GULFPORT ENERGY CORP
Form 10KSB
March 31, 2006

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-KSB

(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, 2005**

OR

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

Commission File Number: 000-19514

Gulfport Energy Corporation

(Name of Small Business Issuer in its Charter)

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

(405) 848-8807

(Issuer s Telephone Number, Including Area Code)

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

Securities registered pursuant to Section 12(g) of the Act: **Common Stock, par value $0.01 per share**

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

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

Check if there is no disclosure of delinquent filers in response to Item 405 of Regulation S-B contained in this form, and no disclosure will be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-KSB or any amendment to this Form 10-KSB. ¨

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

Registrant s revenues for its most recent fiscal year: $27,559,000

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of March 21, 2006 was $168,262,000.

As of March 21, 2006, 32,180,326 shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Certain information called for by Part III is incorporated by reference to certain sections of the Company s Information Statement will be filed with the Securities and Exchange Commission not later than 120 days after December 31, 2005.

Transitional Small Business Disclosure Format (check one): Yes ¨ No x

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FORWARD-LOOKING STATEMENTS

Our disclosure and analysis in this Form 10-KSB may include forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act, and the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. Forward-looking statements give our current expectations and projections relating to our financial condition, results of operations, plans, objectives, future performance and business. You can identify these statements by the fact that they do not relate strictly to historical or current facts. These statements may include words such as anticipate, estimate, expect, project, intend, plan, believe and other words and terms of similar meaning in connection with any discuss timing or nature of future operating or financial performance or other events. All statements other than statements of historical facts included in this Form 10-KSB that address activities, events or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements.

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

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

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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 properties located along the Louisiana Gulf Coast. Our operations are concentrated in two fields: West Cote Blanche Bay, or WCBB, and the Hackberry fields. We seek to achieve reserve growth and increase our cash flow by undertaking drilling programs each year. In 2005, we drilled 17 wells and recompleted 11 existing wells in our WCBB field for a total cost to date of $20.1 million. Of our 17 new wells, nine were completed as producing wells, seven were waiting to be completed at year end (one of which will be side-tracked in 2006 to test deeper zones) and one was a dry hole. During 2006, we intend to drill 22 wells and recomplete 18 existing wells at our WCBB field for an estimated aggregate cost of $34.0 million. To date in 2006, we have drilled nine new wells of which seven are awaiting completion and two were dry holes. During 2005, we completed a 3-D seismic program at our East Hackberry field to enhance our drilling program at that field and we currently intend to drill up to six wells in 2006 for an estimated aggregate cost of $12.5 million. As of December 31, 2005, we had 23.2 MMboe of proved reserves with a present value of estimated future net revenues, discounted at 10%, or PV-10, of approximately $456.9 million and associated standardized measure of discounted future net cash flows of approximately $369.8 million. See Item 2. Description of Property Proved Oil and Natural Gas Reserves for our definition of PV-10, a non-GAAP financial measure, and a reconciliation of our standardized measure of discounted future net cash flows to PV-10.

Principal Oil and Natural Gas Properties

We own interests in producing oil and natural gas properties located along the Louisiana Gulf Coast. The following table presents certain information as of December 31, 2005 reflecting our net interest in our principal producing oil and natural gas properties in Louisiana.

		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)	79.443/100	0	0	258	258	5,668	5,668	2,937	16,663	19,600
E. Hackberry	78.7/100	6	6	70	70	3,147	3,147	693	2,717	3,410
W. Hackberry	87.5/100	3	3	24	24	592	592		157	157
Overrides/Royalty Non-operated	Various	9	0.4	28	1.3	4,956	586		5	5
Total		18	9.4	380	353.3	14,363	9,993	3,630	19,542	23,172

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

(2) On September 21, 2005, we began shutting in all of our producing wells at WCBB and the Hackberry fields in preparation for the arrival of Hurricane Rita. Six of our 11 producing wells in the Hackberry fields returned to production in November 2005. Our WCBB facilities, however, sustained more damage and the 57 wells that were producing on September 20, 2005 before the hurricane struck remained shut-in at December 31, 2005. As a result, all of these wells have been classified as non-producing wells at December 31, 2005 in the above table. Our main tank batteries and gas sales line became operational, and we began returning wells to production, in February 2006. As of March 24, 2006, 27 of the 57 active wells at WCBB prior to Hurricane Rita had returned to production. We expect the remaining wells, as well as 14 additional wells drilled at WCBB after the hurricane but not completed due to the damage to our facilities, to commence production during the second quarter of 2006.

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

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(4) We have a 100% working interest (79.443% average NRI) from the surface to the base of the 13,900 Sand which is located at 11,320 feet. Below the base of the 13,900 Sand, we have a 40.40% non-operated working interest (29.95% NRI).

West Cote Blanche Bay Field

Location and Land

The WCBB field lies approximately five miles off the coast of Louisiana, primarily in St. Mary Parish, in a shallow bay with water depths averaging eight to ten feet. Currently, we own a 100% working interest (79.4% NRI in most of the lease), and are the operator, in depths above the base of the 13,900 Sand which is located at 11,320 feet. In addition, we own a 40.4% non-operated working interest (30.0% NRI) in depths below the base of the 13,900 Sand. Chevron Corporation is the operator below the base of the 13,900 Sand. Our leasehold interests at WCBB cover a portion of Louisiana State Lease 340 and 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 846 wells drilled as of December 31, 2005, 766 were completed as producing wells. As a result, the field has a historic success rate of 90% for all wells drilled. As of September 20, 2005, estimated field cumulative gross production was 193 MMbo and 234 Bcf of gas.

Of the 846 wells drilled in WCBB as of December 31, 2005, 57 were producing prior to being shut-in on September 21, 2005 in preparation for Hurricane Rita, nine were drilled after Hurricane Rita but not completed by year end, 172 were shut-in, 30 were producing intermittently and five were being used as salt water disposal wells. The other 573 wells have been plugged and abandoned. During the period January 1, 2005 through September 21, 2005 (when our wells were shut-in in preparation for Hurricane Rita), our net daily production at WCBB averaged 2,125 barrels of oil, 2,132 Mcf of gas and 11,470 barrels of water.

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 the most recent advances in seismic data processing.

From our acquisition of WCBB in 1997 through December 31, 2005, we drilled 61 new wells,seven of which were dry holes, for an 89% success rate. These wells produced 2,749 gross Mboe through December 31, 2005. We have also re-completed 45 existing wells resulting in 26 producing wells. These re-completed wells produced 1,193 gross Mboe through December 31, 2005.

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.

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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 846 wellbores that had been drilled in the field as of December 31, 2005, over 4,000 potential zones have been penetrated. These sands are highly porous and permeable reservoirs primarily with a strong water drive.

WCBB is a structurally and stratigraphically complex field. All of the proved undeveloped, or PUD, locations at WCBB are adjacent to faults and abut at least one fault. Our drilling programs are designed to penetrate each PUD trap with a new wellbore in a structurally optimum position, usually very close to the fault seal. The majority of these wells have been, and new wells drilled in connection with our drilling programs will be, directionally drilled using steering tools and downhole motors. The tolerance for error in getting near the fault is low, so the complex faulting does introduce the risk of crossing the fault before encountering the zone of interest, which could result in part or all of the zone being absent in the borehole. This, in turn, can result in lower than expected or no reserves for that zone. The new wellbores eliminate the mechanical risk associated with trying to produce the zone from an old existing wellbore, while the wellbore locations are selected in an effort to more efficiently drain each reservoir. The vast majority of the PUD targets are up-dip offsets to wells that produced from a sub-optimal position within a particular zone. Our inventory of prospects includes 122 PUD wells. The drilling schedule used in the reserve report anticipates that all of those wells will be drilled by 2015.

Facilities

We own and operate a production facility at WCBB that includes four production tank batteries and is equipped with hydrocarbon separation equipment, four natural gas compressor platforms, a dehydration unit and a salt water disposal system. We sustained minimal damage to our facilities at WCBB from Hurricane Katrina which came onshore on August 29, 2005. Our WCBB facilities were shut-in and evacuated for precautionary reasons for only four days. On September 24, 2005, however, the tidal surge from Hurricane Rita caused damage to our WCBB facilities and all of our active WCBB wells were shut-in. Our main tank batteries, which handled approximately 70% of our production before Hurricane Rita, and the gas sales line are now operational, and we anticipate that the balance of our production facilities at WCBB will be brought on line in the second and third quarters of 2006. We began returning WCBB wells to production on February 5, 2006, and as of March 24, 2006, 27 of the 57 active wells in the field prior to Hurricane Rita had been returned to production. We continue to reactivate our remaining shut-in WCBB wells and are in the process of completing 14 wells that have been drilled after Hurricane Rita but not completed due to the damage to our facilities caused by that storm. We expect that all of these wells will begin producing during the second quarter of 2006. We have an insurance program in place that we believe will adequately cover damage to our platform and facilities at WCBB. In addition, business interruption insurance has helped mitigate the financial impact of Hurricane Rita on our WCBB operations. Once fully operational, we believe our facilities will have capacity in excess of our current and anticipated production volumes.

Recent and Future Activity

In 2005, we drilled 17 wells and recompleted 11 existing wells at WCBB. Of these 17 new wells, nine were completed as producers, seven were drilled subsequent to Hurricane Rita and have not yet been completed (including one that will be side-tracked in 2006 to test deeper zones) and one was a dry hole. We anticipate drilling 22 wells and 18 recompletions at WCBB during 2006. As of March 24, 2006, we had drilled nine new wells and production casing has been run on seven of these wells, bringing to 14 the number of wells that have been drilled but not yet been completed due to the effects of Hurricane Rita. The 14 wells that are now in the process of being completed are expected to begin producing in the second quarter of 2006. The remaining two wells drilled in 2006 were dry holes.

The nine wells we have drilled at WCBB to date in 2006 include three deep wells, two intermediate depth wells and four shallow wells. The deep wells, with total depths ranging from 8,850 to 9,400 feet, have approximately 373 feet of apparent net pay, the intermediate wells, with total depths ranging from 5,000 to 7,500

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feet, have approximately 188 feet of apparent net pay and two of the shallow wells, at depths of less than 3,000 feet, have 40 feet of apparent net pay. Two additional shallow wells were unsuccessful, including one exploratory well that was drilled to satisfy our drilling commitment to hold the non-productive portions of WCBB.

In the second quarter of 2006, we anticipate drilling a 12,000 foot wildcat test well targeting the higher-pressure gas zones in the field for an anticipated well cost of approximately $5.5 million. The cost of this wildcat well is approximately four times the cost of a typical well drilled to 9,500 feet, and has more geologic risk. However, we believe the additional geological risk is warranted by the higher reserve and production potential of the wildcat test. We have also identified other deeper wildcat gas test wells on the WCBB salt dome acreage, as well as undrilled conventional depth fault blocks. We expect to test these exploratory prospects in 2007 and thereafter based on our drilling results and as cash flow generated by our more conventional drilling targets allow a prudent exploration budget to be pursued.

Production Status

On September 20, 2005, prior to Hurricane Rita, 57 wells, including nine productive wells we drilled in 2005, were producing and total net production at WCBB on that date was 2,480 Boe, 85% of which was from oil and 15% of which was from natural gas, an increase of 100% from December 31, 2004. On March 24, 2006, total net production at WCBB from 27 of the 57 active wells that were shut-in in preparation for Hurricane Rita was 2,137 Boe, 93% of which was from oil and 7% of which was from natural gas. We expect our WCBB production to increase substantially in the second quarter of 2006 as the remaining wells shut-in for Hurricane Rita are returned to production and our 14 new wells drilled after the hurricane, together with additional wells that are now being drilled as part of our 2006 drilling program, are completed and brought on-line.

East Hackberry Field

Location and Land

The East Hackberry field is located along the western shore of Lake Calcasieu in Cameron Parish, Louisiana approximately 80 miles west of Lafayette and 15 miles inland from the Gulf of Mexico. We own a 100% working interest (approximately 79% average NRI) in certain producing oil and natural gas properties situated in the East Hackberry field. The interest includes two separate lease blocks, the Erwin Heirs Block, which is located on land, and the adjacent State Lease 50 Block, which is located primarily in the shallow waters of Lake Calcasieu. The two lease blocks together contain 3,147 acres.

Area History and Production

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

Geology

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

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Facilities

We have land-based production and processing facilities located at the East Hackberry field. The facilities include dehydrating units and disposal pumps. We also have a field office that serves both the East and West Hackberry fields.

Recent and Future Activity

During 2005, we completed a proprietary 42 square mile 3-D seismic survey at East Hackberry for a total cost in 2004 and 2005 of approximately $5.0 million. Given that previous drilling activities at the East Hackberry field were undertaken without the benefit of modern seismic information, we believe that the newly acquired 3-D seismic data will enhance our probability of drilling success. We are evaluating the newly processed 3-D seismic data to identify additional drilling locations. We currently intend to drill six wells during 2006 to measured depths of approximately 13,000 feet using directional drilling techniques. The 3-D seismic data also suggests the possibility of deep gas production and, as a result, we intend to drill a deep wildcat well during 2007 for a total anticipated well cost of approximately $4.0 million. If productive, multiple offset locations could be drilled.

Prior to shutting-in our 11 producing East Hackberry wells on September 20, 2005 in preparation for Hurricane Rita, aggregate net production was approximately 270 Boe. Production was re-established from six of these wells in November 2005, and on March 24, 2006, aggregate net production from these wells was approximately 192 Boe. Due to damage to certain of our production facilities caused by Hurricane Rita, five wells in our State Lease 50 Block remain shut-in. Prior to being shut-in, these five wells in the field had aggregate production of approximately 50 bopd with a limited amount of gas. We plan on replacing or upgrading certain of our East Hackberry facilities in connection with our 2006 drilling program and intend to put the five remaining shut-in wells back on line when these facilities are completed.

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. This West Hackberry storage facility occupies 525 acres and has capacity to store 222 barrels in underground salt caverns.

Area History and Production

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 2005 was 184 Mbo and 127 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. On March 24, 2006, aggregate net production from the wells was approximately 83 barrels of oil.

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.

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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.

Additional Properties

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

Field	Parish	Acreage Working Interest	Overriding Royalty Interests	Producing Wells	Non-Producing Wells
Bayou Long	Iberia	3.125%	0%	1	0
Bayou Penchant	Terrebonne	3.125%	0%	1	13
Bayou Pigeon	Iberia	6.250%	0%	4	8
Deer Island	Terrebonne	6.250%	0%	0	6
Golden Meadow	Lafourche	3.125%	0%	0	1
Napoleonville	Assumption	0%	2.5%	3	0

Thailand. During March 2005, we purchased a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex, at a cost of $2,400,000. The remaining interests in Tatex are owned by other entities controlled by Wexford Capital LLC, or Wexford, an affiliate of ours. Tatex holds approximately 8.5% of the outstanding shares of APICO, LLC, or APICO, an international oil and gas exploration company, and our investment is accounted for on the cost method. APICO has a reserve base located in Southeast Asia through its ownership interests in concessions covering 3 million acres. Our interest in Tatex includes proved reserves, net to our interest of 3.36 Bcf of gas and 10,082 barrels of oil at August 1, 2005, the latest date that reserve information is available to us.

Williston Basin. During 2005, we purchased a 20% ownership interest in Windsor Bakken, LLC, or Bakken. The remaining interests in Bakken are owned by other entities controlled by Wexford, an affiliate of ours. As of December 31, 2005, Bakken had acquired leases covering approximately 83,300 gross and 41,600 net acres, all of which is undeveloped, in the Williston Basin located in western North Dakota and eastern Montana. The Williston Basin has production from 11 major geologic horizons that range in depth from 1,000 to over 14,000 feet, with our current zones of interest lying at depths ranging from 9,000 to 12,000 feet. Activities in this basin are expected to include both exploration and development drilling programs to different horizons including the Bakken shale. It is currently contemplated that Bakken will contribute all of its assets to Windsor Energy Resources, Inc., or Windsor Energy, in connection with Windsor Energy s proposed initial public offering. We would receive an indirect equity interest in Windsor Energy as a result of that contribution. Windsor Energy is beneficially owned by Wexford and is an affiliate of ours.

Marquiss Field. In February 2005, we acquired our interest in the Marquiss field, an approximately 9,500 net acre coalbed methane play in Campbell County, Wyoming, for $375,000. As of December 31, 2005, the Marquiss field included a total of 162 wells, of which 105 were producing and 57 were shut-in. The effective date of the sale was December 1, 2004. The wells produce from multiple horizons with additional upside potential from deeper coals and operational efficiencies. The Marquiss field contained proved gas reserves net to our interest of 212,548 Mcf at December 31, 2005. We plan to contribute these properties to Windsor Energy, an affiliate of our company, in connection with its initial public offering in exchange for common stock of Windsor Energy.

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

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on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These competitors may be better positioned to take advantage of industry opportunities and to withstand changes affecting the industry, such as fluctuations in oil and natural gas prices and production, the availability of alternative energy sources and the application of government regulation.

The availability of a ready market for any oil and/or natural gas we produce depends on numerous factors beyond the control of our management, including but not limited to the extent of domestic production and imports of oil, the proximity and capacity of gas pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of gas sold in interstate commerce. The oil and natural gas we produce in Louisiana is sold to purchasers who service the areas where our wells are located. We sell the majority of our oil to Shell Trading Company, or Shell. Shell takes custody of the oil at the outlet from our oil storage barge. Our production is being sold in accordance with the posted price for West Texas/New Mexico Intermediate crude plus Platt s trade month average P+ value, plus or minus the Platt s WII/LLS differential less $0.85 per barrel for transportation. During 2005, we sold 99% of our oil production to Shell and 88% of our natural gas production to Chevron. During 2004, we sold 99% of our oil production to Shell and 68% and 21% of our natural gas production to Chevron and Apache Corporation, respectively. Our wells are not subject to any agreements that would prevent us from either selling our production on the spot market or committing such natural gas to a long-term contract; however, there can be no assurance that we will continue to have ready access to suitable markets for our future oil and natural gas production.

Production from our Marquiss field in Wyoming is gathered in the field and delivered to Western Gas Resources at two gas sales meters located in our field. We are paid based on a Gas Daily CIG index net of various deductions for gathering, quality and fuel for compression.

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

We established an oil price-hedging program in August 2005 to reduce our exposure to unfavorable changes in oil prices, which are subject to significant and often volatile fluctuation, by taking receive-fixed positions in price swap contracts. We pay the counterparty the excess of the oil market price over the fixed price and will receive the excess of the fixed price over the market price as defined in each contract. These contracts allow us to predict with greater certainty the effective oil prices to be received for hedged production and benefit operating cash flows and earnings when market prices are less than the fixed prices provided in the contracts. However, we will not benefit from market prices that are higher than the fixed prices in the contracts for hedged production. For the year ended December 31, 2005, fixed-price contracts hedged 8.7% of our oil production. As of December 31, 2005, fixed-price contracts were in place to hedge 540,000 barrels of estimated future production during 2006.

Regulation

Regulation of Gas and Oil Production

Oil and natural gas operations are subject to various types of regulation by state and federal agencies. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and natural gas industry and its individual members, some of which 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.

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

Environmental Regulation

Our oil and natural gas exploration, development and production operations are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental agencies, such as the U.S. Environmental Protection Agency, or EPA, issue regulations to implement and enforce such laws, which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties or may result in injunctive relief 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 remedial action to prevent pollution from former operations, such as plugging abandoned wells or closing pits, and impose substantial liabilities for pollution resulting from our operations. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry in general. Our management believes that we are in substantial compliance with current applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements; this trend, however, may not continue in the future.

Waste Handling. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes, affect oil and natural gas exploration and production activities by imposing regulations on the generation, transportation, treatment, storage, disposal and cleanup of hazardous wastes and on the disposal of 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 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 and production wastes as hazardous wastes.

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

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, also known as CERCLA or the Superfund law, generally imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current owner or operator of a contaminated facility, a former owner or operator of the facility at the time of contamination and those persons that disposed or arranged for the disposal of the hazardous substance. Under CERCLA, 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. Therefore, governmental agencies or third parties may seek to hold us responsible under CERCLA for all or part of the costs to clean up sites at which such hazardous substances have been deposited.

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

Air Emissions. The federal Clean Air Act, and associated state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Some of our new facilities will be required to obtain permits before work can begin, permits may be required for our facilities operations, and existing facilities may be required to incur capital costs to remain in compliance. These 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 air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations. Obtaining permits has the potential to delay the development of oil and natural gas projects.

Operational Hazards and Insurance

Our operations are subject to all of the risks normally incident to the production of oil and natural gas, including blowouts, cratering, pipe failure, casing collapse, oil spills and fires, each of which could result in severe damage to or destruction of oil and natural gas wells, production facilities or other property, or injury to persons. The energy business is also subject to environmental hazards, such as oil spills, gas leaks, and ruptures and discharge of toxic substances or gases that could expose us to substantial liability due to pollution and other environmental damage. Although we maintain insurance coverage considered to be customary in the industry for a company of our size, we are not fully insured against certain of these risks, either because such insurance is not available or because of high premium costs. 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 used as our Louisiana headquarters.

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This building contains approximately 6,200 square feet of finished office area and 6,300 square feet of clear span warehouse area.

Employees

At December 31, 2005, we had 63 employees. Certain of our employees perform management and administrative services for affiliated companies. We are reimbursed by these affiliates for the salaries and benefits of these individuals based on the estimated time they spent working for those affiliates. In addition, we receive 100% of the COPAS overhead charges billed to these affiliated companies. For the years ended December 31, 2005 and 2004, expenses reimbursed to us under these arrangements were $6,232,000 and $2,146,000, respectively, and are reflected as a reduction in our general and administrative expenses. A Louisiana well servicing company serves as contract operator of WCBB and the Hackberry fields and provides all necessary field personnel.

ITEM 2. DESCRIPTION OF PROPERTY

Proved Oil and Natural Gas Reserves

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

The following table sets forth estimates of our proved oil and natural gas reserves at December 31, 2005 and 2004, as estimated by Netherland, Sewell & Associates.

	December 31, 2005			December 31, 2004		
	Developed	**Undeveloped**	**Total**	**Developed**	**Undeveloped**	**Total**
Oil (MBbls)	4,308	15,234	19,542	4,633	16,272	20,905
Gas (MMcf)	3,758	18,022	21,780	4,635	18,527	23,162
Mboe	4,934	18,238	23,172	5,405	19,360	24,765
PV-10 (in millions) (1)	$ 135.9	$ 321.0	$ 456.9	$ 89.5	$ 272.0	$ 361.5
Standardized measure (in millions) (2)			$ 369.8			$ 301.0

(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, 2005. The estimated future production is priced at December 31, 2005, without escalation using $57.75 per barrel and $10.08 per MMBtu, adjusted by lease for transportation fees and regional price differentials.

PV-10 is a non-GAAP measure because it excludes income tax effects. Management believes that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. PV-10 is not a measure of financial or operating performance under GAAP. PV-10 should not be considered

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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,	
	2005	2004
Standardized measure of discounted future net cash flows	$ 369,824,000	$ 301,047,000
Add: Present value of future income tax discounted at 10%	87,086,000	60,495,000
PV-10 value	$ 456,910,000	$ 361,542,000

(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 (a) proved reserves, net to our interest in Tatex, of 3.36 Bcf of gas and 10,082 barrels of oil at August 1, 2005 or (b) proved reserves attributable to our Marquiss field of 212,584 Mcf of gas at December 31, 2005. For further discussion of our interest in Tatex and the Marquiss field, see Item 1. Description of Business Additional Properties.

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

Total proved reserves decreased 1,593 Mboe to 23,172 Mboe at December 31, 2005 from 24,765 at December 31, 2004. This decrease in reserves is mainly attributable to reserve revisions and reductions related to our 2005 production. Further, a significant portion of the reserves that were categorized as proved developed producing at December 31, 2004 have been recategorized as proved developed non-producing shut-in or proved undeveloped as a result of the damage caused by Hurricane Rita in September 2005.

Production, Prices, and Production Costs

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

	2005	2004	2003
Production Volumes:			
Oil (MBbls)	517	584	571
Gas (MMcf)	575	284	123
Oil Equivalents (Mboe)	613	631	592
Average Prices:			
Oil (per Bbl)	$ 46.39[(1)]	$ 36.97[(1)]	$ 27.66[(1)]
Gas (per Mcf)	$ 5.98	$ 5.24	$ 4.04
Oil Equivalents (per Mboe)	$ 44.75	$ 36.58	$ 26.70
Average Production Costs (per Boe)	$ 12.04[(2)]	$ 10.44[(2)]	$ 9.93[(2)]
Average Production Taxes (per Boe)	$ 5.91	$ 4.17	$ 3.17
Total Production Costs (per Boe)	$ 17.95	$ 14.61	$ 13.10

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(1) Includes fixed contract prices of:

January 2003	$ 28.50
February 2003	$ 28.34
March 2003	$ 27.95
April 2003	$ 27.08
May 2003	$ 26.95
June 2003	$ 24.27
July 2003	$ 24.33
August 2003	$ 24.42
September 2003	$ 24.45
October 2003	$ 24.45
November 2003	$ 24.25
December 2003	$ 24.10
January June 2004	$ 30.00
July December 2004	$ 33.60
January June 2005	$ 33.10
July December 2005	$ 39.70

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

Excluding the effect of the fixed price contracts, the average oil price for 2005 would have been $56.17 per barrel and $52.99 per barrel oil equivalent price. Excluding the effect of the fixed price contracts, the average oil price for 2004 would have been $42.72 per barrel and $41.88 per barrel oil equivalent price. Excluding the effect of the fixed price contracts, the average oil price for 2003 would have been $32.38 per barrel and $32.08 per barrel oil equivalent price.

(2) Does not include production taxes.

Productive Wells and Acreage

The following table presents our total gross and net productive wells, expressed separately for oil and gas, and the total gross and net developed acres as of December 31, 2005:

	Producing Wells (1)		**Non-Producing Wells**		**Developed Acreage (2)**	
Field	**Gross**	**Net**	**Gross**	**Net**	**Gross (3)**	**Net (4)**
West Cote Blanche Bay	0	0	258	258	5,668	5,668
E. Hackberry	6	6	70	70	3,147	3,147
W. Hackberry	3	3	24	24	592	592
Overrides/Royalty Non-operated	9	0.4	28	1.3	4,956	586
Total	18	9.4	380	353.3	14,363	9,993

(1) On September 21, 2005, we began shutting-in all of our producing wells at WCBB and the Hackberry fields in preparation for the arrival of Hurricane Rita. Six of our 11 producing wells in the Hackberry fields returned to production in November 2005. Our WCBB facilities, however, sustained more damage and the 57 wells that were producing on September 30, 2005 before the hurricane struck remained shut-in at December 31, 2005. As a result, all of these wells have been classified as non-producing wells at December 31, 2005 in the

above table. Our main tank batteries and gas sales line became operational, and we began returning wells to production, in February 2006. As of March 24, 2006, 27 of the 57 active wells

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at WCBB prior to Hurricane Rita had returned to production. We expect the remaining wells, as well as 14 additional wells drilled at WCBB after the hurricane but not completed due to the damage to our facilities, to commence production during the second quarter of 2006.

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

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

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

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.

	2005 (1)		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Recompletions:						
Productive	11	11	13	13	8	8
Dry	0	0	0	0	1	1
Total	11	11	13	13	9	9
Development:						
Productive	16	16	8	8	7	7
Dry	0	0	0	0	0	0
Exploratory:						
Productive	0	0	0	0	0	0
Dry	1	1	0	0	1	1

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

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

We have been named as a defendant in various lawsuits. The ultimate resolution of these matters is not expected to have a material adverse effect on our financial condition or results of operations.

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

On October 18, 2005, a majority of our stockholders of record as of September 9, 2005 approved Amendment No. 1 to our 2005 Stock Incentive Plan by written consent. The written consent of common stockholders was executed by stockholders holding over 61% of the shares of common stock eligible to vote. On December 22, 2005, a majority of our stockholders of record as of November 30, 2005 approved an amendment to our Restated Certificate of Incorporation increasing the total number of shares of capital stock that we are authorized to issue from 40,000,000 to 60,000,000 and increasing the maximum authorized number of shares of common stock from 35,000,000 to 55,000,000 shares.

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PART II

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

Through February 27, 2006, our common stock was traded on the NASD OTC Bulletin Board under the symbol GPOR.OB. Since February 28, 2006, our common stock has been quoted on The Nasdaq National Market under the symbol GPOR. The following table sets forth for the indicated periods the high and low sale prices of our common stock in each quarter:

	Low	High
Year Ending December 31, 2005		
First Quarter	$ 3.24	$ 5.90
Second Quarter	$ 5.00	$ 6.90
Third Quarter	$ 6.70	$ 11.50
Fourth Quarter	$ 9.49	$ 12.75
Year Ending December 31, 2004		
First Quarter	$ 2.80	$ 3.40
Second Quarter	$ 2.15	$ 3.00
Third Quarter	$ 1.55	$ 3.90
Fourth Quarter	$ 2.75	$ 4.00

On March 21, 2006, the last reported sale price of our common stock on The Nasdaq National Market was $14.79. The above quotations prior to February 28, 2006 reflect inter-dealer prices, without retail mark-up, markdown or commissions and may not represent actual transactions.

Holders of Record

At the close of business on March 21, 2006, there were 401 stockholders of record holding 32,180,326 shares of our outstanding common stock.

Dividend Policy

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

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

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

2005 Highlights

Oil and natural gas revenues increased 19% to $27,423,000 for the year ended December 31, 2005 from $23,071,000 for 2004.

Net income increased 153% to $10,895,000 for the year ended December 31, 2005 from $4,304,000 for 2004.

Oil production decreased 11% to 517 MBbls for the year ended December 31, 2005 from 584 MBbls for 2004 due to damage caused by Hurricane Rita during September 2005. See Impact of Hurricanes below.

Redemption of Preferred Stock During 2005, we used the proceeds from warrants exercised during the year, together with a portion of the proceeds from our sale of common stock in February 2005, to redeem all of our outstanding Series A preferred stock for an aggregate of $14,300,000, including accrued but unpaid dividends.

We commenced our 2005 WCBB drilling program in March 2005 and drilled 17 wells and recompleted 11 wells during the year. Of our 17 new wells drilled, nine were completed as producing wells, seven are waiting on completion due to the impact of Hurricane Rita (including one that will be side-tracked in 2006 to test deeper zones) and one was unsuccessful.

Impact of Hurricanes

WCBB. We sustained no damage to our facilities at WCBB from Hurricane Katrina which made landfall on August 29, 2005. Prior to that storm, both our Hackberry and WCBB facilities were shut-in and evacuated for four days for precautionary reasons. In our WCBB field, we used the shut-in period to implement tie-in points for future facilities upgrades.

On September 24, 2005, the tidal surge from Hurricane Rita caused damage to our WCBB and East Hackberry facilities and both fields were shut-in. At WCBB, our main tank batteries, which handled approximately 70% of our production before Hurricane Rita, and the gas sales line are now operational, and we anticipate that the balance of our production facilities at WCBB will be brought on line in the second and third quarters of 2006. We began returning wells to production on February 5, 2006, and as of March 24, 2006, 27 of the 57 active wells in the field prior to Hurricane Rita had been returned to production. We continue to reactivate our remaining shut-in WCBB wells and are in the process of completing 14 that have been drilled after Hurricane Rita but not completed due to the damage to our facilities caused by that storm. We expect that all of these wells will begin producing during the second quarter of 2006.

On September 20, 2005, prior to Hurricane Rita, aggregate net oil production at WCBB was 2,026 barrels of oil, an increase of 51% from December 31, 2004, and aggregate net gas production was 2,030 Mcf of gas, an increase of 19% from December 31, 2004. We have resumed production at WCBB from 27 of the 57 wells that were active prior to Hurricane Rita, with aggregate daily net production ranging from 1,445 to 2,291 barrels of oil and 1,066 to 1,840 Mcf of gas per day during the period March 20, 2006 through March 30, 2006.

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Hackberry Fields. On September 20, 2005, prior to shutting in our 11 producing East Hackberry wells in preparation for Hurricane Rita, aggregate net production was approximately 270 Boe. Production was re-established from six of these wells in November 2005, and on March 24, 2006, aggregate net production from these wells was approximately 192 Boe. Due to damage to certain of our production facilities caused by Hurricane Rita, five wells in our State Lease 50 Block remain shut-in. Prior to being shut-in, these five wells had aggregate production of approximately 50 bopd with a limited amount of gas. We plan on replacing or upgrading certain of our East Hackberry facilities in connection with our 2006 drilling program and intend to put the five remaining shut-in wells back on line when these facilities are completed.

Insurance Coverage. As of December 31, 2005, we had incurred costs of $3,221,000 relating to the damage to our WCBB fields and facilities caused by Hurricane Rita. As of March 16, 2006, we had incurred an additional $2,027,000 in hurricane related costs subsequent to December 31, 2005 at WCBB. Based upon consultations with insurance adjustors and review of our policies, we believe this entire amount will be covered by our insurance. We also maintain business interruption insurance to cover lost production revenue from WCBB in the event of shut-in production. The business interruption insurance begins 60 days after the occurrence of an insurable event, subject to a daily limit of $45,000 and has a maximum coverage of 180 days. Coverage began on November 24, 2005 for shut-in production from WCBB caused by Hurricane Rita. During 2005, we accrued $1,710,000 of business interruption insurance recoveries in other income in our statement of operations, which amount we received subsequent to year end.

Critical Accounting Policies and Estimates

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

Oil and Natural Gas Properties. We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including nonproductive costs and certain general and administrative costs associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. Net capitalized costs are limited to the estimated future net revenues, after income taxes, discounted at 10% per year, from proven oil and natural gas reserves and the cost of the properties not subject to amortization. Such capitalized costs, including the estimated future development costs and site remediation costs, if any, are depleted by an equivalent units-of-production method, converting gas to barrels at the ratio of six Mcf of gas to one barrel of oil. No gain or loss is recognized upon the disposal of oil and natural gas properties, unless such dispositions significantly alter the relationship between capitalized costs and proven oil and natural gas reserves. Oil and natural gas properties not subject to amortization consist of the cost of undeveloped leaseholds and totaled $113,000 at December 31, 2005 and $1,600 at December 31, 2004. 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.

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

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 risk-adjusted 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.

In March 2005, the FASB issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47). FIN 47 clarifies the definition and treatment of conditional asset retirement obligations as discussed in SFAS No. 143, *Accounting for Asset Retirement Obligations*. A conditional asset retirement obligation is defined as an asset retirement activity in which the timing and/or method of settlement are dependent on future events that may be outside the control of the company. FIN 47 states that a company must record a liability when incurred for conditional asset retirement obligations if the fair value of the obligation is reasonably estimable. FIN 47 is intended to provide more information about long-lived assets and future cash outflows for these obligations and more consistent recognition of these liabilities. FIN 47 is effective for fiscal years ending after December 15, 2005. We do not believe that our financial position, results of operations or cash flows will be materially impacted by implementation of FIN 47.

Oil and Gas Reserve Quantities. Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. NSAI has prepared a reserve report 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. NSAI has prepared our reserve estimates, and the projected cash flows derived from these reserve estimates, 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 eventually recovered.

Income Taxes. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized in the year in which realization becomes determinable. Periodically, management performs a forecast of its taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established, if in management s opinion, it is more likely that not that some portion will not be realized. At December 31, 2005 and 2004, a valuation allowance of $37,677,000 and $41,458,000, respectively, had been provided for deferred tax assets.

Revenue Recognition. Gas revenues are recorded in the month produced using the entitlement method, whereby any production volumes received in excess of our ownership percentage in the property are recorded as a liability. If less than our entitlement is received, the underproduction is recorded as a receivable. There was no such liability or asset recorded at December 31, 2005 or 2004. Oil revenues are recognized when ownership transfers, which occurs in the month produced.

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.

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 statement of financial position, 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 the 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 other comprehensive income until the hedged item is recognized in

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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.

Results of Operations

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

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

	2005	2004	2003
Production Volumes:			
Oil (MBbls)	517	584	571
Gas (MMcf)	575	284	123
Oil Equivalents (Mboe)	613	631	592
Average Prices:			
Oil (per Bbl)	\$ 46.39(1)	\$ 36.97(1)	\$ 27.66(1)
Gas (per Mcf)	\$ 5.98	\$ 5.24	\$ 4.04
Oil Equivalents (per Mboe)	\$ 44.75	\$ 36.58	\$ 26.70
Average Production Costs (per Boe)	\$ 12.04(2)	\$ 10.44(2)	\$ 9.93(2)
Average Production Taxes (per Boe)	\$ 5.91	\$ 4.17	\$ 3.17
Total Production Costs (per Boe)	\$ 17.95	\$ 14.61	\$ 13.10

(1) Includes fixed contract prices of:

January 2003	\$ 28.50
February 2003	\$ 28.34
March 2003	\$ 27.95
April 2003	\$ 27.08
May 2003	\$ 26.95
June 2003	\$ 24.27
July 2003	\$ 24.33
August 2003	\$ 24.42
September 2003	\$ 24.45
October 2003	\$ 24.45
November 2003	\$ 24.25
December 2003	\$ 24.10
January June 2004	\$ 30.00
July December 2004	\$ 33.60
January June 2005	\$ 33.10
July December 2005	\$ 39.70

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

Excluding the effect of the fixed price contracts, the average oil price for 2005 would have been \$56.17 per barrel and \$52.99 per barrel oil equivalent price. Excluding the effect of the fixed price contracts, the

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average oil price for 2004 would have been $42.72 per barrel and $41.88 per barrel oil equivalent price. Excluding the effect of the fixed price contracts, the average oil price for 2003 would have been $32.38 per barrel and $32.08 per barrel oil equivalent price.

(2) Does not include production taxes.

From 2003 to 2004, our production increased 6% due primarily to our 2004 drilling program. From 2004 to 2005, our oil production decreased 11% due primarily to a loss of production during the fourth quarter 2005 as a result of the damage caused to our facilities from Hurricane Rita in September 2005. We currently estimate that our 2006 production will be between 1,300,000 and 1,400,000 Boe s with production increasing during the year.

Comparison of the Years Ended December 31, 2005 and December 31, 2004

We reported net income of $10,895,000 for the year ended December 31, 2005 as compared with net income of $4,304,000 for the year ended December 31, 2004. The increase in net income was due primarily to increases in oil and natural gas prices and decreases in our general and administrative and interest expenses.

Oil and Gas Revenues. For the year ended December 31, 2005, we reported oil and gas revenues of $27,423,000**,** a 19% increase from revenues of $23,071,000 during 2004. This increase in revenues was primarily attributable to a 25% increase in the average oil price received for the year ended December 31, 2005 to $46.39 from $36.97 for 2004. This price increase was partially offset by an 18,000 barrel decrease in the number of barrels of oil produced to 613,000 Boe for the year ended December 31, 2005 from 631,000 Boe for 2004. This decrease was primarily the result of our loss of production during the fourth quarter 2005 due to the damage to our facilities from Hurricane Rita in September 2005. Also contributing to the increase in revenues was (1) a 14% increase in the average price received for our gas to $5.98 per Mcf for the year ended December 31, 2005 from $5.24 per Mcf for 2004 and (2) a 102% increase in net gas produced and sold to 575,000 Mcf for the year ended December 31, 2005 from 284,000 Mcf for 2004. This increase in gas production was primarily the result of our 2005 drilling program commenced in March 2005 and the acquisition of the Marquiss gas property in Wyoming in early 2005.

Lease Operating Expenses. Lease operating expenses not including production taxes increased to $7,654,000 for the year ended December 31, 2005 from $6,586,000 for 2004. This increase was mainly due to fuel and field electricity costs and other additional lease operating expenses related to the Wyoming gas properties purchased in early 2005 as well as increases in wages for contract labor and in the cost of supplies for our WCBB and Hackberry fields. This amount also includes unreimbursed repairs for the $250,000 physical damage insurance deductible related to our Hurricane Rita insurance claim.

Production Taxes. Production taxes increased to $3,622,000 for the year ended December 31, 2005 from $2,629,000 for 2004. This increase was directly related to the increases in oil and natural gas sale proceeds for the year ended December 31, 2005 as compared to 2004.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense decreased to $4,789,000 for the year ended December 31, 2005, and consisted of $4,468,000 in depletion on oil and natural gas properties and $321,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $4,952,000 for the year ended December 31, 2004. This decrease was due primarily to a decrease in our production in the fourth quarter due to Hurricane Rita partially offset by an increase in our oil and natural gas property costs as a result of our 2005 drilling program commenced in March 2005.

General and Administrative Expenses. General and administrative expenses are calculated net of reimbursements from affiliates under the terms of administrative services agreements. Such expenses decreased to $1,561,000 for the year ended December 31, 2005 from $2,107,000 for 2004. This was due primarily to a

$4,086,000 increase in general administrative reimbursements from our affiliates to $6,232,000 in 2005 from $2,146,000 in 2004 offset, in part, by increases in the cost of administrative services provided to our affiliates, legal expenses and employee headcount and related salaries and benefits.

Accretion Expense. Accretion expense increased slightly to $516,000 for the year ended December 31, 2005 from $490,000 for 2004, due to a larger obligation at the beginning of 2005 as compared to the beginning of 2004. This resulted from the addition of future abandonment obligations related to wells drilled during 2005 and the acquisition of the Wyoming gas properties also during 2005.

Interest Expense. Interest expense remained relatively constant at $250,000 for the year ended December 31, 2005 as compared to $246,000 for 2004.

Interest Expense Preferred Stock. In accordance with SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* which we adopted in May 2003, we recorded $272,000 of interest expense on our outstanding Series A preferred stock for the year ended December 31, 2005 as compared to $1,949,000 for 2004. During the year ended December 31, 2005, we redeemed all of our outstanding shares of the Series A preferred stock.

Income Taxes. As of December 31, 2005, we had a net operating loss, or NOL, carryforward of approximately $100,356,000, in addition to numerous temporary differences, which gave rise to a deferred tax asset. Periodically, management performs a forecast of 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, 2005, a valuation allowance of $37,677,000 had been provided for deferred tax assets. We had no income tax expense due to a change in the valuation allowance for deferred income taxes for the year ended December 31, 2005.

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, borrowings under our bank and other credit facilities and, from time to time, the sale of oil and natural gas properties. Our ability to access any of these sources of funds can be significantly impacted by unexpected decreases in oil and natural gas prices. To mitigate the effects of commodity price fluctuations, we have entered into hedging contracts for 45,000 barrels of production per month from WCBB during 2006 at $64.05 per barrel.

Net cash flow provided by operating activities was $15,200,000 for the year ended December 31, 2005, as compared to net cash flow provided by operating activities of $8,403,000 for 2004. This increase was the result of higher revenues during the year ended December 31, 2005 due to higher oil and natural gas prices, offset partially by higher payments for hurricane related costs and higher production taxes.

Net cash used in investing activities for the year ended December 31, 2005 was $36,703,000 as compared to $15,123,000 for 2004. During 2005, we spent (a) $30,103,000 in additions to oil and natural gas properties, of which $19,879,000 was spent on our 2005 drilling program, $4,208,000 was spent on the seismic shoot in the East Hackberry field, with the remainder attributable to capitalized general and administrative expenses, expenses relating to our 2004 drilling program and capitalized workover and recompletion activities on existing wells, (b) $2,400,000 to purchase a 23.5% ownership interest in Tatex during March 2005, (c) $1,752,000 to acquire a 20% ownership interest in Bakken and (d) approximately $1,892,000 in additions to oil and gas properties due to the hurricanes. These capital expenditures were financed with cash flow provided by operations and a portion of the proceeds from our sale of common stock in February 2005 and the exercise of warrants primarily in the first quarter of 2005. During 2004, we spent $11,274,000 in additions to oil and natural gas properties, of which $9,054,000 was spent on our 2004 drilling program with the remainder spent on workover

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and recompletion activities on existing wells. In addition, $3,700,000 was used to purchase the building in Oklahoma City, Oklahoma that serves as our headquarters. We financed our capital expenditures with cash flow provided by operations, borrowings under our credit facilities and proceeds from the rights offering we completed in August 2004.

Net cash provided by financing activities for the year ended December 31, 2005 was $16,080,000 as compared to $12,720,000 for 2004. The 2005 amount is attributable to net cash proceeds of approximately $23,576,000 from the issuance of our common stock in two private placements and upon the exercise of outstanding warrants and options and borrowings of approximately $7,000,000 under our revolving credit facility with Bank of America, offset by the approximately $14,300,000 used to redeem all our outstanding shares of Series A preferred stock. The $12,720,000 provided by financing activities in 2004 includes (1) net cash proceeds of approximately $11,134,000 from a rights offering we completed in August 2004, after deducting offering expenses of approximately $120,000; (2) the issuance of notes with a combined original principal amount of $3,389,000 to finance the purchase of our headquarters building and (3) borrowings of $500,000 under our credit facility with CD Holdings, L.L.C., or CD Holdings, which was used to purchase a portion of the pipe needed for the wells to be drilled in our 2004 drilling program. We used approximately $2,200,000 to repay in full the outstanding balance of our line of credit with the Bank of Oklahoma. CD Holdings elected to apply outstanding principal and accrued but unpaid interest in the aggregate amount of $511,000 under its bridge loan to us to the subscription price payable by CD Holdings upon exercise of the rights issued to it in the rights offering.

Issuance of Equity. On February 17, 2005, we entered into a stock purchase agreement with certain accredited investors providing for the issuance by us of an aggregate of 2,000,000 shares of our common stock at a price of $3.50 per share for gross proceeds to us of $7,000,000. On February 22, 2005, we entered into another stock purchase agreement with certain other accredited investors providing for the issuance by us of an aggregate of 2,000,000 shares of our common stock at a price of $3.50 per share for proceeds to us of $7,000,000. The transactions closed effective as of February 18, 2005 and February 23, 2005, respectively. No underwriting discounts or commissions were paid in conjunction with the issuances.

In the first quarter of 2005, the holders of warrants to purchase 7,736,621 shares of our common stock exercised their warrants at an exercise price of $1.19 per share, resulting in proceeds to us of $9,200,000. During the fourth quarter of 2005, the holders of warrants to purchase 221,849 shares of our common stock exercised their warrants for an exercise price of $1.19 per share resulting in proceeds to us of $264,000. During the year ended December 31, 2005, we used the proceeds from the exercise of the warrants, along with a portion of the proceeds from the sale of common stock in February 2005, to redeem all outstanding shares of our Series A preferred stock for an aggregate redemption price of approximately $14,300,000, including accrued but unpaid dividends.

Credit Facilities. On March 11, 2005, we entered into a three-year secured reducing credit agreement providing for a $30.0 million revolving credit facility with Bank of America, N.A. Borrowings under the revolving credit facility are subject to a borrowing base limitation which was initially set at $18.0 million, subject to adjustment. On November 1, 2005, the amount available under the borrowing base limitation was increased to $23.0 million. The credit facility has a term of three years and all principal amounts of revolving loans outstanding under the credit facility, together with all accrued and unpaid interest and fees, will be due and payable on March 11, 2008. Amounts borrowed against the credit facility bear interest at Bank of America prime plus 0.25% (7.5% at December 31, 2005). Our obligations under the credit facility are collateralized by a lien on substantially all of our Louisiana based oil and natural gas assets. We expect to use the proceeds of any borrowings under the credit facility for the development and exploration of oil and natural gas properties and other capital expenditures, acquisition opportunities, and for general corporate purposes. As of March 20, 2006, $14.5 million was outstanding under this credit facility.

In June 2002, we entered into a $2.3 million line of credit with the Bank of Oklahoma. We subsequently extended the maturity date of this line of credit to July 1, 2005. There was no outstanding balance under this line

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of credit when it expired under its own terms on July 1, 2005. Amounts borrowed under the line bore interest at the prime rate charged from time to time by JPMorgan Chase plus 1%, with payments of interest on outstanding balances due monthly.

On April 30, 2004, in connection with our rights offering, we entered into a $3.0 million revolving credit facility with CD Holdings, one of our principal stockholders. Borrowings under the CD Holdings credit facility were due on the earlier of the closing of the rights offering or August 1, 2005, and bore interest at the rate of 10.0% per annum. The CD Holdings credit facility provided that if the rights offering was not completed, CD Holdings had the right to convert any borrowings plus any accrued but unpaid interest under the facility into shares of our common stock at a conversion price equal to $1.20 per share. Under the CD Holdings credit facility, CD Holdings had the option to apply the outstanding principal amount and any accrued but unpaid interest either (1) to the subscription price payable upon exercise of the rights issued to CD Holdings in the rights offering, or (2) to the purchase price for the common stock. Upon closing of the rights offering, $500,000 had been borrowed on the facility to fund a part of our 2004 drilling program. CD Holdings applied all amounts due it under this credit facility to the exercise price payable upon exercise of rights it received in the rights offering.

Building Loans. We have three loans associated with two of our buildings. One loan, in the original principal amount of $99,000, relates to a building in Lafayette, Louisiana that we purchased in 1996 to be used as our Louisiana headquarters. This loan matures in February 2008 and bears interest at the rate of 5.75% per annum. In addition, in June 2004 we purchased the office building we occupy in Oklahoma City, Oklahoma for $3,700,000. The two loans associated with this building mature in March 2006 and June 2011 and bear interest at the rate of 6% and 6.5%, respectively. All building loans require monthly interest and principal payments and are collateralized by the respective land and buildings.

Capital Expenditures. Our primary capital requirements over the past several years have related to the development of our proved reserves and obligations under our credit facilities and outstanding Series A preferred stock.

Our strategy is to continue to (1) increase cash flow generated from our operations by undertaking new drilling, workover, sidetrack and recompletion projects to exploit our reserves and (2) explore other acquisition opportunities. We have upgraded our infrastructure and existing facilities to increase operating efficiencies and volume capacities and lower lease operating expenses. Additionally, we recently completed the reprocessing of 3-D seismic data in our principal property, WCBB. The reprocessed data will enable our geophysicists to continue to generate new prospects and enhance existing prospects in the intermediate zones in the field, thus creating a portfolio of new drilling opportunities.

In our December 31, 2005 reserve report, 79% of our net proved 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 utilize third parties to accomplish those activities.

Our inventory of prospects includes 122 PUD wells at WCBB. The drilling schedule used in the reserve report anticipates that all of those wells will be drilled by 2011. During 2006, we intend to drill 22 wells and 18 recompletions for an estimated aggregate cost of $34.0 million. As of March 25, 2006, we had drilled nine wells, of which seven are in the process of being completed and two were unsuccessful. We also plan to spend approximately $4.0 million during 2006 for facilities at WCBB, including the purchase of three new compressors.

During 2005, we completed a proprietary 42 square mile 3-D seismic survey at East Hackberry for a total cost of approximately $5.0 million. Given that previous drilling activities at the East Hackberry field were undertaken without the benefit of modern seismic information, we believe that the newly acquired 3-D seismic

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data will enhance our probability of drilling success. We are evaluating the newly processed 3-D seismic data to identify additional drilling locations. We currently intend to drill six wells during 2006 at East Hackberry to measured depths of approximately 13,000 feet using directional drilling techniques. We have budgeted $12.5 million for these wells. The 3-D seismic data also suggests the possibility of deep gas production and, as a result, we intend to drill a deep wildcat well during 2007 for a total anticipated well cost of approximately $4.0 million. If productive, multiple offset locations could be drilled. We have budgeted approximately $8.0 million during 2006 for new facilities and upgrades to existing facilities to support our proposed East Hackberry drilling program.

We believe that our cash on hand, insurance proceeds as described above under Impact of Hurricanes Insurance Coverage, cash flow from operations and borrowings under our credit facility will be sufficient to fund our capital expenditures for 2006.

Commitments

In connection with our 1997 acquisition of the remaining 50% interest in the WCBB properties, we assumed the seller s 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 these abandonment obligations have been fulfilled. Beginning in 2007, we can access the trust for use in plugging and abandonment charges associated with the property. As of December 31, 2005, the plugging and abandonment trust totaled approximately $2,878,000, including interest received during the year ended December 31, 2005 of approximately $62,000. We have plugged 188 wells at WCBB since we began our plugging program in 1997. We have fulfilled our funding obligations and are current in our plugging obligations. In addition, we have letters of credit totaling $200,000 secured by certificates of deposit being held for plugging costs in the East Hackberry field. Once specific wells are plugged and abandoned, the $200,000 will be returned to us.

New Accounting Pronouncements

SFAS No. 143

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 risk-adjusted 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.

In March 2005, the FASB issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47). FIN 47 clarifies the definition and treatment of conditional asset retirement obligations

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as discussed in SFAS No. 143, *Accounting for Asset Retirement Obligations*. A conditional asset retirement obligation is defined as an asset retirement activity in which the timing and/or method of settlement are dependent on future events that may be outside the control of the company. FIN 47 states that a company must record a liability when incurred for conditional asset retirement obligations if the fair value of the obligation is reasonably estimable. FIN 47 is intended to provide more information about long-lived assets and future cash outflows for these obligations and more consistent recognition of these liabilities. FIN 47 is effective for fiscal years ending after December 15, 2005. We do not believe that our financial position, results of operations or cash flows will be materially impacted by implementation of FIN 47.

SFAS No. 150

As a result of adopting Statement of Financial Accounting Standard (SFAS) No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* on July 1, 2003, we recorded a liability related to the Series A preferred stock of $14,020,000. Previously, the Series A preferred stock had been classified on the balance sheet between total liabilities and equity. This amount represented the 14,020 preferred shares issued and outstanding as of December 31, 2004, at the redemption and liquidation value of $1,000 per share. We redeemed all outstanding shares of the Series A preferred stock during 2005.

SFAS No. 123(R)

In December 2004, the FASB issued SFAS No. 123(R), *Share Based Payment*, which revised SFAS No. 123, *Accounting for Stock-Based Compensation*. SFAS No. 123(R) requires entities to measure the fair value of equity share-based payments (stock compensation) at grant date, and recognize the fair value over the period during which an employee is required to provide services in exchange for the equity instrument as a component of the income statement. SFAS No. 123(R) is effective for periods beginning after December 15, 2005. We have not evaluated the impact of adoption of SFAS No. 123(R), but adoption could have a material impact on our financial position and results of operations.

SFAS No. 154

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections*, which changes the accounting for and reporting of a change of accounting principle. It requires retrospective application of a change of accounting principle unless impracticable. SFAS No. 154 is effective for fiscal years beginning after December 15, 2005 and is not expected to have a material impact on our financial statements when adopted.

SFAS No. 155

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments*, which amends FASB Statements No. 133 and 140. SFAS No. 155 clarifies certain issues relating to embedded derivatives and beneficial interests in securitized financial assets. The provisions of SFAS 155 are effective for all financial instruments acquired or issued after fiscal years beginning after September 15, 2006. We are currently assessing the impact that the adoption of SFAS 155 will have on our financial statements.

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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 gas;
- weather conditions;
- the level of consumer demand;
- the price and availability of alternative fuels;
- 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-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. The West Texas Intermediate posted price for crude oil on December 31, 2004 was $43.45 per barrel and the Henry Hub spot market price of natural gas on December 31, 2005 was $6.21 per MMBtu and at December 31, 2003 were $32.52 per barrel and $6.19 per MMBtu. The West Texas Intermediate posted price for crude oil on December 31, 2005 was $57.75 per barrel and the Henry Hub spot market price of natural gas on December 31, 2005 was $10.08 per MMBtu. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves, and may result in write downs of oil and natural gas properties due to ceiling test limitations.

Our success depends on acquiring or funding 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 must commence exploratory drilling, undertake other replacement activities or use third parties to accomplish these activities. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration for and development, production and acquisition of oil and natural gas reserves. To date, we have financed capital expenditures primarily with funding from 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 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;

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- the prices at which oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

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

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, including drilling rigs and related equipment and services, horizontal drilling equipment and services, trucking services, tubulars, fracing and completion services and production equipment. The industry has experienced significant price increases for these services during the last year and this trend is expected to continue into the future. These cost increases could in the future significantly increase our development costs and decrease the return possible from drilling and development activities, and possibly render the development of certain proved undeveloped reserves uneconomical.

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 our our 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.

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

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of expenditures, including many factors beyond our control. The reserve information set forth in this Form 10-KSB represents only estimates based on reports prepared by NSAI as of December 31, 2005. 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

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assumptions concerning future oil and natural gas prices, future operating costs, severance and excise taxes, capital expenditures and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net cash flows expected therefrom prepared by different engineers or by the same engineers at different times may vary substantially. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

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

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

The timing of both our production and our incurrence of costs in connection with the development and production of oil and natural gas properties will affect the timing of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. PV-10 is a non-GAAP measure because it excludes income tax effects. See Item 2. Description of Property 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.

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

Our operations are focused on Louisiana, which means our producing properties are geographically concentrated in those areas. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from this region caused by natural disasters such as hurricanes, significant governmental regulation, lack of infrastructure, transportation capacity constraints, curtailment of production or interruption of transportation of natural gas produced from the wells in Louisiana. See Item 6. Management s Discussion and Analysis of Financial Condition and Results of Operations Impact of Hurricanes and Item 1. Description of Business West Cote Blanche Bay Field, East Hackberry Field and West Hackberry Field for a discussion regarding the impact of Hurricane Rita and Hurricane Katrina.

Operating hazards and uninsured risks may result in substantial losses.

Our operations are subject to all of the hazards and operating risks inherent in drilling for and production of oil and 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. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks. We cannot assure you that any insurance will be adequate to cover any losses or liabilities. We also cannot predict the continued availability of insurance, or its availability at premium levels that justify its purchase. In addition, we may be liable for environmental damage caused by previous owners of properties purchased by us, which liabilities would not be covered by insurance.

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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 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 primarily 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 solid 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/or natural gas we produced depends on numerous factors beyond the control of our management, including but not limited to the extent of domestic production and imports of oil, the proximity and capacity of gas pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of gas sold in interstate commerce. The oil and natural gas we produce in Louisiana is sold to purchasers who service the areas where our wells are located. We sell the majority of our oil to Shell Trading Company, or Shell. Shell takes custody of the oil at the outlet from our oil storage barge. Our production is being sold in accordance with the posted price for West Texas/New Mexico Intermediate crude plus Platt s trade month average P+ value, plus or minus the Platt s WII/LLS differential less $0.85 per barrel for transportation. During 2005, we sold 99% of our oil production to Shell and 88% of our natural gas production to Chevron. During 2004, we sold 99% of our production to Shell and 68% and 21% of our natural gas production to Chevron and Apache Corporation, respectively. Our wells are not subject to any agreements that would prevent us from either selling our production on the spot market or committing such gas to a long-term contract; however, there can be no assurance that we will continue to have ready access to suitable markets for our future oil and natural gas production.

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, with the exception of Mr. Liddell, 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

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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.

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.

Our interpretation of seismic data delineates for us those portions of an area that we believe are desirable for drilling. Therefore, we may chose not to acquire option or lease rights prior to acquiring seismic data and, in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in the location. If we are not able to lease those locations on acceptable terms, it would result in our having made substantial expenditures to acquire and analyze 3-D data without having an opportunity to attempt to benefit from those expenditures.

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

In order to reduce our exposure to short-term fluctuations in the price of oil and natural gas, we periodically enter into hedging arrangements. Our hedging arrangements apply to only a portion of our production and provide only partial price protection against declines in oil and natural gas prices. Such hedging arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected, our customers fail to purchase contracted quantities of oil or natural gas or a sudden, unexpected event materially impacts oil or natural gas prices. In addition, our hedging arrangements may limit the benefit to us of increases in the price of oil and natural gas.

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

We will be required to comply with the provisions of Section 404 of the Sarbanes-Oxley Act of 2002 as of December 31, 2007. Section 404 requires that we document and test our internal control over financial reporting and issue management s assessment of our internal control over financial reporting. This section also requires that our independent registered public accounting firm opine on those internal controls and management s assessment of those controls. We are currently evaluating our existing controls against the standards adopted by the Committee of Sponsoring Organizations of the Treadway Commission, or COSO. During the course of our ongoing evaluation and integration of the internal control over financial reporting, we may identify areas requiring improvement, and we may have to design enhanced processes and controls to address issues identified through this review. For example, we anticipate the need to hire additional administrative and accounting personnel to conduct our financial reporting.

We believe that the out-of-pocket costs, the diversion of management s attention from running the day-to-day operations and operational changes caused by the need to comply with the requirements of Section 404 of the Sarbanes-Oxley Act could be significant. If the time and costs associated with such compliance exceed our current expectations, our results of operations could be adversely affected.

We cannot be certain at this time that we will be able to successfully complete the procedures, certification and attestation requirements of Section 404 or that we or our auditors will not identify material weaknesses in

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internal control over financial reporting. If we fail to comply with the requirements of Section 404 or if we or our auditors identify and report such material weakness, the accuracy and timeliness of the filing of our annual and quarterly reports may be materially adversely affected and could cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our common stock. In addition, a material weakness in the effectiveness of our internal control over financial reporting could result in an increased chance of fraud and the loss of customers, reduce our ability to obtain financing and require additional expenditures to comply with these requirements, each of which could have a material adverse effect on our business, results of operations and financial condition.

Risks Related to Our Common Stock

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

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

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

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

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

As of December 31, 2005, our executive officers and directors, in the aggregate, beneficially owned approximately 3.6% of our outstanding common stock. Additionally, Charles E. Davidson beneficially owned approximately 61.0% 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.

Since we are a controlled company for purposes of The Nasdaq National Market s corporate governance requirements, our stockholders will not have, and may never have, the protections that these corporate governance requirements are intended to provide.

Since we are a controlled company for purposes of The Nasdaq National Market s corporate governance requirements, we are not required to comply with the provisions requiring that a majority of our directors be independent or nominees for election to our board of directors be selected by independent directors. As a result, our stockholders will not have, and may never have, the protections that these rules are intended to provide.

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

Through February 27, 2006, our common stock was traded on the NASD OTC Bulletin Board under the symbol GPOR.OB. Since February 28, 2006, our common stock has been quoted on The Nasdaq National Market under the symbol GPOR. There is a limited market for our shares. We cannot assure you that an active trading market will develop, or if it does, that it will be sustained.

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

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

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

As of December 31, 2005, we had a net operating loss, or NOL, carry forward of approximately $100.4 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 NOL s generated through the ownership change date could be limited. In general, the amount of NOL s we could use for any tax year after the date of the ownership change would be limited to the value of our stock (as of the ownership change date) multiplied by the long-term tax-exempt rate.

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

Sales of a substantial number of shares of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline. In addition, the sale of these shares could impair our ability to raise capital through the sale of additional common or preferred stock. As of March 21, 2006, we had 32,180,326 shares of common stock issued and outstanding.

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

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

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

In addition, specific rights granted to future holders of preferred stock could be used to restrict our ability to merge with, or sell our assets to, a third party. The ability of our Board of Directors to issue preferred stock could

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discourage, delay or prevent a takeover of us, thereby preserving control of the company by the current stockholders.

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

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

ITEM 7. FINANCIAL STATEMENTS

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

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

There have been no disagreements with our independent registered public accounting firms of the nature described in Item 304(b) of Regulation S-B promulgated under the Exchange Act. On February 9, 2005, we dismissed Hogan & Slovacek as our independent registered public accounting firm. We engaged Grant Thornton LLP as our new independent registered public accounting firm as of February 9, 2005. As part of our engagement, Grant Thornton audited the balance sheet as of December 31, 2004 and the related statements of operations, stockholders equity and cash flows for the year then ended and has performed a review of our interim financials for each quarter in the fiscal year ending December 31, 2005.

ITEM 8A. CONTROLS AND PROCEDURES

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

As of December 31, 2005, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Vice President and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934. Based upon our evaluation, our Chief Executive Officer and Vice President and Chief Financial Officer have concluded that as of December 31, 2005, our disclosure controls and procedures are effective.

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

ITEM 8B. OTHER INFORMATION

None.

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PART III

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

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

ITEM 10. EXECUTIVE COMPENSATION

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

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

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

ITEM 12. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

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

ITEM 13. EXHIBITS

List the following documents filed as part of this report:

Exhibit Number	Description
3.1	Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on December 1, 1997).
3.2	Amendment to the Restated Certificate of Incorporation changing name of corporation to Gulfport Energy Corporation (incorporated by reference to Exhibit 3.2 to Amendment No. 1 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on June 21, 2004).
3.3	Amendment to the Restated Certificate of Incorporation to increase the number of authorized shares of Common Stock from 50,000,000 to 250,000,000 (incorporated by reference to Exhibit 3.4 to Amendment No. 1 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on June 21, 2004).

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Exhibit Number	Description
3.4	Amendment to the Restated Certificate of Incorporation to effect a 50 to 1 reverse stock split of the issued and outstanding Common Stock (incorporated by reference to Exhibit 3.5 to Amendment No. 1 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on June 21, 2004).
3.5	Amendment to the Restated Certificate of Incorporation to reduce the number of authorized shares of Common Stock from 250,000,000 to 15,000,000 (incorporated by reference to Exhibit 3.6 to Amendment No. 1 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on June 21, 2004).
3.6	Amendment to the Restated Certificate of Incorporation to increase the number of shares of capital stock from 15,000,000 to 25,000,000 (incorporated by reference to Exhibit A to Schedule 14(c), File No. 000-19514, filed by the Company with the SEC on February 20, 2004).
3.7	Certificate of Amendment, dated July 20, 2004, of the Restated Certificate of Incorporation to increase the number of shares of capital stock from 25,000,000 to 40,000,000 (incorporated by reference to Exhibit 3.7 of Amendment No. 1 to Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on February 18, 2005).
3.8	Certificate of Designations, Preferences and Relative Participating, Optional and Other Special Rights of Preferred Stock and Qualifications, Limitations and Restrictions Thereof of Cumulative Preferred Stock Series A, dated March 28, 2002 (incorporated by reference to Exhibit 3.8 of Amendment No. 1 to Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on February 18, 2005).
3.9	Certificate of Amendment, dated July 20, 2004, of the Certificate of Designations, Preferences and Relative Participating, Optional and Other Special Rights of Preferred Stock and Qualifications, Limitations and Restrictions Thereof of Cumulative Preferred Stock Series A (incorporated by reference to Exhibit 3.9 of Amendment No. 1 to 10-QSB/A, File No. 000-19514, filed by the Company with the SEC on February 18, 2005).
3.10	Certificate of Amendment, dated February 17, 2006, of the Restated Certificate of Incorporation to increase the number of shares of capital stock from 40,000,000 to 60,000,000 (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 19, 2005).
3.11	Certificate of Elimination, filed March 1, 2006 (incorporated by reference to Exhibit 3.1 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on March 7, 2006).
3.12	Bylaws (incorporated by reference to Exhibit 3.2 to Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on December 1, 1997).
4.1	Form of Common Stock certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
10.1	Credit Agreement, dated July 1, 2004, by and between the Company and Bank of Oklahoma (incorporated by reference to Exhibit 10.2 to Amendment No. 1 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on June 21, 2004).
10.2+	2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 333-19514, filed by the Company with the SEC on February 18, 2005).
10.3+	Amendment No. 1 to 2005 Stock Incentive Plan (incorporated by reference from Exhibit 10.1 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 19, 2005).

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Exhibit Number	Description
10.4+	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.2 to Form 8-K, File No. 333-19514, filed by the Company with the SEC on February 18, 2005)
10.5+	Form of Stock Option Exercise Agreement (incorporated by reference to Exhibit 10.3 to Form 8-K, File No. 333-19514, filed by the Company with the SEC on February 18, 2005)
10.6+	Form of Warrant Agreement (incorporated by reference to Exhibit 10.4 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
10.7+	Employment Agreement, dated June 2003, by and between the Registrant and Mike Liddell (incorporated by reference to Exhibit 10.5 to Amendment No. 1 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on June 21, 2004)
10.8	Registration Rights Agreement, dated as of February 23, 2005, by and among the Company, Southpoint Fund LP, a Delaware limited partnership, Southpoint Qualified Fund LP, a Delaware limited partnership and Southpoint Offshore Operating Fund, LP, a Cayman Islands exempted limited partnership (incorporated by reference to Exhibit 10.7 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2005).
10.9	Registration Rights Agreement, dated as of February 18, 2005, by and among the Company and Harbert Distressed Investment Master Fund, Ltd., a Cayman Islands exempt company, and Alpha US Sub Fund VI, LLC, a Delaware limited liability company (incorporated by reference to Exhibit 10.8 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2005).
10.10	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).
10.11	Stock Purchase Agreement, dated as of February 17, 2005, by and among the Company, Harbert Distressed Investment Master Fund, Ltd and Alpha US Sub Fund VI, LLC (incorporated by reference to Exhibit 10.10 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2005).
10.12	Stock Purchase Agreement, dated as of February 22, 2005, by and among the Company, Southpoint Fund LP, Southpoint Qualified Fund LP and Southpoint Offshore Operating Fund, LP (incorporated by reference to Exhibit 10.11 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2005).
10.13	Administrative Services Agreement, effective as of April 1, 2005, by and between Bronco Drilling Company, Inc. and Gulfport Energy Corporation (incorporated by reference from Exhibit 10.1 of Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on August 15, 2005).
10.14	Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.3 of Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on November 11, 2005).
10.15*	Amendment No. 1 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.
14.0	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.

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Exhibit Number	Description
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.

* Filed herewith

\+ Management contract, compensatory plan or arrangement.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

For information concerning Item 14 Executive Compensation see our definitive Information 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).

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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 31, 2006

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 31, 2006	By:	/s/ JAMES D. PALM **James D. Palm** **Chief Executive Officer and Director** **(Principal Executive Officer)**
Date: March 31, 2006	By:	/s/ MIKE LIDDELL **Mike Liddell** **Chairman of the Board and Director**
Date: March 31, 2006	By:	/s/ MICHAEL G. MOORE **Michael G. Moore** **Vice President and Chief Financial Officer** **(Principal Financial and Accounting Officer)**
Date: March 31, 2006	By:	/s/ ROBERT E. BROOKS **Robert E. Brooks** **Director**
Date: March 31, 2006	By:	/s/ DAVID L. HOUSTON **David L. Houston** **Director**
Date: March 31, 2006	By:	/s/ MICKEY LIDDELL **Mickey Liddell** **Director**
Date: March 31, 2006	By:	/s/ DAN NOLES **Dan Noles** **Director**
Date: March 31, 2006	By:	/s/ PHILLIP LANCASTER **Phillip Lancaster** **Director**

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ITEM 7. FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors

Stockholders of Gulfport Energy Corporation:

We have audited the accompanying balance sheet of Gulfport Energy Corporation as of December 31, 2005, and the related statements of operations, stockholders equity and comprehensive income and cash flows for the years ended December 31, 2005 and 2004. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Gulfport Energy Corporation as of December 31, 2005, and the results of its operations and its cash flows for the years ended December 31, 2005 and 2004, in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

March 28, 2006

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GULFPORT ENERGY CORPORATION

BALANCE SHEET

	December 31, 2005
Assets	
Current assets:	
Cash and cash equivalents	$ 2,119,000
Accounts receivable	976,000
Insurance settlement receivables	4,681,000
Accounts receivable related parties	3,370,000
Prepaid expenses and other current assets	482,000
Short-term derivative instrument	621,000
Total current assets	12,249,000
Property and equipment:	
Oil and natural gas properties, full-cost accounting	173,135,000
Other property and equipment	6,156,000
Accumulated depletion, depreciation, amortization	(87,163,000)
Property and equipment, net	92,128,000
Other assets	7,443,000
Total assets	$ 111,820,000
Liabilities and Stockholders Equity	
Current liabilities:	
Accounts payable and accrued liabilities	$ 8,684,000
Asset retirement obligation current	480,000
Current maturities of long-term debt	358,000
Total current liabilities	9,522,000
Asset retirement obligation long-term	8,129,000
Long-term debt, net of current maturities	9,842,000
Total liabilities	27,493,000
Commitments and contingencies	
Preferred stock, $.01 par value; 5,000,000 authorized at December 31, 2005, 30,000 authorized as redeemable 12% cumulative preferred stock, Series A; 0 issued and outstanding at December 31, 2005	
Stockholders equity:	
Common stock $.01 par value, 55,000,000 authorized, 32,168,203 issued and outstanding at December 31, 2005	322,000
Paid-in capital	119,192,000

Accumulated other comprehensive income	759,000
Accumulated deficit	(35,946,000)
Total stockholders equity	84,327,000
Total liabilities and stockholders equity	$ 111,820,000

See accompanying notes to financial statements.

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GULFPORT ENERGY CORPORATION

STATEMENTS OF OPERATIONS

	Year Ended December 31, 2005	2004
Revenues:		
Gas sales	$ 3,437,000	$ 1,484,000
Oil and condensate sales	23,986,000	21,587,000
Other income	136,000	119,000
	27,559,000	23,190,000
Costs and expenses:		
Lease operating expenses	7,654,000	6,586,000
Production taxes	3,622,000	2,629,000
Depreciation, depletion, and amortization	4,789,000	4,952,000
General and administrative	1,561,000	2,107,000
Accretion expense	516,000	490,000
	18,142,000	16,764,000
INCOME FROM OPERATIONS:	9,417,000	6,426,000
OTHER (INCOME) EXPENSE:		
Interest expense	250,000	246,000
Interest expense preferred stock	272,000	1,949,000
Business interruption insurance recoveries	(1,710,000)	
Interest income	(290,000)	(73,000)
	(1,478,000)	2,122,000
INCOME BEFORE INCOME TAXES	10,895,000	4,304,000
INCOME TAX EXPENSE:		
NET INCOME	$ 10,895,000	$ 4,304,000
NET INCOME PER COMMON SHARE:		
Basic	$ 0.36	$ 0.31
Diluted	$ 0.34	$ 0.28

See accompanying notes to financial statements.

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GULFPORT ENERGY CORPORATION

STATEMENTS OF STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME

	Common Stock			Notes			
				Receivable	Accumulated		
			Additional	for	Other		Total
			Paid-in	Exercise	Comprehensive	Accumulated	Stockholders
	Shares	**Amount**	**Capital**	**of Options**	**Income**	**Deficit**	**Equity**
Balance at January 1, 2004	10,146,566	$ 101,000	$ 84,192,000	$	$	$ (51,145,000)	$ 33,148,000
Net income						4,304,000	4,304,000
Issuance of Common Stock, net of issue costs of 120,000	10,000,000	100,000	11,545,000				11,645,000
Balance at December 31, 2004	20,146,566	201,000	95,737,000			(46,841,000)	49,097,000
Net income						10,895,000	10,895,000
Other Comprehensive Income:							
Unrealized gain on hedges					621,000		621,000
Deferred gain on settled contracts					114,000		114,000
Loss on hedging ineffectiveness					24,000		24,000
Total Comprehensive Income							11,654,000
Issuance of Common Stock	4,000,000	40,000	13,960,000				14,000,000
Issuance of Common Stock through exercise of Warrants	7,958,470	80,000	9,390,000				9,470,000
Issuance of Common Stock through exercise of options	63,167	1,000	105,000	(105,000)			1,000
Collection of Notes Receivable for Stock				105,000			105,000
Balance at December 31, 2005	32,168,203	$ 322,000	$ 119,192,000	$	$ 759,000	$ (35,946,000)	$ 84,327,000

See accompanying notes to financial statements.

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GULFPORT ENERGY CORPORATION

STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2005	2004
Cash flows from operating activities:		
Net income	$ 10,895,000	$ 4,304,000
Adjustments to reconcile net income to net cash provided by operating activities:		
Accretion of discount Asset Retirement Obligation	516,000	490,000
Interest expense preferred stock	272,000	1,949,000
Depletion, depreciation and amortization	4,789,000	4,952,000
Unrealized loss on hedge ineffectiveness	24,000	
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	2,584,000	(2,220,000)
(Increase) in business interruption insurance settlement receivable	(1,710,000)	
(Increase) in accounts receivable related party	(2,347,000)	(644,000)
(Increase) in prepaid expenses	(270,000)	(33,000)
Increase in accounts payable and accrued liabilities	1,074,000	570,000
Increase in deferred hedge gains	114,000	
Settlement of asset retirement obligation	(741,000)	(965,000)
Net cash provided by operating activities	15,200,000	8,403,000
Cash flows from investing activities:		
(Additions) to cash held in escrow	(57,000)	(72,000)
(Additions) to other property, plant and equipment	(467,000)	(3,777,000)
(Additions) to oil and gas properties	(31,995,000)	(11,274,000)
Proceeds from sale of oil and gas properties	70,000	
Investment in Tatex Thailand II, LLC	(2,502,000)	
Investment in Windsor Bakken, LLC	(1,752,000)	
Net cash used in investing activities	(36,703,000)	(15,123,000)
Cash flows from financing activities:		
Principal payments on borrowings	(204,000)	(2,303,000)
Borrowings on note payable related party		500,000
Borrowings on note payable	7,000,000	3,389,000
Redemption of Series A, Preferred Stock	(14,292,000)	
Proceeds from issuance of common stock and collection of notes receivable	23,576,000	11,134,000
Net cash provided by financing activities	16,080,000	12,720,000
Net increase in cash and cash equivalents	(5,423,000)	6,000,000
Cash and cash equivalents at beginning of period	7,542,000	1,542,000
Cash and cash equivalents at end of period	$ 2,119,000	$ 7,542,000
Supplemental disclosure of cash flow information:		
Interest payments	$ 250,000	$ 246,000

Supplemental disclosure of non-cash transactions:		
Payment of Series A Preferred Stock dividends through issuance of Series A Preferred Stock	$ 272,000	$ 1,949,000
Asset retirement obligation capitalized	$ 1,382,000	$ 92,000
Retirement of related party note and accrued interest for stock	$	$ 511,000

See accompanying notes to financial statements.

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GULFPORT ENERGY CORPORATION

NOTES TO FINANCIAL STATEMENTS

DECEMBER 31, 2005 AND 2004

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business

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

Cash and Cash Equivalents

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

Accounts Receivable

The Company s accounts receivable primarily are from companies in the oil and gas industry located in the southwestern part of the United States. The majority of its receivables are from two purchasers of the Company s oil and gas. Credit is extended based on evaluation of a customer s payment history and, generally, collateral is not required. Accounts receivable are due within 30 days and are stated at amounts due from customers, net of an allowance for doubtful accounts when the Company believes collection is doubtful. Accounts outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company s previous loss history, the customer s current ability to pay its obligation to the Company, amounts which may be obtained by an offset against production proceeds due the customer and the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. No allowance was deemed necessary at December 31, 2005.

Oil and Gas Properties

The Company uses the full cost method of accounting for oil and gas operations. Accordingly, all costs, including nonproductive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and gas properties, are capitalized. Net capitalized costs are limited to the estimated future net revenues, as adjusted for the Company s cash flow hedge positions and net of tax effects, discounted at 10% per year, from proven oil and gas reserves and the cost of the properties not subject to amortization. Such capitalized costs, including the estimated future development costs and site remediation costs of proved undeveloped properties are depleted by an equivalent units-of-production method, converting gas to barrels at the ratio of six Mcf of gas to one barrel of oil. No gain or loss is recognized upon the disposal of oil and gas properties, unless such dispositions significantly alter the relationship between capitalized costs and proven oil and gas reserves. Oil and gas properties not subject to amortization consist of the cost of unproved leaseholds and totaled $113,000 at December 31, 2005. These costs are reviewed periodically by management for impairment, with the impairment provision included in the cost of oil and 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

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GULFPORT ENERGY CORPORATION

NOTES TO FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2005 AND 2004

retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, the Company increases the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related long-lived asset. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.

Other Property and Equipment

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

Net Income per Common Share

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

Income Taxes

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

Revenue Recognition

Gas revenues are recorded in the month produced and delivered to the purchaser using the entitlement method, whereby any production volumes received in excess of the Company s ownership percentage in the property are recorded as a liability. If less than Gulfport s entitlement is received, the underproduction is recorded as a receivable. There is no such liability or asset recorded at December 31, 2005. Oil revenues are recognized when ownership transfers, which occurs in the month produced.

Investments Equity Method

Investments in entities greater than 20% and 50% or less are accounted for under the equity method. The Company s proportionate share of losses during the year was immaterial to the statement of operations. Under the equity method, the Company s share of the investees earnings or loss is recognized in the statement of operations.

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GULFPORT ENERGY CORPORATION

NOTES TO FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2005 AND 2004

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.

Segment Information

The Company s only revenue generating activity is the production and sale of oil and gas from properties located on the Louisiana Gulf Coast. Therefore, no reporting of business segments has been included in these financial statements or the notes thereto.

Fair Value of Financial Instruments

The carrying values of items comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. The carrying value of long-term debt (including current maturities) approximates fair value as a result of the long-term debt having a variable interest rate, or the current rates offered to the Company for long-term debt are the same. The Company s derivative financial instruments are reported at fair value.

Fair value amounts have been estimated using available market information and valuation methodologies. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

Accounting Standards Yet to be Adopted

In December 2004, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standard (SFAS) No. 123(R), *Share Based Payment*, which revised SFAS No. 123, *Accounting for Stock-Based Compensation*. SFAS No. 123(R) requires entities to measure the fair value of equity share-based payments (stock compensation) at grant date, and recognize the fair value over the period during which an employee is required to provide services in exchange for the equity instrument as a component of the income statement. SFAS No. 123(R) is effective for periods beginning after December 15, 2005. The Company will implement SFAS 123(R) in the first quarter of 2006 utilizing the modified prospective method. Management is currently evaluating the impact of adoption of SFAS No. 123(R), but adoption could have a material impact on our financial position and results of operations.

In March 2005, the FASB issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47). FIN 47 clarifies the definition and treatment of conditional asset retirement obligations as discussed in SFAS No. 143, *Accounting for Asset Retirement Obligations*. A conditional asset retirement obligation is defined as an asset retirement activity in which the timing and/or method of settlement are dependent on future events that may be outside the control of the company. FIN 47 states that a company must record a liability when incurred for conditional asset retirement obligations if the fair value of the obligation is reasonably estimable. FIN 47 is intended to provide more information about long-lived assets and future cash outflows for these obligations and more consistent recognition of these liabilities. FIN 47 is effective for fiscal

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GULFPORT ENERGY CORPORATION

NOTES TO FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2005 AND 2004

years ending after December 15, 2005. We do not believe that our financial position, results of operations or cash flows will be materially impacted by implementation of FIN 47.

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections*, which changes the accounting for and reporting of a change of accounting principle. It requires retrospective application of a change of accounting principle unless impracticable. SFAS No. 154 is effective for fiscal years beginning after December 15, 2005 and is not expected to have a material impact on the Company s financial statements when adopted.

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments*, which amends FASB Statements No. 133 and 140. SFAS No. 155 clarifies certain issues relating to embedded derivatives and beneficial interests in securitized financial assets. The provisions of SFAS 155 are effective for all financial instruments acquired or issued after fiscal years beginning after September 15, 2006. We are currently assessing the impact that the adoption of SFAS 155 will have on our financial statements.

Stock-Based Compensation

The Company applies the intrinsic value-based method of accounting prescribed by APB Opinion No. 25, *Accounting for Stock Issued to Employees*, in accounting for its stock options. Accordingly, no compensation cost has been recognized for stock options granted in the accompanying financial statements. SFAS No. 123, *Accounting for Stock-Based Compensation* (SFAS No. 123), established accounting and disclosure requirements using a fair value-based method of accounting for stock-based employee compensation. As allowed by SFAS No. 123, the Company has elected to continue to apply the intrinsic value-based method of accounting described above, and has adopted the disclosure requirements of SFAS No. 123.

If the Company had elected the fair value provisions of SFAS No. 123 and recognized compensation expense over the vesting period based on the fair value of the stock options granted as of their grant date, the Company s 2005 and 2004 pro forma net income and pro forma net income per share would have been as follows:

	Year Ended December 31,	
	2005	**2004**
Net income available to common stockholders, as reported	$ 10,895,000	$ 4,304,000
Stock-based employee compensation expense	549,000	16,000