 70 square mile 3-D seismic survey with 1,100 shot points per mile that processed out 100 fold. In 1993, an undershoot survey around the crest and production facilities was completed. We own the rights to the seismic data. In December 1999, we completed the reprocessing of the seismic data and our technical staff developed prospects from the data. The reprocessed data has enabled us to identify prospects in areas of the field that would have otherwise remained obscure. During the first half of 2005, we again reprocessed the seismic data using advanced seismic data processing.

Geology

WCBB overlies one of the largest salt dome structures on the Gulf Coast. The field is characterized by a piercement salt dome, which created traps from the Pleistocene through the Miocene formations. The relative movements affected deposition and created a complex system of fault traps. The compensating fault sets generally trend northwest to southeast and are intersected by sets having a major radial component. Later-stage movement caused extension over the dome and a large graben system (a downthrown area bounded by normal faults) was formed.

There are over 100 distinct sandstone reservoirs recognized throughout most of the field, and nearly 200 major and minor discrete intervals have been tested. Within the 874 wellbores that had been drilled in the field as of December 31, 2006, over 4,000 potential zones have been penetrated. These sands are highly porous and permeable reservoirs primarily with a strong water drive.

WCBB is a structurally and stratigraphically complex field. All of the proved undeveloped, or PUD, locations at WCBB are adjacent to faults and abut at least one fault. Our drilling programs are designed to penetrate each PUD trap with a new wellbore in a structurally optimum position, usually very close to the fault seal. The majority of these wells have been, and new wells drilled in connection with our drilling programs will be, directionally drilled using steering tools and downhole motors. The tolerance for error in getting near the fault is low, so the complex faulting does introduce the risk of crossing the fault before encountering the zone of interest, which could result in part or all of the zone being absent in the borehole. This, in turn, can result in lower than expected or no reserves for that zone. The new wellbores eliminate the mechanical risk associated with trying to produce the zone from an old existing wellbore, while the wellbore locations are selected in an effort to more efficiently drain each reservoir. The vast majority of the PUD targets are up-dip offsets to wells that produced from a sub-optimal position within a particular zone. Our inventory of prospects includes 118 PUD wells. The drilling schedule used in the reserve report anticipates that all of those wells will be drilled by 2016.

Facilities

We own and operate a production facility at WCBB that includes four production tank batteries, five natural gas compressors, a dehydration unit and a salt water disposal system.

Recent and Future Activity

In 2006, we drilled 27 wells and recompleted 19 existing wells at WCBB. Of these 27 new wells, 24 were completed as producers, and three were dry holes. We anticipate drilling 26 to 28 wells and recompleting 18 wells at WCBB during 2007. As of March 20, 2007, we had drilled four new wells, all of which were considered deep wells. Of these four new wells, one is producing, one is waiting on completion and two were unsuccessful. Of the four wells, all four were considered deep wells. The two productive wells, with total depths ranging from 7,700 to 9,990 feet, have approximately 96 feet of aggregate apparent net pay. The other two wells are non-productive, including one exploratory well that was drilled to satisfy our drilling commitment with the State of Louisiana to hold the non-productive portions of WCBB.

Production Status

In December 2006, production at WCBB was 118,530 barrels of oil equivalent (“BOE”) or an average of 3,824 BOE per day, 93% of which was from oil and 7% of which was from natural gas. In March 2007, our average net daily production at WCBB through March 26 was 4,001 BOE, 94% of which was from oil and 6% of which was from natural gas.

East Hackberry Field

Location and Land

The East Hackberry field is located along the western shore of Lake Calcasieu in Louisiana, 15 miles inland from the Gulf of Mexico. We own a 100% working interest (approximately 79% average NRI) in certain producing oil and natural gas properties situated in the East Hackberry field. The interest includes two separate lease blocks, the Erwin Heirs Block, which is located on land, and the adjacent State Lease 50 Block, which is located primarily in the shallow waters of Lake Calcasieu. The two lease blocks together contain 3,147 acres. In addition, we recently exercised our option to acquire additional acreage at the Hackberry field. The option will increase our acreage position significantly to approximately 6,400 acres, an increase of approximately 3,300 acres. State approval on the lease is expected anytime.

Area History and Production

The East Hackberry field was discovered in 1926 by Gulf Oil Company, now Chevron Corporation, by a gravitational anomaly survey. The massive shallow salt stock presented an easily recognizable gravity anomaly indicating a productive field. Initial production began in 1927 and has continued to the present. The estimated cumulative oil and condensate production through 2005 was over 49 thousand barrels of oil, or MBbls, and 41 Bcf of casinghead gas production. There have been a total of 170 wells drilled on our portion of the field. As of December 31, 2006, six wells had daily production, 84 were shut-in and two had been converted to salt water disposal wells. The remaining 78 wells had been plugged and abandoned.

Geology

The Hackberry field is a major salt intrusive feature, elliptical in shape as opposed to a classic “dome,” divided into east and west field entities by a saddle. Structurally, our East Hackberry acreage is located on the eastern end of the Hackberry salt ridge. There are over 30 pay zones at this field. The salt intrusion formed a series of structurally complex and steeply dipping fault blocks in the Lower Miocene and Oligocene age rocks. These fault blocks serve as traps for hydrocarbon accumulation. Our wells currently produce from perforations found between 5,100 and 12,200 feet.

Facilities

We have a field office that serves both the East and West Hackberry fields. In addition, we expect to complete installation of a new production barge at the East Hackberry field early in the second quarter of 2007. Once in-service, the barge is designed to have the ability to process on a per day basis approximately 5,000 barrels of liquid, 30 Mmcf of high pressure natural gas, 6.5 Mmcf of low pressure natural gas and 10,000 barrels of salt water.

Recent and Future Activity

During 2005, we completed a proprietary 42 square mile 3-D seismic survey at East Hackberry. Given that drilling activities at the East Hackberry field prior to our acquisition of the field in 1997 were undertaken without the benefit of modern seismic information, we believe that the newly acquired 3-D seismic data will enhance our probability of drilling success. We continue to evaluate the 3-D seismic data to identify additional drilling locations. We have drilled three wells, are currently drilling two wells and intend to drill two additional wells in East Hackberry during the second quarter of 2007. Once we have evaluated the results of these wells and completed the installation of the new production barge facility, which is currently scheduled for early in the second quarter of 2007, we will be in a position to finalize our 2007 East Hackberry drilling program. Drilling activity in this field will target measured depths of approximately 13,000 feet using directional drilling techniques.

In October 2006, we spud our first exploratory well at East Hackberry based on the new seismic data. That well will be completed once our new production facilities are operational. We were unable to reach the primary target, the Camerina formation at approximately 13,000 feet, in this well due to mechanical difficulties. However, anticipated productive zones in the well are at approximately 9,000 to 10,000 feet.

In January 2007, a new discovery was made by the second exploratory well drilled by us in East Hackberry since acquiring and processing proprietary 3-D seismic on the field. This well, the Hackberry 2007 No. 1 well, reached a total measured depth of approximately 12,000 feet. Based on the electric log analysis, the discovery well encountered a gross interval of 300 feet in the Upper Oligocene Marg How Sand. The zone has 155 feet of apparent net pay with average porosity of 26% at a depth of 10,850 feet. The well also encountered pay in the upper Camerina, with approximately 18 feet of apparent net pay at approximately 11,700 feet. In addition, we have drilled one additional exploratory well since January 2007 and are currently drilling our fourth exploratory well (third in 2007) in Lake Calcasieu. In addition, we have added a second rig on land at East Hackberry and are drilling our first onshore well in this field. Completion activities on these wells have begun. Production from the wells in Lake Calcasieu will be processed through our new barge production facility, which is scheduled to be in service early in the second quarter of 2007.

On September 20, 2005, we shut in our 11 producing East Hackberry wells in preparation for Hurricane Rita. Production was re-established from six of these wells in November 2005; however, five wells in our State Lease 50 Block remain shut-in due to damage to certain of our production facilities caused by the hurricane. There are no current plans to replace or repair these facilities. We intend to reactivate at least two of these wells upon installation of the new production facility.

Production Status

In December 2006, net production at East Hackberry was 5,141 BOE, or an average of 166 BOE per day, 93% of which was from oil and 7% of which was from natural gas. In March 2007, our average net daily production at East Hackberry through March 29 was 136 BOE, 94% of which was from oil and 6% of which was from natural gas.

West Hackberry Field

Location and Land

The West Hackberry field is located on land and is five miles west of Lake Calcasieu in Cameron Parish, Louisiana, approximately 85 miles west of Lafayette and 15 miles inland from the Gulf of Mexico. We own a 100% working interest (approximately 87.5% NRI) in 592 acres within the West Hackberry field. Our leases at West Hackberry are located within two miles of one of the United States Department of Energy's Strategic Petroleum Reserves.

Area History

The first discovery well at West Hackberry was drilled in 1938 and the field was developed by Superior Oil Company, now ExxonMobil Corporation, between 1938 and 1988. The estimated cumulative oil and condensate production through 2006 was 209 Mbo and 140 Bcf of natural gas. There have been 36 wells drilled to date on our portion of West Hackberry. Currently, three are producing, 24 are shut-in and one has been converted to a saltwater disposal well. The remaining eight wells have been plugged and abandoned.

Geology

Structurally, our West Hackberry acreage is located on the western end of the Hackberry salt ridge. There are over 30 pay zones at this field. West Hackberry consists of a series of fault-bounded traps in the Oligocene-age Vincent and Keough sands associated with the Hackberry Salt Ridge. Recoveries from these thick, porous, water-drive reservoirs have resulted in per well cumulative production of almost 700 Mboe.

Production Status

In December 2006, net production at West Hackberry was 1,512 BOE. In March 2007, our average net daily production at West Hackberry through March 29 was 42 BOE.

Facilities

We have land-based production and processing facilities located at the West Hackberry field and maintain a field office that serves both the East and West Hackberry fields.

Additional Properties

Louisiana. In addition to our interests in the WCBB, East Hackberry and West Hackberry fields, we also own working interests and overriding royalty interest in various fields in Louisiana as described in the following table:

Field	Parish	Acreage Working Interest	Overriding Royalty Interests	Producing Wells	Non-Producing Wells
Bayou Long	Iberia	3.125%	0%	1	0
Bayou Penchant	Terrebonne	3.125%	0%	7	6
Bayou Pigeon	Iberia	6.250%	0%	7	3
Deer Island	Terrebonne	6.250%	0%	0	6
Golden Meadow	Lafourche	3.125%	0%	0	1
Napoleonville	Assumption	0%	2.5%	3	0

Thailand. During March 2005, we purchased a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex, at a cost of $2,400,000. The remaining interests in Tatex are owned by other entities controlled by Wexford Capital LLC, or Wexford, an affiliate of ours. Tatex holds approximately 8.5% of the outstanding shares of APICO, LLC, or APICO, an international oil and gas exploration company, and our investment is accounted for on the equity method. The investment of Tatex in APICO is accounted for by Tatex using the cost method. APICO has a reserve base located in Southeast Asia through its ownership interests in concessions covering three million acres. In December 2006, first gas sales were achieved at the Phu Horm field located in northeast Thailand. Phu Horm's initial gross production was approximately 60 million cubic feet per day. Hess Corporation operates the field with a 35% interest. Other interest owners include: APICO (35% interest), PTTEP (20% interest) and ExxonMobil (10% interest). Production is expected to exceed 100 million cubic feet per day in 2007. Our gross working interest (through Tatex as a member of APICO) in the Phu Horm field is 0.7%. Proved reserves from the Phu Horm field, net to our interest, are 3.5 BCF. Due to the fact that our ownership in the Phu Horm field is indirect as Tatex's investment in APICO is accounted for by the cost method, these reserves are not included in our year-end reserve information. Our net capital expenditures for 2006 for this project in Thailand total $964,000.

Williston Basin. During 2005, we purchased a 20% ownership interest in Windsor Bakken, LLC, or Bakken. The remaining interests in Bakken are owned by other entities controlled by Wexford, an affiliate of ours. As of December 31, 2006, Bakken had acquired leases covering approximately 100,300 gross and 51,400 net acres, all of which are undeveloped, in the Williston Basin located in western North Dakota and eastern Montana. The Williston Basin has production from 11 major geologic horizons that range in depth from 1,000 to over 14,000 feet, with our current zones of interest lying at depths ranging from 9,000 to 12,000 feet. Activities in this basin are expected to include both exploration and development drilling programs to different horizons including the Bakken shale. At December 31, 2006, our net investment in Bakken was approximately $2.4 million.

Marquiss Field. In February 2005, but effective as of December 1, 2004, we acquired our interest in the Marquiss field, an approximately 9,500 net acre coalbed methane play in Campbell County, Wyoming, for $375,000. As of December 31, 2006, the Marquiss field included a total of 162 wells, all of which were shut-in as a result of the economic status of the field as a result of a decline in natural gas prices for this field. The wells (when on line) produced from multiple horizons with additional upside potential from deeper coals and operational efficiencies. Our interest in the Marquiss field was sold in February 2007 for $500,000.

Grizzly Oil Sands During the third quarter of 2006, we purchased a 25% interest in Grizzly Oil Sands ULC, or Grizzly, a Canadian unlimited liability company holding leases in the Athabasca region located in northern Alberta Province, Canada near Fort McMurray in the same area as existing oil sands projects. The remaining interests of Grizzly are owned by other entities controlled by Wexford, an affiliate of ours. As of December 31, 2006, our net investment in Grizzly was approximately $8.5 million. As of March 21, 2007, Grizzly had over 315,000 acres under lease. Grizzly has drilled 62 core holes during the 2006/2007 winter delineation drilling season and tested three separate lease blocks with four drilling rigs. Core hole samples have been collected and sent to a lab to assess the quantity and thickness of the bitumen in place on our acreage. Future plans may include continuing to acquire leases, additional core hole drilling during the 2007/2008 winter drilling season, and possible construction of a 10,000 barrel per day steam assisted gravity drainage facility as soon as 2008 which could lead to initial production in 2009. Estimated gross capital expenditures for a comparable production facility are approximately $195 million.

Competition and Markets

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These competitors may be better positioned to take advantage of industry opportunities and to withstand changes affecting the industry, such as fluctuations in oil and natural gas prices and production, the availability of alternative energy sources and the application of government regulation.

The availability of a ready market for any oil and/or natural gas we produce depends on numerous factors beyond the control of our management, including but not limited to the extent of domestic production and imports of oil, the proximity and capacity of gas pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of gas sold in interstate commerce. The oil and natural gas we produce in Louisiana is sold to purchasers who service the areas where our wells are located. We sell the majority of our oil to Shell Trading Company, or Shell. Shell takes custody of the oil at the outlet from our oil storage barge. Our production is being sold in accordance with the posted price for West Texas/New Mexico Intermediate crude plus Platt's trade month average P+ value, plus or minus the Platt's WII/LLS differential less $0.85 per barrel for transportation. During 2006, we sold 100% of our oil production to Shell and 96% of our natural gas production to Chevron and during 2005, we sold 99% of our oil production to Shell and 88% of our natural gas production to Chevron. Our wells are not subject to any agreements that would prevent us from either selling our production on the spot market or committing such natural gas to a long-term contract; however, there can be no assurance that we will continue to have ready access to suitable markets for our future oil and natural gas production.

Oil and natural gas prices can be extremely volatile and are subject to substantial seasonal, political and other fluctuations. The prices at which the oil and natural gas we produce may be sold is uncertain and it is possible that under some market conditions the production and sale of oil and natural gas from some or all of our properties may not be economical. Because of all of the factors influencing the price of oil and natural gas, it is impossible to accurately predict future prices.

We established an oil price-hedging program in August 2005 to reduce our exposure to unfavorable changes in oil prices, which are subject to significant and often volatile fluctuation, by taking receive-fixed positions in price swap contracts. We paid the counterparty the excess of the oil market price over the fixed price and received the excess of the fixed price over the market price as defined in each contract. These contracts allowed us to predict with greater certainty the effective oil prices to be received for hedged production and benefited operating cash flows and earnings when market prices were less than the fixed prices provided in the contracts. However, we did not benefit from market prices that were higher than the fixed prices in the contracts for hedged production. In October 2006, we terminated the remaining three months of our hedging contracts. Through the termination of these remaining contracts, we received a total of $566,000 of proceeds during the fourth quarter of 2006 resulting from the differential in the fixed hedged price of $64.05 per barrel and the market prices of the associated futures contracts at the date of the termination of these contracts. Excluding the effect of the fixed price contracts, the average oil price for 2006 would have been $65.56 per barrel and $62.30 per barrel of oil equivalent, compared to $64.43 per barrel and $61.30 per barrel of oil equivalent. The total volume hedged for 2006 represented approximately 62% of our total oil sales volumes for the year.

Regulation

Regulation of Gas and Oil Production

Oil and natural gas operations such as ours are subject to various types of legislation, regulation and other legal requirements enacted by governmental authorities. This legislation and regulation affecting the oil and natural gas industry is under constant review for amendment or expansion. Some of these requirements carry substantial penalties for failure to comply. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability.

We own interests in a number of producing oil and natural gas properties located along the Louisiana Gulf Coast and Wyoming. These states regulate the production and sale of oil and natural gas, including requirements for obtaining drilling permits, the method of developing new fields and the spacing and operation of wells. In addition, regulations governing conservation matters aimed at preventing the waste of oil and natural gas resources could affect the rate of production and may include maximum daily production allowables for wells on a market demand or conservation basis.

Environmental Regulation

Our oil and natural gas exploration, development and production operations are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental agencies, such as the U.S. Environmental Protection Agency, or EPA, issue regulations to implement and enforce such laws, which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, and impose substantial liabilities for pollution resulting from our operations. The strict liability nature of such laws and regulations could impose liability upon us regardless of fault. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry in general. Our management believes that we are in substantial compliance with current applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements; this trend, however, may not continue in the future.

Waste Handling. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes and regulations promulgated thereunder, affect oil and natural gas exploration, development and production activities by imposing requirements regarding the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. With federal approval, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Although most wastes associated with the exploration, development and production of crude oil and natural gas are exempt from regulation as hazardous wastes under RCRA, such wastes may constitute "solid wastes" that are subject to the less stringent requirements of non-hazardous waste provisions. However, there can be no assurance that the EPA or the state or local governments will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time to re-categorize certain oil and natural gas exploration, development and production wastes as "hazardous wastes."

Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements. We believe that we are in substantial compliance with the requirements of RCRA and related state and local laws and regulations, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we do not believe that the current costs of managing our wastes as they are presently classified to be significant, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, also known as CERCLA or the "Superfund" law, generally imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current owner or operator of a contaminated facility, a former owner or operator of the facility at the time of contamination and those persons that disposed or arranged for the disposal of the hazardous substance. Under CERCLA and comparable state statutes, such persons may be subject to strict joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our operations, we use materials, that, if released, would be subject to CERCLA and comparable state statutes. Therefore, governmental agencies or third parties may seek to hold us responsible under CERCLA and comparable state statutes for all or part of the costs to clean up sites at which such “hazardous substances” have been deposited.

Water Discharges. The Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, the Oil Pollution Act and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other gas and oil wastes, into state waters or waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. These proscriptions also prohibit certain activity in wetlands unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. We believe that we have obtained or applied for and are in substantial compliance with all permits required under the Clean Water Act. Sanctions for failure to comply with Clean Water Act requirement include administrative, civil and criminal penalties, as well as injunctive obligations.

Air Emissions. The federal Clean Air Act, and comparable state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Some of our new facilities will be required to obtain permits before work can begin, permits may be required for our facilities’ operations, and existing facilities may be required to incur capital costs to remain in compliance. These laws and regulations may increase the costs of compliance for some facilities we own or operate, and federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. We believe that we are in substantial compliance with all applicable air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations. Obtaining or renewing permits has the potential to delay the development of oil and natural gas projects.

Operational Hazards and Insurance

Our operations are subject to all of the risks normally incident to the production of oil and natural gas, including blowouts, cratering, pipe failure, casing collapse, oil spills and fires, each of which could result in severe damage to or destruction of oil and natural gas wells, production facilities or other property, or injury to persons. The energy business is also subject to environmental hazards, such as oil spills, gas leaks, and ruptures and discharge of toxic substances or gases that could expose us to substantial liability due to pollution and other environmental damage and consequences thereof, including personal injuries and property damage. We currently maintain insurance covering some, but not all of these risks. The occurrence of a significant event that is not fully insured against could have a material adverse effect on our financial position.

Headquarters and Other Facilities

We own an approximately 28,500 square foot office building in Oklahoma City, Oklahoma that serves as our corporate headquarters. We lease a portion of this office space to certain of our affiliates. We also own an approximately 12,500 square foot building in Lafayette, Louisiana that is leased to an unrelated third party. This building contains approximately 6,200 square feet of finished office area and 6,300 square feet of clear span warehouse area. We also lease 3,722 square feet in a building in Lafayette that we use as our Louisiana headquarters. Each of these properties is suitable and adequate for its use.

Employees

At December 31, 2006, we had 151 employees. Certain of our employees perform management and administrative services for affiliated companies. We are reimbursed by these affiliates for the salaries and benefits of these individuals based on the estimated time they spent working for those affiliates. In addition, we receive 100% of the COPAS overhead charges billed to these affiliated companies. For the years ended December 31, 2006 and 2005, expenses reimbursed to us under these arrangements were $12,738,000 and $6,232,000, respectively, and are reflected as a reduction in our general and administrative expenses. A Louisiana well servicing company provides all necessary field personnel needed to operate the WCBB and the Hackberry fields.

ITEM 2. DESCRIPTION OF PROPERTY

Proved Oil and Natural Gas Reserves

The oil and natural gas reserve information set forth below represents estimates of our proved oil and natural gas reserves as prepared by the independent engineering firm of Netherland, Sewell & Associates, Inc., or NSAI, with respect to WCBB, our primary field, and by our internal personnel with respect to our other interests. Reserve engineering is a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices, and future production rates and costs. See “Risk Factors” contained elsewhere in this Form 10-KSB. We have not filed any estimates of total, proved net oil or gas reserves with any federal authority or agency other than the SEC since the beginning of our last fiscal year.

The following table sets forth estimates of our proved oil and natural gas reserves at December 31, 2006 and 2005. Reserve estimates at December 31, 2005 were prepared by NSAI and the reserve estimates at December 31, 2006 were prepared by NSAI with respect to our WCBB field (82% of proved reserves PV-10 value at December 31, 2006) and by our personnel with respect to our Hackberry fields and our overrides and non-operated interests (18% of proved reserves PV-10 value at December 31, 2006).

	December 31, 2006			December 31, 2005		
	Developed	Undeveloped	Total	Developed	Undeveloped	Total
Oil (MBbls)	4,876	14,816	19,692	4,308	15,234	19,542
Gas (MMcf)	4,077	16,724	20,801	3,758	18,022	21,780
Mboe	5,556	17,603	23,159	4,934	18,238	23,172
PV-10 (in millions) (1)	$120.0	$ 279.4	$ 399.4	$135.9	$ 321.0	$ 456.9
Standardized measure (in millions) (2)	—	—	$ 352.6	—	—	$ 369.8

(1) Represents present value, discounted at 10% per annum, of estimated future net revenue before income tax of our estimated proven reserves. The estimated future net revenues set forth above were determined by using reserve quantities of proved reserves and the periods in which they are expected to be developed and produced based on economic conditions prevailing at December 31, 2006. The estimated future production is priced at December 31, 2006, without escalation using $57.75 per barrel and $5.64 per MMBtu, adjusted by lease for transportation fees and regional price differentials.

PV-10 is a non-GAAP measure because it excludes income tax effects. Management believes that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. PV-10 is not a measure of financial or operating performance under GAAP. PV-10 should not be considered as an alternative to the standardized measure as defined under GAAP. We have included a reconciliation of PV-10 to the most directly comparable GAAP measure—standardized measure of discounted future net cash flows. The following table reconciles the standardized measure of future net cash flows to the PV-10 value:

	December 31,	
	2006	2005
Standardized measure of discounted future net cash flows	$352,648,000	$369,824,000
Add: Present value of future income tax discounted at 10%	46,804,000	87,086,000
PV-10 value	$399,452,000	$456,910,000

(2) The standardized measure represents the present value of estimated future cash inflows from proved oil and natural gas reserves, less future development, abandonment, production, and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized measure differs from PV-10 because standardized measure includes the effect of future income taxes.

The above table does not include proved reserves net to our interest in Tatex, or 3.5 Bcf of gas and 10,082 barrels of oil at April 30, 2006. For further discussion of our interest in Tatex, see Item 1. "Description of Business—Additional Properties."

Proved developed reserves are proved reserves that are expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled to known reservoirs on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells on which a relatively major expenditure is required to establish production.

Total proved reserves decreased slightly to 23,159 Mboe at December 31, 2006 from 23,172 Mboe at December 31, 2005. This decrease in reserves is attributable to reserve revisions and reductions related to our 2006 production, mostly offset by reserve additions from our 2006 drilling activity.

Production, Prices, and Production Costs

The following table presents our production volumes and average prices received during the periods indicated:

	2006	2005
Production Volumes:		
Oil (MBbls)	870	517
Gas (MMcf)	677	575
Oil Equivalents (Mboe)	983	613
Average Prices:		
Oil (per Bbl)	$64.43(1)	$46.39(1)
Gas (per Mcf)	$ 6.20	$ 5.98
Oil Equivalents (per Mboe)	$61.30	$44.75
Average Production Costs (per Boe)	$10.86(2)	$12.49(2)
Average Production Taxes (per Boe)	$ 7.50	$ 5.91
Total Production Costs (per Boe)	$18.36	$18.40

(1) Includes fixed contract prices of:

January – June 2004	$30.00
July – December 2004	$33.60
January – June 2005	$33.10
July – December 2005	$39.70
January – December 2006	$64.05

Also includes financial hedge contracts with an average mark-to-market value of approximately $50,000 per month for the months of July-December 2005 and approximately $82,000 per month for the months of January-December 2006.

Excluding the effect of the fixed price contracts, the average oil price for 2006 would have been $65.56 per barrel and $62.30 per barrel of oil equivalent. The total volume hedged for 2006 represents approximately

62% of our total oil sales volumes for the year. Excluding the effect of the fixed price contracts, the average oil price for 2005 would have been $56.17 per barrel and $52.99 per barrel of oil equivalent.

(2) Does not include production taxes.

Productive Wells and Acreage

The following table presents our total gross and net productive wells, expressed separately for oil and gas, and the total gross and net developed acres as of December 31, 2006:

	Producing Wells (1)		Non-Producing Wells		Developed Acreage (2)	
Field	**Gross**	**Net**	**Gross**	**Net**	**Gross (3)**	**Net (4)**
West Cote Blanche Bay	78	78	195	195	5,668	5,668
E. Hackberry (5)	6	6	84	84	3,147	3,147
W. Hackberry	3	3	24	24	592	592
Overrides/Royalty Non-operated	18	0.8	16	.7	4,956	586
Total	105	87.8	319	303.7	14,363	9,993

(1) Includes 30 gross and net wells at WCBB that are producing intermittently.

(2) Developed acres are acres spaced or assigned to productive wells. All of our acreage is developed acreage. All of the oil and natural gas leases in which we own an interest have been perpetuated by production. The operator may surrender the leases at any time by notice to the lessors, or by the cessation of production.

(3) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(4) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

(5) We have exercised an option with the State of Louisiana to acquire an additional 3,280 gross and net acres in the East Hackberry field. Final documentation and approval by the State of Louisiana is in progress.

Completed and Present Drilling and Recompletion Activities

The following table sets forth information with respect to wells completed during the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	2006		2005 (1)		2004	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Recompletions:						
Productive	18	18	11	11	13	13
Dry	1	1	0	0	0	0
Total	19	19	11	11	13	13
Development:						
Productive	24	24	16	16	8	8
Dry	2	2	0	0	0	0
Exploratory:						
Productive	1	1	0	0	0	0
Dry	1	1	1	1	0	0

(1) Includes seven gross and net wells that were drilled during 2005 but not completed due to the damage caused by Hurricane Rita. For further discussion of the impact of Hurricane Rita, see Item 6. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Impact of Hurricane Rita."

Title to Oil and Natural Gas Properties

It is customary in the oil and natural gas industry to make only a cursory review of title to undeveloped oil and natural gas leases at the time they are acquired and to obtain more extensive title examinations when acquiring producing properties. In future acquisitions, we will conduct title examinations on material portions of such properties in a manner generally consistent with industry practice. Certain of our oil and natural gas properties may be subject to title defects, encumbrances, easements, servitudes or other restrictions, none of which, in management's opinion, will in the aggregate materially restrict our operations.

RISK FACTORS

Risks Related to Our Business and Industry

The volatility of oil and natural gas prices due to factors beyond our control greatly affects our profitability.

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control, including:

- worldwide and domestic supplies of oil and natural gas;
- the level of prices, and expectations about future prices, of oil and natural gas;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the expected rates of declining current production;
- weather conditions, including hurricanes, that can affect oil and natural gas operations over a wide area;
- the level of consumer demand;
- the price and availability of alternative fuels;
- technical advances affecting energy consumption;
- risks associated with operating drilling rigs;
- the availability of pipeline capacity;
- the price and level of foreign imports;
- domestic and foreign governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil and natural gas producing regions; and
- the overall economic environment.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, over the last three years, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.83 per barrel, or bbl, in January 2004 to a high of $71.17 per bbl in July 2006. The Henry Hub spot market price of natural gas has ranged from a low of $4.20 per million British thermal units, or MMBtu, in October 2006 to a high of $13.93 per MMBtu in October 2005. Until recently, these prices have generally been at historically high levels. On December 31, 2006, the West Texas Intermediate posted price for crude oil was $57.80 per bbl for crude oil and the Henry Hub spot market price of natural gas was $5.635 per MMBtu. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves, and may result in write downs of oil and natural gas properties due to ceiling test limitations.

Our success depends on finding, developing or acquiring additional reserves.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. To increase reserves and production, we undertake development, exploration and other replacement activities or use third parties to accomplish these activities. We make and expect to continue to make substantial capital expenditures in our business and operations for the development, production, exploration and acquisition of oil and natural gas reserves. To date, we have financed capital expenditures primarily with cash flow from operations, the issuance of equity securities and borrowings under our bank and other credit facilities. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

We cannot assure you that we will have sufficient resources to undertake our exploration and development activity, production and acquisition of oil and natural gas reserves, that our exploratory projects or other replacement activities will result in significant additional reserves or that we will have success drilling productive wells at low finding and development costs. Furthermore, although our revenues may increase if prevailing oil and natural gas prices increase significantly, our finding costs for additional reserves could also increase.

Our failure to successfully identify, complete and integrate future acquisitions of properties or businesses could reduce our earnings and slow our growth.

There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Completed acquisitions could require us to invest further in operational, financial and management information systems and to attract, retain, motivate and effectively manage additional employees. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

Our Canadian oil sands project is a complex undertaking and may not be completed on schedule or at budgeted cost or at all.

During the third quarter of 2006, we purchased a 25% interest in Grizzly Oil Sands ULC, a Canadian unlimited liability company holding leases in the Athabasca region located in northern Alberta Province, Canada near Fort McMurray in the same area as existing oil sands projects. The remaining interests of Grizzly are owned by other entities controlled by Wexford, an affiliate of ours. As of December 31, 2006, our net investment in Grizzly was approximately $8.5 million. As of March 21, 2007 Grizzly had over 310,000 acres under lease. Grizzly has drilled 62 core holes during the 2006/2007 winter delineation drilling season and tested three separate lease blocks with four drilling rigs. Core hole samples have been collected and sent to a lab to assess the quantity and thickness of the bitumen in place on our acreage. Future plans may include continuing to acquire leases, additional core hole drilling during the 2007/2008 winter drilling season, and possible construction of a 10,000 barrel per day steam assisted gravity drainage facility as soon as 2008, which could lead to initial production in 2009. Estimated gross capital expenditures for comparable production facility are approximately $195 million. This is a complex project and financing has not yet been secured. There can be no assurance that this project can be completed on schedule, at our estimated cost or at all.

Shortage of rigs, equipment, supplies or personnel may restrict our operations.

The oil and natural gas industry is cyclical, and at the present time there is a shortage of drilling rigs, equipment, supplies and personnel. The costs and delivery times of rigs, equipment and supplies has increased as drilling activities have increased. In addition, demand for, and wage rates of, qualified drilling rig crews have risen with increases in the number of active rigs in service. In accordance with customary industry practice, we rely on independent third party service providers to provide most of the services necessary to drill new wells. Shortages of drilling rigs, equipment, supplies, personnel, trucking services, tubulars, fracing and completion services and production equipment could delay or restrict our exploration and development operations, which in turn could impair our financial condition and results of operations.

We rely on a few key employees whose absence or loss could disrupt our operations resulting in a loss of revenues.

Many key responsibilities within our business have been assigned to a small number of employees. The loss of their services, particularly the loss of Mike Liddell, our Chairman of the Board, James D. Palm, our Chief Executive Officer, Michael G. Moore, our Chief Financial Officer, or our two geophysicists, Stuart Maier and Randy Wilson, could disrupt our operations resulting in a loss of revenues. We do not have an employment contract with any of our executives, with the exception of Mr. Liddell, and our executives are not restricted from competing with us if they cease to be employed by us. Additionally, as a practical matter, any employment agreement we may enter into will not assure the retention of our employees. In addition, we do not maintain "key person" life insurance policies on any of our employees. As a result, we are not insured against any losses resulting from the death of our key employees.

Estimates of oil and natural gas reserves are uncertain and may vary substantially from actual production.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of expenditures, including many factors beyond our control. The reserve information contained in this report represents only estimates based on reports prepared by Netherland, Sewell & Associates, Inc. as of December 31, 2006 with respect to our WCBB field and by our personnel with respect to our Hackberry fields and our overrides and non-operated interests. Petroleum engineering is not an exact science. Information relating to our proved oil and natural gas reserves is based upon engineering estimates. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, future site restoration and abandonment costs, the assumed effects of regulations by governmental agencies and assumptions concerning future oil and natural gas prices, future operating costs, severance and excise taxes, capital expenditures and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net cash flows expected therefrom prepared by different engineers or by the same engineers at different times may vary substantially. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

The present value of future net revenues from our proved reserves is not necessarily the same as the current market value of our estimated oil and natural gas reserves. We base the estimated discounted future net revenue from our proved reserves on prices and costs in effect on the day of estimate. However, actual future net revenues from our oil and natural gas properties also will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- the amount and timing of actual production;
- supply of and demand for oil and natural gas; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of costs in connection with the development and production of oil and natural gas properties will affect the timing of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

The marketability of our production is dependent upon gathering lines, transportation barges and other facilities that we do not control. When these facilities are unavailable, our operations can be interrupted and our revenues reduced.

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of natural gas lines and transportation barges owned by third parties. In general, we do not control these facilities and our access to them may be limited or denied due to circumstances beyond our control. A significant disruption in the availability of these facilities could adversely impact our ability to deliver to market the oil and natural gas we produce and thereby cause a significant interruption in our operations. We are at particular risk with respect to oil and natural gas produced at our WCBB field, which is our largest field. In October 2006, for example, a natural gas line in this field operated by our natural gas purchaser was ruptured by a third party contractor, requiring the field to be shut in for approximately seven weeks until the line could be repaired. Further, we are dependent on our oil purchaser to provide the barges necessary to transport our oil production from the WCBB field. The increasing demand for transportation barges in the Louisiana Gulf Coast region has adversely impacted our ability to transport our oil production from the tank batteries in our field to shore for delivery. This has required us to shut in or curtail production from time to time as we have only limited storage capacity in the field. If, in the future, we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements, we will be required to again shut in or curtail production from the field. Any such shut in or curtailment, or an inability to obtain favorable terms for delivery of the oil and natural gas produced from the field, would adversely affect our financial condition and results of operations.

Substantially all of our producing properties are located in Louisiana, making us vulnerable to risks associated with operating in this region.

Our operations are concentrated in Louisiana and our largest field, WCBB, is located approximately five miles off the coast of Louisiana in a shallow bay with water depths averaging eight to ten feet. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from this region caused by weather conditions such as fog or rain, hurricanes or other natural disasters, or lack of field infrastructure. Losses could occur for uninsured risks or in amounts in excess of any existing insurance coverage. We cannot assure you that we will be able to obtain and maintain adequate insurance at rates we consider reasonable or that any particular types of coverage will be available.

Our identified drilling locations comprise an estimation of part of our future drilling plans over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have identified over 200 drilling locations on our Louisiana properties. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, oil and natural gas prices, inclement weather, costs and drilling results. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Operating hazards and uninsured risks may result in substantial losses.

Our operations are subject to all of the hazards and operating risks inherent in drilling for and production of oil and natural gas, including the risk of fire, explosions, blowouts, pipe failure, abnormally pressured formations and environmental hazards such as oil spills, gas leaks, ruptures or discharges of toxic gases. The occurrence of any of these events could result in substantial losses to us due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. For example, in October 2006, an accident occurred north of our production facilities in the WCBB field in southern Louisiana involving two contracted vessels that were performing work on our behalf in the field. A tugboat and two barges laden with construction materials ruptured an underwater natural gas pipeline and a subsequent fire damaged the vessels. Six fatalities resulted from the accident, which is currently under investigation by the National Transportation Safety Board and the United States Coast Guard. Several lawsuits relating to this incident have been filed against us, among other parties. See Item 3—"Legal Proceedings" included elsewhere in this report. Litigation is inherently uncertain and its outcome cannot be predicted at this time; however, if this litigation is not resolved in a manner that is favorable to us, our financial condition and results of operations may be negatively impacted.

In accordance with customary industry practice, we historically have maintained insurance against some, but not all, of our business risks. We cannot assure you that our insurance will be adequate to cover any losses or liabilities we may suffer. We also cannot predict the continued availability of insurance, or its availability at premium levels that justify its purchase. In addition, we understand that insurance carriers are modifying or otherwise restricting insurance coverage or ceasing to provide certain types of insurance coverage in the Gulf Coast region. We may also be liable for environmental damage caused by previous owners of properties purchased by us, which liabilities may not be covered by insurance.

Our operations are subject to various governmental regulations which require compliance that can be burdensome and expensive.

Our oil and natural gas operations are subject to various federal, state and local governmental regulations that may be changed from time to time in response to economic and political conditions. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below actual production capacity to conserve supplies of oil and gas. In addition, the production, handling, storage, transportation, emission and disposal of oil and gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations are subject to regulation under federal, state and local laws and regulations relating to protection of human health and the environment. These laws and regulations have continually imposed increasingly strict requirements for water and air pollution control and waste management. Significant expenditures may be required to comply with governmental laws and regulations applicable to us. We believe the trend of more expansive and stricter environmental legislation and regulations will continue.

We face extensive competition in our industry.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These competitors may be better positioned to take advantage of industry opportunities and to withstand changes affecting the industry, such as fluctuations in oil and natural gas prices and production, the availability of alternative energy sources and the application of government regulation.

We depend upon two customers for the sale of most of our oil and natural gas production.

The availability of a ready market for any oil and natural gas we produce depends on numerous factors beyond the control of our management, including but not limited to the extent of domestic production and imports of oil, the proximity and capacity of gas pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of gas sold in interstate commerce. The oil and natural gas we produce in Louisiana is sold to purchasers who service the areas where our wells are located. We sell the majority of our oil to Shell Trading Company, or Shell. Shell takes custody of the oil at the outlet from our oil storage barge. At December 31, 2006, our production was being sold in accordance with the posted price for West Texas/New Mexico Intermediate crude plus Platt's trade month average P+ value, plus or minus the Platt's WII/LLS differential less $0.85 per Bbl for transportation. For the year ended December 31, 2006, we sold 100% of our oil production to Shell and 96% of our natural gas production to Chevron. During 2005, we sold 99% of our oil production to Shell and 88% of our natural gas production to Chevron. Our wells are not subject to any agreements that would prevent us from either selling our production on the spot market or committing such gas to a long-term contract; however, there can be no assurance that we will continue to have ready access to suitable markets for our future oil and natural gas production.

Our method of accounting for oil and natural gas properties may result in impairment of asset value.

We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including nonproductive costs and certain general and administrative costs associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. Net capitalized costs are limited to the estimated future net revenues, after income taxes, discounted at 10% per year, from proven oil and natural gas reserves and the cost of the properties not subject to amortization. Such capitalized costs, including the estimated future development costs and site remediation costs, if any, are depleted by an equivalent units-of-production method, converting gas to barrels at the ratio of six Mcf of gas to one barrel of oil.

Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on unescalated year-end prices and costs, adjusted for any contract provisions or financial derivatives, if any, that hedge oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, less income tax effects related to differences between the book and tax basis of the oil and natural gas properties. If the net book value reduced by the related net deferred income tax liability exceeds the ceiling, an impairment or noncash writedown is required. A ceiling test impairment can give us a significant loss for a particular period. Once incurred, a write down of oil and natural gas properties is not reversible at a later date, even if oil or gas prices increase.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

We have hedged and may in the future hedge a portion of our production, which may result in our making cash payments or prevent us from receiving the full benefit of increases in prices for oil and gas.

To reduce our exposure to short-term fluctuations in the price of oil and natural gas, we periodically enter into hedging arrangements. Our hedging arrangements for 2006 involved 45,000 barrels of oil per month at a price of $64.05 per barrel. In October 2006, we terminated the remaining three months of our hedging contracts and currently have no hedging arrangements in place, but we may enter into such arrangements in the future. Such hedging arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. For example, under these arrangements the counterparty may require us to post cash collateral approximately equal to the difference between the agreed contract price of $64.05 per barrel and a defined market price multiplied by the remaining barrels of oil under the open contracts. As a result, significant increases in oil prices could adversely affect our financial position. In addition, our hedging arrangements may limit the benefit to us of increases in the price of oil.

A terrorist attack or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts and other armed conflicts involving the United States or other countries may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our customers' operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. Management cannot predict the impact of the changing demand for oil and gas services and products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and cash flows.

We will be subject to the requirements of Section 404 of the Sarbanes-Oxley Act. If we are unable to timely comply with Section 404 or if the costs related to compliance are significant, our profitability, stock price and results of operations and financial condition could be materially adversely affected.

Under current rules, we will be required to comply with the provisions of Section 404 of the Sarbanes-Oxley Act of 2002 as of December 31, 2007. Section 404 requires that we document and test our internal control over financial reporting and issue management's assessment of our internal control over financial reporting. This section also requires that our independent registered public accounting firm opine on those internal controls and management's assessment of those controls. We will be required to evaluate our existing controls against the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, or COSO. During the course of our ongoing evaluation and integration of the internal control over financial reporting, we may identify areas requiring improvement, and we may have to design enhanced processes and controls to address issues identified through this review.

We believe that the out-of-pocket costs, the diversion of management's attention from running the day-to-day operations and operational changes caused by the need to comply with the requirements of Section 404 of the Sarbanes-Oxley Act could be significant.

We cannot be certain at this time that we will be able to successfully complete the procedures, certification and attestation requirements of Section 404 or that we or our auditors will not identify material weaknesses in internal control over financial reporting. If we fail to comply with the requirements of Section 404 or if we or our auditors identify and report such material weakness, the accuracy and timeliness of the filing of our annual and quarterly reports may be materially adversely affected and could cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our common stock. In addition, a material weakness in the effectiveness of our internal control over financial reporting could result in an increased chance of fraud and the loss of customers, reduce our ability to obtain financing and require additional expenditures to comply with these requirements, each of which could have a material adverse effect on our business, results of operations and financial condition.

Risks Related to Our Common Stock

If our quarterly revenues and operating results fluctuate significantly, the price of our common stock may be volatile.

Our revenues and operating results may in the future vary significantly from quarter to quarter. If our quarterly results fluctuate, it may cause our stock price to be volatile. We believe that a number of factors could cause these fluctuations, including:

- changes in oil and natural gas prices;
- changes in production levels;
- changes in governmental regulations and taxes;
- geopolitical developments;
- the level of foreign imports of oil and natural gas; and
- conditions in the oil and natural gas industry and the overall economic environment.

Because of the factors listed above, among others, we believe that our quarterly revenues, expenses and operating results may vary significantly in the future and that period-to-period comparisons of our operating results are not necessarily meaningful. You should not rely on the results of one quarter as an indication of our future performance. It is also possible that in some future quarters, our operating results will fall below our expectations or the expectations of market analysts and investors. If we do not meet these expectations, the price of our common stock may decline significantly.

Our officers and directors together with our largest stockholder control a significant percentage of our common stock, and their interests may conflict with those of our other stockholders.

As of March 20, 2007, our executive officers and directors, in the aggregate, beneficially owned approximately 3.98% of our outstanding common stock. Additionally, Charles E. Davidson beneficially owned approximately 41.4% of our outstanding common stock. As a result, these stockholders acting together are able to exercise significant influence over most matters requiring approval by our stockholders, including the election of directors and the approval of significant corporate transactions. Such a concentration of ownership may have the effect of delaying or preventing a change in control of us, including transactions in which stockholders might otherwise receive a premium for their shares over then current market prices.

We can give no assurances as to the market for our common stock.

Since July 14, 2006, our common stock has been listed on The NASDAQ Global Select Market under the symbol "GPOR." From February 28, 2006 until that date, our common stock was listed on the NASDAQ National Market. Prior to that date, our common stock was traded on the NASD OTC Bulletin Board under the symbol "GPOR.OB." There is a limited market for our shares. We cannot assure you that an active trading market will develop, or if it does, that it will be sustained.

We do not currently pay dividends on our common stock and do not anticipate doing so in the future.

We have paid no cash dividends on our common stock, and there can be no assurance that we will achieve sufficient earnings to pay cash dividends on our common stock in the future. We intend to retain any earnings to fund our operations. Therefore, we do not anticipate paying any cash dividends on our common stock in the foreseeable future. In addition, the terms of our credit agreement prohibit the payment of any dividends to the holders of our common stock.

A change of control could limit our use of net operating losses.

As of December 31, 2006, we had a net operating loss, or NOL, carry forward of approximately $95.9 million for federal income tax purposes. Transfers of our stock in the future could result in an ownership change.

In such a case, our ability to use the NOLs generated through the ownership change date could be limited. In general, the amount of NOLs we could use for any tax year after the date of the ownership change would be limited to the value of our stock (as of the ownership change date) multiplied by the long-term tax-exempt rate.

Future sales of our common stock may depress our stock price.

Sales of a substantial number of shares of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline. In addition, the sale of these shares could impair our ability to raise capital through the sale of common or preferred stock. As of March 20, 2007, there were 35,096,768 shares of our common stock issued and outstanding.

In addition, some of our current stockholders may have "demand" and/or "piggyback" registration rights in connection with future offerings of our common stock. "Demand" rights enable the holders to demand that their shares be registered and may require us to file a registration statement under the Securities Act at our expense. "Piggyback" rights require that we provide notice to the relevant holders of our stock if we propose to register any of our securities under the Securities Act, and grant such holders the right to include their shares in the registration statement.

We could issue additional preferred stock which could be entitled to dividend, liquidation and other special rights and preferences not shared by holders of our common stock or which could have anti-takeover effects.

We are authorized to issue up to 5,000,000 shares of preferred stock, par value $0.01 per share. Shares of preferred stock may be issued from time to time in one or more series as our board of directors, by resolution or resolutions, may from time to time determine, each such series to be distinctively designated. The voting powers, preferences and relative, participating, optional and other special rights, and the qualifications, limitations or restrictions, if any, of each such series of preferred stock may differ from those of any and all other series of preferred stock at any time outstanding, and, subject to certain limitations of our certificate of incorporation and the Delaware General Corporation Law, or DGCL, our board of directors may fix or alter, by resolution or resolutions, the designation, number, voting powers, preferences and relative, participating, optional and other special rights, and qualifications, limitations and restrictions thereof, of each such series preferred stock. The issuance of any such preferred stock could materially adversely affect the rights of holders of our common stock and, therefore, could reduce the value of our common stock.

In addition, specific rights granted to future holders of preferred stock could be used to restrict our ability to merge with, or sell our assets to, a third party. The ability of our board of directors to issue preferred stock could discourage, delay or prevent a takeover of us, thereby preserving control of the company by the current stockholders.

Provisions in our organizational documents could delay or prevent a change in control of our company, even if that change would be beneficial to our stockholders.

The existence of some provisions in our organizational documents could delay or prevent a change in control of our company, even if that change would be beneficial to our stockholders. Our certificate of incorporation and bylaws contain provisions that may make acquiring control of our company difficult.

ITEM 3. LEGAL PROCEEDINGS

The Louisiana State Mineral Board is disputing our royalty payments to the State of Louisiana resulting from the sale of oil under fixed price contracts. The Board maintains that we paid approximately $1,400,000 less in royalties under the fixed price contracts than the royalties we would have had to pay had we sold the oil at prevailing market rates. We have denied any liability to the Board for underpayment of royalties and have maintained that we were entitled to enter into the fixed price contracts with unrelated third parties and pay royalties based upon the sales proceeds from those contracts. In May 2006, we offered to settle the claim for $180,000. The Board rejected the offer, but continues to participate in discussions to resolve this dispute. We continue to believe that the dispute will be satisfactorily resolved, either through settlement, litigation, or arbitration.

In October 2006, an accident occurred north of our production facilities in the WCBB field in southern Louisiana involving two contracted vessels that were performing field work on our behalf. A tugboat, the M/V Miss Megan, and two barges laden with construction materials ruptured an underwater natural gas pipeline and a subsequent fire damaged the vessels. Six fatalities resulted from the accident, which is currently under investigation by the NTSB and USCG; however, the following lawsuits relating to this incident have been filed:

- On October 13, 2006, Athena Construction LLC, or Athena, the owner of the two barges, filed a limitation action in the United States District Court for the Eastern District of Louisiana, alleging that all losses and damages as a result of the pipeline incident were incurred without fault on its part. Furthermore, Athena claims the benefit of the limitation of liability provided for in 42 U.S.C. § 183 and seeks an injunction restraining the commencement and prosecution of any further lawsuits against Athena, which are related to the pipeline incident. The limitation of liability action was subsequently transferred to the United States District Court for the Western District of Louisiana, where the case is pending. On December 20, 2006, 4-K Marine LLC, as owner of the M/V Miss Megan, and Central Boat Rentals, Inc., as operator of the M/V Miss Megan also filed a limitation action in the Western District. On January 10, 2007, the Athena and the 4-K/Central Boat limitation proceedings were consolidated by order of the Court.
- On October 16, 2006, a lawsuit was filed in the 16th Judicial District Court for the Parish of St. Mary, Louisiana against us, Athena and Central Boat seeking compensatory and punitive damages for claims related to the death of the plaintiff's husband, a crewmember on the Athena barge. The suit alleges that the husband's death was caused by the defendants' negligence and the unseaworthiness of the barge to which he was assigned. Under the Blanket Time Charter between us and Central Boat, Central Boat tendered the defense and indemnification of the lawsuit to us. On November 2, 2006, all proceedings were stayed as a result of the limitation of liability action discussed above.
- On October 22, 2006, a lawsuit was filed in United States District Court for the Southern District of Texas, Galveston Division against us, Central Boat, Diamondback Energy Services LLC, one of our affiliates, Chevron Pipeline Company, Chevron USA, Inc., and ChevronTexaco Pipeline Holdings, Inc. This lawsuit is a result of the death of three individuals employed by Athena and on the barge at the time of the accident. The plaintiffs seek compensatory and punitive damages as a result of the alleged negligence of defendants. Central Boat has tendered the defense and indemnification of this lawsuit to us. A joint motion to transfer venue to the Western District of Louisiana was filed by the defendants on December 28, 2006. The court denied the motion to transfer by order dated February 2, 2007. On February 12, 2007, a joint motion for new trial and/or rehearing was filed requesting the court to reconsider its denial of the prior motion to transfer. The plaintiffs have filed an opposition and the motion is currently pending.
- On February 2, 2007, a lawsuit was filed in the United States District Court for the Western District of Louisiana, Lafayette Division against Chevron Pipeline Company, Chevron USA Inc., Chevron Texaco Pipeline Holdings, Inc., Chevron Natural Gas Services Inc., Diamondback Energy Services LLC, one of our affiliates, and us. The suit was filed on behalf of April Hummel, individually and as the representative of the minor, Aleya Hummel, the surviving child of Terry Abraham. We obtained an informal extension to file responsive pleadings. No other deadlines have been set.
- On January 11, 2007, plaintiffs Janet Rink, individually and as the personal representative of the Estate of Kenneth Rink, Tysie Rink and Scott Rink filed a lawsuit in the United States District Court for the Western District of Louisiana against defendants Chevron Pipeline Company, Chevron USA, Inc., ChevronTexaco Pipeline Holdings, Inc., Chevron Natural Gas Services, Inc., us and Diamondback

Energy Services LLC, one of our affiliates. The plaintiffs allege the fault, negligence, unseaworthiness and/or strict liability of defendants in the death of Kenneth Rink, a crew member on one of the Athena barges, and seek unspecified damages. We obtained an indefinite informal extension of time to file responsive pleadings. No other deadlines have been set.

In November 2006, Cudd Pressure Control, Inc., or Cudd, filed a lawsuit in the 129th Judicial District Harris County, Texas. The lawsuit alleges RICO violations, as well as conspiracy to misappropriate trade secrets to secure breach of fiduciary duty, misappropriation of trade secrets and unfair competition relating to an affiliate company's employment of several former Cudd employees and seeks unspecified monetary damages and injunctive relief. The defendants in the suit are Ronnie Roles, Rocky Roles, Steve Winters, Bert Ballard, Nelson Britton, Michael Fields, Steve Bickle, Great White Pressure Control LLC, one of our affiliates, and us. On stipulation by the parties, the plaintiff's RICO claim was dismissed without prejudice by order of the court on February 14, 2007. A pretrial conference is set for April 2, 2007, regarding the remaining allegations. We will file our initial answer prior to the pretrial conference.

Litigation is inherently uncertain and the outcome of the above-referenced matters cannot be predicted at this time. Adverse decisions in one or more of the above matters could have a material adverse affect on our financial condition or results of operations.

In addition to the above, we have been named as a defendant in various other lawsuits related to our business. The ultimate resolution of such other matters is not expected to have a material adverse effect on our financial condition or results of operations.

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

None.

PART II

ITEM 5. MARKET FOR COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND SMALL BUSINESS ISSUER PURCHASES OF EQUITY SECURITIES

Through February 27, 2006, our common stock was traded on the NASD OTC Bulletin Board under the symbol "GPOR.OB." Since February 28, 2006, our common stock has been quoted on The NASDAQ National Market and since July 14, 2006, our common stock has been quoted on The NASDAQ Global Select Market, in each instance under the symbol "GPOR." The following table sets forth the high and low sale prices of our common stock for the periods presented:

	Price Range of Common Stock	
	High	Low
2005		
First Quarter	$ 5.90	$ 3.24
Second Quarter	6.90	5.00
Third Quarter	11.50	6.70
Fourth Quarter	13.00	9.10
2006		
First Quarter	16.00	10.00
Second Quarter	15.89	9.90
Third Quarter	13.64	9.82
Fourth Quarter	14.11	9.95
2007		
First Quarter (through March 27, 2007)	13.89	10.82

On March 27, 2007, the last reported sale price of our common stock on The NASDAQ Global Select Market was $13.31. The above quotations for the periods prior to February 28, 2006 reflect inter-dealer prices, without retail mark-up, markdown or commissions and may not represent actual transactions.

Unregistered Sales of Equity Securities and Use of Proceeds

None.

Holders of Record

At the close of business on March 20, 2007, there were 382 stockholders of record holding 35,096,768 shares of our outstanding common stock.

Dividend Policy

We have never paid dividends on our common stock. We currently intend to retain all earnings to fund our operations. Therefore, we do not intend to pay any cash dividends on the common stock in the foreseeable future. In addition, the terms of our credit facility prohibits the payment of any dividends to the holders of our common stock.

ITEM 6. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with the consolidated financial statements and related notes included elsewhere in this annual report on Form 10-KSB. This discussion contains forward-looking statements reflecting our current expectations, estimates and assumptions concerning events and financial trends that may affect our future operating results or financial position. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors, including those discussed in the sections entitled "Risk Factors" and "Cautionary Note Regarding Forward-Looking Statements" appearing elsewhere in this annual report on Form 10-KSB.

2006 Highlights

- Oil and natural gas revenues increased $32.8 million to $60.2 million for the year ended December 31, 2006 from $27.4 million for 2005.
- Net income increased 155% to $27.8 million for the year ended December 31, 2006 from $10.9 million for 2005.
- Production increased 60% to 982,531 BOE for the year ended December 31, 2006 from 613,000 BOE for 2005.
- We received net proceeds of $10.4 million from the sale of our common stock in an underwritten public offering completed on May 10, 2006 after deducting the underwriting discount and before offering expenses. These net proceeds were used to pay down existing debt under our credit facility.
- During the third quarter of 2006, Gulfport purchased a 25% interest in Grizzly Oil Sands ULC, a Canadian unlimited liability company holding leases in the Athabasca region located in northern Alberta Province, Canada near Fort McMurray in the same area as existing oil sands projects. As of December 31, 2006, our net investment in Grizzly was approximately $8.5 million. As of March 21, 2007 Grizzly has over 310,000 acres under lease. Grizzly drilled 62 core holes during the 2006/2007 winter delineation drilling season and tested three separate lease blocks with four drilling rigs. Core hole samples have been collected and sent to a lab to assess the quantity and thickness of the bitumen in place on our acreage. Future plans may include continuing to acquire leases, additional core hole drilling during the 2007/2008 winter drilling season, possible construction of a 10,000 barrel per day steam assisted gravity drainage facility as soon as 2008, which could lead to initial production in 2009. Estimated gross capital expenditures for comparable production facility are approximately $195 million.
- During 2006 we drilled 28 wells and recompleted 19 wells. Of our 28 new wells drilled, 25 were completed as producing wells and three were non-productive.

Impact of Hurricane Rita

WCBB. On September 24, 2005, the tidal surge from Hurricane Rita caused damage to our WCBB and East Hackberry facilities and both fields were shut-in. We began returning wells to production on February 5, 2006, and during 2006 all of the 57 active wells in the field prior to Hurricane Rita were returned to production.

Hackberry Fields. On September 20, 2005, we shut in our 11 producing East Hackberry wells in preparation for Hurricane Rita. Production was re-established from six of these wells in November 2005, however, five wells in our State Lease 50 Block remain shut-in due to damage to certain of our production facilities caused by the hurricane. There are no current plans to replace or repair these facilities. We intend to reactivate at least two of these wells upon installation of the new production facility, which is expected to occur early in the second quarter of 2007.

As a result, the impact of Hurricane Rita had an affect on our operations and financial results in both 2005 and 2006.

Insurance Coverage. We sustained damage to both our Hackberry field located in Cameron Parish, Louisiana and our WCBB field located in St. Mary Parish, Louisiana as a result of Hurricane Rita in September 2005. As of December 31, 2006, we had incurred costs of approximately $13,084,000 relating to the replacement of equipment and facilities. Of this amount, $250,000 represents insurance deductible amounts that were expensed to lease operating expenses in 2005. During the year ended December 31, 2006, we received $7,855,000 in insurance proceeds related to physical damage which is reflected in cash flows from investing activities in our consolidated statements of cash flows. Approximately $4,330,000 of the costs we incurred during 2006 related to replacement of equipment and facilities is not expected to be reimbursed by insurance and is included in the full cost pool. Approximately $108,000 previously included in insurance settlement receivables will not be collected and was expensed in 2006. The remaining $541,000 is included in insurance settlement receivables in the accompanying consolidated balance sheet at December 31, 2006 and was received subsequent to December 31, 2006.

We also maintained business interruption insurance to cover lost production revenue in the event of shut-in production. The business interruption insurance begins 60 days after the occurrence of an insurable event, subject to a daily limit of $45,000 and had a maximum coverage of 180 days. Coverage began on November 24, 2005 for shut-in production caused by Hurricane Rita. During the year ended December 31, 2006, we recognized $3,601,000 of business interruption insurance proceeds in other income in the consolidated statements of income. As of December 31, 2006, we had received proceeds of $5,311,000, $1,710,000 of which was accrued in 2005, related to business interruption for the period of November 24, 2005 to May 1, 2006. Such recoveries are presented as operating cash flows in the consolidated statements of cash flows.

Effective May 24, 2006, we renewed our platform and business interruption insurance. Due to the large increases in premiums, we reduced the amount of platform insurance coverage from $12.1 million to a total of $3.0 million in coverage. During replacement of our facilities, we attempted to rebuild our facilities to better enable them to withstand a similar hurricane with less damage. Additionally, our new policy now provides for $7.5 million of business interruption insurance coverage for a period of 45 days which begins after a waiting period of 90 days after the date of a qualifying event. Collectively, these coverages have a self-insured retention of $1.0 million.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. The preparation of these consolidated financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in Note 1 to our consolidated financial statements included elsewhere in this annual report on Form 10-KSB. We have identified certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management. We analyze our estimates including those related to oil and natural gas properties, revenue recognition, income taxes and commitments and contingencies, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our consolidated financial statements:

Oil and Natural Gas Properties. We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including nonproductive costs and certain general and administrative costs associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. Net capitalized costs are limited to the estimated future net revenues, after income taxes, discounted at 10% per year, from proven oil and natural gas reserves and the cost of the properties not subject to amortization. Such capitalized costs, including the estimated future development costs and site remediation costs, if any, are depleted by an equivalent units-of-production method, converting gas to barrels at the ratio of six Mcf of gas to one barrel of oil. No gain or loss is recognized upon the disposal of oil and natural gas properties, unless such dispositions significantly alter the relationship between capitalized costs and proven oil and natural gas reserves. Oil and natural gas properties not subject to amortization consist of the cost of undeveloped leaseholds and totaled $1,459,000 at December 31, 2006 and $113,000 at December 31, 2005. These costs are reviewed periodically by management for impairment, with the impairment provision included in the cost of oil and natural gas properties subject to amortization. Factors considered by management in its impairment assessment include our drilling results and those of other operators, the terms of oil and natural gas leases not held by production and available funds for exploration and development.

Ceiling Test. Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on unescalated year-end prices and costs, adjusted for any contract provisions or financial derivatives, if any, that hedge our oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, less income tax effects related to differences between the book and tax basis of the oil and natural gas properties. If the net book value reduced by the related net deferred income tax liability exceeds the ceiling, an impairment or noncash writedown is required. A ceiling test impairment can give us a significant loss for a particular period; however, future depletion expense would be reduced. A future decline in oil and gas prices may result in an impairment of oil and gas properties.

Asset Retirement Obligations. We have obligations to remove equipment and restore land at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells and associated production facilities.

We account for abandonment and restoration liabilities under Statement of Financial Accounting Standards No. 143, "*Accounting for Asset Retirement Obligations*" ("SFAS No. 143"), which requires us to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, we increase the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related long-lived asset. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.

The fair value of the liability associated with these retirement obligations is determined using significant assumptions, including current estimates of the plugging and abandonment or retirement, annual inflations of these costs, the productive life of the asset and our risk adjusted cost to settle such obligations discounted using our credit adjustment risk free interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the asset retirement obligation are recorded with an offsetting change to the carrying amount of the related long-lived asset, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long life of most of our oil and natural gas assets, the costs to ultimately retire these assets may vary significantly from previous estimates.

Oil and Gas Reserve Quantities. Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. NSAI and to a lesser extent our personnel have prepared reserve reports of our reserve estimates on a well-by-well basis for our properties.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Our reserve estimates and the projected cash flows derived from these reserve estimates have been prepared in accordance with SEC guidelines. The accuracy of our reserve estimates is a function of many factors including the following:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgments of the individuals preparing the estimates.

Our proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil and natural gas eventually recovered.

Income Taxes. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized in the year in which realization becomes determinable. Periodically, management performs a forecast of its taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established, if in management's opinion, it is more likely that not that some portion will not be realized. At December 31, 2006 and 2005, a valuation allowance of $25,509,000 and $37,677,000, respectively, had been provided for deferred tax assets based on the uncertainty of future taxable income.

Revenue Recognition. We derive almost all of our revenue from the sale of crude oil and natural gas produced from our oil and gas properties. Revenue is recorded in the month the product is delivered to the purchaser. We receive payment on substantially all of these sales from one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers that month and the price we will receive. Variances between our estimated revenue and actual payment received for all prior months are recorded at the end of the quarter after payment is received. Historically, our actual payments have not significantly deviated from our accruals.

Commitments and Contingencies. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. We are involved in certain litigation for which the outcome is uncertain. Changes in the certainty and the ability to reasonably estimate a loss amount, if any, may result in the recognition and subsequent payment of legal liabilities.

Derivative Instruments and Hedging Activities. We seek to reduce our exposure to unfavorable changes in oil prices by utilizing energy swaps and collars, or fixed-price contracts. We follow the provisions of SFAS 133, *"Accounting for Derivative Instruments and Hedging Activities,"* as amended. It requires that all derivative instruments be recognized as assets or liabilities in the balance sheet, measured at fair value. We estimate the fair value of all derivative instruments using established index prices and other sources. These values are based upon, among other things, futures prices, correlation between index prices and our realized prices, time to maturity and credit risk. The values reported in the financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. Designation is established at the inception of a derivative, but re-designation is permitted. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of SFAS 133, changes in fair value are recognized in accumulated other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. We recognize any change in fair value resulting from ineffectiveness immediately in earnings. As of December 31, 2006, we have no derivative contracts but may enter into such contracts in the future.

Results of Operations

The markets for oil and natural gas have historically been, and will continue to be, volatile. Prices for oil and natural gas may fluctuate in response to relatively minor changes in supply and demand, market uncertainty and a variety of factors beyond our control.

The following table presents our production volumes and average prices received during the periods indicated:

	2006	2005
Production Volumes:		
Oil (MBbls)	870	517
Gas (MMcf)	677	575
Oil Equivalents (Mboe)	983	613
Average Prices:		
Oil (per Bbl)	$64.43(1)	$46.39(1)
Gas (per Mcf)	$ 6.20	$ 5.98
Oil Equivalents (per Boe)	$61.30	$44.75
Average Production Costs (per Boe)	$10.86(2)	$12.49(2)
Average Production Taxes (per Boe)	$ 7.50	$ 5.91
Total Production Costs (per Boe)	$18.36	$18.40

(1) Includes fixed contract prices of:

January – June 2004	$30.00
July – December 2004	$33.60
January – June 2005	$33.10
July – December 2005	$39.70
January – December 2006	$64.05

Also includes financial hedge contracts with an average mark-to-market value of approximately $50,000 per month for the months of July-December 2005 and approximately $82,000 per month for the months of January-December 2006.

Excluding the effect of the fixed price contracts, the average oil price for 2006 would have been $65.56 per barrel and $62.30 per BOE. The total volume hedged for 2006 represents approximately 62% of our total oil sales volumes for the year. Excluding the effect of the fixed price contracts, the average oil price for 2005 would have been $56.17 per barrel and $52.99 per BOE.

(2) Does not include production taxes.

From 2005 to 2006, our net oil production increased 68% to 869,728 Boe due to our continued drilling activity. From 2004 to 2005, our oil production decreased 11% due primarily to a loss of production during the fourth quarter 2005 as a result of the damage caused to our facilities from Hurricane Rita in September 2005. We currently estimate that our 2007 production will be between 1,700,000 and 1,900,000 BOE with production increasing during the year.

Comparison of the Years Ended December 31, 2006 and December 31, 2005

We reported net income of $27,808,000 for the year ended December 31, 2006, compared to $10,985,000 for the year ended December 31, 2005. This 155% increase in net income was due primarily to (1) a 60% increase in net production to 982,531 BOE for the year ended December 31, 2006 from 612,840 BOE for 2005, (2) a 39% increase in the average oil price received to $64.43 per barrel for the year ended December 31, 2006 from $46.39 per barrel for 2005 and (3) business interruption insurance recoveries of $3,601,000 due to Hurricane Rita.

Oil and Gas Revenues. For the year ended December 31, 2006, we reported oil and gas revenues of $60,232,000, compared to oil and gas revenues of $27,423,000 during 2005. This 120% increase in revenues is mainly attributable to a 60% increase in net production to 982,531 BOE for the year ended December 31, 2006 from 612,840 BOE for 2005 and a 39% increase in the average oil price received to $64.43 per barrel for the year ended December 31, 2006 from $46.39 per barrel for 2005. This increase in oil and natural gas production was the result of production from our 2006 drilling program and restoration of fields and facilities for which production was curtailed due to Hurricane Rita. Production in 2005 and 2006 was adversely affected by the damage caused by Hurricane Rita. See "—Impact of Hurricane Rita" above. In addition, production in 2006 was adversely affected by the accident in our field on October 12, 2006, which shut in our facilities from that date through early December 2006.

The following table summarizes our oil and natural gas production and related pricing for the years ended December 31, 2006 and December 31, 2005:

	Year Ended December 31	
	2006	**2005**
Oil production volumes (MBbls)	870	517
Gas production volumes (MMcf)	677	575
Oil equivalents (Mboe)	983	613
Average oil price (per Bbl)	$64.43	$46.39
Average gas price (per Mcf)	$ 6.20	$ 5.98
Oil equivalents (per Boe)	$61.30	$44.75

Lease Operating Expenses. Lease operating expenses not including production taxes increased to $10,670,000 for 2006 from $7,654,000 for 2005. This increase was mainly due to increases in insurance costs, $972,000 in one time non-recurring repairs to the WCBB gas sales pipeline related to the tug boat accident that occurred in October 2006 and the increases in the general costs of labor and supplies in our operating area along the Louisiana Gulf Coast.

Production Taxes. Production taxes increased to $7,366,000 for 2006 from $3,622,000 for 2005. This increase was directly related to a 120% increase in oil and gas revenues as a result of the 37% improvement in the price received per barrel oil equivalent and a 60% increase in production for 2006 compared to 2005.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased to $12,652,000 for the year ended December 31, 2006, and consisted of $12,259,000 in depletion on oil and natural gas properties and $393,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $4,789,000 for the year ended December 31, 2005. This increase was due primarily to an increase in our oil and natural gas property costs associated with our 2006 drilling program and an increase in our oil and gas production for the period.

General and Administrative Expenses. Net general and administrative expenses increased to $3,251,000 for 2006 from $1,561,000 for 2005. This increase was due primarily to the $1,063,000 effect of the implementation of SFAS No. 123(R), "*Share Based Payment*" (less $276,000 capitalized for personnel directly related to our exploration and development activities), a $250,000 increase in corporate fees relating to being a NASDAQ listed company, and general increases in payroll costs and related benefits as a result of the increased number of employees. These increases were partially offset by increases in general administrative reimbursements from our affiliates.

Accretion Expense. Accretion expense increased $80,000 to $596,000 for 2006 from $516,000 for 2005, due to a larger obligation at the beginning of 2006 compared to the beginning of 2005, resulting from the addition of future abandonment obligations on new wells drilled during 2005.

Interest Expense. Ordinary interest expense increased to $1,956,000 for 2006 from $250,000 for 2005 due to an increase in average debt outstanding. At December 31, 2006, total debt outstanding under our facility with Bank of America was $34,800,000. At December 31, 2005, $7,000,000 was outstanding under this facility.

Interest Expense—Preferred Stock. During the year ended December 31, 2005, we incurred interest expense on preferred stock classified as a liability under SFAS No. 150, "*Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*." During 2005, we redeemed all of the remaining outstanding shares of our Series A preferred stock. As a result, we incurred no interest expense relating to preferred stock during 2006 as compared to $272,000 in interest expense incurred during 2005.

Income Taxes. As of December 31, 2006, we had a net operating loss carry forward of approximately $95.9 million, in addition to numerous temporary differences, which gave rise to a deferred tax asset. Periodically, management performs a forecast of our future taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management's opinion, it is more likely than not that some portion will not be realized. At December 31, 2006, a valuation allowance of $25.5 million had been provided for our entire net deferred tax asset. We had no income tax expense due to a change in the valuation allowance for deferred income taxes for the year ended December 31, 2006.

Liquidity and Capital Resources

Overview. Historically, our primary sources of funds have been cash flow from our producing oil and natural gas properties, the issuance of equity securities and borrowings under our bank and other credit facilities. Our ability to access any of these sources of funds can be significantly impacted by decreases in oil and natural gas prices or oil and gas production. In 2005 and 2006, recoveries under our insurance coverages also provided a significant source of funds due to damage from Hurricane Rita in September 2005 and the resulting interruption of our business during the fourth quarter of 2005 and the first quarter of 2006.

Net cash flow provided by operating activities was $39,523,000 for the year ended December 31, 2006, compared to net cash flow provided by operating activities of $15,200,000 for 2005. This increase was primarily the result of an increase in cash receipts from our oil and gas purchasers due to higher prices received for oil production and a 60% increase in net production, partially offset by increases in cash paid for lease operating expenses and production taxes.

Net cash used in investing activities for the year ended December 31, 2006 was $73,876,000 compared to $36,703,000 for the year ended December 31, 2005. During the year ended December 31, 2006, we spent $62,403,000 in additions to oil and natural gas properties, of which $40,040,000 was spent on our 2006 drilling program, $5,175,000 was attributable to the wells drilled during 2005, $2,179,000 was spent on additions to oil and natural gas properties due to the hurricane net of insurance proceeds, $5,157,000 was spent on new compressors for WCBB, with the remainder attributable mainly to capitalized general and administrative expenses and recompletions. In addition, during the year ended December 31, 2006, we made investments of $964,000 in Tatex Thailand II, $1,416,000 in Windsor Bakken LLC, and $8,493,000 in Grizzly Oil Sands ULC. We used cash from operations, proceeds from the sale of company stock, insurance recoveries and borrowings under our credit facility to fund our investing activities.

Net cash provided by financing activities for the year ended December 31, 2006 was $38,861,000 compared to $16,080,000 for the year ended December 31, 2005. The 2006 amount provided by financing activities is primarily attributable to net borrowings of $27,848,000 on our credit facility with Bank of America and net proceeds of $10.4 million from the sale of shares as a result of the underwriters' exercise of their over-allotment option in connection with the May 2006 underwritten public offering described below. These net proceeds were used to pay down existing debt under our credit facility. The $16,080,000 provided by financing activities during the year ended December 31, 2005 is primarily attributable to aggregate net cash proceeds of approximately $23,600,000 from (1) the issuance of common stock in two private placements and (2) the exercise of the outstanding warrants and net borrowings of $6,796,000, partially offset by the approximately $14,292,000 used to redeem all 14,292 outstanding shares of our Series A preferred stock.

Issuance of Equity. On May 3, 2006, certain of our stockholders sold 6,050,000 shares of our common stock in an underwritten public offering at an offering price to the public of $14.00 per share. In connection with the offering, we granted the underwriters a 30-day option to purchase additional shares of our common stock to cover over-allotments, if any. On May 8, 2006, the underwriters exercised their option with respect to 790,000 shares. We received net proceeds of $10.4 million from the sale of these shares on May 10, 2006 after deducting the underwriting discount and before offering expenses. These net proceeds were used to pay down existing debt under our credit facility.

During the year ended December 31, 2006, certain holders of warrants issued by us in 2002 in conjunction with a private placement offering exercised their warrants resulting in our issuance of 113,852 shares of common stock. We received $121,000 in connection with these exercises. At December 31, 2006, 60,550 warrants remained outstanding. They are exercisable for 203,529 shares of our common stock at a current exercise price of $1.19 per share, subject to adjustment.

On January 30, 2007, we sold 1,150,000 shares of our common stock in an underwritten offering at an offering price to the public of $11.92 per share. In connection with the offering, we granted the underwriter an option to purchase up to an additional 172,500 shares of common stock to cover any over-allotments, which the underwriter exercised in full on February 1, 2007. We received the net proceeds of approximately $15.3 million from the sale of these shares on February 5, 2007 after deducting the underwriting discount and before offering expenses. These net proceeds were used to pay down outstanding debt under our credit facility.

Credit Facility. On March 11, 2005, we entered into a three-year secured reducing credit agreement providing for a $30.0 million revolving credit facility with Bank of America, N.A. Borrowings under the revolving credit facility are subject to a borrowing base limitation, which was initially set at $18.0 million, subject to adjustment. On November 1, 2005, the amount available under the borrowing base limitation was increased to $23.0 million and was redetermined without change on May 30, 2006. On December 19, 2006, the amount available under the borrowing base limitation was increased to $30.0 million. The credit facility has a term of three years and all principal amounts of revolving loans outstanding under the credit facility, together with all accrued and unpaid interest and fees will be due and payable on March 11, 2008. We make quarterly interest payments on amounts borrowed under the facility, which amounts bear interest at Bank of America prime plus .25% (8.5% at December 31, 2006). Our obligations under the credit facility are collateralized by a lien on substantially all of our assets. The credit facility contains certain affirmative and negative covenants, including, but not limited to the following financial covenants: (a) the ratio of current assets to current liabilities may not be less than 1.00 to 1.00; (b) the ratio of funded debt to EBITDAX (net income before deductions for taxes, excluding unrealized gains and losses related to trading securities and commodity hedges, plus depreciation, depletion, amortization and interest expense, plus exploration costs deducted in determining net income under full cost accounting) for a twelve-month period may not be greater than 2.00 to 1.00; and (c) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. We were not in compliance with the current ratio covenant at December 31, 2006, however, a waiver was obtained from the lender. As of December 31, 2006, approximately $29.8 million was outstanding under this facility, which is included in long-term debt, net of current maturities on the accompanying consolidated balance sheet. We have used the proceeds of our borrowings under the credit facility for the exploration of our oil and natural gas properties and other capital expenditures, acquisition opportunities, replacement of facilities and equipment due to Hurricane Rita and for other general corporate purposes.

On July 10, 2006, we entered into a $5 million term loan agreement with Bank of America, N.A. related to the purchase of new gas compressor units. The loan amortizes quarterly beginning March 31, 2007 on a straight-line basis over seven years based on the outstanding principal balance at December 31, 2006. We could draw on the note until (a) the note was fully advanced, or (b) December 31, 2006, whichever occurred first. Amounts borrowed bear interest at Bank of America prime (8.25% at December 31, 2006). We make quarterly interest payments on amounts borrowed under the agreement. Our obligations under the agreement are collateralized by a lien on the compressor units. As of December 31, 2006, approximately $5 million was outstanding under this agreement, of which $714,000 and $4,286,000 are included in current maturities of long-term debt and long-term debt, net of current maturities, respectively, on our accompanying consolidated balance sheet.

Building Loans. We have three loans associated with two of our buildings. One loan, in the original principal amount of $115,000, related to a building in Lafayette, Louisiana, that we purchased in 1996 to be used as our Louisiana headquarters. This loan matures in February 2009 and bears interest at the rate of 5.75% per annum. In addition, in June 2004 we purchased the office building we occupy in Oklahoma City, Oklahoma for $3.7 million. One of the two loans associated with this building, with an original principal amount of $389,000, matured in March 2006 and bore interest at a rate of 6% per annum. The other loan associated with this building, with an original principal amount of $3.0 million, matures in June 2011 and bears interest at a rate of 6.5% per annum. All building loans require monthly interest and principal payments and are collateralized by the respective land and buildings.

Capital Expenditures. Our recent capital commitments have been primarily for the development of our proved reserves and the replacement of our facilities damaged by Hurricane Rita. Our strategy is to continue to (1) increase cash flow generated from our operations by undertaking new drilling, workover, sidetrack and recompletion projects to exploit our existing properties and (2) explore other acquisition opportunities. We have upgraded our infrastructure and our existing facilities to increase operating efficiencies and volume capacities and lower lease operating expenses. These upgrades were also intended to better enable our facilities to withstand future hurricanes with less damage. Additionally, we completed the reprocessing of 3-D seismic data in our principal property, WCBB. The reprocessed data will enable our geophysicists to continue to generate new prospects and enhance existing prospects in the intermediate zones in the field, thus creating a portfolio of new drilling opportunities.

In our December 31, 2006 reserve report, 76% of our net reserves were categorized as proved undeveloped. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved developed reserves, or both. To realize reserves and increase production, we must continue our exploratory drilling, undertake other replacement activities or use third parties to accomplish those activities.

Our inventory of prospects includes approximately 118 wells at WCBB. The drilling schedule used in our December 31, 2006 reserve report anticipates that all of those wells will be drilled by 2016. During 2007, we intend to drill 26 to 28 wells and recomplete 18 existing wells at our WCBB field. We currently intend to spend approximately $55 million in our WCBB field in 2007.

In our East Hackberry field, we have drilled three exploratory wells, are currently drilling two wells and intend to drill two additional wells in the second quarter of 2007 as part of our initial drilling program. Once we have evaluated the results of these wells and completed the installation of our new barge production facility, we will be in a position to finalize our 2007 East Hackberry drilling program.

During the third quarter of 2006, we purchased a 25% interest in Grizzly Oils Sands ULC, a Canadian unlimited liability company. The remaining interests in Grizzly are owned by other entities controlled by Wexford Capital LLC, an affiliate of ours. During 2006, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray within a few miles of other existing oil sands projects. As of December 31, 2006, our net investment in Grizzly was approximately $8.5 million. Capital requirements in 2007 for this project are currently estimated to be approximately $4.0 million, primarily for additional lease acquisitions and expenses associated with our recently completed 62 well "core hole" drilling program and our proposed 2007/2008 winter drilling program.

Our total capital for 2007, excluding expenditures related to our East Hackberry field, are currently estimated to be $60.0 million to $65.0 million. We believe that our cash on hand, insurance proceeds as described above under "Recent Developments—Insurance Coverage," cash flow from operations and borrowings under our credit facility will be sufficient to meet our normal recurring operating needs, debt service obligations, capital requirements and contingencies for the next twelve months. In the event we elect to expand our drilling programs, pursue acquisitions or accelerate our Canadian oil sands project, we may be required to obtain additional funds. If we seek additional capital for these or other reasons, we may do so through traditional borrowings, offerings of debt or equity securities or other means, including the sale of assets. Needed capital may not be available to us on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to implement our business plan.

To mitigate the effects of commodity price fluctuations, we entered into price swap contracts to hedge 45,000 barrels of production per month from WCBB during 2006 with a fixed price of $64.05 per barrel. As part of the agreement with our counterparty, we established a deposit account to cover margin calls if required. Under these arrangements, the counterparty could require us to post cash collateral approximately equal to the difference between the agreed contract price of $64.05 per barrel and a defined market price multiplied by the remaining barrels of oil under the open contracts. At September 30, 2006, the account totaled approximately $3.2 million which was returned to us in October 2006. In October 2006, we terminated the remaining three months of our hedging contracts. Through the termination of these remaining contracts, we received a total of $566,000 of proceeds during the fourth quarter of 2006 resulting from the differential in the fixed hedged price of $64.05 per barrel and the market prices of the associated futures contracts at the date of the termination of these contracts. In accordance with SFAS 133, "*Accounting for Derivative Instruments and Hedging Activities*," these amounts were recognized into earnings during the fourth quarter of 2006, the period in which the hedged forecasted transactions occurred.

Commitments

In connection with the acquisition in 1997 of the remaining 50% interest in the WCBB properties, we assumed the seller's (Chevron) obligation to contribute approximately $18,000 per month through March 2004, to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until abandonment obligations to Chevron have been fulfilled. Beginning in 2009, we can access the trust for use in plugging and abandonment charges associated with the property. As of December 31, 2006, the plugging and abandonment trust totaled approximately $2,983,000, including interest received during 2006 of approximately $105,000. We have plugged 231 wells at WCBB since we began our plugging program in 1997, which management believes fulfills our minimum plugging obligation through March 31, 2007.

New Accounting Pronouncements

SFAS No. 155

In February 2006, the Financial Accounting Standards Board ("FASB") issued SFAS No. 155, "*Accounting for Certain Hybrid Financial Instruments*," which amends FASB Statements No. 133 and 140. SFAS No. 155 clarifies certain issues relating to embedded derivatives and beneficial interests in securitized financial assets. The provisions of SFAS 155 are effective for all financial instruments acquired or issued after fiscal years beginning after September 15, 2006. We do not believe the effect of adopting this pronouncement will have a material impact on our consolidated financial statements.

FIN 48

In June 2006, the FASB issued FASB Interpretation Number 48, "*Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109*." This Interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, "*Accounting for Income Taxes*." This Interpretation is effective for fiscal years beginning after December 15, 2006. We do not believe the effect of adopting this statement will have a material effect on our consolidated financial statements.

SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, "*Fair Value Measurements*." SFAS No. 157 addresses how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under generally accepted accounting principles. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, with earlier adoption permitted. We are currently assessing the impact, if any, of the adoption of SFAS No. 157.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, "*The Fair Value Option for Financial Assets and Financial Liabilities—Including an Amendment of FASB Statement No. 115.*" SFAS No. 159 permits companies to choose to measure certain financial instruments and other items at fair value. The objective is to improve financial reporting by providing companies with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Unrealized gains and losses on any items for which we elect the fair value measurement option would be reported in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. However, early adoption is permitted for fiscal years beginning on or before November 15, 2007, provided we also elect to apply the provisions of SFAS No. 157, *Fair Value Measurements*, at the same time. We are currently assessing the impact, if any, of the adoption of SFAS No. 159.

SAB No. 108

In September 2006, the Securities Exchange Commission issued Staff Accounting Bulletin No. 108 ("SAB No. 108") "*Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*." SAB No. 108 addresses how the effects of prior year uncorrected misstatements should be considered when quantifying misstatements in current year financial statements. SAB No. 108 requires companies to quantify misstatements using a balance sheet and income statement approach and to evaluate whether either approach results in quantifying an error that is material in light of relevant quantitative and qualitative factors. When the effect of initial adoption is material, companies will record the effect as a cumulative effect adjustment to beginning of year retained earnings and disclose the nature and amount of each individual error being corrected in the cumulative adjustment. Management adopted SAB No. 108 as of December 31, 2006. Adoption of SAB No. 108 did not have a material effect on our financial position or results of operations.

ITEM 7. FINANCIAL STATEMENTS

The information required by this item appears beginning on page F-1 following the signature pages of this Report.

ITEM 8. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not applicable.

ITEM 8A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures. Under the direction of our Chief Executive Officer and Vice President and Chief Financial Officer, we have established disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and Vice President and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

As of December 31, 2006, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Vice President and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934. Based upon our evaluation, our Chief Executive Officer and Vice President and Chief Financial Officer have concluded that as of December 31, 2006, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting. There have not been any changes in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

ITEM 8B. OTHER INFORMATION

None.

PART III

ITEM 9. DIRECTORS, EXECUTIVE OFFICERS, PROMOTERS, CONTROL PERSONS AND CORPORATE GOVERNANCE; COMPLIANCE WITH SECTION 16(A) OF THE EXCHANGE ACT

For information concerning Item 9—Directors, Executive Officers, Promoters, Control Persons and Corporate Governance; Compliance with Section 16(A) of the Exchange Act, see our definitive Proxy Statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 10. EXECUTIVE COMPENSATION

For information concerning Item 10—Executive Compensation, see our definitive Proxy Statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 11. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

For information concerning Item 11—Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, see our definitive Proxy Statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 12. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

For information concerning Item 12—Certain Relationships and Related Transactions, and Director Independence, see our definitive Proxy Statement, which will be filed with the Securities and Exchange Commission with 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 13. EXHIBITS

List the following documents filed as part of this report:

Exhibit Number	Description
3.1	Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
3.2	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 12, 2006).
4.1	Form of Common Stock certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
10.1+	Amended and Restated 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
10.2+	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.2 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).

Exhibit Number	Description
10.3+	Form of Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.3 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
10.4+	Form of Warrant Agreement (incorporated by reference to Exhibit 10.4 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
10.5+	Employment Agreement, dated June 2003, by and between the Registrant and Mike Liddell (incorporated by reference to Exhibit 10.5 to Amendment No. 1 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on June 21, 2004)
10.6	Registration Rights Agreement, dated as of February 23, 2005, by and among the Company, Southpoint Fund LP, a Delaware limited partnership, Southpoint Qualified Fund LP, a Delaware limited partnership and Southpoint Offshore Operating Fund, LP, a Cayman Islands exempted limited partnership (incorporated by reference to Exhibit 10.7 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2005).
10.8	Credit Agreement, dated as of March 11, 2005, by and among the Company, each lender from time to time party thereto and Bank of America, N.A., as agent (incorporated by reference to Exhibit 10.9 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2005).
10.9	Administrative Services Agreement, effective as of April 1, 2005, by and between Bronco Drilling Company, Inc. and Gulfport Energy Corporation (incorporated by reference from Exhibit 10.1 of Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on August 15, 2005).
10.10	Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.3 of Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on November 11, 2005).
10.11	Amendment No. 1, dated February 14, 2006, to the Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.15 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2006).
14	Code of Ethics (incorporated by reference to Exhibit 14 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 14, 2006).
21*	Subsidiaries of the Registrant.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.

* Filed herewith
+ Management contract, compensatory plan or arrangement.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

For information concerning Item 14—Principal Accountant Fees and Services, see our definitive Proxy Statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: March 30, 2007

GULFPORT ENERGY CORPORATION

By: /s/ JAMES D. PALM

James D. Palm
Chief Executive Officer

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date: March 30, 2007 By: /s/ JAMES D. PALM

James D. Palm
Chief Executive Officer and Director
(Principal Executive Officer)

Date: March 30, 2007 By: /s/ MIKE LIDDELL

Mike Liddell
Chairman of the Board and Director

Date: March 30, 2007 By: /s/ MICHAEL G. MOORE

Michael G. Moore
Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer)

Date: March 30, 2007 By: /s/ ROBERT E. BROOKS

Robert E. Brooks
Director

Date: March 30, 2007 By: /s/ DAVID L. HOUSTON

David L. Houston
Director

Date: March 30, 2007 By: /s/ MICKEY LIDDELL

Mickey Liddell
Director

Date: March 30, 2007 By: /s/ DAN NOLES

Dan Noles
Director

Date: March 30, 2007 By: /s/ SCOTT E. STRELLER

Scott E. Streller
Director

ITEM 7. FINANCIAL STATEMENTS

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Gulfport Energy Corporation:

We have audited the accompanying consolidated balance sheet of Gulfport Energy Corporation and Subsidiary (the "Company") as of December 31, 2006, and the related consolidated statements of operations, stockholders' equity and comprehensive income, and cash flows for each of the two years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Gulfport Energy Corporation and Subsidiary as of December 31, 2006, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payment,* on a modified prospective basis effective January 1, 2006.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 30, 2007

GULFPORT ENERGY CORPORATION

CONSOLIDATED BALANCE SHEET

	December 31, 2006
Assets	
Current assets:	
Cash and cash equivalents	$ 6,627,000
Accounts receivable—oil and gas	7,585,000
Insurance settlement receivables	541,000
Accounts receivable—related parties	4,202,000
Prepaid expenses and other current assets	972,000
Total current assets	19,927,000
Property and equipment:	
Oil and natural gas properties, full-cost accounting, $1,459,000 excluded from amortization	250,838,000
Other property and equipment	6,651,000
Accumulated depletion, depreciation and amortization	(99,815,000)
Property and equipment, net	157,674,000
Other assets	17,550,000
Total assets	$195,151,000
Liabilities and Stockholders' Equity	
Current liabilities:	
Accounts payable and accrued liabilities	$ 24,793,000
Asset retirement obligation—current	480,000
Current maturities of long-term debt	835,000
Total current liabilities	26,108,000
Asset retirement obligation—long-term	8,378,000
Long-term debt, net of current maturities	36,856,000
Total liabilities	71,342,000
Commitments and contingencies (Notes 16 and 17)	
Preferred stock, $.01 par value; 5,000,000 authorized, 30,000 authorized as redeemable 12% cumulative preferred stock, Series A; 0 issued and outstanding	—
Stockholders' equity:	
Common stock—$.01 par value, 55,000,000 authorized, 33,659,759 issued and outstanding	337,000
Paid-in capital	131,610,000
Accumulated deficit	(8,138,000)
Total stockholders' equity	123,809,000
Total liabilities and stockholders' equity	$195,151,000

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2006	2005
Revenues:		
Gas sales	$ 4,194,000	$ 3,437,000
Oil and condensate sales	56,038,000	23,986,000
Other income	158,000	136,000
	60,390,000	27,559,000
Costs and expenses:		
Lease operating expenses	10,670,000	7,654,000
Production taxes	7,366,000	3,622,000
Depreciation, depletion, and amortization	12,652,000	4,789,000
General and administrative	3,251,000	1,561,000
Accretion expense	596,000	516,000
	34,535,000	18,142,000
INCOME FROM OPERATIONS	25,855,000	9,417,000
OTHER (INCOME) EXPENSE:		
Interest expense	1,956,000	250,000
Interest expense—preferred stock	—	272,000
Business interruption insurance recoveries	(3,601,000)	(1,710,000)
Interest income	(308,000)	(290,000)
	(1,953,000)	(1,478,000)
INCOME BEFORE INCOME TAXES	27,808,000	10,895,000
INCOME TAX EXPENSE	—	—
NET INCOME	$27,808,000	$10,895,000
NET INCOME PER COMMON SHARE:		
Basic	$ 0.85	$ 0.36
Diluted	$ 0.82	$ 0.34

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME

	Common Stock		Additional Paid-in Capital	Notes Receivable for Exercise of Options	Accumulated Other Comprehensive Income	Accumulated Deficit	Total Stockholders' Equity
	Shares	Amount					
Balance at January 1, 2005	20,146,566	$201,000	$ 95,737,000	$ —	$ —	$(46,841,000)	$ 49,097,000
Net income	—	—	—	—	—	10,895,000	10,895,000
Other Comprehensive Income:							
Deferred gain on settled contracts	—	—	—	—	114,000	—	114,000
Loss on hedging ineffectiveness	—	—	—	—	24,000	—	24,000
Unrealized gain on hedges	—	—	—	—	621,000	—	621,000
Total Comprehensive Income							11,654,000
Issuance of Common Stock	4,000,000	40,000	13,960,000	—	—	—	14,000,000
Issuance of Common Stock through exercise of warrants	7,958,470	80,000	9,390,000	—	—	—	9,470,000
Issuance of Common Stock through exercise of options	63,167	1,000	105,000	(105,000)	—	—	1,000
Repayment of Notes Receivable for Stock	—	—	—	105,000	—	—	105,000
Balance at December 31, 2005	32,168,203	322,000	119,192,000	—	759,000	(35,946,000)	84,327,000
Net income	—	—	—	—	—	27,808,000	27,808,000
Other Comprehensive Income:							
Deferred gain on settled contracts	—	—	—	—	(114,000)	—	(114,000)
Gain on hedging ineffectiveness	—	—	—	—	(24,000)	—	(24,000)
Reclassification adjustment on settled hedges	—	—	—	—	(621,000)	—	(621,000)
Total Comprehensive Income							27,049,000
Stock Compensation	—	—	1,063,000	—	—	—	1,063,000
Issuance of Common Stock in public offering, net of related expenses of $479,000	790,000	8,000	9,965,000	—	—	—	9,973,000
Issuance of Restricted Stock	21,981	—	—	—	—	—	—
Issuance of Common Stock through exercise of Warrants	113,852	1,000	120,000	—	—	—	121,000
Issuance of Common Stock through exercise of Options	565,723	6,000	1,270,000	—	—	—	1,276,000
Balance at December 31, 2006	33,659,759	$337,000	$131,610,000	$ —	$ —	$ (8,138,000)	$123,809,000

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,	
	2006	2005
Cash flows from operating activities:		
Net income	$ 27,808,000	$ 10,895,000
Adjustments to reconcile net income to net cash provided by operating activities:		
Accretion of discount—Asset Retirement Obligation	596,000	516,000
Interest expense—preferred stock	—	272,000
Depletion, depreciation and amortization	12,652,000	4,789,000
Stock-based compensation expense	787,000	—
Loss from equity investments	76,000	—
Unrealized (gain) loss on hedge ineffectiveness	(24,000)	24,000
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	(6,609,000)	2,584,000
Decrease (increase) in business interruption insurance settlement receivable	1,710,000	(1,710,000)
(Increase) in accounts receivable—related party	(832,000)	(2,347,000)
(Increase) in prepaid expenses	(490,000)	(270,000)
Decrease in deposits	107,000	—
Increase in accounts payable and accrued liabilities	4,608,000	1,074,000
(Increase) decrease in deferred hedge gains	(114,000)	114,000
Settlement of asset retirement obligation	(752,000)	(741,000)
Net cash provided by operating activities	39,523,000	15,200,000
Cash flows from investing activities:		
Additions to cash held in escrow	(105,000)	(57,000)
Additions to other property, plant and equipment	(495,000)	(467,000)
Additions to oil and gas properties	(62,403,000)	(31,995,000)
Proceeds from sale of oil and gas properties	—	70,000
Investment in Grizzly Oil Sands ULC	(8,493,000)	—
Investment in Tatex Thailand II, LLC	(964,000)	(2,502,000)
Investment in Windsor Bakken, LLC	(1,416,000)	(1,752,000)
Net cash used in investing activities	(73,876,000)	(36,703,000)
Cash flows from financing activities:		
Principal payments on borrowings	(10,809,000)	(204,000)
Borrowings on note payable	38,300,000	7,000,000
Redemption of Series A, Preferred Stock	—	(14,292,000)
Proceeds from issuance of common stock, net of offering costs of $479,000, and exercise of stock options	11,370,000	23,576,000
Net cash provided by financing activities	38,861,000	16,080,000
Net increase (decrease) in cash and cash equivalents	4,508,000	(5,423,000)
Cash and cash equivalents at beginning of period	2,119,000	7,542,000
Cash and cash equivalents at end of period	$ 6,627,000	$ 2,119,000
Supplemental disclosure of cash flow information:		
Interest payments	$ 1,956,000	$ 250,000
Supplemental disclosure of non-cash transactions:		
Investment subscription payable	$ —	$ 688,000
Capitalized stock based compensation	$ 276,000	$ —
Payment of Series A Preferred Stock dividends through issuance of Series A Preferred Stock	$ —	$ 272,000
Asset retirement obligation capitalized	$ 405,000	$ 1,382,000

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2006 AND 2005

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business

Gulfport Energy Corporation ("Gulfport" or the "Company") is a domestic independent oil and gas exploration, development and production company with its principal properties located in the Louisiana Gulf Coast.

Principles of Consolidation

The consolidated financial statements include the Company and its wholly owned subsidiary, Grizzly Holdings, Inc. All intercompany balances and transactions are eliminated in consolidation.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents for purposes of the statement of cash flows.

Accounts Receivable—Oil and Gas

The Company's accounts receivable—oil and gas primarily are from companies in the oil and gas industry located in the southwestern part of the United States. The majority of its receivables are from two purchasers of the Company's oil and gas. Credit is extended based on evaluation of a customer's payment history and, generally, collateral is not required. Accounts receivable are due within 30 days and are stated at amounts due from customers, net of an allowance for doubtful accounts when the Company believes collection is doubtful. Accounts outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the customer's current ability to pay its obligation to the Company, amounts which may be obtained by an offset against production proceeds due the customer and the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. No allowance was deemed necessary at December 31, 2006.

Oil and Gas Properties

The Company uses the full cost method of accounting for oil and gas operations. Accordingly, all costs, including nonproductive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and gas properties, are capitalized. Net capitalized costs are limited to the estimated future net revenues, as adjusted for the Company's cash flow hedge positions and net of tax effects, discounted at 10% per year, from proven oil and gas reserves and the cost of the properties not subject to amortization. Such capitalized costs, including the estimated future development costs and site remediation costs of proved undeveloped properties are depleted by an equivalent units-of-production method, converting gas to barrels at the ratio of six Mcf of gas to one barrel of oil. No gain or loss is recognized upon the disposal of oil and gas properties, unless such dispositions significantly alter the relationship between capitalized costs and proven oil and gas reserves. Oil and gas properties not subject to amortization consist of the cost of unproved leaseholds and totaled $1,459,000 at December 31, 2006. These costs are reviewed periodically by management for impairment, with the impairment provision included in the cost of oil and gas properties subject to amortization. Factors considered by management in its impairment assessment include drilling results by Gulfport and other operators, the terms of oil and gas leases not held by production, and available funds for exploration and development.

The Company accounts for its abandonment and restoration liabilities under Statement of Financial Accounting Standards No. 143, "*Accounting for Asset Retirement Obligations*" ("SFAS No. 143"), which requires the Company to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, the Company increases the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related long-lived asset. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.

Other Property and Equipment

Depreciation of other property and equipment is provided on a straight-line basis over estimated useful lives of the related assets, which range from 7 to 30 years.

Net Income per Common Share

Basic net income per common share is computed by dividing income attributable to common stock by the weighted average number of common shares outstanding for the period. Diluted net income per common share reflects the potential dilution that could occur if options or other contracts to issue common stock were exercised or converted into common stock. Potential common shares are not included if their effect would be anti-dilutive. Calculations of basic and diluted net income per common share are illustrated in Note 12.

Income Taxes

Gulfport uses the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized as income in the year in which realization becomes determinable. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

Revenue Recognition

Gas revenues are recorded in the month produced and delivered to the purchaser using the entitlement method, whereby any production volumes received in excess of the Company's ownership percentage in the property are recorded as a liability. If less than Gulfport's entitlement is received, the underproduction is recorded as a receivable. There is no such liability or asset recorded at December 31, 2006 because the Company has no imbalances. Oil revenues are recognized when ownership transfers, which occurs in the month produced.

Investments—Equity Method

Investments in entities greater than 20% and 50% or less are accounted for under the equity method. Under the equity method, the Company's share of investees' earnings or loss is recognized in the statement of operations.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements and revenues and expenses during the reporting period. Actual results could differ materially from those estimates. Significant estimates with regard to these financial statements include the estimate of proved oil and gas reserve quantities and the related present value of estimated future net cash flows there from, the amount and timing of asset retirement obligations and the realization of future net operating loss carryforwards available as reductions of income tax expense.

Accounting Standards Yet to be Adopted

In February 2006, the Financial Accounting Standards Board ("FASB") issued SFAS No. 155, "*Accounting for Certain Hybrid Financial Instruments*," which amends FASB Statements No. 133 and 140. SFAS No. 155 clarifies certain issues relating to embedded derivatives and beneficial interests in securitized financial assets. The provisions of SFAS 155 are effective for all financial instruments acquired or issued after fiscal years beginning after September 15, 2006. The Company does not believe the effect of adopting this Pronouncement will have a material impact on its consolidated financial statements.

In June 2006, the FASB issued FASB Interpretation Number 48, "*Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109*." This Interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, "*Accounting for Income Taxes*." This Interpretation is effective for fiscal years beginning after December 15, 2006, and the Company will adopt it in the first quarter 2007. The Company does not expect the adoption of this Interpretation to have a material impact on its consolidated financial statements.

In September 2006, the FASB issued SFAS No. 157, *"Fair Value Measurements."* SFAS No. 157 addresses how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under generally accepted accounting principles. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, with earlier adoption permitted. The Company is currently assessing the impact, if any, of the adoption of SFAS 157.

In February 2007, the FASB issued SFAS No. 159, "*The Fair Value Option for Financial Assets and Financial Liabilities—Including an Amendment of FASB Statement No. 115*". SFAS No. 159 permits companies to choose to measure certain financial instruments and other items at fair value. The objective is to improve financial reporting by providing companies with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Unrealized gains and losses on any items for which the Company elects the fair value measurement option would be reported in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. However, early adoption is permitted for fiscal years beginning on or before November 15, 2007, provided the Company also elects to apply the provisions of SFAS No. 157, *Fair Value Measurements*, at the same time. The Company is currently assessing the impact, if any, of the adoption of SFAS No. 159.

Accounting for Stock-Based Compensation

Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standard No. 123(R), "*Share-Based Payment*" ("SFAS No. 123(R)"), using the modified prospective transition method. SFAS No. 123(R) requires share-based payments to employees, including grants of employee stock options, to be recognized as equity or liabilities at the fair value on the date of grant and to be expensed over the applicable vesting period. The Company recognizes compensation expense for share payments on a straight-line basis. Under the modified prospective transition method, share-based awards granted or modified on or after January 1, 2006, are recognized as compensation expense over the applicable vesting period. Also, any previously granted awards that are not fully vested as of January 1, 2006 are recognized as compensation expense over the remaining vesting period. No retroactive or cumulative effect adjustments were required upon the Company's adoption of SFAS No. 123(R) (see Note 8).

Prior to adopting SFAS No. 123(R), the company accounted for its fixed-plan employee stock options using the intrinsic-value based method prescribed by Accounting Principles Board Opinion No. 25, *"Accounting for Stock Issued to Employees"* ("APB No. 25"), and related interpretations. This method required compensation expense to be recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price.

If the Company had elected the fair value provisions of SFAS No. 123(R) and recognized compensation expense over the vesting period based on the fair value of the stock options granted as of their grant date, the Company's 2005 net income and net income per share would have differed from the amounts actually reported as shown in the following table.

	Year Ended December 31, 2005
Net income, as reported	$10,895,000
Stock-based employee compensation expense	248,000
Net income, pro forma	$10,647,000
Net income per share:	
As reported:	
Basic	$ 0.36
Diluted	$ 0.34
Pro forma:	
Basic	$ 0.35
Diluted	$ 0.33

Accounting for Derivative Instruments and Hedging Activities

The Company seeks to reduce its exposure to unfavorable changes in oil prices by utilizing energy swaps and collars (collectively "price swap contracts"). The Company follows the provisions of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended. It requires that all derivative instruments be recognized as assets or liabilities in the statement of financial position, measured at fair value.

The Company estimates the fair value of all derivative instruments using established index prices and other sources. These values are based upon, among other things, futures prices, correlation between index prices and the Company's realized prices, time to maturity and credit risk. The values reported in the consolidated financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

Accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. Designation is established at the inception of a derivative, but re-designation is permitted. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of SFAS 133, changes in fair value are recognized in other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value resulting from ineffectiveness is recognized immediately in earnings. The Company had no derivative contracts at December 31, 2006.

2. INSURANCE SETTLEMENT RECEIVABLE

The Company sustained damage to both its Hackberry field located in Cameron Parish, Louisiana and its West Cote Blanche Bay ("WCBB") field located in St. Mary Parish, Louisiana as a result of Hurricane Rita in September 2005. As of December 31, 2006, the Company had incurred costs of $13,084,000 relating to the damage to the fields and facilities. Of this amount, $250,000 represents insurance deductible amounts that were expensed to lease operating expenses in 2005. During the year ended December 31, 2006, the Company received $7,855,000 in insurance proceeds related to physical damage which are reflected as investing activity in the consolidated statements of cash flows. Approximately $4,330,000 of costs incurred during 2006 related to equipment and facilities replacement costs which will not be reimbursed by insurance and is included in the full cost pool. Approximately $108,000 previously included in insurance settlement receivables will not be collected and was expensed in 2006. The remaining $541,000 is included in insurance settlement receivables in the accompanying consolidated balance sheet at December 31, 2006. Subsequent to December 31, 2006, the Company has received the remaining $541,000 in insurance proceeds for physical damage.

The Company maintained business interruption insurance to cover lost production revenue in the event of shut-in production. The business interruption insurance began 60 days after the occurrence of the insurable event, subject to a daily limit of $45,000 and had a maximum coverage of 180 days. Coverage began on November 24, 2005 for shut-in production caused by Hurricane Rita. For the years ended December 31, 2006 and 2005, the Company recognized $3,601,000 and $1,710,000, respectively, of business interruption insurance proceeds in other income in the consolidated statements of income. As of December 31, 2006, the Company had received proceeds of $5,311,000 ($1,710,000 of which was accrued in 2005) related to business interruption for the period of November 24, 2005 to May 1, 2006. Such recoveries are presented as operating cash flows in the consolidated statements of cash flows.

3. ACCOUNTS RECEIVABLE—RELATED PARTY

Included in the accompanying December 31, 2006 balance sheet are amounts receivable from affiliates of the Company. These receivables represent amounts billed by the Company for general and administrative functions, such as accounting, human resources, legal, and technical support, performed by Gulfport's personnel on behalf of the affiliates. These services are solely administrative in nature and for entities in which the Company has no property interests. The amounts reimbursed to the Company for these services are for the purpose of Gulfport recovering costs associated with the services and do not include the assessment of any fees or other amounts beyond the estimated costs of performing such services. At December 31, 2006, this receivable amount totaled $4,202,000. The Company was reimbursed $12,738,000 and $6,232,000 for the twelve months ended December 31, 2006 and 2005, respectively, for general and administrative functions which is reflected as a reduction of general and administrative expenses in the consolidated statements of operations and include the amounts under service contracts discussed below.

Effective April 1, 2005, the Company entered into an administrative services agreement with Bronco Drilling Company, Inc. ("Bronco"), which was amended on January 1, 2006 and terminated effective April 1, 2006. Under the amended agreement, the Company's services for Bronco included accounting, human resources, legal and technical support. In return for the services rendered by the Company, Bronco paid the Company an annual fee of approximately $150,000, payable in equal monthly installments during the term of the agreement. In addition, Bronco leased approximately 2,500 square feet of office space from the Company for which it paid the company annual rent of approximately $44,000, payable in equal monthly installments. The services provided to Bronco and the fees for such services could be amended by mutual agreement of the parties. The administrative services agreement had a three-year term, and upon expiration of that term the agreement would continue on a month-to-month basis until cancelled by either party with at least 30 days prior written notice. The administrative services agreement was terminable (1) by Bronco at any time with at least 30 days prior written notice to the Company and (2) by either party if the other party was in material breach and such breach has not been cured within 30 days of receipt of written notice of such breach. The Company was reimbursed approximately $49,000 and $346,000 in consideration for those services during the years ended December 31, 2006 and 2005. This amount is reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

Effective September 29, 2006, the Company entered into an administrative services agreement with Diamondback Energy Services LLC (“Diamondback”). Under the agreement, the Company’s services for Diamondback include accounting, human resources, legal and technical support. The services provided to Diamondback and the fees for such services can be amended by mutual agreement of the parties. The administrative services agreement has a three-year term, and upon expiration of that term the agreement will continue on a month-to-month basis until cancelled by either party with at least 30 days prior written notice. The administrative services agreement is terminable (1) by Diamondback at any time with at least 30 days prior written notice to the Company and (2) by either party if the other party is in material breach and such breach has not been cured within 30 days of receipt of written notice of such breach. The Company was reimbursed approximately $823,000 and $294,000 in consideration for those services during the years ended December 31, 2006 and 2005, respectively. These amounts are reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

Effective July 22, 2006, the Company entered into an administrative services agreement with Great White Energy Services LLC (“Great White”). Under the agreement, the Company’s services for Great White include accounting, human resources, legal and technical support. The services provided to Great White and the fees for such services can be amended by mutual agreement of the parties. The administrative services agreement has a three-year term, and upon expiration of that term the agreement will continue on a month-to-month basis until cancelled by either party with at least 30 days prior written notice. The administrative services agreement is terminable (1) by Great White at any time with at least 30 days prior written notice to the Company and (2) by either party if the other party is in material breach and such breach has not been cured within 30 days of receipt of written notice of such breach. The Company was reimbursed approximately $2,222,000 in consideration for those services during the year ended December 31, 2006. This amount is reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

4. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depreciation, depletion and amortization as of December 31, 2006 are as follows:

	December 31, 2006
Oil and gas properties	$250,838,000
Office furniture and fixtures	2,465,000
Building	3,926,000
Land	260,000
Total property and equipment	257,489,000
Accumulated depreciation, depletion, amortization and impairment reserve	(99,815,000)
Property and equipment, net	$157,674,000

Included in oil and gas properties at December 31, 2006 is the cumulative capitalization of $3,928,000 in general and administrative costs incurred and capitalized to the full cost pool. General and administrative costs capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All general and administrative costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized general and administrative costs were approximately $976,000 and $346,000 for the years ended December 31, 2006 and 2005, respectively.

A reconciliation of the asset retirement obligation for the year ended December 31, 2006, is as follows:

	December 31, 2006
Asset retirement obligation, December 31, 2005	$8,609,000
Liabilities incurred	405,000
Liabilities settled	(639,000)
Change in cash flow estimate	(113,000)
Accretion expense	596,000
Asset retirement obligation as of end of year	8,858,000
Less current portion	480,000
Asset retirement obligation, long-term	$8,378,000

5. OTHER ASSETS

Other assets consist of the following as of December 31, 2006:

Plugging and abandonment escrow account on the WCBB properties (Note 16)	$ 2,983,000
Investment in Tatex Thailand II, LLC	3,465,000
Investment in Windsor Bakken, LLC	2,433,000
Investment in Grizzly Oil Sands ULC	8,465,000
Certificates of Deposit securing letter of credit	200,000
Deposits	4,000
	$17,550,000

Tatex Thailand II, LLC

During 2005, the Company purchased a 23.5% ownership interest in Tatex Thailand II, LLC ("Tatex") at a cost of $2,400,000. The remaining interests in Tatex are owned by other entities controlled by Wexford Capital LLC, an affiliate of Gulfport. Tatex, a non-public entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC ("APICO"), an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering three million acres which includes the Phu Horm Field. During 2006, Gulfport paid $964,000 in cash calls, bringing its total investment in Tatex (including previous investments) to $3,465,000.

Windsor Bakken, LLC

During 2005, the Company purchased a 20% ownership interest in Windsor Bakken, LLC ("Bakken"). The remaining interests in Bakken are owned by other entities controlled by Wexford Capital LLC, an affiliate of Gulfport. In 2005 and 2006, Bakken acquired leases on undeveloped acreage in the Williston Basin areas of western North Dakota and eastern Montana. As of December 31, 2006, Gulfport's net investment in Bakken is $2,433,000. As of December 31, 2006, Bakken has not yet commenced drilling of its undeveloped acreage.

Grizzly Oil Sands ULC

During third quarter 2006, the Company, through its wholly owned subsidiary Grizzly Holdings Inc., purchased a 25% interest in Grizzly Oils Sands ULC ("Grizzly"), a Canadian unlimited liability company, for approximately $8.2 million. The remaining interests in Grizzly are owned by other entities controlled by Wexford Capital LLC, an affiliate of Gulfport. During 2006, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray within a few miles of other existing oil sands projects. Grizzly has commenced drilling of core holes for feasibility of oil production in three separate lease blocks but has not commenced development of operations. As of December 31, 2006, Gulfport's, net investment in Grizzly is $8,465,000.

6. LONG-TERM DEBT

A break-down of long-term debt as of December 31, 2006 is as follows:

	December 31, 2006
Reducing credit agreement (1)	$29,848,000
Term loan (1)	5,000,000
Building loans (2)	2,843,000
Less: current maturities of long term debt	(835,000)
Debt reflected as long term	$36,856,000

Maturities of long-term debt as of December 31, 2006 are as follows:

2007	$ 835,000
2008	30,662,000
2009	815,000
2010	822,000
2011	3,128,000
Thereafter	1,429,000
Total	$37,691,000

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(1) On March 11, 2005, Gulfport entered into a three-year secured reducing credit agreement providing for a $30.0 million revolving credit facility with Bank of America, N.A. Borrowings under the revolving credit facility are subject to a borrowing base limitation, which was initially set at $18.0 million, subject to adjustment. On November 1, 2005, the amount available under the borrowing base limitation was increased to $23.0 million and was redetermined without change on May 30, 2006. On December 19, 2006, the amount available under the borrowing base limitation was increased to $30.0 million. The credit facility has a term of three years and all principal amounts of revolving loans outstanding under the credit facility, together with all accrued and unpaid interest and fees will be due and payable on March 11, 2008. Subsequent to December 31, 2006, the maturity date was amended to March 31, 2009. The Company makes quarterly interest payments on amounts borrowed under the facility. Amounts borrowed under the credit facility bear interest at Bank of America Prime plus .25% (8.5% at December 31, 2006). The Company's obligations under the credit facility are collateralized by a lien on substantially all of the Company's assets. The credit facility contains certain affirmative and negative covenants, including, but not limited to the following financial covenants: (a) the ratio of current assets to current liabilities may not be less than 1.00 to 1.00; (b) the ratio of funded debt to EBITDAX (net income before deductions for taxes, excluding unrealized gains and losses related to trading securities and commodity hedges, plus depreciation, depletion, amortization and interest expense, plus exploration costs deducted in determining net income under full cost accounting) for a twelve month period may not be greater than 2.00 to 1.00; and (c) the ratio of EBITDAX to interest expense for a twelve month period may not be less than 3.00 to 1.00. The Company was not in compliance with the current ratio covenant at December 31, 2006, however, a waiver was obtained from the lender. As of December 31, 2006, approximately $29.8 million was outstanding under this facility, which is included in long-term debt, net of current maturities on the accompanying consolidated balance sheet. The Company has used the proceeds of borrowings under the credit facility for the exploration of oil and gas properties and other capital expenditures, acquisition opportunities, repair of damaged facilities and for other general corporate purposes.

    On July 10, 2006, Gulfport entered into a $5 million term loan agreement with Bank of America, N.A. related to the purchase of new gas compressor units. The loan amortizes quarterly beginning March 31, 2007 on a straight-line basis over seven years based on the outstanding principal balance at December 31, 2006. The Company could draw on the note until the earlier to occur of a) the note was fully advanced, or b) December 31, 2006. Amounts borrowed bear interest at Bank of America Prime (8.25% at December 31, 2006). The Company makes quarterly interest payments on amounts borrowed under the agreement. The Company's obligations under the agreement are collateralized by a lien on the compressor units. As of December 31, 2006, approximately $5 million was outstanding under this agreement, of which $714,000 and $4,286,000 are included in current maturities of long-term debt and long-term debt, net of current maturities, respectively, on the accompanying consolidated balance sheet.

(2) The building loans include $38,000 related to a building in Lafayette, Louisiana, purchased in 1996 to be used as the Company's Louisiana headquarters. This loan matures in February of 2008 and bears interest at the rate of 5.75% per annum.

In addition, in June 2004 the Company purchased the office building it occupies in Oklahoma City, Oklahoma, for $3,700,000. One loan associated with this building matured in March 2006 and bore interest at the rate of 6% per annum, while the other loan matures in June 2011 and bears interest at the rate of 6.5% per annum. All building loans require monthly interest and principal payments and are collateralized by the respective land and buildings.

7. COMMON STOCK OPTIONS, RESTRICTED STOCK, WARRANTS AND CHANGES IN CAPITALIZATION

Options

The Company sponsors the 1999 Stock Option Plan (the "Plan"), which is administered by the Compensation Committee (the "Committee") of the Board of Directors of the Company. Under the terms of the Plan, the Committee could determine: to which eligible participants options shall be granted, the number of shares covered by such options, the purchase price or exercise price of such options, the vesting period of such options and the exercisable period of such options. Eligible participants are defined as (i) all directors of the Company; (ii) all officers of the Company; and (iii) all key employees of the Company with a customary work week of at least 40 hours in the employ of the Company. The maximum number of shares for which options could be granted under the Plan, as adjusted for changes in capitalization which have taken place since the Plan's adoption, was 883,000. The Company has granted 627,337 options for the purchase of shares of the Company's common stock under the Plan as of December 31, 2006. No additional securities will be issued under the Plan other than upon exercise of options that are outstanding.

The Company replaced the Plan in January 2005 with the 2005 Stock Incentive Plan ("2005 Plan"), which is administered by the Committee. Under the terms of the 2005 Plan, the Committee may determine: when options shall be granted, to which eligible participants options shall be granted, the number of shares covered by such options, the purchase price or exercise price of such options, the vesting periods of such options and the exercisable period of such options. Eligible participants are defined as employees, consultants, and directors of the Company.

On April 20, 2006, the Company amended and restated the 2005 Plan to include (a) Incentive Stock Options, (b) Nonstatutory Stock Options, (c) Restricted Awards (Restricted Stock and Restricted Stock Units), (d) Performance Awards and (e) Stock Appreciation Rights; and to increase the maximum aggregate amount of common stock that may be issued under the 2005 Plan from 1,904,606 shares to 3,000,000 shares, including the 627,337 shares underlying options granted to employees under the Plan prior to adoption of the 2005 Plan. As of December 31, 2006, the Company has granted and outstanding 997,269 options for the purchase of shares of the Company's common stock under the 2005 Plan.

During the first quarter of 2005, the Company granted a total of 677,269 options for the purchase of shares of the Company's common stock. The exercise price per share of these options is $3.36. During the third quarter of 2005, the Company granted a total of 120,000 options for the purchase of shares of the Company's common stock. The exercise price per share of these options is $9.07. In the fourth quarter 2005, the Company granted a total of 200,000 options for the purchase of shares of the Company's common stock. The exercise price per share of these options is $11.20. All options were issued at the market value of the Company's stock on the date of issuance. During the second and third quarters of 2005, several non-executive employees of the Company exercised stock options by signing full recourse notes receivable for the exercise price of those options. The notes bore interest at an annual rate of 6%. All principal amounts along with related accrued interest were paid as of December 31, 2005.

During the first quarter of 2006, the Company granted a total of 40,000 options for the purchase of shares of the Company's common stock. The exercise price per share of these options is $12.17. The options vest in equal monthly installments over a three-year period and expire ten years after the date of grant. During August 2006, these options were cancelled and 6,666 restricted shares of the Company's common stock were issued to the option holder. These shares were fully vested on the date of grant.

Restricted Stock

On May 16, 2006, the Company issued 57,000 shares of restricted common stock of the Company. These shares vest in equal monthly installments over a three-year period. During August and September 2006, 29,666 shares of restricted common stock were issued. These shares vest in equal monthly installments over a three-year period. On August 17, 2006, the Company issued an additional 6,666 shares of fully vested restricted common stock in connection with the cancellation of 40,000 options to purchase the Company's common stock.

Exercise of Warrants

During the first quarter of 2006, the holders of warrants issued in 2002 in conjunction with a private placement offering exercised their warrants resulting in 12,171 net shares of the Company's common stock issued. No proceeds were received by the Company related to the exercise of these warrants. During the third quarter of 2006, the holders of warrants exercised their warrants resulting in 101,681 net shares of the Company's common stock issued. The Company had 60,550 warrants outstanding at December 31, 2006 which can be converted into 203,529 shares of common stock at current exercise price of $1.19 per share. The warrants expire in 2012.

Sale of Common Stock

On February 17, 2005, the Company entered into a stock purchase agreement with certain accredited investors providing for the issuance by the Company of an aggregate of 2,000,000 shares of the Company's common stock at a price of $3.50 per share for gross proceeds to the Company of $7,000,000. On February 22, 2005 the Company entered into another stock purchase agreement with certain other accredited investors providing for the issuance by the Company of an aggregate of 2,000,000 shares of the Company's common stock at a price of $3.50 per share for gross proceeds to the Company of $7,000,000. The transactions closed effective as of February 18, 2005 and February 23, 2005, respectively. The Company granted certain piggyback registration rights to the investors. The Company also filed a registration statement on Form S-3 with respect to the resale of the shares of common stock purchased by the investors in the private placements, which was declared effective by the Securities and Exchange Commission on December 31, 2005. No underwriting discounts or commissions were paid in conjunction with the issuances.

In May of 2006, the Company closed a public offering of 6,050,000 shares of common stock at a price of $14.00 per share. All shares were sold by the Company's selling shareholders and the Company did not receive any proceeds. In connection with the offering, the Company granted the underwriters a 30-day option to purchase additional shares of the Company's common stock to cover over-allotments, if any. On May 8, 2006, the underwriters exercised their option with respect to 790,000 shares. The Company received net proceeds of $10,452,000 from the sale of these shares on May 10, 2006 after deducting the underwriting discount and before offering expenses. These net proceeds were used to pay down existing debt under the Company's credit facility.

Private Placement Offering

In March 2002, the Company completed a private placement offering of 10,000 units. Each unit consisted of (i) one share of Cumulative Preferred Stock, Series A, of the Company (Preferred) and (ii) a warrant to purchase up to 250 shares of common stock, par value $0.01 per share, of the Company. Holders of the Preferred were entitled to receive dividends at the rate of 12% of the liquidation preference per annum payable quarterly in cash or, at the option of the Company for all quarters ending on or prior to March 31, 2004, payable in whole or in part in additional shares of Preferred at the rate of 15% of the liquidation preference per annum. All preferred shares were redeemed in 2005.

The 2,322,962 Warrants issued have a term of ten years and an exercise price of $1.19 per share of common stock subject to adjustment. The Company granted to holders of the Warrants certain demand and piggyback registration rights with respect to shares of common stock issuable upon exercise of the warrants. The Company considered the valuation of these warrants and did not consider them materially significant. At December 31, 2006, 60,550 warrants were outstanding.

Exercise of Warrants and Redemption of Preferred Stock

During 2005, the holders of warrants to purchase 7,958,470 shares of the Company's common stock exercised their warrants for an exercise price of $1.19 per share resulting in proceeds to the Company of $9.5 million. No underwriting discounts or commissions were paid in conjunction with the issuances. The total warrants exercised in 2005 included 108,625 warrants issued to CD Holdings, LLC, ("CD Holdings") in accordance with the origination of the note payable to Gulfport Funding in 2002 (and retired during 2002).

Also during the 2005, the Company used the proceeds from the exercise of the warrants, along with a portion of the proceeds from the sale of common stock, to redeem all of the 14,292 shares of the Company's outstanding Series A preferred stock for an aggregate of $14.3 million, including accrued but unpaid dividends.

8. STOCK-BASED COMPENSATION

As discussed in Note 1, on January 1, 2006, the Company changed its method of accounting for share-based compensation from the APB No. 25 intrinsic-value accounting method to the fair value recognition provisions of SFAS No. 123 (R). During the year ended December 31, 2006, the Company's stock-based compensation expense was $1,063,000 of which the Company capitalized $276,000, relating to its exploration and development efforts, which reduced basic and diluted earnings per share by $0.02 for the year ended December 31, 2006. If the fair value recognition provisions of SFAS No. 123(R) were implemented for the year ended December 31, 2005, net income would have been reduced by $248,000 and basic and diluted earnings per share would have been reduced by $0.01. Options and restricted common stock are reported as share based payments and their fair value is amortized to expense using the straight line method over the vesting period. The shares of stock issued once the options are exercised will be from authorized but unissued common stock.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option valuation model that uses the assumptions noted in the following table. Expected volatilities are based on the historical volatility of the market price of Gulfport's common stock over a period of time ending on the grant date. Based upon historical experience of the Company, the expected term of options granted is equal to the vesting period plus one year. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of the grant. The Plan provides that all options must have an exercise price not less than the fair value of the Company's common stock on the date of the grant.

The following table provides information relating to outstanding stock options for the years ended December 31, 2006 and 2005:

	December 31, 2006	December 31, 2005
Expected volatility	40.9%	40.7%
Expected life in years	4.0	4.0
Weighted average risk free interest rate	4.0%	4.0%

The Company has not declared dividends and does not intend to do so in the foreseeable future, and thus did not use a dividend yield. In each case, the actual value that will be realized, if any, depends on the future performance of the common stock and overall stock market conditions. There is no assurance that the value an optionee actually realizes will be at or near the value estimated using the Black-Scholes model.

The fair value of restricted common stock awards is based on the closing price of the Company's common stock on date of the grant. The Company issued 57,000 restricted shares of common stock in May 2006 with a fair value of $756,000, which will be recorded as compensation expense over the three year vesting period of the restricted shares. In September 2006, 1,833 shares of unvested restricted shares issued during May 2006 were forfeited as a result of the termination of the recipient's employment with the Company.

During August and September 2006, an additional 29,666 shares of restricted shares of common stock were issued with an aggregate fair value of $356,000, which will be recorded as compensation expense over the three year vesting period of the restricted shares. During August 2006, the Company issued an additional 6,666 restricted shares in connection with the cancellation of 40,000 options. As the fair value of these restricted shares was less than the fair value of the cancelled options, the fair value of the original award was recognized in third quarter 2006 in accordance with SFAS 123(R). Approximately $151,000 related to this award modification was recognized as additional compensation expense during the third quarter of 2006 as these restricted shares were vested on the date of grant. The 40,000 options granted in 2006 and subsequently cancelled had a fair value of $4.40 per share, or $176,000.

A summary of the status of stock options and related activity for the years ended December 31, 2006 and 2005 are presented below:

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Options outstanding at December 31, 2004	627,337	$ 2.00	4.85	$ 816,000
Granted	997,269	5.62		
Exercised	(63,167)	2.01		
Forfeited/expired	(2,666)	3.36		
Options outstanding at December 31, 2005	1,558,773	4.31	7.33	12,061,000
Granted	40,000	12.17		
Cancelled	(40,000)	12.17		
Exercised	(565,723)	2.26		5,770,000
Forfeited/expired	(25,817)	3.26		
Options outstanding at December 31, 2006	967,233	$ 5.54	7.76	$ 7,782,000
Options exercisable at December 31, 2006	254,307	$ 6.16	6.31	$ 1,890,000

Unrecognized compensation expense as of December 31, 2006 related to outstanding stock options and restricted shares was $2,477,000. The expense is expected to be recognized over a weighted average period of 1.73 years.

The following table summarizes information about the stock options outstanding at December 31, 2006:

Exercise Price	Number Outstanding	Weighted Average Remaining Life (in years)	Number Exercisable
$ 2.00	103,418	2.85	103,418
$ 3.36	543,815	8.06	28,667
$ 9.07	120,000	8.69	50,000
$11.20	200,000	8.92	72,222
	967,233		254,307

The following table summarizes restricted stock activity:

	Number of Unvested Restricted Shares	Weighted Average Grant Date Fair Value
Unvested shares as of December 31, 2005	—	$ —
Granted	93,332	12.78
Vested	(21,981)	12.64
Forfeited	(1,833)	13.27
Unvested shares as of December 31, 2006	69,518	$12.81

9. DIVIDENDS ON SERIES A PREFERRED STOCK

As discussed in Note 7, the Company may, at its option, accrue additional shares of Preferred Stock for the payment of dividends at a rate of 15% per annum rather than accrue cash dividends at a rate of 12% per annum during the initial two years following the closing date of its Offering which expired on March 31, 2004. Effective April 1, 2004, as a result of the amendment discussed below, the Company continued to issue additional shares of Preferred Stock for payment of dividends. As a result, the Company issued additional shares with liquidation preference totaling $272,000 for the year ended December 31, 2005 related to the Preferred Stock Series A shares issued and outstanding during that time period. These dividends were calculated based upon the Preferred's $1,000 per share redemptive value. As a result of the adoption of SFAS 150, the dividends issued as additional shares for the year ended December 31, 2005 are shown as "Interest expense—preferred stock" in the accompanying consolidated statements of income.

10. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amounts on the accompanying balance sheet for cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and current and long-term debt are carried at cost, which approximates market value.

The fair value of the derivative instruments are computed based on the difference between the prices provided by the fixed-price contracts and forward market prices as of the specified date, as adjusted for basis differentials. Forward market prices for oil are dependent upon supply and demand factors in such forward market and are subject to significant volatility.

11. INCOME TAXES

A reconciliation of the statutory federal income tax amount to the recorded expense follows:

	2006	2005
Income before federal income taxes	$ 27,808,000	$ 10,895,000
Expected income tax at statutory rate	9,455,000	3,704,000
Interest expense not tax deductible	—	272,000
State income taxes	1,668,000	654,000
Other timing differences	1,034,000	(849,000)
Changes in valuation allowance	(12,157,000)	(3,781,000)
Income tax expense recorded	$ —	$ —

The tax effects of temporary differences and net operating loss carryforwards, which give rise to deferred tax assets and liabilities at December 31, 2006 and 2005, are estimated as follows:

	2006	2005
Deferred tax assets:		
Net operating loss carryforward	$ 38,373,000	$ 40,143,000
SFAS 123(R) compensation expense	319,000	—
Unrealized loss on hedging activities	—	211,000
Non-oil and gas property basis difference	99,000	144,000
Total deferred tax assets	38,791,000	40,498,000
Deferred tax liabilities:		
Oil and gas property basis difference	13,273,000	2,821,000
Unrealized gain on hedging activities	9,000	—
Total deferred tax liabilities	13,282,000	2,821,000
Total deferred tax asset	25,509,000	37,677,000
Valuation allowance	(25,509,000)	(37,677,000)
Net deferred tax asset (liability)	$ —	$ —

The Company has an available tax net operating loss carry forward estimated at approximately $95,933,000 as of December 31, 2006. This carryforward will begin to expire in the year 2012. A valuation allowance has been provided at December 31, 2006 and 2005 because it is management's belief, based upon the Company's past history of no taxable income, it is more likely than not the net deferred tax asset will not be realized.

12. EARNINGS PER SHARE

A reconciliation of the components of basic and diluted net income per common share is presented in the table below:

	2006			2005		
	Income	Shares	Per Share	Income	Shares	Per Share
Basic:						
Net income	$27,808,000	32,789,280	$0.85	$10,895,000	30,329,682	$0.36
Effect of dilutive securities:						
Stock options and awards	—	1,146,794		—	2,171,782	
Diluted:						
Net income	$27,808,000	33,936,074	$0.82	$10,895,000	32,501,464	$0.34

Options to purchase 200,000 shares at $11.20 per share were excluded from the calculation of dilutive earnings per share for the year ended December 31, 2006 because they were anti-dilutive. Options to purchase 120,000 shares at $9.07 per share and 200,000 shares at $11.20 per share were excluded from the calculation of dilutive earnings per share for the year ended December 31, 2005 because they were anti-dilutive.

13. FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Oil Price Hedging Activities

The Company established an oil price-hedging program in August 2005. The Company seeks to reduce its exposure to unfavorable changes in oil prices, which are subject to significant and often volatile fluctuation, by taking receive-fixed positions in price swap contracts. The Company pays the counterparty the excess of the oil market price over the fixed price and will receive the excess of the fixed price over the market price as defined in each contract. These contracts allow the Company to predict with greater certainty the effective oil prices to be received for hedged production and benefit operating cash flows and earnings when market prices are less than the fixed prices provided in the contracts. However, the Company will not benefit from market prices that are higher than the fixed prices in the contracts for hedged production. For the years ended December 31, 2006 and 2005, price swap contracts hedged 62% and 8.7% of the Company's oil production, respectively. As December 31, 2005, price swap contracts were in place to hedge 540,000 barrels ("Bbls") of estimated future production during 2006. There were no price swap contracts in place as of December 31, 2006.

The Company's price swap contracts were tied to commodity prices on the New York Mercantile Exchange ("NYMEX"). The Company received the fixed price amount stated in the contract and paid to its counterparty the current market price for oil as listed on the NYMEX West Texas Index (WTI). However, due to the geographic location of the Company's assets and the cost of transporting oil to another market, the amount that the Company receives when it actually sells its oil differs from the index price. The difference between oil prices on the NYMEX WTI and average price received by the Company during the month for its oil is referred to as a basis differential.

The following table summarizes the estimated volumes, fixed prices, fixed-price sales and fair value attributable to the price swap contracts as of December 31, 2005.

	Year Ending December 31, 2005
Contract volumes (Bbls)	540,000
Weighted average fixed price per Bbls	$ 64.05
Fixed-price sales	$34,587,000
Fair value, of hedging (assets)	$ 621,000

The estimates of fair value of the price swap contracts are computed based on the difference between the prices provided by the price swap contracts and forward market prices as of the specified date, as adjusted for basis differentials. Forward market prices for oil are dependent upon supply and demand factors in such forward market and are subject to significant volatility. The fair value estimates shown above are subject to change as forward market prices and basis change.

All price swap contracts have been executed in connection with the Company's oil price hedging program. The differential between the fixed price and the floating price for each contract settlement period multiplied by the associated contract volume is the contract profit or loss. For price swap contracts qualifying as cash flow hedges pursuant to SFAS 133, the realized contract profit or loss is included in oil sales in the period for which the underlying production was hedged. For the years ended December 31, 2006 and 2005, there were net realized losses of $1,008,000 and $26,000 under price swap contracts, respectively, which are included in oil sales on the consolidated statements of operations. The losses for the year ended December 31, 2006 included $191,000 of gains that had previously been deferred within accumulated other comprehensive income and are further discussed in the subsequent paragraph.

The Company's oil production was shut-in during the fourth quarter of 2005 and for a portion of the first quarter of 2006 due to Hurricane Rita's impact on the Company's facilities. In accordance with SFAS 133 Derivative Implementation Group Issue Number G3, certain extenuating circumstances that impact the timing of the forecasted transaction and are outside the control or influence of the Company permit the gain or loss related to the cash flow hedge being reported in accumulated other comprehensive income until the forecasted transaction is recognized in earnings. As a result, all fourth quarter 2005 and first quarter 2006 contract profits and losses (net gain of $114,000 and $77,000, respectively) remained in accumulated other comprehensive income at March 31, 2006. During the second quarter of 2006, production was restored and the Company recognized gains of $47,000 in the second quarter of 2006. The remaining deferred gain of $144,000 was recognized during the third quarter of 2006.

For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of SFAS 133, changes in fair value are recognized in accumulated other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value resulting from ineffectiveness is recognized immediately in earnings. During the year ended December 31, 2006, a gain of $24,000 was recognized into earnings resulting from hedge ineffectiveness.

In October 2006, the company terminated the remaining three months of its hedging contracts. Through the termination of these remaining contracts the Company received a total of $566,000 of proceeds during the fourth quarter of 2006 resulting from the differential in the fixed hedged price of $64.05 per barrel and the market prices of the associated futures contracts at the date of the termination of these contracts. In accordance with SFAS 133, these amounts were recognized into earnings during the fourth quarter of 2006, the period in which the hedged forecasted transactions occurred. The Company has no derivative contracts at December 31, 2006.

14. OPERATING LEASES

The Company began leasing the Louisiana building that it owns in October 2006. The cost of the building totaled approximately $217,000 and accumulated depreciation amounted to approximately $68,000 as of December 31, 2006. The lease commended on October 15, 2006 and expires October 14, 2009, with equal monthly installments of $10,500. The future minimum lease payments to be received are as follows:

Fiscal year ending December 31	
2007	$126,000
2008	126,000
2009	94,500
	$346,500

15. RELATED PARTY TRANSACTIONS

In the ordinary course of business, the Company conducts business activities with certain of its significant shareholders.

Certain personnel of the Company perform management and administrative services for affiliate companies. The Company is reimbursed for salaries and benefits of these individuals based on the estimated time spent on those affiliates compared to time spent on the Company. For the years ended December 31, 2006 and 2005, expenses reimbursed to the Company under this arrangement and reflected as a reduction to general and administrative expense were $12,738,000 and $6,232,000, respectively.

Windsor Energy Group ("WEG"), an affiliate of Gulfport, operates the Marquiss wells in Wyoming. At December 31, 2006, the Company owed WEG approximately $225,000 related to operation of these wells.

Athena Construction LLC ("Athena"), an affiliate of Gulfport, performs services for our WCBB and Hackberry fields. At December 31, 2006, the Company owed Athena approximately $1,045,000 related to these services.

16. COMMITMENTS

Plugging and Abandonment Funds

In connection with the acquisition in 1997 of the remaining 50% interest in the WCBB properties, the Company assumed the seller's (Chevron) obligation to contribute approximately $18,000 per month through March 2004, to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until abandonment obligations to Chevron have been fulfilled. Beginning in 2009, the Company can access the trust for use in plugging and abandonment charges associated with the property. As of December 31, 2006, the plugging and abandonment trust totaled approximately $2,983,000, including interest received during 2006 of approximately $105,000. The Company has plugged 231 wells at WCBB since it began its plugging program in 1997, which management believes fulfills its minimum plugging obligation through March 31, 2007.

Texaco Global Settlement

Pursuant to the terms of a global settlement between Texaco and the State of Louisiana which includes the State Lease No. 50 portion of Gulfport's East Hackberry Field, Gulfport was obligated to commence drilling a well or other qualifying development operation on certain non-producing acreage in the field prior to March 1998. Because of prevailing market conditions during 1998, the Company believed it was commercially impractical to shoot seismic or commence drilling operations on the subject property. As a result, Gulfport has agreed to surrender approximately 440 non-producing acres in this field to the State of Louisiana. At December 31, 2006, Gulfport was in the process of releasing these properties to the State of Louisiana.

Contributions to 401(k) Plan

Gulfport sponsors a 401(k) and Profit Sharing plan under which eligible employees may contribute up to 15% of their total compensation through salary deferrals. Also under these plans, the Company will make a contribution each calendar year on behalf of each employee equal to at least 3% of his or her salary, regardless of the employee's participation in salary deferrals. During the years ended December 31, 2006 and 2005, Gulfport incurred $308,000 and $144,000, respectively, in contributions expense related to this plan.

Employment Agreement

At December 31, 2006, Gulfport has an employment agreement with its Chairman of the Board. This agreement expired May 31, 2004 and automatically renews for a one year term until May 31, 2009, and called for an annual salary of $200,000, which may be adjusted for cost of living increases.

17. CONTINGENCIES

The Louisiana State Mineral Board ("LSMB") is disputing Gulfport's royalty payments to the State of Louisiana resulting from the sale of oil under fixed price contracts. The LSMB maintains that Gulfport paid approximately $1,400,000 less in royalties under the fixed price contracts than the royalties Gulfport would have had to pay had it sold the oil at prevailing market rates. Gulfport has denied any liability to the LSMB for underpayment of royalties and has maintained that it was entitled to enter into the fixed price contracts with unrelated third parties and pay royalties based upon the sales proceeds from those contracts. In May 2006, Gulfport offered to settle the claim for $180,000 which has been accrued in accounts payable and accrued liabilities in the accompanying balance sheet. The LSMB rejected the offer, but continues to participate in discussions to resolve this dispute. Gulfport continues to believe that the dispute will be satisfactorily resolved, either through settlement, litigation or arbitration.

Other Litigation

In November 2006, Cudd Pressure Control, Inc. ("Cudd") filed a lawsuit against Gulfport and Great White Pressure Control LLC, an affiliate of the Company, among others, in the 129th Judicial District Harris County, Texas. The lawsuit alleges RICO violations and several other causes of action relating to an affiliate company's employment of several former Cudd employees. The defendants in the suit are Ronnie Roles, Rocky Roles, Steve Winters, Bert Ballard, Nelson Britton, Michael Fields, Steve Bickle, Great White Pressure Control LLC and Gulfport. On stipulation by the parties, Plaintiff's RICO claim was dismissed without prejudice by order on February 14, 2007. A pretrial conference is set for April 2, 2007, regarding the remaining allegations. Gulfport will file its initial answer prior to the pretrial conference.

In October 2006, an accident occurred north of the Company's production facilities in the WCBB field in southern Louisiana involving two contracted vessels that were performing work on behalf of the Company in the field. A tugboat, the M/V Miss Megan, and two barges laden with construction materials ruptured an underwater natural gas pipeline and a subsequent fire damaged the vessels. Six fatalities resulted from the accident. The accident is currently under investigation by the NTSB and USCG; however, the following lawsuits relating to this incident have been filed:

- On October 13, 2006, Athena, the owner of the two barges, filed a limitation action in the United States District Court for the Eastern District of Louisiana, alleging that all losses and damages as a result of the pipeline incident were incurred without fault on its part. Furthermore, Athena claims the benefit of the limitation of liability provided for in 42 U.S.C. § 183 and seeks an injunction restraining filing commencement and further prosecution in any court of any lawsuit against Athena related to the pipeline incident. The limitation of liability action was subsequently transferred to the United States District Court for the Western District of Louisiana, which is where the case remains pending. On December 20, 2006, 4-K Marine LLC, as owner of the M/V Miss Megan, and Central Boat Rentals, Inc., as operator of the M/V Miss Megan also filed a limitation action in the western District. On January 10, 2007, the Athena and the 4-K/Central Boat limitation proceedings were consolidated by order of the Court.
- On October 16, 2006, a lawsuit was filed in the 16th Judicial District Court for the Parish of St. Mary, Louisiana against Gulfport, Athena and Central Boat seeking compensatory and punitive damages for claims related to the death of the plaintiff's husband, a crewmember on the Athena barge. The suit alleges that the husband's death was caused by the defendants' negligence and the unseaworthiness of the barge to which he was assigned. Under the Blanket Time Charter between Gulfport and Central Boat, Central Boat tendered the defense and indemnification of the lawsuit to Gulfport. The Company was served in November 2006. On November 2, 2006, all proceedings were stayed as a result of the limitation of liability action discussed above.
- On October 22, 2006, a lawsuit was filed in United States District Court for the Southern District of Texas, Galveston Division against Gulfport, Central Boat, Diamondback Energy Services LLC, an affiliate of Gulfport, Chevron Pipeline Company, Chevron USA, Inc., and ChevronTexaco Pipeline Holdings, Inc. This lawsuit is a result of the death of three individuals. These individuals were employed by Athena and were on the Athena barge at the time of the accident. The plaintiffs seek compensatory and punitive damages as a result of the alleged negligence of defendants. Central Boat has tendered the defense and indemnification of this lawsuit to Gulfport. A joint motion to transfer venue to the Western District of Louisiana was filed on December 28, 2006. The court denied the motion to transfer by order dated February 2, 2007. On February 12, 2007, a joint motion for new trial and/or rehearing was filed by the defendants requesting the court to reconsider its denial of the prior motion to transfer. The plaintiffs have filed an opposition and the motion is currently pending.
- On February 2, 2007, a lawsuit was filed in the United States District Court for the Western District of Louisiana, Lafayette Division against Chevron Pipeline Company, Chevron USA Inc., Chevron Texaco Pipeline Holdings, Inc., Chevron Natural Gas Services Inc., Diamondback Energy Services LLC, an affiliate of Gulfport, and Gulfport. The suit was filed on behalf of April Hummel, individually and as the representative of the minor, Aleya Hummel, the surviving child of Terry Abraham. The Company obtained an informal extension to file responsive pleadings by March 26, 2007. No other deadlines have been set.
- On January 11, 2007, plaintiffs Janet Rink, individually and as the personal representative of the Estate of Kenneth Rink, Tysie Rink and Scott Rink filed a lawsuit in the United States District Court for the

Western District of Louisiana against defendants Chevron Pipeline Company, Chevron USA, Inc., ChevronTexaco Pipeline Holdings, Inc., Chevron Natural Gas Services, Inc., the Company and Diamondback Energy Services LLC, an affiliate of Gulfport. In this action, the plaintiffs allege the fault, negligence, unseaworthiness and/or strict liability of defendants in the death of Kenneth Rink, a crew member on one of the Athena barges, and seek unspecified damages. Gulfport obtained an indefinite information extension of time to file responsive pleadings. No other deadlines have been set.

Due to the early stages of the above litigation the outcome is uncertain and management cannot determine the amount of loss, if any, that may result.

The Company has been named as a defendant on various other litigation matters. The ultimate resolution of these matters is not expected to have a material adverse effect on the Company's financial condition or results of operations for the periods presented in the consolidated financial statements.

Concentration of Credit Risk

Gulfport operates in the oil and gas industry principally in the state of Louisiana with sales to refineries, re-sellers such as pipeline companies, and local distribution companies. While certain of these customers are affected by periodic downturns in the economy in general or in their specific segment of the oil and gas industry, Gulfport believes that its level of credit-related losses due to such economic fluctuations has been immaterial and will continue to be immaterial to the Company's results of operations in the long term.

The Company maintains cash balances at several banks. Accounts at each institution are insured by the Federal Deposit Insurance Corporation up to $100,000. At December 31, 2006, Gulfport held cash in excess of insured limits in these banks totaling $6,307,000.

During the year ended December 31, 2006, approximately 100% of Gulfport's oil sales and 96% of Gulfport's gas sales were attributable to two purchasers: Shell and Chevron, respectively. During the year ended December 31, 2005, Gulfport sold 99% of its oil production to Shell and 88% of its gas production to Chevron.

18. LITIGATION TRUST ENTITY

Pursuant to the Company's 1997 plan of reorganization, all of Gulfport's possible causes of action against third parties (with the exception of certain litigation related to recovery of marine and rig equipment assets and claims against Tri-Deck), existing as of the effective date of that plan, were transferred into a "Litigation Trust" controlled by an independent party for the benefit of most of the Company's existing unsecured creditors. The litigation related to recovery of marine and rig equipment and the Tri-Deck claims were subsequently transferred to the Litigation Trust as described below.

The Litigation Trust was funded by a $3,000,000 cash payment from the Company, which was made on the effective date of reorganization. Gulfport owns a 12% interest in the Litigation Trust with the other 88% being owned by the former general unsecured creditors of Gulfport. For financial statement reporting purposes, Gulfport has not recognized the potential value of recoveries which may ultimately be obtained, if any, as a result of the actions of the Litigation Trust, treating the entire $3,000,000 payment as a reorganization cost at the time of Gulfport's reorganization.

On January 20, 1998, Gulfport and the Litigation Trust entered into a Clarification Agreement whereby the rights to pursue various claims reserved by Gulfport under the plan of reorganization were assigned to the Litigation Trust. In connection with this agreement, the Litigation Trust agreed to reimburse the Company

$100,000 for legal fees Gulfport had incurred in connection with these claims. As additional consideration for the contribution of this claim to the Litigation Trust, Gulfport is entitled to 20% to 80% of the net proceeds from these claims.

No proceeds were received from the Litigation Trust for the years ended December 31, 2006 and 2005. The Company does not have knowledge of the amount or timing of any future proceeds.

19. SUBSEQUENT EVENTS

On January 30, 2007, the Company sold 1,150,000 shares of common stock in an underwritten offering at an offering price to the public of $11.92 per share. In connection with the offering, the Company granted the underwriter an option to purchase up to an additional 172,500 shares of common stock to cover any over-allotments, which the underwriter exercised in full on February 1, 2007. Gulfport received the net proceeds of approximately $15.3 million from the sale of these shares on February 5, 2007 after deducting the underwriting discount and before offering expenses. These net proceeds were used to pay down existing debt under the Company's credit facility.

20. SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES

The following is historical revenue and cost information relating to the Company's oil and gas operations located entirely in the southeastern United States:

Capitalized Costs Related to Oil and Gas Producing Activities

	2006	2005
Proven Properties	$249,379,000	$173,022,000
Unproven Properties	1,459,000	113,000
	250,838,000	173,135,000
Accumulated depreciation, depletion amortization and impairment reserve	(97,574,000)	(85,315,000)
Net capitalized costs	$153,264,000	$ 87,820,000

Costs Incurred in Oil and Gas Property Acquisition and Development Activities

	2006	2005
Acquisition	$ —	$ 376,000
Development of Proved Undeveloped Properties	41,770,000	19,783,000
Exploratory	8,607,000	4,382,000
Recompletions	4,235,000	5,593,000
Capitalized Asset Retirement Obligation	405,000	1,382,000
Total	$55,017,000	$31,516,000

Results of Operations for Producing Activities

The following schedule sets forth the revenues and expenses related to the production and sale of oil and gas. The income tax expense is calculated by applying the current statutory tax rates to the revenues after deducting costs, which include depreciation, depletion and amortization allowances, after giving effect to the permanent differences. The results of operations exclude general office overhead and interest expense attributable to oil and gas production.

	2006	2005
Revenues	$ 60,232,000	$ 27,423,000
Production costs	(18,036,000)	(11,276,000)
Depletion	(12,259,000)	(4,468,000)
	29,937,000	11,679,000
Income tax expense		
Current	—	—
Deferred	—	—
	—	—
Results of operations from producing activities	$ 29,937,000	$ 11,679,000
Depletion per BOE	$ 12.48	$ 7.29

Oil and Gas Reserves (Unaudited)

The following table presents estimated volumes of proven developed and undeveloped oil and gas reserves as of December 31, 2006 and 2005 and changes in proven reserves during the last two years, assuming continuation of economic conditions prevailing at the end of each year. Volumes for oil are stated in thousands of barrels (MBbls) and volumes for gas are stated in millions of cubic feet (MMcf). The weighted average prices at December 31, 2006 used for reserve report purposes are $57.75 and $5.64, adjusted by lease for transportation fees and regional price differentials, and for oil and gas reserves, respectively.

Gulfport emphasizes that the volumes of reserves shown below are estimates which, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data, as well as production performance data. These estimates are reviewed annually and revised, either upward or downward, as warranted by additional performance data.

	2006		2005	
	Oil	Gas	Oil	Gas
Proven Reserves				
Beginning of the period	19,542	21,781	20,905	23,162
Purchases in oil and gas reserves in place	—	—	—	—
Revisions of prior reserve estimates	1,020	(303)	(846)	(806)
Current production	(870)	(677)	(517)	(575)
End of period	19,692	20,801	19,542	21,781
Proven developed reserves	4,876	4,077	4,308	3,758

Discounted Future Net Cash Flows (Unaudited)

Estimates of future net cash flows from proven oil and gas reserves were made in accordance with SFAS No. 69, "Disclosures about Oil and Gas Producing activities." The following tables present the estimated future cash flows, and changes therein, from Gulfport's proven oil and gas reserves as of December 31, 2006 and 2005, assuming continuation of economic conditions prevailing at the end of each year.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proven Oil and Gas Reserves (Unaudited)

	Year ended December 31,	
	2006	2005
Future cash flows	$1,296,729,000	$1,380,555,000
Future development and abandonment costs	(193,543,000)	(174,462,000)
Future production costs	(261,955,000)	(234,508,000)
Future production taxes	(155,566,000)	(172,282,000)
Future income taxes	(93,569,000)	(172,045,000)
Future net cash flows	592,096,000	627,258,000
10% discount to reflect timing of cash flows	(239,448,000)	(257,434,000)
Standardized measure of discounted future net cash flows	$ 352,648,000	$ 369,824,000

In order to develop it's proved undeveloped reserves according to the drilling schedule used by the engineers in Gulfport's reserve report, the Company will need to spend $35,812,000, $32,182,000 and $16,851,000 during years 2007, 2008 and 2009, respectively.

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proven Oil and Gas Reserves (Unaudited)

	Year ended December 31,	
	2006	2005
Sales and transfers of oil and gas produced, net of production costs	$(42,196,000)	$ (16,147,000)
Net changes in prices and production costs	(67,273,000)	126,255,000
Revisions of previous quantity estimates, less related production costs	14,419,000	(14,869,000)
Accretion of discount	36,982,000	30,105,000
Net changes in income taxes	40,282,000	(26,591,000)
Change in production rates and other	610,000	(29,976,000)
Total change in standardized measure of discounted future net cash flows	$(17,176,000)	$ 68,777,000

Exhibit 31.1

CERTIFICATION

I, James D. Palm, Chief Executive Officer of Gulfport Energy Corporation, certify that:

1. I have reviewed this annual report on Form 10-KSB of Gulfport Energy Corporation;

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

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

4. The small business issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the small business issuer and have:

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

   b) evaluated the effectiveness of the small business issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

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

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

   a) all significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the small business issuer's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the small business issuer's internal controls over financial reporting.

Date: March 30, 2007

/s/ James D. Palm

James D. Palm
Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Michael G. Moore, Chief Financial Officer of Gulfport Energy Corporation, certify that:

1. I have reviewed this annual report on Form 10-KSB of Gulfport Energy Corporation;

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

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

4. The small business issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the small business issuer and have:

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

   b) evaluated the effectiveness of the small business issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

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

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

   a) all significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the small business issuer's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the small business issuer's internal controls over financial reporting.

Date: March 30, 2007

/s/ Michael G. Moore

Michael G. Moore
Chief Financial Officer

Exhibit 32.1

CERTIFICATION OF PERIODIC REPORT

I, James D. Palm, Chief Executive Officer of Gulfport Energy Corporation (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) the Annual Report on Form 10-KSB of the Company for the period ended December 31, 2006 (the "Report") fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

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

Date: March 30, 2007

/s/ James D. Palm

James D. Palm
Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION OF PERIODIC REPORT

I, Michael G. Moore, Chief Financial Officer of Gulfport Energy Corporation (the “Company”), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) the Annual Report on Form 10-KSB of the Company for the year ended December 31, 2006 (the “Report”) fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

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

Date: March 30, 2007

/s/ Michael G. Moore

Michael G. Moore
Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Board of Directors

Robert E. Brooks* David L. Houston* Mike Liddell
James D. Palm Scott E. Streller*

*Independent Directors

Annual Meeting

The Annual Meeting of Shareholders is scheduled to be held at 10:00 a.m. on June 13, 2007 at the company headquarters at 14313 North May Avenue, Oklahoma City, OK

Transfer Agent

For information regarding change of address, lost certificates or similar inquiries, please contact our transfer agent:

UMB Bank
928 Grand Boulevard
Kansas City, MO 64106
(800) 884-4225

Market Information

Gulfport Energy's common stock is traded on the NASDAQ Global Select Market under the symbol GPOR

Independent Registered Public Accounting Firm

Grant Thornton

More Information

Anyone interested in company presentations, press releases and other materials can find such documents, request copies and sign up for email alerts through our website, www.gulfportenergy.com

For additional information concerning Gulfport Energy's operations or financial results, please contact: John Kilgallon, Director, Investor Relations and Corporate Affairs, 405.242.4474

Stock Trading History

	2006		2005	
	High	Low	High	Low
First Quarter	$16.00	$10.00	$5.90	$3.24
Second Quarter	15.89	9.90	6.90	5.00
Third Quarter	13.64	9.82	11.50	6.70
Fourth Quarter	14.11	9.95	13.00	9.10

Left to Right:
Mike Moore, Chief Financial Officer
Mike Liddell, Chairman of the Board
Jim Palm, Chief Executive Officer

GULFPORT ENERGY CORPORATION

GULFPORT ENERGY CORPORATION
14313 NORTH MAY AVENUE
OKLAHOMA CITY, OK 73134
(405) 848-8807