GULFPORT ENERGY CORP
Form 10-K
March 16, 2009
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

x **ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2008

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

(Exact Name of Registrant as Specified 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

(Registrant s Telephone Number, Including Area Code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	**The NASDAQ Stock Market LLC**

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (Section 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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

Large Accelerated filer ¨ Accelerated filer x Non-accelerated filer ¨ Smaller reporting company ¨

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

The aggregate market value of the voting and non-voting common stock held by non-affiliates of the registrant computed as of June 30, 2008, based on the closing price of the common stock on the NASDAQ Global Select Market on June 30, 2008, the last business day of the registrant s most recently completed second fiscal quarter ($16.47 per share) was $701,877,647.

As of March 1, 2009, 42,647,034 shares of the registrant s common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Gulfport Energy Corporation s Proxy Statement for the 2009 Annual Meeting of Stockholders are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K.

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FORWARD-LOOKING STATEMENTS

Our disclosure and analysis in this Form 10-K 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, proj and similar expressions intended to identify forward-looking statements. All statements, other than statements of historical facts, included in this Form 10-K 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-K 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-K. All forward-looking statements speak only as of the date of this Form 10-K. 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.

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PART I

ITEM 1. DESCRIPTION OF BUSINESS

General

We are an independent oil and natural gas exploration and production company with our principal producing properties located along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields, and in West Texas in the Permian Basin. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, or Grizzly, and in the Bakken Shale, and have interests in entities that operate in Southeast Asia, including the Phu Horm gas field in Thailand. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

In 2008, at our WCBB field, we drilled eight wells and recompleted 48 existing wells for a total cost of approximately $31.0 million as of December 31, 2008. Of our eight new wells drilled at WCBB in 2008, seven were completed as producing wells and one was non-productive. During 2009, we currently anticipate drilling four wells and recompleting 20 wells at our WCBB field for an estimated aggregate cost of $7.5 to $8.5 million. In December 2008, production at WCBB was 109,292 net barrels of oil equivalent, or BOE, or an average of 3,526 BOE per day, 98% of which was from oil and 2% of which was from natural gas. From January 1, 2009 through March 9, 2009, our average net daily production at WCBB was 3,037 BOE, 99% of which was from oil and 1% of which was from natural gas.

In 2008, at our East Hackberry field, we drilled five wells and recompleted seven existing wells for a total cost of approximately $18.0 million as of December 31, 2008. All five wells drilled during 2008 were completed as producing wells. During 2009, we currently anticipate drilling four land wells and recompleting three wells for an aggregate estimated cost of $4.5 to $5.5 million. In December 2008, net production at East Hackberry was 12,243 BOE, or an average of 395 BOE per day, 98% of which was from oil and 2% of which was from natural gas. From January 1, 2009 through March 9, 2009, our average net daily production at East Hackberry was 439 BOE, 95% of which was from oil and 5% of which was from natural gas.

On December 20, 2007, we completed the acquisition of strategic assets in West Texas in the Permian Basin for approximately $83.8 million, with an effective date of November 1, 2007. Through this transaction, we acquired 4,100 net acres with production at the time of acquisition of approximately 800 net BOE a day from 32 gross wells, predominately from the Wolfcamp formation. In 2008, 31 gross (15.5 net) wells were drilled on this acreage, including one gross well spud in 2007 and completed in 2008 and one Henry Petroleum operated well for a total cost of approximately $33.9 million. As of March 1, 2009, 29 of the 31 wells had been completed and the other two wells were awaiting completion. We currently anticipate drilling three gross (1.5 net) wells on this acreage in 2009 for an estimated average completed gross well cost of $1.34 million. In December 2008, net production from our Permian acreage was 26,943 BOE, or an average of 869 BOE per day, 84% of which was from oil and natural gas liquids and 16% of which was from natural gas. From January 1, 2009 through March 9, 2009, our average daily net production from our Permian acreage was 725 BOE per day, 83% of which was from oil and natural gas liquids and 17% of which was from natural gas.

During the third quarter of 2006, we, through our wholly owned subsidiary Grizzly Holdings Inc., purchased a 24.9999% interest in Grizzly. The remaining interests in Grizzly are owned by entities controlled by Wexford Capital LLC, or Wexford. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray near other oil sands development projects. Grizzly has approximately 511,000 acres under lease and our total net investment in Grizzly was $21.9 million at December 31, 2008. During the 2006/2007 and 2007/2008 winter delineation drilling seasons, Grizzly drilled an aggregate of 117 core holes, tested five separate lease blocks using up to four different rigs and undertook a seismic program. Grizzly s 2009 plans currently include drilling 15 additional core holes, which were completed in the first quarter of 2009 for approximately $4.3 million.

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During 2005, we purchased a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex. The remaining interests in Tatex are owned by entities controlled by Wexford. Tatex, a privately held entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC, or 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 2005, we purchased a 20% ownership interest in Windsor Bakken, LLC, or Bakken. The remaining interests in Bakken are owned by entities controlled by Wexford. In 2006, Bakken acquired leases for undeveloped acreage in the Williston Basin area of western North Dakota and eastern Montana. Effective January 1, 2008, we acquired a direct, undivided 20% interest in Bakken s assets in redemption of our 20% interest in Bakken. As of December 31, 2008, we had participated, or committed to participate, in 53 gross wells in the Williston Basin with an average working interest of 2.52%. In December 2008, net production from this acreage was 8,692 BOE, or an average of 280 BOE per day. From January 1, 2009 through March 9, 2009, our average net daily production from this acreage was 271 BOE and was 100% oil. Plans for 2009 currently include drilling approximately 0.5 net wells for an estimated net cost of $2.5 million.

As of December 31, 2008, we had 25.5 million barrels of oil equivalent, or MMBOE, of proved reserves with a present value of estimated future net revenues, discounted at 10%, or PV-10, of approximately $126.2 million and associated standardized measure of discounted future net cash flows of approximately $126.2 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

The following table presents certain information as of December 31, 2008 reflecting our net interest in our principal producing oil and natural gas properties along the Louisiana Gulf Coast, in the Permian Basin in West Texas and in the Williston Basin.

		Producing Wells (2)		Non-Producing Wells		Developed Acreage (3)		Proved Reserves		
Field	**NRI/WI (1) Percentages**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gas Mboe**	**Oil Mboe**	**Total Mboe**
West Cote Blanche Bay (4)	80.335/100	107	107	158	158	5,668	5,668	2,009	11,391	13,400
E. Hackberry (5)	79.424/100	18	18	80	80	3,291	3,291	282	2,441	2,723
W. Hackberry	87.5/100	3	3	24	24	592	592		132	132
Permian	38.075/49.48	61	30.5			8,075	4,150	1,367	7,028	8,395
Bakken (6)	2.285/2.181	38	0.8			8,153	891	47	776	823
Overrides/Royalty Non-operated	Various	9	.5	17	.8	4,956	586	1	3	4
Total		236	159.8	279	262.8	30,735	15,178	3,706	21,771	25,477

(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. Approximately 42% of our acreage is developed acreage and has been perpetuated by production.

(4) We have a 100% working interest (80.335% average NRI) from the surface to the base of the 13900 Sand which is located at 11,320 feet. Below the base of the 13900 Sand, we have a 40.40% non-operated working interest (29.95% NRI).

(5) NRI shown is for producing wells.

(6) NRI/WI is from wells that have been drilled or in which we have elected to participate.

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West Cote Blanche Bay Field

Location and Land

The WCBB field is located 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 (80.335% 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 40.40% non-operated working interest (29.95% 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 908 wells drilled as of December 31, 2008, 816 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, 2008, we drilled 128 new wells, 15 of which were non-productive, for an 88% success rate. As of December 31, 2008, estimated field cumulative gross production was 188.6 MMBOE and 235.9 billion cubic feet, or Bcf, of gas. Of the 908 wells drilled in WCBB as of December 31, 2008, 77 were producing, 158 were shut-in, 30 were producing intermittently and five were being used as salt water disposal wells. The other 638 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 908 wellbores that had been drilled in the field as of December 31, 2008, 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

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that produced from a sub-optimal position within a particular zone. Our inventory of prospects at WCBB as of December 31, 2008 included 81 PUD wells. The drilling schedule used in the reserve report anticipates that all of those wells will be drilled by 2019.

Facilities

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

Recent and Future Activity

In 2008, we drilled eight wells and recompleted 48 existing wells at WCBB. Of these eight new wells, seven were completed as producers, and one was non-productive. As of March 1, 2009, we had recompleted seven wells during 2009. Of the eight wells drilled in 2008, all eight were considered deep wells. The seven productive wells, with total depths ranging from 6,900 to 9,600 feet, have approximately 824 feet of aggregate apparent net pay. We currently anticipate drilling four wells and recompleting 20 wells at WCBB during 2009.

Production Status

In December 2008, production at WCBB was 109,292 net BOE, or an average of 3,526 BOE per day, 98% of which was from oil and 2% of which was from natural gas. From January 1, 2009 through March 9, 2009, our average net daily production at WCBB was 3,037 BOE, 99% of which was from oil and 1% of which was from natural gas.

East Hackberry Field

Location and Land

The East Hackberry field in Louisiana is located along the western shore and the land surrounding Lake Calcasieu, 15 miles inland from the Gulf of Mexico. We own a 100% working interest (approximately 79.424% average NRI) in certain producing oil and natural gas properties situated in the East Hackberry field. We hold beneficial interests in approximately 7,233 acres, including 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.

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 2008 was over 409,701 barrels of oil and 330 Bcf of casinghead gas production. A total of 187 wells have been drilled on our portion of the field. As of December 31, 2008, 18 wells had daily production, 80 were shut-in and two had been converted to salt water disposal wells. The remaining 86 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.

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Facilities

We have a field office that serves both the East and West Hackberry fields. In addition, we completed installation of a new production barge at the East Hackberry field in the second quarter of 2007. 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 this 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. During 2008 at East Hackberry, we drilled four land wells and one well on water and recompleted seven existing wells. All of the five wells drilled during 2008 were completed as producing wells. As of March 1, 2009, we had recompleted three wells during 2009. We currently intend to drill four land wells and have recompleted three wells at East Hackberry during 2009.

Production Status

In December 2008, net production at East Hackberry was 12,243 BOE, or an average of 395 BOE per day, 98% of which was from oil and 2% of which was from natural gas. From January 1, 2009 through March 9, 2009, our average net daily production at East Hackberry was 439 BOE, 95% of which was from oil and 5% of which was from natural gas. Production has increased since year end as a result of mechanical well enhancements.

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 2008 was 242 MBOE 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 2008, net production at West Hackberry was 763 BOE, or 25 BOE per day. From January 1, 2009 through March 9, 2009, our average net daily production at West Hackberry was 34 BOE and was 100% oil.

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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.

Permian Basin (West Texas)

Location and Land

We acquired approximately 4,100 net acres in West Texas (near Midland) in the Permian Basin on December 20, 2007, effective date as of November 1, 2007, from ExL Petroleum, LP and certain other sellers. The Permian Basin area covers a significant portion of western Texas and eastern New Mexico and is considered one of the major producing basins in the United States. The terrain in the Permian Basin is semi-arid mesquite-mixed grassland steppe. Windsor Energy is the operator of this field.

Area History

The Permian Basin formed as an area of rapid Mississippian-Pennsylvanian subsidence in the foreland of the Ouachita Foldbelt. The Wolfcamp play was a long-established reservoir in West Texas, first found in the 1950s as wells aiming for deeper targets occasionally intersected slump blocks or reef facies with reservoir properties. Exploration with 2-D seismic located additional fields, but it was not until the use of 3-D seismic in the 1990s that the greater extent of the Wolfcamp prospects was revealed. During the late 1990s, Arco began a drilling program targeting the Spraberry formation at 10,000 feet and then drilled another 200 to 300 feet to pick up the upper part of the Wolfcamp formation. Henry Petroleum, a private firm, owned interest in the Pegusas field in Midland and Upton counties. While drilling in the same area as the Arco project, Henry Petroleum decided to drill completely through the Wolfcamp section as Devonian wells. Henry Petroleum mapped the trend and began acquiring acreage and drilling wells using multiple slick-water fracs across the entire Wolfcamp interval. In 2005, former members of Henry Petroleum s Wolfcamp team formed their own private company, ExL Petroleum, and began replicating Henry Petroleum s program. After ExL had drilled 32 productive Wolfcamp/Spraberry wells through late 2007, they decided to monetize approximately 15% of their acreage position which enabled us to participate in this play. Recent advancements in enhanced recovery techniques continue to make the basin an active play for exploration and production companies. Currently, we hold interests in 61 gross producing wells.

Geology

The Wolfcamp/Spraberry play, which we refer to as Wolfberry, of the Midland Basin lies in the area where the historically productive Spraberry trend geographically overlaps the productive area of the emerging Wolfcamp carbonate play. The Wolfcamp is characterized by an approximately 2,000 feet section of organic rich basin floor debris flows shed from the Central Basin Platform. The best reservoir rock within the section is generally found in close proximity to the Central Basin Platform.

Wolfberry well reserves are typically approximately 80% from the Wolfcamp section and 20% from the Spraberry section. Pinnacle Energy Services, LLC, an independent petroleum engineering firm, has estimated that at December 31, 2008, proved reserves net to our interest in these assets were approximately 8.4 million BOE, of which 25% were classified as proved developed producing, or PDP. Proved undeveloped, or PUD, reserves included in this estimate were from 115 gross well locations on 40-acre units. The proved reserves are located in the Wolfcamp and Spraberry formations, which are generally characterized as long-lived, with predictable production profiles. The gross estimated ultimate recovery, or EUR, as estimated by Pinnacle Energy Services, LLC, is expected to average gross 145,000 BOE per well or approximately 55,000 BOE net to our interest.

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Production Status

In December 2008, net production from the Permian field was 26,943 BOE or an average of 869 BOE per day, 59% of which was oil, 25% was natural gas liquids and 16% was natural gas. From January 1, 2009 through March 9, 2009, our average daily net production from our Permian acreage was 725 BOE per day, 83% of which was from oil and natural gas liquids and 17% of which was from natural gas. As a result of the cessation of drilling, fracing and recompletion activities, production has decreased since year end due to normal production declines.

Facilities

There are typical land oil and gas processing facilities in the Permian Basin. Our facilities located at well locations include storage tank batteries, oil/gas/water separation equipment and pumping units.

Recent and Future Activity

In 2008, 31 gross (15.5 net) wells were drilled in our Permian acreage, including one gross well spud in 2007 and completed in 2008 and one Henry Petroleum operated well. We have identified 147 gross future development drilling locations. We currently expect an estimated three gross (1.5 net) wells to be drilled on our acreage in 2009. The wells are expected to be drilled to approximately 10,200 feet at an estimated average completed gross well cost of $1.34 million.

Bakken

Location and Land

Bakken is located in the Williston Basin areas of western North Dakota and eastern Montana. During 2005, we purchased a 20% ownership interest in Windsor Bakken, LLC, or Bakken. The remaining interests in Bakken are owned by entities controlled by Wexford. Beginning in 2005, Bakken acquired leases on undeveloped acreage in the Williston Basin. As of December 31, 2007, Bakken had commenced participating in the drilling of some of its undeveloped acreage. Effective January 1, 2008, we acquired a direct, undivided 20% interest in Bakken s assets in redemption of our 20% interest in Bakken. As a result, we currently hold interests in approximately 17,801 net acres, which includes approximately 4,600 acres in Mountrail Country, in the Bakken play.

As of December 31, 2008, we had participated, or committed to participate, in 53 gross wells in the Williston Basin with an average working interest of 2.52%. Windsor Energy, the operator of our acreage, drilled and completed the first two Windsor operated wells in 2008. We own working interests of approximately 15.5% and 3.9%, respectively, in these two wells.

Production Status

In December 2008, net production from the Bakken field was 8,692 BOE, or an average of 280 BOE per day, 100% of which was oil. From January 1, 2009 through March 9, 2009, our average net daily production from this acreage was 271 BOE and was 100% oil.

Facilities

There are typical land oil and gas processing facilities in the Williston Basin. The facilities located at well locations include storage tank batteries, oil/gas/water separation equipment and pumping units.

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Recent and future activities

In 2008, 37 gross (0.95 net) wells were drilled in our Bakken acreage including both those operated by Windsor and other non-operated wells. We have identified 31 gross future development drilling locations. We currently expect an estimated 0.5 net wells to be drilled on our Bakken acreage in 2009. The wells are expected to be drilled to approximately 14,500 total measured depth, or TMD, feet at an estimated average gross completed well cost of $4.7 million.

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%	0	0
Bayou Penchant	Terrebonne	3.125%	0%	2	5
Bayou Pigeon	Iberia	6.250%	0%	4	5
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 2005, we purchased a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex, at a cost of $2.4 million. The remaining interests in Tatex are owned by entities controlled by Wexford. Tatex, a privately held entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC, or 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 the year ended December 31, 2008, we paid $50,000 in cash calls and received $912,000 in distributions, bringing our total investment in Tatex (including previous investments) to $2.7 million. Our investment is accounted for on the equity method. Tatex accounts for its investment in APICO using the cost method. 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. Current net production is approximately 90 Mcf 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). Our gross working interest (through Tatex as a member of APICO) in the Phu Horm field is 0.7%. Estimated proved reserves from the Phu Horm field as of December 31, 2007, net to our interest, are 3.5 BCF of gas and 19,000 barrels of oil. Due to the fact that our ownership in the Phu Horm field is indirect and Tatex s investment in APICO is accounted for by the cost method, these reserves are not included in our year-end reserve information.

Grizzly Oil Sands. During the third quarter of 2006, we, through our wholly-owned subsidiary Grizzly Holdings Inc., purchased a 24.9999% interest in Grizzly. The remaining interests in Grizzly are owned by entities controlled by Wexford. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray near other oil sands development projects. Grizzly has approximately 511,000 acres under lease and our total net investment in Grizzly was $21.9 million at December 31, 2008. During the 2006/2007 and 2007/2008 winter delineation drilling seasons, Grizzly drilled an aggregate of 117 core holes, tested five separate lease blocks and undertook a seismic program. Grizzly s 2009 plans currently include drilling approximately 15 additional core holes, which were completed in the first quarter 2009.

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 from WCBB, other than the production sold under forward sales contracts, is being sold in accordance with the Shell posted price for West Texas/New Mexico Intermediate crude plus or minus Platt s trade month average P+ value, plus or minus the Platt s HLS/WTI trade month average differential less $3.45 per barrel for transportation. During 2008, we sold 87% of our oil production to Shell and 11% to Windsor Energy Group LLC, or Windsor, the operator of the Permian wells, 100% of our natural gas liquids production to Windsor, and 60%, 22%, and 16% of our natural gas production to Chevron, Windsor, and Hilcorp Energy Company, respectively. During 2007, we sold 99% of our oil production to Shell and 69% of our natural gas production to Chevron and 23% of our natural gas production to Hilcorp Energy Company and during 2006, we sold 100% of our oil production to Shell and 96% of our natural gas production to Chevron. There can be no assurance, however, 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.

To mitigate the effects of commodity price fluctuations, during 2008, we were party to forward sales contracts for the sale of 3,500 barrels of WCBB production per day at a weighted average daily price of $78.56 per barrel before transportation costs. We delivered approximately 73% of our 2008 production under these agreements. For the period January through December 2009, we had entered into agreements to sell 3,000 barrels of WCBB production per day at a weighted average daily price of $89.06 per barrel before transportation costs. In December 2008, we terminated these 2009 forward sales contracts in exchange for $39.0 million in cash. Subsequently, we entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $55.17 per barrel, before transportation costs, for the period April 2009 to August 2009. We have also entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs, for the period September 2009 to December 2009. For the period January 2010 through February 2010, we have entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs. For the period March 2010 through December 2010, we have entered into forward sales contracts for the sale of 2,000 barrels of WCBB production per day at a weighted average daily price of $57.35 per barrel, before transportation costs. Under these contracts, we have committed to deliver approximately 50% of our estimated 2009 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. Since these contracts require physical delivery of production quantities, they normally would be exempted from the provisions of SFAS 133 as normal sales of production. However, as a result of the early termination of the contracts in December 2008, we will not be able to apply this election on new contracts and they will be accounted for at fair value until we re-establish a history of physical delivery without early termination. In addition, these arrangements may limit the benefit to us of increases in the price of oil.

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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, West Texas and the Williston Basin. 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 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 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 or relate to our owned or operated facilities. 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 pollution control or 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 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 applicable requirements related to waste handling, 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 released.

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 laws and regulations 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 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. Our air emissions may also soon be affected by rapidly emerging regulation of green house gases, such as carbon dioxide and methane, which are emitted in the course of oil and natural gas exploration and production.

Operational Hazards and Insurance

Our operations are subject to all of the risks normally incident to the production of oil and natural gas, including, but not limited to, 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 or death to persons and wildlife. 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, 2008, we had 37 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, in the past, we have also received 100% of the COPAS overhead charges billed to these affiliated companies. For the years ended December 31, 2008 and 2007, expenses reimbursed to us under these arrangements were $1.4 million and $11.2 million, 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.

Available Information

Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are made available free of charge on the Investor Relations page of our website at www.gulfportenergy.com as soon as reasonably practicable after such material is electronically filed with, or furnished to, the Securities and Exchange Commission, or SEC. Information contained on our website, or on other websites that may be linked to our website, is not incorporated by reference into this annual report on Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

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ITEM 1A. 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, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.28 per barrel, or bbl, in December 2008 to a high of $145.31 per bbl in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $3.53 per million British thermal units, or MMBtu, in September 2006 to a high of $15.52 per MMBtu in January 2006. On December 31, 2008, the West Texas Intermediate posted price for crude oil was $44.60 per bbl and the Henry Hub spot market price of natural gas was $5.63 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.

Declining general economic, business or industry conditions may have a material adverse effect on our results of operations, liquidity and financial condition.

Recently, concerns over inflation, energy costs, geopolitical issues, the availability and cost of credit, the United States mortgage market and a declining real estate market in the United States have contributed to increased economic uncertainty and diminished expectations for the global economy. These factors, combined with volatile prices of oil, natural gas and natural gas liquids, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and a recession. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad continues to deteriorate, demand for petroleum products could

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continue to diminish, which could impact the price at which we can sell our oil, natural gas and natural gas liquids, affect our vendors, suppliers and customers ability to continue operations, and ultimately adversely impact our results of operations, liquidity and financial condition.

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 have made and expect in the future 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 may not have sufficient resources to undertake our exploration, development and production activities or the, acquisition of oil and natural gas reserves, our exploratory projects or other replacement activities may not result in significant additional reserves and we may not 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 at our estimated cost or at all.

During the third quarter of 2006, we, through our wholly owned subsidiary Grizzly Holdings Inc., purchased a 24.9999% interest in Grizzly. The remaining interests in Grizzly are owned by entities controlled by Wexford. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray near other oil sands development projects. Grizzly has approximately 511,000 acres under lease and our total net investment in Grizzly was $21.9 million at December 31, 2008. During the 2006/2007 and 2007/2008 winter delineation drilling seasons, Grizzly drilled an aggregate of 117 core holes, tested five separate lease blocks and undertook a seismic program. 2009 plans currently include drilling approximately 15 additional core holes and possibly acquiring additional leases. This is a complex project and financing has not been secured. This project may not be completed at our estimated cost or at all.

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

The oil and natural gas industry is cyclical, which can result in a shortage of drilling rigs, equipment, supplies and personnel. As a result, the costs and delivery times of rigs, equipment and supplies increase and demand for, and wage rates of, qualified drilling rig crews also rise 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 associated with estimating quantities of proved reserves and in projecting future rates of production and timing of expenditures. The reserve information included in this report represents only estimates based on reports prepared by Netherland, Sewell & Associates, Inc. as of December 31, 2008 with respect to our WCBB field, by Pinnacle Energy Services, LLC with respect to our assets in the Permian Basin in West Texas and by our personnel with respect to our Hackberry and Bakken 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.

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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.

There are numerous uncertainties in estimating quantities of bitumen reserves and resources and the indicated level of reserves or recovery of bitumen may not be realized.

There are numerous uncertainties in estimating quantities of bitumen reserves and resources, and the indicated level of reserves or recovery of bitumen may not be realized. In general, estimates of economically recoverable bitumen reserves and the future net cash flow from such reserves are based upon a number of factors and assumptions made as of the date on which the reserve and resource estimates were determined, such as geological and engineering estimates which have uncertainties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable bitumen, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially.

Estimates with respect to reserves and resources that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history may result in variations in the estimated reserves. Reserve and resource estimates may require revision based on actual production experience. Reserve and resources estimates are determined with reference to assumed oil prices and operating costs. Market price fluctuations of oil prices may render uneconomic the recovery of certain grades of bitumen. The actual gravity or quality of bitumen to be produced from Grizzly s lands cannot be determined at this time.

The marketability of our production is dependent upon compressors, gathering lines, transportation barges and other facilities, certain of which 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 transportation facilities and our access to them may be limited or denied. A significant disruption in the availability of these transportation facilities or our compression and other production facilities could adversely impact our ability to deliver to market or produce our oil and natural gas 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. If, in the future, we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter compression or other production related difficulties, 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.

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An substantial portion of our producing properties is 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 may not 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 150 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 associated with 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. Several lawsuits relating to this incident were filed against us, among other parties. These lawsuits against us have all been settled.

In accordance with customary industry practice, we historically have maintained insurance against some, but not all, of our business risks. Our insurance may not be adequate to cover any losses or liabilities we may suffer. Also, insurance may no longer be available to us or, if it is, its availability may be at premium levels that do not 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, 2008, our WCBB production, other than production sold under forward sales contracts, was being sold in accordance with the Shell posted price for West Texas/New Mexico Intermediate crude plus or minus Platt s trade month average P+ value, plus or minus the Platt s HLS/WTI trade month average differential less $3.45 per Bbl for transportation. For the year ended December 31, 2008 and the year ended December 31, 2007, we sold approximately 87% and 99%, respectively, of our oil production to Shell and 60% and 69%, respectively, of our natural gas production to Chevron. During 2008, we sold approximately 11%, 100%, and 22% of our oil, natural gas liquids, and natural gas production, respectively, to Windsor and 16% of our natural gas production to Hilcorp Energy Company. During 2007, we sold approximately 23% of our natural gas production to Hilcorp Energy Company. During 2006, we sold 100% of our oil production to Shell and 96% of our natural gas production to Chevron. We may not 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. For instance, as a result of the drop in commodity prices on December 31, 2008, we recognized a ceiling test impairment of $272,722,000 for the year ended December 31, 2008. This impairment, however, reduces future depletion expense. If prices of oil, natural gas and natural gas liquids continue to decrease, we may be required to further write down the value of our oil and gas properties. Future non-cash asset impairments could negatively affect our results of operations.

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 entered into forward sales contracts and may in the future enter into additional contracts for 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 mitigate the effects of commodity price fluctuations, during 2008, we were party to forward sales contracts for the sale of 3,500 barrels of WCBB production per day at a weighted average daily price of $78.56 per barrel before transportation costs. We delivered approximately 73% of our 2008 production under these agreements. For the period January through December 2009, we had entered into agreements to sell 3,000 barrels of WCBB production per day at a weighted average daily price of $89.06 per barrel before transportation costs. In December 2008, we terminated these 2009 forward sales contracts in exchange for $39.0 million in cash. Subsequently, we entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $55.17 per barrel, before transportation costs, for the period April 2009 to August 2009. We have also entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs, for the period September 2009 to December 2009. For the period January 2010 through February 2010, we have entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs. For the period March 2010 through December 2010, we have entered into forward sales contracts for the sale of 2,000 barrels of WCBB production per day at a weighted average daily price of $57.35 per barrel, before transportation costs. Under these contracts, we have committed to deliver approximately 50% of our estimated 2009 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. Since these contracts require physical delivery of production quantities, they normally would be exempted from the provisions of SFAS 133 as normal sales of production. However, as a result of the early termination of the contracts in December 2008, we will not be able to apply this election on new contracts and they will be accounted for at fair value until we re-establish a history of physical delivery without early termination. In addition, these 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. The impact of the changing demand for oil and gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

We are subject to the requirements of Section 404 of the Sarbanes-Oxley Act. If the costs related to such compliance are significant, our profitability, stock price and results of operations and financial condition could be materially adversely affected.

Commencing with our fiscal year ended December 31, 2007, we became subject to Section 404 of the Sarbanes-Oxley Act of 2002, or Section 404, which 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 audit our internal control over financial reporting. We are 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. 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 have been significant. If the future time and costs associated with such compliance exceed our current expectations, our results of operations could be adversely affected. If we fail to fully comply with the requirements of Section 404 or if we determine that we have a material weakness or significant deficiencies, or if our auditors disagree with our assessment in connection with the presentation of our financial statements, the accuracy and timeliness of the filing of our periodic 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 or significant deficiency in our internal control over financial reporting could result in an increased chance of fraud, 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.

Our system of disclosure and internal controls and procedures may not be successful in preventing all errors and fraud, or in making all material information known in a timely manner to management.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and internal controls will prevent all errors and fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. These limitations include the realities that judgments in decision making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control.

The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and any design may not succeed in achieving its stated goals under all potential future conditions. Over time, a control may become inadequate because of changes in conditions, or the degree of compliance with

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the policies or procedures may deteriorate. Because of the limitations in a cost effective control system, misstatements due to error or fraud may occur and not be detected that 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 December 31, 2008, our executive officers and directors, in the aggregate, beneficially owned approximately 4% of our outstanding common stock and Charles E. Davidson, one of our major stockholders, beneficially owned approximately 36% 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.

An active trading market for our common stock may not develop or be sustained.

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. An active trading market may not develop, or if it does, it may not 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 we may not 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.

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

As of December 31, 2008, we had a net operating loss, or NOL, carry forward of approximately $60 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.

We and certain of our stockholders have registered a substantial number of shares of our common stock under a registration statement filed with the SEC. Sales of these 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, sales by certain of our stockholders of their shares could impair our ability to raise capital through the sale of common or preferred stock. As of March 1, 2009, there were 42,647,034 shares of our common stock issued and outstanding, excluding 85,037 shares of restricted stock awarded under our 2005 Stock Incentive Plan.

We could issue 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.

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 1B. UNRESOLVED STAFF COMMENTS

None

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ITEM 2. PROPERTIES

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, Pinnacle Energy Services, LLC, or Pinnacle, and by our personnel. 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-K. 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, 2008, 2007 and 2006. Reserve estimates at December 31, 2008 were prepared by NSAI with respect to our WCBB field (48% of proved reserves PV-10 value at December 31, 2008), by Pinnacle with respect to our assets in the Permian Basin in West Texas (28% of proved reserves PV-10 value at December 31, 2008) and by our personnel with respect to our Hackberry fields and our overriding royalty and non-operated interests including Bakken (24% of proved reserves PV-10 value at December 31, 2008). Reserve estimates at December 31, 2007 were prepared by NSAI with respect to our WCBB field (61% of proved reserves PV-10 value at December 31, 2007), by Pinnacle with respect to our assets in the Permian Basin in West Texas (18% of proved reserves PV-10 value at December 31, 2007) and by our personnel with respect to our Hackberry fields and our overriding royalty and non-operated interests (21% of proved reserves PV-10 value at December 31, 2007). 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 overriding royalty and non-operated interests (18% of proved reserves PV-10 value at December 31, 2006).

	December 31, 2008			December 31, 2007			December 31, 2006		
	Developed	Undeveloped	Total	Developed	Undeveloped	Total	Developed	Undeveloped	Total
Oil (MBbls)	7,072	14,699	21,771	7,116	17,999	25,115	4,876	14,816	19,692
Gas (MMcf)	7,187	15,048	22,235	6,746	17,513	24,259	4,077	16,724	20,801
Mboe	8,269	17,208	25,477	8,240	20,918	29,158	5,556	17,603	23,159
PV-10 (in millions) (1)	$ 91.6	$ 34.6	$ 126.2	$ 294.7	$ 526.5	$ 821.2	$ 120.0	$ 279.4	$ 399.4
Standardized measure (in millions) (2)			$ 126.2			$ 668.3			$ 352.6

(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, 2008. The estimated future production in our WCBB and Hackberry fields is priced at December 31, 2008, 2007 and 2006, without escalation using $41.00 per barrel and $5.71 per MMBtu, $92.50 per barrel and $6.80 per MMBtu and $57.75 per barrel and $5.64 per MMBtu, respectively, 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.

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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, 2008	2007	2006
Standardized measure of discounted future net cash flows	$ 126,240,000	$ 668,295,000	$ 352,648,000
Add: Present value of future income tax discounted at 10%		152,949,000	46,804,000
PV-10 value	$ 126,240,000	$ 821,244,000	$ 399,452,000

(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 of 3.5 Bcf of gas and 19,000 barrels of oil at December 31, 2008. For further discussion of our interest in Tatex, see Item 1. Description of Business Additional Properties.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, *i.e.*, prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices only by contractual arrangements, but not on escalations based on future conditions. 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 were 25,477 Mboe at December 31, 2008, 29,158 Mboe at December 31, 2007 and 23,159 Mboe at December 31, 2006. The decrease in 2008 reserves, as compared to 2007 reserves, is primarily attributable to the decline in oil prices. The increase in 2007 reserves, as compared to 2006 reserves, is mainly attributable to the acquisition of our Permian assets in December 2007. As of December 31, 2008, 36.7% of our total proved reserves were classified as proved developed non-producing.

The following table sets forth certain information with respect to the total proved undeveloped reserves that were converted to proved developed status over the past five years.

YEAR	Beginning of Year Proved Undeveloped Reserves MBOE	PUD Reserves Converted to Proved Developed MBOE	% PUD Reserves Converted to Proved Developed %	Capital Related to Development of PUD Reserves MM$
2004	20,138	493.0	2.4%	6.2
2005	19,361	1,300.0	6.7%	18.9
2006	18,238	1,435.0	7.9%	33.0
2007	17,603	2,804.0	15.9%	55.6
2008	20,918(1)	2,586.0	12.4%	61.8

(1) Includes 5,041 MBOE added from the acquisition of the Permian Basin in December 2007.

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Our total proved oil and gas reserves of 25,477 Mboe at December 31, 2008 include reserves attributable to 81 PUD wells at WCBB that we anticipate will be drilled by 2019. Of these total reserves, an aggregate of 2,839 Mboe of undeveloped reserves at WCBB are scheduled for development from 2014 through 2019 for aggregate estimated development costs of $69.1 million. These proved undeveloped reserves with a development schedule beyond five years have been included in our reserve estimate based on the results of an extensive engineering and geological field analysis undertaken by us and our independent third party petroleum engineer, our subsequent reprocessing and reinterpreting of our seismic data and an analysis of historical subsurface well data and data gathered from our drilling activities. Over the past 12 years, we have drilled 128 wells at WCBB, excluding exploratory wells drilled to preserve acreage, with a success rate in excess of 88%. We have included these PUD locations in our reserves based on our historical drilling experience and our belief that they will be drilled within the ten-year period contemplated by our reserve report.

Production, Prices, and Production Costs

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

	2008	2007	2006
Production Volumes:			
Oil (MBbls)	1,584	1,501	870
Gas (MMcf)	712	816	677
Natural gas liquids (Gallons)	2,583		
Oil equivalents (Mboe)	1,764	1,637	983
Average Prices:			
Oil (per Bbl)	$ 83.23(1)	$ 66.71(1)	$ 64.43(1)
Gas (per Mcf)	$ 9.23	$ 7.40	$ 6.20
Natural gas liquids (per Gallon)	$ 1.26	$	$
Oil equivalents (per Mboe)	$ 80.30	$ 64.86	$ 61.30
Production Costs:			
Average production costs (per Boe)	$ 12.96(2)	$ 10.18(2)	$ 10.86(2)
Average production taxes (per Boe)	$ 8.96	$ 7.74	$ 7.50
Total production costs (per Boe)	$ 21.92	$ 17.92	$ 18.36

(1) Includes fixed contract prices at a weighted average price of:

January December 2006	$ 64.05
June December 2007	$ 66.10
January December 2008	$ 78.56

Excluding the net effect of the fixed price contracts, the average oil price for 2008 would have been $118.63 per barrel and $112.08 per barrel of oil equivalent. The total volume hedged for 2008 represented approximately 73% of our total oil sales for the year. Excluding the net effect of the fixed price contracts, the average oil price for 2007 would have been $72.25 per barrel and $69.93 per barrel of oil equivalent. The total volume hedged for 2007 represented approximately 43% of our total oil sales volumes for the year. 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 represented approximately 62% of our total oil sales volumes for the year. Also includes financial hedge contracts with an average mark-to-market value of approximately $82,000 per month for the months of January-December 2006.

(2) Does not include production taxes.

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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, 2008:

		Producing Wells (2)		Non-Producing Wells		Developed Acreage (3)		Undeveloped Acreage	
Field	NRI/WI (1) Percentages	Gross	Net	Gross	Net	Gross	Net	Gross	Net
West Cote Blanche Bay (4)	80.3/100	107	107	158	158	5,668	5,668		
E. Hackberry (5)	79.4/100	18	18	80	80	3,291	3,291	3,942	3,942
W. Hackberry	87.5/100	3	3	24	24	592	592		
Permian	38.1/49.5	61	30.5			8,075	4,150	480	160
Bakken (6)	2.3/2.2	38	0.8			8,153	891	154,737	16,910
Overrides/Royalty Non-operated	Various	9	0.5	17	0.8	4,956	586		
Total		236	159.8	279	262.8	30,735	15,178	159,159	21,012

(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. Approximately 42% of our acreage is developed acreage and has been perpetuated by production.
(4) We have a 100% working interest (80.335% average NRI) from the surface to the base of the 13900 Sand which is located at 11,320 feet. Below the base of the 13900 Sand, we have a 40.40% non-operated working interest (29.95% NRI).
(5) NRI shown is for producing wells.
(6) NRI/WI is from wells that have been drilled or in which we have elected to participate.

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.

	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Recompletions:						
Productive	58	56.5	62	62	18	18
Dry					1	1
Total	58	56.5	62	62	19	19
Development:						
Productive	69	27	23	23	24	24
Dry			3	3	2	2
Total	69	27	26	26	26	26
Exploratory:						
Productive	0	0	9	9	1	1
Dry	1	1	3	3	1	1

Total	1	1	12	12	2	2

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.

ITEM 3. LEGAL PROCEEDINGS

The Louisiana Department of Revenue, or LDR, is disputing our severance tax payments to the State of Louisiana from the sale of oil under fixed price contracts during the years 2005 through 2007. The LDR maintains that we paid approximately $1.8 million less in severance taxes under fixed price terms than the severance taxes we would have had to pay had we paid severance taxes on the oil at the contracted market rates only. We have denied any liability to the LDR for underpayment of severance taxes and have maintained that we were entitled to enter into the fixed price contracts with unrelated third parties and pay severance taxes based upon the proceeds received under those contracts. We have maintained our right to contest any final assessment or suit for collection if brought by the State.

In November 2006, Cudd Pressure Control, Inc., or Cudd, filed a lawsuit against us and Great White Pressure Control LLC, an affiliate of ours, among others, in the 129th Judicial District Harris County, Texas. The lawsuit was subsequently removed to the United States District Court for the Southern District of Texas (Houston Division). The lawsuit alleges RICO violations and several other causes of action 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, Great White Pressure Control LLC, 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. We filed a motion for summary judgment on October 5, 2007. The Court entered a final interlocutory judgment in favor of all defendants, including us, on April 8, 2008. On November 3, 2008, Cudd filed its appeal with the U.S. Court of Appeals for the Fifth Circuit. The defendants filed their response appellate brief on December 19, 2008, and Cudd filed its reply brief on January 19, 2009. We are currently awaiting the Fifth Circuit s ruling on this matter.

On July 27, 2007, Robotti & Company, LLC filed a putative class action lawsuit in the Court of Chancery for the State of Delaware in and for Kent County, Delaware. The original complaint alleged a breach of fiduciary duty by us and our then present directors in connection with the pricing of our 2004 rights offering. Plaintiff filed an amended complaint on January 15, 2008, and we filed a motion to dismiss in early February 2008 and filed the brief in support of such motion on April 29, 2008. The court held a hearing on October 3, 2008, ultimately deciding to allow the plaintiff to file a second amended complaint. Plaintiff filed its second amended complaint December 22, 2008, which sets forth class action and derivative claim allegations that our then present directors breached their fiduciary duty in connection with the pricing of the 2004 rights offering. The defendants filed their motion to dismiss on January 19, 2009 and their brief in support of such motion on February 20, 2009. Briefing by the parties is scheduled to conclude April 6, 2009 and we anticipate the court will rule on the defendants motion to dismiss thereafter.

Due to the current stages of the above litigation, the outcomes are uncertain and management cannot determine the amount of loss, if any, that may result. Litigation is inherently uncertain. 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.

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PART II

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

Since July 14, 2006, our common stock has been quoted on The NASDAQ Global Select Market 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	Price Range of Common Stock Low
2007		
First Quarter	$ 13.89	$ 10.82
Second Quarter	21.34	12.86
Third Quarter	23.70	15.36
Fourth Quarter	25.62	16.60
2008		
First Quarter	$ 19.41	$ 10.16
Second Quarter	$ 17.67	$ 10.43
Third Quarter	$ 17.07	$ 9.00
Fourth Quarter	$ 10.03	$ 2.87
2009		
First Quarter (through February 28, 2009)	$ 5.20	$ 2.12

On March 12, 2009, the last reported sale price of our common stock on The NASDAQ Global Select Market was $2.59.

Unregistered Sales of Equity Securities and Use of Proceeds

None.

Holders of Record

At the close of business on March 3, 2009, there were 404 stockholders of record holding 42,647,034 shares of our outstanding common stock. There were approximately 7,399 beneficial owners of our common stock as of March 3, 2009.

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 prohibit the payment of any dividends to the holders of our common stock.

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ITEM 6. SELECTED FINANCIAL DATA

You should read the following selected consolidated financial data in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements and the related notes appearing elsewhere in this report. The selected consolidated statements of operations data for the fiscal years ended December 31, 2008, December 31, 2007 and December 31, 2006 and the selected consolidated balance sheet data at December 31, 2008 and December 31, 2007 are derived from our audited consolidated financial statements appearing elsewhere in this report. The selected consolidated statements of operations data for the fiscal years ended December 31, 2005 and December 31, 2004 and the selected consolidated balance sheet data at December 31, 2006, December 31, 2005 and December 31, 2004 are derived from our audited consolidated financial statements that are not included in this report. The historical data presented below is not indicative of future results. We did not pay any cash dividends on our common stock during any of the periods set forth in the following table.

	Fiscal Year Ended December 31,				
	2008	**2007**	**2006**	**2005**	**2004**
Selected Consolidated Statements of Operations Data:					
Revenues	$ 141,217,000	$ 105,838,000	$ 60,390,000	$ 27,559,000	$ 23,190,000
Costs and expenses:					
Lease operating expenses	22,856,000	16,670,000	10,670,000	7,654,000	6,586,000
Production taxes	15,813,000	12,667,000	7,366,000	3,622,000	2,629,000
Depreciation, depletion and amortization	42,472,000	29,681,000	12,652,000	4,789,000	4,952,000
Impairment of oil and natural gas properties	272,722,000				
General and administrative	6,843,000	5,802,000	3,251,000	1,561,000	2,107,000
Accretion expense	560,000	554,000	596,000	516,000	490,000
	361,266,000	65,374,000	34,535,000	18,142,000	16,764,000
Income (Loss) from Operations	(220,049,000)	40,464,000	25,855,000	9,417,000	6,426,000
Other (Income) Expense:					
Interest expense	4,762,000	3,091,000	1,956,000	250,000	246,000
Interest expense preferred stock				272,000	1,949,000
Insurance recoveries	(769,000)		(3,601,000)	(1,710,000)	
Settlement of fixed price contracts	(39,000,000)				
Interest income	(540,000)	(523,000)	(308,000)	(290,000)	(73,000)
	(35,547,000)	2,568,000	(1,953,000)	(1,478,000)	2,122,000
Income (Loss) before Income Taxes	(184,502,000)	37,896,000	27,808,000	10,895,000	4,304,000
Income Tax Expense		121,000			
Net Income (Loss)	(184,502,000)	37,775,000	27,808,000	10,895,000	4,304,000
Net Income (Loss) Available to Common Stockholders	$ (184,502,000)	$ 37,775,000	$ 27,808,000	$ 10,895,000	4,304,000
Net Income (Loss) Per Common Share Basic:	$ (4.33)	$ 1.03	$ 0.85	$ 0.36	$ 0.31
Net Income (Loss) Per Common Share Diluted:	$ (4.33)	$ 1.01	$ 0.82	$ 0.34	$ 0.28

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	At December 31,				
	2008	2007	2006	2005	2004
Selected Consolidated Balance Sheet Data:					
Total assets	$ 221,873,000	$ 419,137,000	$ 195,151,000	$ 111,820,000	$ 78,150,000
Total debt, including current maturity	$ 70,731,000	$ 66,533,000	$ 37,691,000	$ 10,200,000	$ 3,404,000
Total liabilities	$ 107,772,000	$ 115,015,000	$ 71,342,000	$ 27,493,000	$ 29,053,000
Stockholders equity	$ 114,101,000	$ 304,122,000	$ 123,809,000	$ 84,327,000	$ 49,097,000

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ITEM 7. 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-K. 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-K.

Overview

We are an independent oil and natural gas exploration and production company with our principal producing properties located along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields, and in West Texas in the Permian Basin. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC and in the Bakken Shale, and have interests in entities that operate in Southeast Asia, including the Phu Horm gas field in Thailand. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

2008 Highlights

- Oil and natural gas revenues increased $35.6 million to $141.7 million for the year ended December 31, 2008 from $106.1 million for 2007.

- Net loss including impairment of oil and gas assets of $272.7 million was $184.5 million for the year ended December 31, 2008. Before impairment of oil and natural gas properties, net income increased 133% to $88.2 million for the year ended December 31, 2008 from $37.8 million for 2007.

- Production increased 8% to 1,764,000 BOE for the year ended December 31, 2008 from 1,637,000 BOE for 2007.

- During 2008, we drilled 81 wells and recompleted 58 wells. Of our 81 new wells drilled, 69 were completed as producing wells, one was non-productive and 11 are waiting on completion.

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. 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 non-productive costs and certain general and administrative costs directly 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 $22.5 million at December 31, 2008 and $37.3 million at December 31, 2007. 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. Ceiling test impairment can give us a significant loss for a particular period; however, future depletion expense would be reduced. A decline in oil and gas prices may result in an impairment of oil and gas properties. For instance, as a result of the drop in commodity prices on December 31, 2008 and subsequent reduction in our proved reserves, we recognized a ceiling test impairment of $272,722,000 for the year ended December 31, 2008. If prices of oil, natural gas and natural gas liquids continue to decrease, we may be required to further write down the value of our oil and gas properties, which could negatively affect our results of operations.

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. Netherland, Sewell & Associates, Inc., Pinnacle Energy Services, LLC 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 than not that some portion will not be realized. At December 31, 2008, a valuation allowance of $81.9 million 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.

To mitigate the effects of commodity price fluctuations, during 2008, we were party to forward sales contracts for the sale of 3,500 barrels of WCBB production per day at a weighted average daily price of $78.56 per barrel before transportation costs. We delivered approximately 73% of our 2008 production under these agreements. For the period January through December 2009, we had entered into agreements to sell 3,000 barrels of WCBB production per day at a weighted average daily price of $89.06 per barrel before transportation costs. In December 2008, we terminated these 2009 forward sales contracts in exchange for $39.0 million in cash. Subsequently, we entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $55.17 per barrel, before transportation costs, for the period April 2009 to August 2009. We have also entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs, for the period September 2009 to December 2009. For the period January 2010 through February 2010 we have entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs. For the period March 2010 through December 2010, we have entered into forward sales contracts for the sale of 2,000 barrels of WCBB production per day at a weighted average daily price of $57.35 per barrel, before transportation costs. Under these 2009 contracts, we have committed to deliver approximately 50% of our estimated 2009 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. Since these contracts require physical delivery of production quantities, they normally would be exempted from the provisions of SFAS 133 as normal sales of production. However, as a result of the early termination of the contracts in December 2008, we will not be able to apply this election on new contracts and they will be accounted for at fair value until we re-establish a history of physical delivery without early termination. In addition, these arrangements may limit the benefit to us of increases in the price of oil.

RESULTS OF OPERATIONS

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.

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

	2008	2007	2006
Production Volumes:			
Oil (MBbls)	1,584	1,501	870
Gas (MMcf)	712	816	677
Natural gas liquids (Gallons)	2,583		
Oil equivalents (Mboe)	1,764	1,637	983
Average Prices:			
Oil (per Bbl)	$ 83.23(1)	$ 66.71(1)	$ 64.43(1)
Gas (per Mcf)	$ 9.23	$ 7.40	$ 6.20
Natural gas liquids (per Gallon)	$ 1.26	$	$
Oil equivalents (per Mboe)	$ 80.30	$ 64.86	$ 61.30
Production Costs:			
Average production costs (per Boe)	$ 12.96(2)	$ 10.18(2)	$ 10.86(2)
Average production taxes (per Boe)	$ 8.96	$ 7.74	$ 7.50
Total production costs (per Boe)	$ 21.92	$ 17.92	$ 18.36

(1) Includes fixed contract prices at a weighted average price of:

January December 2006	$ 64.05
June December 2007	$ 66.10
January December 2008	$ 78.56

Excluding the net effect of the fixed price contracts, the average oil price for 2008 would have been $118.63 per barrel and $112.08 per barrel of oil equivalent. The total volume hedged for 2008 represented approximately 73% of our total oil sales for the year. Excluding the net effect of the fixed price contracts, the average oil price for 2007 would have been $72.25 per barrel and $69.93 per barrel of oil equivalent. The total volume hedged for 2007 represented approximately 43% of our total oil sales volumes for the year. 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 represented approximately 62% of our total oil sales volumes for the year. Also includes financial hedge contracts with an average mark-to-market value of approximately $82,000 per month for the months of January-December 2006.

(2) Does not include production taxes.

From 2007 to 2008, our net oil equivalent production increased 8% from 1,637,000 barrels to 1,764,000 due primarily to continued drilling and recompletion activities. From 2006 to 2007, our net oil production increased 73% from 870,000 barrels to 1,501,000 barrels due to our continued drilling activity. We currently estimate that our 2009 production will be between 1,600,000 and 1,800,000 BOE. However, such estimate may change based on the changing economic climate and unforeseen events, such as hurricanes.

Comparison of the Years Ended December 31, 2008 and December 31, 2007

We reported a net loss of $184,502,000 for the year ended December 31, 2008, compared to net income of $37,775,000 for the year ended December 31, 2007. This net loss was primarily attributable to an impairment charge of $272,722,000 related to the drastic decline in oil and gas prices, partially offset by a $39.0 million gain from the sale in December 2008 of all of our then existing 2009 fixed price contracts. Excluding the effect of the impairment, our net income increased 133% due primarily to (1) a 8% increase in net production to 1,764,053 BOE for the year ended December 31, 2008 from 1,636,902 BOE for 2007, (2) a 25% increase in the average oil price received to $83.23 per barrel for the year ended December 31, 2008 from $66.71 per barrel for 2007 and (3) a $39.0 million gain from the sale in December 2008 of all of our then existing fixed price contracts.

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Oil and Gas Revenues. For the year ended December 31, 2008, we reported oil and gas revenues of $141,650,000, compared to oil and gas revenues of $106,163,000 during 2007. This 33% increase in revenues is mainly attributable to an 8% increase in net production to 1,764,053 BOE for the year ended December 31, 2008 from 1,636,902 BOE for 2007 and a 25% increase in the average oil price received to $83.23 per barrel for the year ended December 31, 2008 from $66.71 per barrel for 2007. This increase in oil and natural gas production was the result of production from our 2008 drilling programs and the acquisition of the Permian wells in December 2007. Production in 2008 was adversely affected by the damage caused by Hurricane Ike with production not fully restored until December, 2008. We estimate that approximately 170,000 barrels of oil equivalents production were deferred to other periods.

The following table summarizes our oil and natural gas production and related pricing for the years ended December 31, 2008 and December 31, 2007:

	Year Ended December 31,	
	2008	**2007**
Oil production volumes (MBbls)	1,584	1,501
Gas production volumes (MMcf)	712	816
Natural gas liquids production volumes (Gallons)	2,583	
Oil equivalents (Mboe)	1,764	1,637
Average oil price (per Bbl)	$ 83.23	$ 66.71
Average gas price (per Mcf)	$ 9.23	$ 7.40
Average natural gas liquids (per gallon)	$ 1.26	$
Oil equivalents (per Boe)	$ 80.30	$ 64.86

Lease Operating Expenses. Lease operating expenses, or LOE, excluding the effects of hurricane related costs and production taxes, increased to $19,448,000 for 2008 from $16,670,000 for 2007. The increase in ongoing LOE was mainly due to $2,700,000 of LOE related to the Permian properties acquired in December 2007. In addition, there were also increases in personal property taxes and repairs to compressors and other equipment in our operating area along the Louisiana Gulf Coast. Included in total LOE of $22,856,000 before production taxes is $3,408,000 of hurricane related LOE costs incurred during 2008.

Production Taxes. Production taxes increased to $15,813,000 for 2008 from $12,667,000 for 2007. This increase was directly related to a 33% increase in oil and gas revenues as a result of the 24% improvement in the price received per barrel of oil equivalent and an 8% increase in production for 2008 as compared to 2007.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased to $42,472,000 for the year ended December 31, 2008, and consisted of $42,194,000 in depletion on oil and natural gas properties and $278,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $29,681,000 for the year ended December 31, 2007, which consisted of $29,220,000 in depreciation on oil and natural gas properties and $461,000 in depreciation of other property and equipment. This increase was due primarily to an increase in our oil and natural gas property costs associated with our 2008 drilling program, an increase in our oil and gas production for the period and a decrease in our total oil and gas reserve volumes.

Impairment of Oil and Gas Properties. We use the full cost method of accounting for oil and gas properties and are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of our 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 our 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 write-down is required. As a result of the drop in commodity prices on December 31, 2008, we recognized a ceiling test impairment of $272,722,000 for the year ended December 31, 2008. This impairment however will reduce future depletion expense. There was no impairment charge for the year ended December 31, 2007.

General and Administrative Expenses. Net general and administrative expenses increased to $6,843,000 for 2008 from $5,802,000 for 2007. This $1,041,000 increase was due primarily to an $832,000 increase in franchise taxes as a result of an increase in total assets and shares outstanding and slight increases in audit fees and insurance costs.

Accretion Expense. Accretion expense increased slightly to $560,000 for 2008 from $554,000 for 2007, due to a larger obligation at the beginning of 2008 compared to the beginning of 2007, resulting from the addition of future abandonment obligations on new wells drilled during 2007.

Interest Expense. Interest expense increased to $4,762,000 for 2008 from $3,091,000 for 2007 due to an increase in average debt outstanding. Total weighted debt outstanding under our facilities with Bank of America was $84.2 million for 2008 as compared to $33.2 million for 2007.

Settlement of Fixed Price Contracts. In December 2008, we terminated all of our then existing 2009 fixed price contracts. Through the termination of these contracts, we received a $39.0 million payment during the fourth quarter of 2008, and in accordance with SFAS 133, these amounts were recognized into earnings during the fourth quarter of 2008, the period in which the fixed price contracts were settled. There was not a termination of any fixed price contracts during the year ended December 31, 2007.

Income Taxes. As of December 31, 2008, we had a net operating loss carry forward of approximately $60 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, 2008, a valuation allowance of $81.9 million had been provided for our entire net deferred tax asset, with the exception of $653,000 related to alternative minimum taxes.

Comparison of the Years Ended December 31, 2007 and December 31, 2006

We reported net income of $37,775,000 for the year ended December 31, 2007, compared to $27,808,000 for the year ended December 31, 2006. This 36% increase in net income was due primarily to (1) a 67% increase in net production to 1,636,902 BOE for the year ended December 31, 2007 from 982,531 BOE for 2006 as a result of our continued drilling activity and (2) a 6% increase in the average BOE oil price received to $64.86 per barrel for the year ended December 31, 2007 from $61.30 per barrel for 2006. Although we closed the acquisition of the assets in the Permian Basin in West Texas on December 20, 2007, effective as of November 1, 2007, under GAAP only the oil and gas activities for the days subsequent to the closing date, which in this case were from December 21 through December 31, 2007, can be included in our 2007 oil and gas activities. As a result, activities related to these new assets had little impact on our results of operations for the year ended December 31, 2007.

Oil and Gas Revenues. For the year ended December 31, 2007, we reported oil and gas revenues of $106,163,000, compared to oil and gas revenues of $60,232,000 during 2006. This $45,931,000, or 76%, increase in revenues is primarily attributable to a 67% increase in net production to 1,636,902 BOE for the year ended December 31, 2007 from 982,531 BOE for the year ended December 31, 2006. Production in the first half of 2006 was negatively impacted by the damage caused by Hurricane Rita, as production from our wells at WCBB was not fully restored until later in 2006.

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The following table summarizes our oil and natural gas production and related pricing for the years ended December 31, 2007 and 2006:

	Year Ended December 31, 2007	2006
Oil production volumes (MBbls)	1,501	870
Gas production volumes (MMcf)	816	677
Oil equivalents (Mboe)	1,637	983
Average oil price (per Bbl)	$ 66.71	$ 64.43
Average gas price (per Mcf)	$ 7.40	$ 6.20
Oil equivalents (per Boe)	$ 64.86	$ 61.30

Lease Operating Expenses. Lease operating expenses not including production taxes increased to $16,670,000 for the year ended December 31, 2007 from $10,670,000 for 2006. Since our WCBB facilities continued to be shut in until late in the first quarter of 2006 due to the impact of Hurricane Rita some of the costs that would have normally been associated with our lease operating expenses were instead spent on ongoing restoration and repair activities during the year ended December 31, 2006. In addition, lease operating expenses for the year ended December 31, 2007 increased due to increased labor requirements associated with a ramp up in overall activity in both fields, increases in rates paid for labor and other services, increases in the cost of oil-based supplies, non-recurring repairs including repairs to compressors, and increases in property taxes in both fields as a result of the on-going capital programs. These increases were partially offset by a reduction in lease operating expenses attributable to our interest in the Marquiss field which we sold during February 2007.

Production Taxes. Production taxes increased to $12,667,000 for the year ended December 31, 2007 from $7,366,000 for 2006. This increase was directly related to a 76% increase in oil and gas revenues as a result of the increase in production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased to $29,681,000 for the year ended December 31, 2007, and consisted of $29,220,000 in depletion on oil and natural gas properties and $461,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $12,652,000 for the year ended December 31, 2006. This increase was due primarily to an increase in our production, an increase in our oil and natural gas property costs associated with our 2006 and 2007 drilling programs and an increase in our future development costs.

General and Administrative Expenses. Net general and administrative expenses increased to $5,802,000 for 2007 from $3,251,000 for 2006. This increase was due primarily to increases in payroll costs and related benefits as a result of increases in the total number of employees. In addition, this increase also resulted from $310,000 of costs associated with the implementation of Section 404 of the Sarbanes-Oxley Act, an increase of $300,000 in franchise taxes, an increase of $220,000 for the services provided by our external reserve engineers, an increase of $100,000 in our business and D&O insurance costs and an increase of $95,000 for expenses associated with SFAS No. 123(R), *Share Based Payment.* These increases were partially offset by an increase in the amount of capitalized general and administrative expenses and a decrease in legal expenses and corporate fees.

Accretion Expense. Accretion expense decreased to $554,000 for 2007 from $596,000 for 2006. Although there was a larger obligation at the beginning of 2007 than there was at the beginning of 2006 resulting from the addition of future abandonment obligations on new wells drilled during 2006, the effect of the increase on the larger obligations was more than offset by the effect of the sale of the Marquiss properties in February 2007.

Interest Expense. Interest expense increased to $3,091,000 for 2007 from $1,956,000 for 2006 due to an increase in average debt outstanding. Total weighted debt outstanding under our facilities with Bank of America was $33.2 million for the year ended December 31, 2007, as compared to $18.8 million for 2006. In addition, during July 2006 we entered into a new $5.0 million term loan agreement with Bank of America. As a result, during the year ended December 31, 2007, we recognized a full year of interest related to the term loan in the amount of $382,000 as compared to only $115,000 for 2006.

Income Taxes. As of December 31, 2007, we had a net operating loss carry forward of approximately $93 million, in addition to numerous temporary differences, which gave rise to a deferred tax asset. Periodically, management performs a forecast of our 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, 2007, a valuation allowance of $9.8 million had been provided for deferred tax assets. We had only a slight income tax expense of $121,000 during the year ended December 31, 2007 related to the payment of alternative minimum taxes due for 2006 and 2007. Although we have substantial net operating loss carryforwards, these cannot be used to offset alternative minimum tax liabilities.

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. During the year ended December 31, 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 six months ended June 2006.

Net cash flow provided by operating activities was $135,323,000 for 2008, as compared to $68,902,000 for 2007. The increase of $66,421,000 in 2008 was primarily the result of the termination in December 2008 of our then existing 2009 fixed price contracts for $39,000,000, an increase in cash receipts from our oil and gas purchasers due to higher prices received for oil production and a 8% increase in net production, partially offset by increase in cash paid for lease operating expenses and production taxes.

Net cash flow provided by operating activities was $68,902,000 for 2007, as compared to net cash flow provided by operating activities of $39,523,000 for 2006. This increase was primarily the result of an increase in cash receipts from our oil and gas purchasers due to a 67% 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 2008 was $136,823,000, as compared to $240,733,000 for 2007. During the year ended December 31, 2008, we spent $126,030,000 in additions to oil and natural gas properties, of which $77,074,000 was spent on our 2008 drilling and recompletion program, $27,131,000 was attributable to the wells drilled or recompleted during 2007, $4,665,000 was spent on compressors, $3,200,000 was spent on facilities, $1,148,000 was spent on plugging activities, $1,933,000 was spent on lease related costs primarily in the Bakken, $1,128,000 was spent on our Belize activities, $841,000 was spent on a new storage barge with the remainder attributable mainly to capitalized general and administrative expenses. In addition, during the year ended December 31, 2008, we received cash distributions of $862,000 from Tatex Thailand II and we made cash investments of $885,000 in Tatex Thailand III and $10,670,000 in Grizzly. We used cash from operations and borrowings under our credit facility to fund our investing activities in 2008.

Net cash used in investing activities for 2007 was $240,733,000, as compared to $73,876,000 for 2006. During the year ended December 31, 2007, we spent $220,044,000 in additions to oil and natural gas properties, of which $96,113,000 was spent on our 2007 drilling program, $85,230,000 was spent on our acquisition of certain strategic assets in Upton County, Texas in the Permian Basin, $12,319,000 was spent on expenses attributable to the wells drilled during 2006, $9,467,000 was spent on our new Hackberry barge facilities, $2,834,000 was spent on additions to oil and natural gas properties due to Hurricane Rita, with the remainder attributable mainly to facility enhancement and capitalized general and administrative expenses. During the year ended December 31, 2007, we made investments of $17,316,000 in Grizzly. During the year ended December 31, 2007, we used cash from operations, proceeds from the sale of 8,547,500 shares of our common stock and borrowings under our credit facility to fund our investing activities.

Net cash provided by financing activities for 2008 was $4,680,000, which amount is primarily attributable to $30,000,000 of borrowings under our line of credit, mostly offset by repayments on the line.

Net cash provided by financing activities for 2007 was $167,968,000, as compared to $38,861,000 for 2006. The 2007 amount provided by financing activities is primarily attributable to borrowings of $76,000,000 under our credit facility with Bank of America and aggregate proceeds of approximately $138,258,000 from the sale of shares of our common stock in February 2007, May 2007, July 2007 and December 2007, after deducting the underwriting discount and offering expenses, and $868,000 from the exercise of stock options. Net proceeds were used to pay down $46,328,000 of outstanding existing debt under our credit facility with Bank of America, fund substantially all of the purchase price for the acquisition of our interest in certain strategic assets in Upton County, Texas in the Permian Basin and for other general corporate purposes. The 2006 amount provided by financing activities is attributable to draws of $33,300,000 on our credit facility with Bank of America and proceeds before offering costs of $10,451,000 from the issuance of common stock in our May 2006 underwritten public offering and $1,276,000 from the exercise of stock options.

Issuance of Equity. In January 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 our common stock to cover any over-allotments, which the underwriter exercised in full. 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.

In May 2007, we sold 1,500,000 shares of our common stock in an underwritten offering at an offering price to the public of $16.00 per share. In connection with the offering, we granted the underwriter an option to purchase up to an additional 225,000 shares of our common stock to cover any over-allotments, which the underwriter exercised in full. We received the net proceeds of approximately $26.8 million from the sale of these shares on May 22, 2007 after deducting the underwriting discount and before offering expenses. These net proceeds were used to pay down outstanding debt under our credit facility.

In July 2007, we sold 1,000,000 shares of our common stock in an underwritten offering at an offering price to the public of $22.00 per share. We received the net proceeds of approximately $21.2 million from our sale of these shares on July 25, 2007 after deducting the underwriting discount and before offering expenses.

In December 2007, we sold 4,500,000 shares of our common stock in an underwritten offering at an offering price to the public of $17.50 per share. We received the net proceeds of approximately $75.6 million from our sale of these shares on December 12, 2007 after deducting underwriting discounts and commissions and before offering expenses. We used the net proceeds from this offering to fund substantially all of the purchase price for our interest in the acquisition of certain strategic assets in Upton County, Texas in the Permian Basin. In connection with this offering, a selling stockholder granted the underwriters an option to purchase an additional 675,000 shares of our common stock at a price of $16.80 per share solely to cover any over-allotments, which underwriters exercised in full. We did not receive any proceeds from the sale of shares of our common stock by the selling stockholder.

Credit Facility. On March 11, 2005, we entered into a three-year secured reducing credit agreement, as amended, providing for a 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. Effective July 19, 2007, the credit facility increased to $150.0 million and the amount available under the borrowing base limitation was increased to $60.0 million. In connection with our acquisition of strategic assets in West Texas in the Permian Basin, effective as of December 20, 2007, our borrowing base under the revolving credit facility increased from $60.0 million to $90.0 million and the Eurodollar interest rate, which we can elect to use at our option, was reduced by 0.75%. In addition, the maturity date was extended from March 31, 2009 to March 31, 2010. We agreed to pay a borrowing base increase fee of 0.50% of any increase of the borrowing base over the highest borrowing base previously in effect, payable on the day such increased borrowing base becomes effective. The facility is subject to annual and semi annual redeterminations. We are currently in the process of a redetermination based on our year-end reserve information and bank pricing decks among other considerations. Preliminary indications from the bank indicate that our borrowing base may be reset at approximately $60.0 million but the exact outcome cannot be predicted at this time. We make quarterly interest payments on amounts borrowed under the facility, which amounts bear interest at Bank of America prime plus 0.5% (3.75% at December 31, 2008). Our obligations under the credit facility are collateralized by a lien on substantially all of our Louisiana and West Texas oil and gas assets.

The credit facility contains certain affirmative and negative covenants, including, but not limited to the following financial covenants: (a) 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 (b) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. We were in compliance with all covenants at December 31, 2008. As of December 31, 2008, approximately $64.5 million was outstanding under this facility, which is included in long-term debt, net of current maturities on the accompanying consolidated balance sheet. As of February 28, 2009, approximately $59.0 million was outstanding under this facility. 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 Hurricanes Rita and for other general corporate purposes.

On July 10, 2006, we entered into a $5.0 million term loan agreement with Bank of America, N.A. related to the purchase of new gas compressor units. The loan began amortizing quarterly on March 31, 2007 on a straight-line basis over seven years based on the outstanding principal balance at December 31, 2006. Amounts borrowed bear interest at Bank of America prime (3.25% at December 31, 2008). 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, 2008, approximately $3.6 million was outstanding under this agreement, of which $714,000 and $2,874,000 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 had 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 bore interest at the rate of 5.75% per annum. We repaid this loan in full during the third quarter of 2007. 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. As of December 31, 2008, approximately $2.6 million was outstanding on this loan. The remaining building loan requires monthly interest and principal payments and is collateralized by the respective land and buildings.

Capital Expenditures. Our recent capital commitments have been primarily for the development of our proved reserves, to increase our net acreage position in Grizzly and fund Grizzly s delineation drilling program and for acquisitions, primarily our acquisition in the Permian Basin in December 2007. Our strategy, subject to economic and industry conditions, 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, subject to economic and industry conditions, and (2) explore acquisition and disposition opportunities. We have upgraded our infrastructure and our existing facilities in Southern Louisiana with the goal of increasing operating efficiencies and volume capacities and lowering 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 one of our principal properties, WCBB. The reprocessed data enables 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 addition, with our acquisition of strategic assets in the Permian Basin in West Texas, we are required to pay 50% of all drilling costs for drilling activity on such properties. To combat significant declines in the commodity prices during the second half of 2008, management undertook a series of actions aimed at reducing capital spending and operating costs. As a result, we reduced our drilling and other capital activities to a minimum in the fourth quarter of 2008, releasing all rigs in Southern Louisiana and the Permian and only selectively participating in wells in the Bakken. During 2009, we are not bound by lease obligations and long term capital commitments relating to the exploration or development of our oil and gas properties. In addition, we have reduced our estimated capital activities and aggressively sought price concessions from our service providers and have recently received indications of 20% to 25% in cost reductions and believe an additional 10% to 20% in reduction may be possible.

In our December 31, 2008 reserve reports, 67.5% 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 81 drilling locations at WCBB. The drilling schedule used in our December 31, 2008 reserve report anticipates that all of those wells will be drilled by 2019. From January 1, 2009 through March 1, 2009, we recompleted seven existing wells at our WCBB field. We currently intend to spend a total of approximately $7.5 to $8.5 million to drill four wells and recomplete 20 wells in our WCBB field during 2009.

In our East Hackberry field, from January 1, 2009 through March 1, 2009, we recompleted three wells. We intend to drill four additional land wells during 2009. Total capital expenditures for our East Hackberry field during 2009 are estimated at $4.5 to $5.5 million.

We currently anticipate that our capital requirements for our properties in the Permian Basin in West Texas will be approximately $2.0 to $2.5 million during 2009. We have identified 147 gross (73.5 net) future development drilling locations. We currently expect that approximately 1.5 net wells will be drilled on this acreage in 2009 at estimated average gross completed gross well cost of $1.34 million.

During the third quarter of 2006, we purchased a 24.9999% interest in Grizzly. As of December 31, 2008, our net investment in Grizzly was approximately $21.9 million. Capital requirements in 2009 for this project are estimated to be approximately $4.3 million, primarily for the expenses associated with the drilling of 15 well core holes during Grizzly s 2008/2009 drilling program.

Capital expenditures in 2009 relating to our interest in Thailand are expected to be approximately $1.0 million, which we believe will be mostly offset from our share of production from the Phu Horm field.

Capital expenditures in 2009 relating to our interest in the Bakken Shale in the Williston Basin are expected to be approximately $2.5 million, which we believe will be partially offset from our share of production from the field.

Our total capital expenditures for 2009 are currently estimated to be $22 million. This is down significantly from $95 million in 2008 due to the current commodity pricing and cost environment. In response to the challenging economic conditions, we have for now reduced drilling and other capital activities to a minimum in 2009 and released all rigs in Southern Louisiana and the Permian and intend to participate selectively in wells in the Bakken. In addition, through our cost reduction initiative, we have already received indications of 20% to 25% in cost reductions and we are targeting an additional 10% to 20% reduction. We intend to monitor pricing and cost developments and make adjustments to our capital expenditure program as warranted.

We believe that our cash on hand, cash flow from operations and availability under our credit facility, if any, will be sufficient to meet our normal recurring operating needs, debt service obligations, and our WCBB, Hackberry, Bakken, Permian Basin and Grizzly capital requirements for the next twelve months. In the event we elect to further expand or accelerate our drilling programs, pursue acquisitions or accelerate our Canadian oil sands project, we may be required to obtain additional funds which 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 be required to delay or curtail implementation of our business plan or not be able to complete acquisitions that may be favorable to us.

Commodity Price Risk

To mitigate the effects of commodity price fluctuations, during 2008, we were party to forward sales contracts for the sale of 3,500 barrels of WCBB production per day at a weighted average daily price of $78.56 per barrel before transportation costs. We delivered approximately 73% of our 2008 production under these agreements. For the period January through December 2009, we had entered into agreements to sell 3,000 barrels of WCBB production per day at a weighted average daily price of $89.06 per barrel before transportation costs. In December 2008, we terminated these 2009 forward sales contracts in exchange for $39.0 million in cash. Subsequently, we entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $55.17 per barrel, before transportation costs, for the period April 2009 to August 2009. We have also entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs, for the period September 2009 to December 2009. For the period January 2010 through February 2010 we have entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs. For the period March 2010 through December 2010, we have entered into forward sales contracts for the sale of 2,000 barrels of WCBB production per day at a weighted average daily price of $57.35 per barrel, before transportation costs. Under these contracts, we have committed to deliver approximately 50% of our estimated 2009 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. Since these contracts require physical delivery of production quantities, they normally would be exempted from the provisions of SFAS 133 as normal sales of production. However, as a result of the early termination of the contracts in December 2008, we will not be able to apply this election on new contracts and they will be accounted for at fair value until we re-establish a history of physical delivery without early termination. In addition, these arrangements may limit the benefit to us of increases in the price of oil.

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, 2008, the plugging and abandonment trust totaled approximately $3,144,000 including interest received during 2008 of approximately $45,000. At December 31, 2008, we had plugged 273 wells at WCBB since we began our plugging program in 1997, which management believes fulfills our current minimum plugging obligation.

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Contractual and Commercial Obligations

		Payment due by period (1)			
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Short-term and long-term debt	$ 70,731,000	$ 815,000	$ 69,185,000	$ 731,000	$
Asset retirement obligations	9,269,000	635,000	1,200,000	816,000	6,618,000
Total	$ 80,000,000	$ 1,450,000	$ 70,385,000	$ 1,547,000	$ 6,618,000

(1) Does not include estimated interest of $2,496,000 less than one year, $7,052,000 1-3 years, and $2,223,000 3-5 years.

New Accounting Pronouncements

Effective January 1, 2008, we implemented FASB SFAS No. 157, *Fair Value Measurements.* SFAS No. 157 defines fair value, establishes a framework for its measurement and expands disclosures about fair value measurements. We elected to implement this Statement with the one-year deferral permitted by FASB Staff Position (FSP) 157-2 for nonfinancial assets and nonfinancial liabilities measured at fair value, except those that are recognized or disclosed on a recurring basis. The deferral applies to nonfinancial assets and liabilities measured at fair value in a business combination; impaired properties; plants and equipment; intangible assets and goodwill; and initial recognition of asset retirement obligations and restructuring costs for which fair value is used. We are currently assessing the impact, if any, of FSP No. FAS 157-2 in relation to nonfinancial assets and nonfinancial liabilities. The adoption of the provisions of SFAS No. 157 did not have a material impact on our consolidated financial statements.

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. We adopted SFAS No. 159 effective January 1, 2008. The adoption did not have a material impact on our consolidated financial statements.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS 141(R)), which replaces FASB Statement No. 141. SFAS 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. SFAS 141(R) also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for acquisitions that occur in an entity s fiscal year that begins after December 15, 2008. We are currently assessing the impact, if any; the adoption of SFAS 141(R) may have on any future acquisitions.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements-an amendment of ARB No. 51*. SFAS No. 160 requires that accounting and reporting for minority interest will be recharacterized as noncontrolling interest and classified as a component of equity. SFAS No. 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interest of the parent and the interests of the noncontrolling owners. SFAS No. 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding noncontrolling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement is effective as of the beginning of an entity s first fiscal year beginning after December 15, 2008. We are currently assessing the impact, if any, of the adoption of SFAS No. 160.

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In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133*. SFAS No. 161 requires enhanced disclosures for derivative and hedging activities, including (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under SFAS No. 133 and related interpretations, and (c) how derivative instruments and related hedged items affect an entity s financial position, results of operations, and cash flows. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We are currently assessing the impact, if any, of the adoption of SFAS No. 161.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*. SFAS No. 162 identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America (the GAAP hierarchy). This statement was effective November 15, 2008 (60 days following the SEC s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, *The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles)*. The adoption of SFAS No. 162 did not have a material impact to our financial statements.

In December 2008, the Securities and Exchange Commission published a Final Rule, *Modernization of Oil and Gas Reporting*. The new rule permits the use of new technologies to determine proved reserves if those technologies have been demonstrated to lead to reliable conclusions about reserve volumes. The new requirements also will allow companies to disclose their probable and possible reserves. In addition, the new disclosure requirements require companies to (a) report the independence and qualifications of its reserve preparer, (b) file reports when a third party is relied upon to prepare reserve estimates or conducts a reserve audit, and (c) report oil and gas reserves using an average price based upon the prior 12 month period rather than year end prices. The use of average prices will impact future impairment and depletion calculations. The new requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. Early adoption is not permitted in quarterly reports prior to the first annual report in which the revised disclosures are required. We are currently assessing the impact of this Final Rule.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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, 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, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.28 per barrel, or bbl, in December 2008 to a high of $145.31 per bbl in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $3.53 per million British thermal units, or MMBtu, in September 2006 to a high of $15.52 per MMBtu in January 2006. On December 31, 2008, the West Texas Intermediate posted price for crude oil was $44.60 per bbl and the Henry Hub spot market price of natural gas was $5.63 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.

To mitigate the effects of commodity price fluctuations, during 2008, we were party to forward sales contracts for the sale of 3,500 barrels of WCBB production per day at a weighted average daily price of $78.56 per barrel before transportation costs. We delivered approximately 73% of our 2008 production under these agreements. For the period January through December 2009, we had entered into agreements to sell 3,000 barrels of WCBB production per day at a weighted average daily price of $89.06 per barrel before transportation costs. In December 2008, we terminated these 2009 forward sales contracts in exchange for $39.0 million in cash. Subsequently, we entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $55.17 per barrel, before transportation costs, for the period April 2009 to August 2009. We have also entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs, for the period September 2009 to December 2009. For the period January 2010 through February 2010 we have entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs. For the period March 2010 through December 2010, we have entered into forward sales contracts for the sale of 2,000 barrels of WCBB production per day at a weighted average daily price of $57.35 per barrel, before transportation costs. Under these contracts, we have committed to deliver approximately 50% of our estimated 2009 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. Since these contracts require physical delivery of production quantities, they normally would be exempted from the provisions of SFAS 133 as normal sales of production. However, as a result of the early termination of the contracts in December 2008, we will not be able to apply this election on new contracts and they will be accounted for at fair value until we re-establish a history of physical delivery without early termination. In addition, these arrangements may limit the benefit to us of increases in the price of oil.

Our credit facility and term loan with Bank of America are structured under floating rate terms and, as such, our interest expense is sensitive to fluctuations in the prime rates in the U.S. Borrowings under our revolving credit facility with Bank of America bear interest at Bank of America prime plus 0.5% (3.75% at December 31, 2008). Borrowings under our term loan with Bank of America bear interest at Bank of America prime (3.25% at December 31, 2008). Based on the current debt structure, a 1% increase in interest rates would increase interest expense by approximately $681,000 per year, based on an aggregate of $68.1 million outstanding under our credit facilities as of December 31, 2008. As of December 31, 2008, we did not have any interest rate swaps to hedge our interest risks.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

None.

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ITEM 9A. 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, 2008, 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(b) 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, 2008, 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.

Management s Report on Internal Control Over Financial Reporting

Management is responsible for the fair presentation of the consolidated financial statements of Gulfport Energy Corporation. Management is also responsible for establishing and maintaining a system of internal controls over financial reporting as defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. These internal controls are designed to provide reasonable assurance that the reported financial information is presented fairly, that disclosures are adequate and that the judgments inherent in the preparation of financial statements are reasonable. There are inherent limitations in the effectiveness of any system of internal control, including the possibility of human error and overriding of controls. Consequently, an effective internal control system can only provide reasonable, not absolute, assurance with respect to reporting financial information.

Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in Internal Control Integrated Framework, management did not identify any material weaknesses in our internal control over financial reporting and concluded that our internal control over financial reporting was effective as of December 31, 2008.

Grant Thornton LLP, the independent registered public accounting firm that audited our financial statements for the year ended December 31, 2008 included with this Annual Report on Form 10-K, has also audited our internal control over financial reporting as of December 31, 2008, as stated in their accompanying report.

/s/ James D. Palm	/s/ Michael G. Moore
Name: James D. Palm	Name: Michael G. Moore
Title: Chief Executive Officer	Title: Chief Financial Officer

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders

Gulfport Energy Corporation:

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

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

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

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

In our opinion, Gulfport Energy Corporation and Subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Gulfport Energy Corporation and Subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of operations, stockholders equity and comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2008 and our report dated March 16, 2009 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

March 16, 2009

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

For information concerning Item 10 Directors, Executive Officers and Corporate Governance, 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. EXECUTIVE COMPENSATION

For information concerning Item 11 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 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

For information concerning Item 12 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 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

For information concerning Item 13 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 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

For information concerning Item 14 Principal Accounting Fees and Services, 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).

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

List the following documents filed as part of this report:

Exhibit Number	Description
2.1	Purchase and Sale Agreement, dated as of November 28, 2007, by and among Ambrose Energy I, Ltd. and each of the other persons, which are listed as a party seller, and Windsor Permian (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 24, 2007).
2.2	Second Amendment to the Purchase and Sale Agreement, dated as of December 18, 2007, by and among Ambrose Energy I, Ltd., each of the other parties which are listed as a party seller, Windsor Permian and Gulfport (incorporated by reference to Exhibit 2.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 24, 2007).
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).
4.2	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).
4.3	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).
4.4	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).
4.5	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).
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).
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).

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Exhibit Number	Description
10.4+	Employment Agreement, dated as of May 18, 1999 and effective as of June 1, 1999, by and between the Registrant and Mike Liddell (incorporated by reference to Exhibit 10.5 of Amendment No. 1 to Form 10-KSB/A, File No. 000-19514, filed by the Company with the SEC on May 11, 2007).
10.5	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).
10.6	Second Amendment to Credit Agreement, dated as of July 19, 2007, between the Company and Bank of America, N.A. (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 19, 2007).
10.7	Note dated July 19, 2007 issued by the Company for the benefit of Bank of America, N.A. (incorporated by reference to Exhibit 10.2 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 19, 2007).
10.8	Third Amendment to Credit Agreement, dated as of December 20, 2007, between the Company, Bank of America, N.A., as a lender and administrative agent and such other lenders from time to time party hereto (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 26, 2007).
10.9	Note dated December 20, 2007 issued by the Company for the benefit of Bank of America, N.A. (incorporated by reference to Exhibit 10.2 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 26, 2007).
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.
23.3*	Consent of Pinnacle Energy Services, LLC
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.

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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 16, 2009

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 16, 2009	By:	/s/ JAMES D. PALM **James D. Palm** **Chief Executive Officer and Director** **(Principal Executive Officer)**
Date: March 16, 2009	By:	/s/ MIKE LIDDELL **Mike Liddell** **Chairman of the Board and Director**
Date: March 16, 2009	By:	/s/ MICHAEL G. MOORE **Michael G. Moore** **Vice President and Chief Financial Officer** **(Principal Financial and Accounting Officer)**
Date: March 16, 2009	By:	/s/ DONALD DILLINGHAM **Donald Dillingham** **Director**
Date: March 16, 2009	By:	/s/ DAVID L. HOUSTON **David L. Houston** **Director**
Date: March 16, 2009	By:	/s/ SCOTT E. STRELLER **Scott E. Streller** **Director**

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders

Gulfport Energy Corporation:

We have audited the accompanying consolidated balance sheets of Gulfport Energy Corporation and Subsidiaries (the Company) as of December 31, 2008 and 2007, and the related consolidated statements of operations, stockholders equity and comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Gulfport Energy Corporation and Subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Gulfport Energy Corporation and Subsidiaries internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 16, 2009 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

March 16, 2009

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GULFPORT ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(Amounts rounded to nearest thousand)

	December 31, 2008	December 31, 2007
Assets		
Current assets:		
Cash and cash equivalents	$ 5,944,000	$ 2,764,000
Accounts receivable oil and gas	12,543,000	10,510,000
Accounts receivable related parties	1,101,000	2,208,000
Prepaid expenses and other current assets	1,045,000	1,346,000
Total current assets	20,633,000	16,828,000
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $22,543,000 and $37,278,000 excluded from amortization in 2008 and 2007, respectively	599,761,000	484,487,000
Other property and equipment	7,168,000	7,108,000
Accumulated depletion, depreciation, amortization and impairment	(444,690,000)	(129,496,000)
Property and equipment, net	162,239,000	362,099,000
Other assets:		
Equity investments	25,440,000	33,822,000
Other assets	3,755,000	6,388,000
Note receivable related party	9,153,000	
Total other assets	38,348,000	40,210,000
Deferred tax asset	653,000	
Total assets	$ 221,873,000	$ 419,137,000
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 27,772,000	$ 39,848,000
Asset retirement obligation current	635,000	480,000
Current maturities of long-term debt	815,000	808,000
Total current liabilities	29,222,000	41,136,000
Asset retirement obligation long-term	8,634,000	8,154,000
Long-term debt, net of current maturities	69,916,000	65,725,000
Total liabilities	107,772,000	115,015,000
Commitments and contingencies (Notes 18 and 19)		
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, 42,639,201 issued and outstanding in 2008 and 42,453,587 in 2007	426,000	424,000
Paid-in capital	273,343,000	271,807,000
Accumulated other comprehensive income (loss)	(4,803,000)	2,254,000
Retained earnings (accumulated deficit)	(154,865,000)	29,637,000
Total stockholders equity	114,101,000	304,122,000
Total liabilities and stockholders equity	$ 221,873,000	$ 419,137,000

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(Amounts rounded to nearest thousand)

	Year Ended December 31, 2008	2007	2006
Revenues:			
Oil and condensate sales	$ 131,825,000	$ 100,120,000	$ 56,038,000
Gas sales	6,570,000	6,043,000	4,194,000
Natural gas liquid sales	3,255,000		
Other income (expense)	(433,000)	(325,000)	158,000
	141,217,000	105,838,000	60,390,000
Costs and expenses:			
Lease operating expenses	22,856,000	16,670,000	10,670,000
Production taxes	15,813,000	12,667,000	7,366,000
Depreciation, depletion, and amortization	42,472,000	29,681,000	12,652,000
Impairment of oil and gas properties	272,722,000		
General and administrative	6,843,000	5,802,000	3,251,000
Accretion expense	560,000	554,000	596,000
	361,266,000	65,374,000	34,535,000
INCOME (LOSS) FROM OPERATIONS	(220,049,000)	40,464,000	25,855,000
OTHER (INCOME) EXPENSE:			
Interest expense	4,762,000	3,091,000	1,956,000
Settlement of fixed price contracts	(39,000,000)		
Business interruption insurance recoveries			(3,601,000)
Insurance proceeds	(769,000)		
Interest income	(540,000)	(523,000)	(308,000)
	(35,547,000)	2,568,000	(1,953,000)
INCOME (LOSS) BEFORE INCOME TAXES	(184,502,000)	37,896,000	27,808,000
INCOME TAX EXPENSE		121,000	
NET INCOME (LOSS)	$ (184,502,000)	$ 37,775,000	$ 27,808,000
NET INCOME (LOSS) PER COMMON SHARE:			
Basic	$ (4.33)	$ 1.03	$ 0.85
Diluted	$ (4.33)	$ 1.01	$ 0.82

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY AND

COMPREHENSIVE INCOME (LOSS)

(Amounts rounded to nearest thousand)

	Common Stock		Additional	Accumulated Other	Retained Earnings	Total
	Shares	Amount	Paid-in Capital	Comprehensive Income (Loss)	(Accumulated Deficit)	Stockholders Equity
Balance at January 1, 2006	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
Net income					37,775,000	37,775,000
Other Comprehensive Income:						
Foreign currency translation adjustment				2,254,000		2,254,000
Total Comprehensive Income						40,029,000
Stock Compensation			1,158,000			1,158,000
Issuance of Common Stock in public offerings, net of related expenses of $740,000	8,547,500	85,000	138,173,000			138,258,000
Issuance of Restricted Stock	35,930					
Issuance of Common Stock through exercise of options	210,398	2,000	866,000			868,000
Balance at December 31, 2007	42,453,587	424,000	271,807,000	2,254,000	29,637,000	304,122,000
Net loss					(184,502,000)	(184,502,000)
Other Comprehensive Income (Loss):						
Foreign currency translation adjustment				(7,057,000)		(7,057,000)
Total Comprehensive Income (Loss)						(191,559,000)
Stock Compensation			1,056,000			1,056,000
Issuance of Restricted Stock	41,493					
Issuance of Common Stock through exercise of options	144,121	2,000	480,000			482,000

Balance at December 31, 2008	42,639,201	$ 426,000	$ 273,343,000	$ (4,803,000)	$ (154,865,000)	$ 114,101,000

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Amounts rounded to nearest thousand)

	Year Ended December 31,		
	2008	**2007**	**2006**
Cash flows from operating activities:			
Net income (loss)	$ (184,502,000)	$ 37,775,000	$ 27,808,000
Adjustments to reconcile net income to net cash provided by operating activities:			
Accretion of discount Asset Retirement Obligation	560,000	554,000	596,000
Depletion, depreciation and amortization	42,472,000	29,681,000	12,652,000
Impairment of oil and gas properties	272,722,000		
Stock-based compensation expense	634,000	845,000	787,000
Loss from equity investments	656,000	477,000	76,000
Interest income note receivable	(410,000)		
Deferred income tax benefit	(653,000)		
Unrealized gain on hedge ineffectiveness			(24,000)
Changes in operating assets and liabilities:			
Increase in accounts receivable	(2,033,000)	(2,925,000)	(6,609,000)
Decrease in business interruption insurance settlement receivable			1,710,000
Decrease (increase) in accounts receivable related party	1,107,000	1,994,000	(832,000)
Decrease (increase) in prepaid expenses	301,000	(374,000)	(490,000)
Decrease in deposits			107,000
Increase in accounts payable and accrued liabilities	5,328,000	2,153,000	4,608,000
Increase in deferred hedge gains			(114,000)
Settlement of asset retirement obligation	(859,000)	(1,278,000)	(752,000)
Net cash provided by operating activities	135,323,000	68,902,000	39,523,000
Cash flows from investing activities:			
Additions to cash held in escrow	(40,000)	(121,000)	(105,000)
Additions to deposits for oil and gas properties		(3,080,000)	
Additions to other property, plant and equipment	(60,000)	(457,000)	(495,000)
Additions to oil and gas properties	(126,030,000)	(220,044,000)	(62,403,000)
Proceeds from sale of oil and gas properties		500,000	
Note receivable related party	(10,519,000)		
Investment in Grizzly Oil Sands ULC	(151,000)	(17,316,000)	(8,493,000)
Investment in Tatex Thailand II, LLC	862,000	(88,000)	(964,000)
Investment in Tatex Thailand III, LLC	(885,000)		
Investment in Windsor Bakken, LLC		(127,000)	(1,416,000)
Net cash used in investing activities	(136,823,000)	(240,733,000)	(73,876,000)
Cash flows from financing activities:			
Principal payments on borrowings	(25,802,000)	(47,158,000)	(10,809,000)
Borrowings on line of credit	30,000,000	76,000,000	38,300,000
Proceeds from issuance of common stock, net of offering costs of $740,000 and $479,000 for 2007 and 2006, respectively, and exercise of stock options	482,000	139,126,000	11,370,000
Net cash provided by financing activities	4,680,000	167,968,000	38,861,000
Net increase (decrease) in cash and cash equivalents	3,180,000	(3,863,000)	4,508,000
Cash and cash equivalents at beginning of period	2,764,000	6,627,000	2,119,000
Cash and cash equivalents at end of period	$ 5,944,000	$ 2,764,000	$ 6,627,000

Supplemental disclosure of cash flow information:						
Interest payments	$	4,898,000	$	3,341,000	$	1,956,000
Income tax payments	$	135,000	$	121,000	$	
Supplemental disclosure of non-cash transactions:						
Investment subscription payable	$		$	151,000	$	
Capitalized stock based compensation	$	422,000	$	313,000	$	276,000
Asset retirement obligation capitalized	$	934,000	$	500,000	$	405,000
Dissolution of interest in Windsor Bakken, LLC	$	2,468,000				
Foreign currency translation gain (loss) on investment in Grizzly Oil Sands ULC	$	(5,281,000)	$	2,254,000		
Foreign currency translation gain (loss) on note receivable related party	$	(1,776,000)				

See accompanying notes to consolidated financial statements.

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business

Gulfport Energy Corporation (Gulfport or the Company) is an independent oil and gas exploration, development and production company with its principal properties located in the Louisiana Gulf Coast and in West Texas in the Permian Basin and has investments in companies operating in Canada and Thailand.

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.

Principles of Consolidation

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

Accounts Receivable

The Company s accounts receivable oil and gas primarily are from companies in the oil and gas industry. The majority of its receivables are from two purchasers of the Company s oil and gas and one operator of certain of the Company s properties. 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, 2008 and December 31, 2007.

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, based on year-end prices and costs 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 $22,543,000 and $37,278,000 at December 31, 2008 and December 31, 2007, respectively. These costs are reviewed quarterly by management for impairment. If an impairment has

GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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occurred, the portion of cost in excess of the current value is transferred to 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 3 to 30 years.

Foreign Currency

The U.S. dollar is the functional currency for Gulfport s consolidated operations. However, the Company has an equity investment in a Canadian entity whose functional currency is the Canadian dollar. The assets and liabilities of the Canadian investment are translated into U.S. dollars based on the current exchange rate in effect at the balance sheet dates. Canadian income and expenses are translated at average rates for the periods presented. Translation adjustments have no effect on net income and are included in accumulated other comprehensive income in stockholders equity.

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 14.

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.

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GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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(Amounts rounded to nearest thousand)

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, 2008 and 2007 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 less than 50% 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. The Company reviews its investments to determine if a loss in value which is other than a temporary decline has occurred. If such loss has occurred, the Company recognizes an impairment provision. There was no impairment of equity method investments at December 31, 2008 or 2007.

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. 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 10). The shares of stock issued once the options are exercised will be from authorized but unissued common stock.

Accounting for Derivative Instruments and Hedging Activities

The Company may seek 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

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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, 2008 and 2007.

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. The estimate of the Company s oil and gas reserves is used to compute depletion, depreciation, amortization and impairment of oil and gas properties.

Recent Accounting Pronouncements

Effective January 1, 2008, the Company implemented FASB SFAS No. 157, *Fair Value Measurements.* SFAS No. 157 defines fair value, establishes a framework for its measurement and expands disclosures about fair value measurements. The Company elected to implement this Statement with the one-year deferral permitted by FASB Staff Position (FSP) 157-2 for nonfinancial assets and nonfinancial liabilities measured at fair value, except those that are recognized or disclosed on a recurring basis. The deferral applies to nonfinancial assets and liabilities measured at fair value in a business combination; impaired properties; plants and equipment; intangible assets and goodwill; and initial recognition of asset retirement obligations and restructuring costs for which fair value is used. The Company is currently assessing the impact, if any, of FSP No. FAS 157-2 in relation to nonfinancial assets and nonfinancial liabilities. The adoption of the provisions of SFAS No. 157 did not have a material impact on the Company s consolidated financial statements.

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. The Company adopted SFAS No. 159 effective January 1, 2008. The adoption did not have a material impact on the Company s consolidated financial statements.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS 141(R)), which replaces FASB Statement No. 141. SFAS 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. SFAS 141(R) also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for acquisitions that occur in an entity s fiscal year that begins after December 15, 2008. The Company is currently assessing the impact, if any, the adoption of SFAS 141(R) may have on any future acquisitions.

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In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements-an amendment of ARB No. 51*. SFAS No. 160 requires that accounting and reporting for minority interest will be recharacterized as noncontrolling interest and classified as a component of equity. SFAS No. 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interest of the parent and the interests of the noncontrolling owners. SFAS No. 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding noncontrolling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement is effective as of the beginning of an entity s first fiscal year beginning after December 15, 2008. The Company is currently assessing the impact, if any, of the adoption of SFAS No. 160.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133*. SFAS No. 161 requires enhanced disclosures for derivative and hedging activities, including (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under SFAS No. 133 and related interpretations, and (c) how derivative instruments and related hedged items affect an entity s financial position, results of operations, and cash flows. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The Company is currently assessing the impact, if any, of the adoption of SFAS No. 161.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*. SFAS No. 162 identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America (the GAAP hierarchy). This statement was effective November 15, 2008 (60 days following the SEC s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, *The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles)*. The adoption of SFAS No. 162 did not have a material impact to the Company s financial statements.

In December 2008, the Securities and Exchange Commission published a Final Rule, *Modernization of Oil and Gas Reporting*. The new rule permits the use of new technologies to determine proved reserves if those technologies have been demonstrated to lead to reliable conclusions about reserve volumes. The new requirements also will allow companies to disclose their probable and possible reserves. In addition, the new disclosure requirements require companies to (a) report the independence and qualifications of its reserve preparer, (b) file reports when a third party is relied upon to prepare reserve estimates or conducts a reserve audit, and (c) report oil and gas reserves using an average price based upon the prior 12 month period rather than year end prices. The use of average prices will impact future impairment and depletion calculations. The new requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. Early adoption is not permitted in quarterly reports prior to the first annual report in which the revised disclosures are required. The Company is currently assessing the impact of this Final Rule.

2. ACQUISITIONS

On December 20, 2007, Gulfport closed on the acquisition of an ownership interest in certain oil and gas properties located in the Permian Basin of West Texas, consisting of approximately 4,100 net acres with 32 gross producing wells from ExL Petroleum, LP and 12 other sellers. The effective date of the acquisition was November 1, 2007. The total purchase price for the assets, as adjusted at the original closing on December 20, 2007, was $85.2 million, which was recorded as oil and natural gas properties on the accompanying balance

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sheet. This amount includes an adjustment for the results of operations of the assets between the November 1, 2007 effective date and the December 20, 2007 closing date. The final post closing adjustments occurred 90 days from the original closing date of December 20, 2007, or March 20, 2008, and the purchase price was adjusted accordingly. The total adjusted purchase price for the assets was $83.8 million.

Gulfport funded this transaction predominately through a 4.5 million common share offering, which closed on December 12, 2007. The Company received net proceeds of approximately $75.6 million from the equity offering, as discussed in Note 9. The Company funded the remainder of the purchase price from borrowings under its line of credit.

The following unaudited pro forma results for the year ended December 31, 2006 show the effect on the Company s consolidated results of operations as if the acquisition had occurred on January 1, 2006. The unaudited pro forma results for the year ended December 31, 2007 show the effect on the Company s consolidated results of operations as if the acquisition had occurred on January 1, 2007. The pro forma results for the 2006 and 2007 periods presented are the result of combining the Company s consolidated statements of operations with the revenues and direct operating expenses of the acquired properties adjusted for (1) incremental depletion, depreciation, and amortization of oil and natural gas properties associated with the acquisition, amortized on a unit-of-production basis over the remaining life of total proved reserves, as applicable, (2) incremental accretion of discount on asset retirement obligation associated with the acquired properties, (3) estimated incremental interest expenses associated with borrowings under Gulfport s revolving credit facility to fund the acquisitions, and (4) the issuance of 4.5 million shares of common stock in the offering at January 1, 2006 and January 1, 2007 rather than December 12, 2007. The pro forma information is based upon numerous assumptions, and is not necessarily indicative of what the Company s actual results would have been or the Company s future results of operations.

	Unaudited Year Ended December 31, 2007	2006
Total revenue	$ 121,903,000	$ 64,458,000
Net income	46,799,000	29,029,000
Net income per common share:		
Basic	$ 1.14	$ 0.78
Diluted	$ 1.12	$ 0.76

3. HURRICANE INSURANCE

The Company sustained damage to both its Hackberry fields 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. 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 year ended December 31, 2006, the Company recognized $3,601,000 of business interruption insurance proceeds in other income in the consolidated statements of operations. 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. All business interruption recoveries were collected in 2006.

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4. ACCOUNTS RECEIVABLE RELATED PARTIES

Included in the accompanying December 31, 2008 and December 31, 2007 consolidated balance sheets 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, 2008 and December 31, 2007, these receivables totaled $1,101,000 and $2,208,000, respectively. The Company was reimbursed $1,363,000, $11,153,000 and $12,738,000 for the years ended December 31, 2008, 2007 and 2006, respectively, for general and administrative functions which are reflected as a reduction of general and administrative expenses in the consolidated statements of operations and include the amounts under service contracts discussed below.

The Company is or has been a party to administrative service agreements with Caliber Development Company, LLC, Bronco Drilling Company, Inc., Great White Energy Services LLC, and Diamondback Energy Services LLC. Under these agreements, the Company s services include accounting, human resources, legal and technical support. The services provided and the fees for such services can be amended by mutual agreement of the parties. Each of these administrative service agreements has a three-year term, and upon expiration of that term the agreements will continue on a month-to-month basis until cancelled by either party with at least 30 days prior written notice. Each administrative service agreement is terminable (1) by the counterparty 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 is also a party to administrative service agreements with Stampede Farms LLC, Grizzly Oil Sands ULC, Everest Operations Management LLC and Tatex Thailand III, LLC. Under these agreements, the Company s services include professional and technical support and office space. The services provided and the fees for such services can be amended by mutual agreement of the parties. Each of these administrative service agreements has a two-year term, and upon expiration of that term such agreement will continue on a month-to-month basis until cancelled by either party to such agreement with at least 60 days prior written notice. Each administrative service agreement is terminable (1) by the counterparty 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.

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The Company was reimbursed the following amounts by the specified entities in consideration for its administrative services for the years ended December 31, 2008, 2007 and 2006. These amounts are reflected as a reduction of general and administrative expenses in the consolidated statements of operations. Wexford Capital LLC (Wexford) controls and/or owns a greater than 10% interest in each of these entities. Affiliates of Wexford own approximately 36% of Gulfport s outstanding stock.

Agreement Effective Date	Entity	December 31, 2008	2007	2006
2/9/2005	Caliber Development Company, LLC**	$ 60,000	$ 1,249,000	$ 431,000
4/1/2005	Bronco Drilling Company, Inc. *			49,000
7/22/2006	Great White Energy Services LLC	83,000	754,000	2,222,000
9/26/2006	Diamondback Energy Services LLC**	10,000	17,000	823,000
3/1/2008	Stampede Farms LLC	159,000	123,000	
3/1/2008	Grizzly Oil Sands ULC	368,000	953,000	198,000
3/1/2008	Everest Operations Management LLC	154,000		
3/1/2008	Tatex Thailand III, LLC			

* Agreement was terminated effective April 1, 2006.

** Agreement was terminated effective December 10, 2008.

For the year ended December 31, 2008, the Company was also reimbursed approximately $20,000 and $26,000 by Stampede Farms LLC and Everest Operations Management LLC, respectively, for office space under the administrative service agreements, which is included in other income (expense) in the consolidated statements on operations.

Effective July 1, 2008, the Company is party to an acquisition team agreement with Everest Operations Management LLC (Everest) to identify and evaluate potential oil and gas properties in which the Company and Everest may wish to invest. Upon a successful closing of an acquisition or divestiture, each party participating in the successful closing shall pay a fee equal to 1% of its proportionate share of the acquisition or divestiture consideration to the party that identified the acquisition or divestiture. The agreement has a one year term unless earlier terminated by either party upon 30 days notice.

5. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of December 31, 2008 and 2007 are as follows:

	December 31, 2008	2007
Oil and gas properties	$ 599,761,000	$ 484,487,000
Office furniture and fixtures	2,982,000	2,922,000
Building	3,926,000	3,926,000

Land	260,000	260,000
Total property and equipment	606,929,000	491,595,000
Accumulated depletion, depreciation, amortization and impairment	(444,690,000)	(129,496,000)
Property and equipment, net	$ 162,239,000	$ 362,099,000

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At December 31, 2008, the net book value of the Company s oil and gas properties, less related deferred income taxes, was above the calculated ceiling as a result of reduced commodity prices at December 31, 2008. As a result, the Company was required to record an impairment of its oil and gas properties under the full cost method of accounting in the amount of $272.7 million for the year ended December 31, 2008.

Included in oil and gas properties at December 31, 2008 and December 31, 2007 is the cumulative capitalization of $10,614,000 and $5,969,000, respectively, 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 $4,645,000, $2,041,000 and $976,000 for the years ended December 31, 2008, 2007 and 2006, respectively.

The following is a summary of Gulfport s oil and gas properties not subject to amortization as of December 31, 2008:

	Costs Incurred in				
	2008	2007	2006	Prior to 2006	Total
Acquisition costs	$ 6,261,000	$ 13,766,000	$ 1,342,000	$	$ 21,369,000
Exploration costs	1,069,000	105,000			1,174,000
Development costs					
Total oil and gas properties not subject to amortization	$ 7,330,000	$ 13,871,000	$ 1,342,000	$	$ 22,543,000

At December 31, 2008, approximately $2,175,000 of oil and gas properties related to the Company s Belize properties is excluded from amortization as it relates to non-producing properties. In addition, approximately $12,592,000 of non-producing leasehold costs resulting from the Company s acquisition of West Texas Permian properties and $6,255,000 of non-producing leasehold costs related to the Company s Bakken properties are excluded from amortization at December 31, 2008. Approximately $1,521,000 of non-producing leasehold costs related to the Company s Southern Louisiana assets was also excluded from amortization. At December 31, 2007, approximately $37,278,000 of non-producing leasehold costs was not subject to amortization.

The Company evaluates the costs excluded from its amortization calculation at least annually. Subject to industry conditions and the level of the Company s activities, the inclusion of most of the above referenced costs into the Company s amortization calculation is expected to occur within three to five years.

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A reconciliation of the asset retirement obligation for the years ended December 31, 2008 and 2007 is as follows:

	December 31, 2008	December 31, 2007
Asset retirement obligation, beginning of period	$ 8,634,000	$ 8,858,000
Liabilities incurred	934,000	500,000
Liabilities settled	(859,000)	(1,278,000)
Accretion expense	560,000	554,000
Asset retirement obligation as of end of period	9,269,000	8,634,000
Less current portion	635,000	480,000
Asset retirement obligation, long-term	$ 8,634,000	$ 8,154,000

6. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of December 31, 2008 and 2007:

	December 31, 2008	December 31, 2007
Investment in Tatex Thailand II, LLC	$ 2,683,000	$ 3,553,000
Investment in Tatex Thailand III, LLC	876,000	
Investment in Windsor Bakken, LLC		2,468,000
Investment in Grizzly Oil Sands ULC	21,881,000	27,801,000
	$ 25,440,000	$ 33,822,000

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 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 2008, Gulfport paid $50,000 in cash calls and received $912,000 in distributions, bringing its total investment in Tatex (including previous investments) to $2,683,000. The Company recognized a loss on equity investment of $8,000 for the year ended December 31, 2008, which is included in other income (expense) in the consolidated statements of operations. The loss on equity investment related to Tatex was immaterial for the years ended December 31, 2007 and 2006.

Tatex Thailand III, LLC

During the first quarter of 2008, the Company purchased a 5% ownership interest in Tatex Thailand III, LLC (Tatex III) at a cost of $850,000. Approximately 68.7% of the remaining interests in Tatex III are owned by entities controlled by Wexford, an affiliate of Gulfport. During the year ended December 31, 2008, Gulfport paid $35,000 in cash calls, bringing its total investment in Tatex III to $876,000. The Company recognized a loss

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on equity investment of $9,000 for the year ended December 31, 2008 which is included in other income (expense) in the consolidated statements of operations.

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 entities controlled by Wexford, an affiliate of Gulfport. Beginning in 2005, Bakken acquired leases on undeveloped acreage in the Williston Basin areas of western North Dakota and eastern Montana. As of December 31, 2007, Gulfport s net investment in Bakken was $2,468,000. As of December 31, 2007, Bakken had commenced drilling of some of its undeveloped acreage. The Company recognized losses on equity investment of $92,000 and $48,000 for the years ended December 31, 2007 and 2006, respectively, which are included in other income (expense) in the consolidated statements of operations.

Effective January 1, 2008, the Company acquired a direct, undivided 20% interest in Bakken s assets in redemption of its 20% interest in Bakken. As a result, the Company recognized $2,468,000 of oil and natural gas assets which was included in oil and natural gas properties on the accompanying consolidated balance sheets.

Grizzly Oil Sands ULC

During the third quarter of 2006, the Company, through its wholly owned subsidiary Grizzly Holdings Inc., purchased a 24.9999% interest in Grizzly Oil Sands ULC (Grizzly), a Canadian unlimited liability company, for approximately $8.2 million. The remaining interests in Grizzly are owned by entities controlled by Wexford, an affiliate of Gulfport. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray near other oil sands development projects. Grizzly has commenced drilling of core holes for feasibility of oil production in five separate lease blocks but has not commenced development of operations. As of December 31, 2008 and 2007, Gulfport s net investment in Grizzly was $21,881,000 and $27,801,000, respectively. Grizzly s functional currency is the Canadian dollar. The Company s investment in Grizzly was decreased by $5,281,000 as a result of a currency translation loss for the year ended December 31, 2008 and increased by $2,254,000 as a result of a currency translation gain for the year ended December 31, 2007. The Company recognized a loss on equity investment of $639,000, $385,000 and $28,000 for the years ended December 31, 2008, 2007 and 2006, respectively, which is included in other income (expense) in the consolidated statements of operations.

The Company, through its wholly owned subsidiary Grizzly Holdings Inc., entered into a loan agreement with Grizzly effective January 1, 2008, under which Grizzly may borrow funds from the Company. Borrowed funds bear interest at LIBOR plus 400 basis points. Interest is paid on a paid-in-kind basis by increasing the outstanding balance of the loan. The loan matures on December 31, 2012. The Company loaned Grizzly approximately $10,519,000 during the year ended December 31, 2008. The Company recognized interest income of approximately $410,000 for the year ended December 31, 2008, which is included in interest income in the consolidated statements of operations. The note balance was decreased by approximately $1,776,000 as a result of a currency translation loss for the year ended December 31, 2008. The total $9,153,000 due from Grizzly is included in note receivable related party on the accompanying consolidated balance sheets.

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7. OTHER ASSETS

Other assets consist of the following as of December 31, 2008 and 2007:

	December 31, 2008	December 31, 2007
Plugging and abandonment escrow account on the WCBB properties (Note 18)	$ 3,144,000	$ 3,104,000
Certificates of Deposit securing letter of credit	200,000	200,000
Prepaid drilling costs	407,000	
Deposits	4,000	3,084,000
	$ 3,755,000	$ 6,388,000

8. LONG-TERM DEBT

A break-down of long-term debt as of December 31, 2008 and 2007 is as follows:

	December 31, 2008	December 31, 2007
Reducing credit agreement (1)	$ 64,521,000	$ 59,521,000
Term loan (1)	3,588,000	4,294,000
Building loans (2)	2,622,000	2,718,000
Less: current maturities of long term debt	(815,000)	(808,000)
Debt reflected as long term	$ 69,916,000	$ 65,725,000

Maturities of long-term debt as of December 31, 2008 are as follows:

2009	$ 815,000
2010	65,343,000
2011	3,128,000
2012	714,000
2013	714,000
Thereafter	17,000
Total	$ 70,731,000

(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. Effective July 19, 2007, the credit facility was increased to $150.0 million and the amount available under the borrowing base limitation was increased to $60.0 million. On December 20, 2007, the amount available under the borrowing base limitation was increased to $90.0 million and the Eurodollar interest rate, which the Company can elect to use at its option, was reduced by 0.75%. In addition, the maturity date was extended from March 31, 2009 to March 31, 2010. The facility is subject to

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annual and semi-annual redeterminations. The Company is currently in the process of a redetermination based on year-end reserve information and bank pricing decks, among other considerations. Preliminary indications from the bank indicate that the Company s borrowing base under this facility may be reset at approximately $60.0 million, but the exact outcome cannot be predicted at this time. 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 0.5% (3.75% at December 31, 2008). The Company s obligations under the credit facility are collateralized by a lien on substantially all of the Company s Louisiana and West Texas assets. The credit facility contains certain affirmative and negative covenants, including, but not limited to the following financial covenants: (a) 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 (b) 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 in compliance with all covenants at December 31, 2008. As of December 31, 2008, approximately $64.5 million was outstanding under this facility, which is included in long-term debt, net of current maturities on the accompanying consolidated balance sheet.

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 began amortizing quarterly on March 31, 2007 on a straight-line basis over seven years based on the outstanding principal balance at December 31, 2006. The Company makes quarterly principal payments of approximately $176,000. Amounts borrowed bear interest at Bank of America Prime (3.25% at December 31, 2008). 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, 2008, approximately $3.6 million was outstanding under this agreement, of which $714,000 and $2.9 million 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) In June 2004, the Company purchased the office building it occupies in Oklahoma City, Oklahoma, for $3.7 million. 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. In addition, the building loans included a loan related to a building in Lafayette, Louisiana, purchased in 1996 to be used as the Company s Louisiana headquarters. This loan bore interest at the rate of 5.75% per annum. The Company paid this loan in full during the third quarter of 2007, in advance of its February 2008 maturity date. The remaining building loan requires monthly interest and principal payments of approximately $23,000 and is collateralized by the Oklahoma City office building and associated land.

9. 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 all directors of the Company, all officers of the Company and all key employees of the Company with a customary work week of at

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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, 2008. 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 (i) 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 (ii) 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, 2008, the Company has granted 997,269 options for the purchase of shares of the Company s common stock under the 2005 Plan.

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.

On April 1, 2007, the Company granted 16,389 shares of restricted common stock of the Company. These shares vest monthly over a three year period. On May 15, 2007, the Company granted 10,000 shares of restricted common stock of the Company. These shares vest in equal monthly installments over a three year period. On August 14, 2007, the Company granted 8,000 shares of restricted common stock of the Company. These shares vest in equal monthly installments over a three year period. On November 9, 2007, the Company granted 3,000 shares of restricted common stock of the Company. These shares vest in equal monthly installments over a three year period.

On March 13, 2008, the Company granted 6,666 shares of restricted common stock of the Company, of which 740 shares vested on April 1, 2008 with the remaining shares vesting over 36 equal monthly installments beginning on May 1, 2008. On August 6, 2008, the Company granted 2,000 shares of restricted common stock of the Company. The shares vest over twelve equal quarterly installments beginning on September 17, 2008. On

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September 15, 2008, the Company granted 10,000 shares of restricted common stock of the Company. The shares vest over twelve equal quarterly installments beginning on September 17, 2008. On December 5, 2008, the Company granted 66,667 shares of restricted common stock of the Company. The shares vest over twelve equal quarterly installments beginning on December 17, 2008. All shares of restricted common stock of the Company were granted under the amended and restated 2005 Plan.

Exercise of Warrants

During the first quarter of 2006, holders of warrants issued by the Company in 2002 in conjunction with a private placement offering exercised their warrants resulting in 12,171 shares of the Company s common stock being issued. No proceeds were received by the Company related to the exercise of these warrants. During the third quarter of 2006, holders of warrants exercised their warrants resulting in 101,681 shares of the Company s common stock being issued. The Company had 60,550 warrants outstanding at December 31, 2008 which can be converted into 203,529 shares of common stock at an exercise price of $1.19 per share. The warrants expire in 2012.

Sale of Common Stock

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 certain of the Company s stockholders 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 approximately $10.5 million from the sale of these shares on May 10, 2006 after deducting the underwriting discount and before offering expenses.

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. The Company 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.

In May 2007, the Company sold 1,500,000 shares of common stock in an underwritten offering at an offering price to the public of $16.00 per share. In connection with the offering, the Company granted the underwriter an option to purchase up to an additional 225,000 shares of common stock to cover any over-allotments, which the underwriter exercised in full. The Company received the net proceeds of approximately $26.8 million from the sale of these shares on May 22, 2007 after deducting the underwriting discount and before offering expenses.

In July 2007, the Company sold 1,000,000 share of common stock in an underwritten offering at an offering price to the public of $22.00 per share. The Company received the net proceeds of approximately $21.2 million from the sale of these shares on July 25, 2007 after deducting the underwriting discount and before offering expenses.

In December 2007, the Company sold 4,500,000 shares of common stock in an underwritten offering at an offering price to the public of $17.50 per share. The Company received the net proceeds of approximately $75.6 million from the sale of these shares on December 12, 2007 after deducting underwriting discounts and before

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offering expenses. In connection with the offering, a selling stockholder granted the underwriter an option to purchase an additional 675,000 shares of common stock to cover any over-allotments, which the underwriter exercised in full. The Company did not receive any proceeds from the sale of shares of the common stock by the selling stockholder.

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 (the Preferred) and (ii) a warrant to purchase up to 250 shares of common stock, par value $0.01 per share, of the Company (the Warrants). 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 a current 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 the Warrants and did not consider them materially significant. At December 31, 2008 and 2007, 60,550 Warrants were outstanding.

10. STOCK-BASED COMPENSATION

During the years ended December 31, 2008, 2007 and 2006, the Company s stock-based compensation cost was $1,056,000, $1,158,000 and $1,063,000, respectively, of which the Company capitalized $422,000, $313,000 and $276,000, respectively, relating to its exploration and development efforts, which reduced basic and diluted earnings per share by $0.01 and $0.02 for the years ended December 31, 2008 and December 31, 2007, respectively.

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 2005 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.

No stock options were issued during the year ended December 31, 2008 and 2007. The following table provides information relating to stock options granted for the year ended December 31, 2006:

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

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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.

A summary of the status of stock options and related activity for the years ended December 31, 2008, 2007 and 2006 are presented below:

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
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
Granted				
Exercised	(210,398)	4.13		2,284,000
Forfeited/expired	(82,445)	3.66		
Options outstanding at December 31, 2007	674,390	6.22	6.97	$ 8,098,000
Granted				
Exercised	(144,121)	3.34		1,694,000
Forfeited/expired	(7,889)	6.17		
Options outstanding at December 31, 2008	522,380	$ 7.01	6.24	$ (1,599,000)