Cathell David W
Form 5
February 13, 2018

FORM 5

OMB APPROVAL

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Form 3 Holdings Reported
Form 4 Transactions Reported

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

ANNUAL STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

1. Name and Address of Reporting Person *
Cathell David W

(Last) (First) (Middle)

465 IDAVILLE YORK SPRINGS ROAD

(Street)

GARDNERS,Â PAÂ 17324

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
ACNB CORP [ACNB]

3. Statement for Issuer's Fiscal Year Ended (Month/Day/Year)
12/31/2017

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

_____ Director _____ 10% Owner
__X__ Officer (give title below) _____ Other (specify below)
EVP, Treasurer & CFO

6. Individual or Joint/Group Reporting

(check applicable line)

_X_ Form Filed by One Reporting Person
___ Form Filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)	4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5) Amount	(A) or (D)	Price	5. Amount of Securities Beneficially Owned at end of Issuer's Fiscal Year (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
ACNB Corporation Common	Â	Â	Â	Â	Â	Â	14,153.5879 (1)	D	Â

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)	5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)		8. Price of Derivative Security (Instr. 5)	9. of D Se Be O Er Is Fi (I
					(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares		

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
Cathell David W 465 IDAVILLE YORK SPRINGS ROAD GARDNERS,Â PAÂ 17324	Â	Â	Â EVP, Treasurer & CFO	Â

Signatures

/s/ David W. Cathell	02/13/2018
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, see Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) The amount of securities beneficially owned was increased to include 57.64874 aggregate shares of common stock acquired in 2017 through the automatic reinvestment of dividends, which are exempt from the reporting requirements of Section 16 of the Securities Exchange Act of 1934.

Note: File three copies of this Form, one of which must be manually signed. If space provided is insufficient, *see* Instruction 6 for procedure. Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. an" SIZE="2">ITEM 1A. RISK FACTORS 17

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FORWARD-LOOKING STATEMENTS

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

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

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

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PART I

ITEM 1. DESCRIPTION OF BUSINESS

General

We are an independent oil and natural gas exploration and production company with our principal producing properties located along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields, and in West Texas in the Permian Basin. In 2010, we acquired an acreage position in the Niobrara Formation of Western Colorado. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, or Grizzly, and have interests in entities that operate in Southeast Asia, including the Phu Horm gas field in Thailand. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

In 2010, at our WCBB field, we recompleted 72 wells and drilled 23 wells for a total cost of approximately $40.9 million as of December 31, 2010. All 23 new wells drilled at WCBB in 2010 were completed as producing wells. During 2011, we currently anticipate drilling 20 to 24 wells and recompleting 60 wells at our WCBB field for an estimated aggregate cost of $36.0 to $38.0 million. In the fourth quarter of 2010, production at WCBB was 293,372 net barrels of oil equivalent, or BOE, or an average of 3,189 BOE per day, 97% of which was from oil and 3% of which was from natural gas. From January 1, 2011 through February 28, 2011, our average net daily production at WCBB was 2,721 BOE, 97% of which was from oil and 3% of which was from natural gas.

In 2010, at our East Hackberry field, we recompleted ten wells and drilled eight wells for a total cost of approximately $20.0 million as of December 31, 2010. All wells drilled during 2010 were completed as producing wells. During 2011, we currently anticipate drilling seven to ten wells and recompleting five wells for an aggregate estimated cost of $24.0 to $26.0 million. In the fourth quarter of 2010, net production at East Hackberry was 157,349 BOE, or an average of 1,710 BOE per day, 96% of which was from oil and 4% of which was from natural gas. From January 1, 2011 through February 28, 2011, our average net daily production at East Hackberry was 1,899 BOE, 93% of which was from oil and 7% of which was from natural gas.

In the fourth quarter of 2010, net production at West Hackberry was 3,121 BOE, or an average of 34 BOE per day, 100% of which was from oil. From January 1, 2011 through February 28, 2011, our average net daily production at West Hackberry was 35 BOE, 100% of which was from oil.

In 2007, we acquired approximately 4,100 net acres in West Texas in the Permian Basin with production at the time of acquisition from 32 gross (16 net) wells, predominately from the Wolfcamp formation. Subsequently, we acquired approximately 10,600 additional net acres, which brought our total net acreage position in the Permian Basin to approximately 14,700 net acres. During the year ended December 31, 2010, 25 gross (11 net) wells were drilled and four gross (two net) wells were recompleted on this acreage. As of March 1, 2011, 24 of the 25 wells had been completed and one well was awaiting completion. We currently anticipate that 40 to 42 gross (19 to 20 net) wells will be drilled and ten gross (five net) wells will be recompleted on this acreage in 2011 for an estimated aggregate net cost of $37.0 to $39.0 million. In the fourth quarter of 2010, net production from our Permian acreage was 72,791 BOE, or an average of 791 BOE per day, 84% of which was from oil and natural gas liquids and 16% of which was from natural gas. From January 1, 2011 through February 28, 2011, our average daily net production from our Permian acreage was 787 BOE, 87% of which was from oil and natural gas liquids and 13% of which was from natural gas.

Effective as of April 1, 2010, we acquired leasehold interests in the Niobrara Formation in Colorado and held leases for 19,172 net acres as of March 1, 2011. During the year ended December 31, 2010, we recompleted one gross (0.4 net) well on this acreage. In the fourth quarter of 2010, net production at Niobrara was 3,380 BOE, or an average of 37 BOE per day, 100% of which was from oil. From January 1, 2011 through February 28, 2011, our average net daily production at Niobrara was 36 BOE, 100% of which was from oil. We are in the process of permitting a 60 square mile 3-D seismic survey and expect to begin shooting in mid-2011.

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As of December 31, 2010, we held approximately 900 net acres in the Williston Basin of western North Dakota and eastern Montana with interests in five wells and an overriding royalty interest in wells drilled prior to our sale, wells drilled subsequent to our sale and wells that might be drilled in the future. In the fourth quarter of 2010, our net production from this acreage was 6,522 BOE, or an average of 71 BOE per day, 95% of which was from oil and natural gas liquids and 5% of which was from natural gas. From January 1, 2011 through February 28, 2011, our average daily net production from our Bakken acreage was 64 BOE, 93% of which was from oil and 7% of which was from natural gas.

During the third quarter of 2006, we, through our wholly-owned subsidiary Grizzly Holdings Inc., purchased a 24.9% interest in Grizzly. The remaining interests in Grizzly are owned by entities controlled by Wexford Capital LP, or Wexford. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray within a few miles of other existing oil sands projects. Grizzly has approximately 534,000 acres under lease and our total net investment in Grizzly was approximately $46.5 million, including a note receivable of $20.0 million, at December 31, 2010. To date, Grizzly has drilled an aggregate of 199 core holes and three water supply test wells, tested nine separate lease blocks and conducted a seismic program. In March 2010, Grizzly filed an application in Alberta, Canada for the development of an 11,300 barrel per day oil sand SAGD facility at Algar Lake. Grizzly expects regulatory approval by mid-2011, followed by an anticipated construction period of 18 months leading to first production. Grizzly recently received the supplemental information request, or SIR, pertaining to its Algar Lake project application from the Alberta regulatory agencies. This is the standard process by which the Alberta regulatory agencies request additional information on all oil sands project applications. The SIR was received in a timeframe consistent with anticipated timeline for project approval. The engineering and procurement contract for Grizzly s proposed steam assisted gravity drainage, or SAGD, facility at Algar Lake has been awarded to SNC-Lavin. Work on the detailed engineering design is underway out of Grizzly s Calgary office and the detailed design of the project is expected to be complete by April 2011. Grizzly s currently contemplated 2011 activities include the completion of the 2010/2011 core hole drilling activity, seismic program and the initial preparations for the Algar Lake SAGD facility.

We own a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex. The remaining interests in Tatex are owned by entities controlled by Wexford. Tatex, a privately held entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC, or APICO, an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering approximately two million acres which includes the Phu Horm Field.

We also own a 17.9% ownership interest in Tatex Thailand III, LLC, or Tatex III. Approximately 68.7% of the remaining interests in Tatex III are owned by entities controlled by Wexford. Tatex III owns a concession covering approximately one million acres. During 2010, Tatex completed a 3-D seismic survey on this concession. The first well drilled on our concession in 2010 was temporarily abandoned pending further scientific evaluation. A second well was drilled to a depth of 15,026 feet and logged approximately 5,000 feet of apparent possible gas saturated column. The well experienced gas shows and carried a flare measuring up to 25 feet throughout drilling below the intermediate casing point of 9,695 feet. Tatex III is currently in the process of completing the well.

As of December 31, 2010, we had 22.4 million barrels of oil equivalent, or MMBOE, of proved reserves with a present value of estimated future net revenues, discounted at 10%, or PV-10, of approximately $392.6 million and associated standardized measure of discounted future net cash flows of approximately $315.5 million. See Item 2. Properties Proved Oil and Natural Gas Reserves for our definition of PV-10, a non-GAAP financial measure, and a reconciliation of our standardized measure of discounted future net cash flows to PV-10.

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Principal Oil and Natural Gas Properties

The following table presents certain information as of December 31, 2010 reflecting our net interest in our principal producing oil and natural gas properties along the Louisiana Gulf Coast, in the Permian Basin in West Texas, in the Niobrara Formation in western Colorado and in the Williston Basin in western North Dakota and eastern Montana.

								Proved Reserves		
		Productive Wells (2)		Non-Productive Wells		Developed Acreage (3)				
Field	NRI/WI (1) Percentages	Gross	Net	Gross	Net	Gross	Net	Gas Mboe	Oil Mboe	Total Mboe
West Cote Blanche Bay Field (4)	80.108/100	93	93	179	179	5,668	5,668	386	4,133	4,519
E. Hackberry Field (5)	79.424/100	27	27	74	74	3,291	3,291	291	2,561	2,852
W. Hackberry Field	87.5/100	3	3	22	22	592	592		146	146
Permian Basin	37.38/49.05	82	40			15,888	7,124	1,988	12,465	14,453
Niobrara Formation	36.4/44.04	4	2	1	0.4	2,240	628	23	339	362
Williston Basin (6)	3.2/3.9	5	0.2			2,560	127	5	58	63
Overrides/Royalty Non-operated	Various	77	0.2	2					2	2
Total		291	165.4	278	275.4	30,239	17,430	2,693	19,704	22,397

(1) Net Revenue Interest (NRI)/Working Interest (WI).
(2) Includes nine gross and net wells at WCBB that are producing intermittently.
(3) Developed acres are acres spaced or assigned to productive wells. Approximately 36% of our acreage is developed acreage and has been perpetuated by production.
(4) We have a 100% working interest (80.108% average NRI) from the surface to the base of the 13900 Sand which is located at 11,320 feet. Below the base of the 13900 Sand, we have a 40.40% non-operated working interest (29.95% NRI).
(5) NRI shown is for producing wells.
(6) NRI/WI is from wells that have been drilled or in which we have elected to participate.

West Cote Blanche Bay Field

Location and Land

The WCBB field is located approximately five miles off the coast of Louisiana in a shallow bay with water depths averaging eight to ten feet. We own a 100% working interest (80.108% net revenue interest, or NRI), and are the operator, in depths above the base of the 13900 Sand which is located at 11,320 feet. In addition, we own a 40.40% non-operated working interest (29.95% NRI) in depths below the base of the 13900 Sand, which is operated by Chevron Corporation. Our leasehold interests at WCBB contain 5,668 gross acres.

Area History and Production

Texaco, now Chevron Corporation, drilled the discovery well in this field in 1940 based on a seismic and gravitational anomaly. WCBB was subsequently developed on an even 160-acre pattern for much of the remainder of the decade. Developmental drilling continued and reached its peak in the 1970s when over 300 wells were drilled in the field. Of the 973 wells drilled as of December 31, 2010, 880 were completed as producing wells. As a result, the field has a historic success rate of 90% for all wells drilled. From the date of our acquisition of WCBB in 1997 through December 31, 2010, we drilled 162 new wells, 146 of which were productive, for a 90% success rate. As of December 31, 2010, estimated field cumulative gross production was 191.3 MMBOE and 236.4 billion cubic feet, or Bcf, of gas. Of the 973 wells drilled in WCBB as of December 31, 2010, 84 were producing, 179 were shut-in, nine were producing intermittently and five were being used as salt water disposal wells. The other 696 wells have been plugged and abandoned.

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

Geology

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

There are over 100 distinct sandstone reservoirs recognized throughout most of the field, and nearly 200 major and minor discrete intervals have been tested. Within the 973 wells that had been drilled in the field as of December 31, 2010, 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 at WCBB as of December 31, 2010 included 29 PUD wells. The drilling schedule used in the reserve report anticipates that all of those wells will be drilled by 2013.

Facilities

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

Recent and Future Activity

In 2010, we recompleted 72 gross and net wells and drilled 23 gross and net wells at WCBB. All 23 new wells were completed as producers. As of March 11, 2011, we had drilled two wells and recompleted twelve wells during 2011. Of the 23 wells drilled in 2010, 17 were considered deep wells. The 23 productive wells, with total depths ranging from 1,800 to 9,560 feet, have approximately 2,063 feet of aggregate apparent net pay. We currently anticipate drilling 20 to 24 gross and net wells and recompleting 60 gross and net wells at WCBB during 2011.

Production Status

In the fourth quarter of 2010, production at WCBB was 293,372 net BOE, or an average of 3,189 BOE per day, 97% of which was from oil and 3% of which was from natural gas. From January 1, 2011 through February 28, 2011, our average net daily production at WCBB was 2,721 BOE, 97% of which was from oil and

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3% of which was from natural gas. The decrease in production was due to operating inefficiencies with wells, machinery and equipment resulting from the sub-freezing weather conditions during January and February 2011 in Southern Louisiana.

East Hackberry Field

Location and Land

The East Hackberry field in Louisiana is located along the western shore and the land surrounding Lake Calcasieu, 15 miles inland from the Gulf of Mexico. We own a 100% working interest (approximately 79.424% average NRI) in certain producing oil and natural gas properties situated in the East Hackberry field. We hold beneficial interests in approximately 4,870 acres, including the Erwin Heirs Block, which is located on land, and the adjacent State Lease 50 Block, which is located primarily in the shallow waters of Lake Calcasieu. We also hold 2,868 net acres subject to a two-year exploration agreement we entered into with an active gulf coast operator. We are the designated operator under the agreement and will participate in proposed wells with at least a 70% working interest. We have licensed approximately 54 square miles of 3-D seismic data covering a portion of the area and are reprocessing the data.

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 2010 was over 1,015 MBOE and 330 Bcf of casinghead gas production. A total of 201 wells have been drilled on our portion of the field. As of December 31, 2010, 27 wells had daily production, 74 were shut-in and two had been converted to salt water disposal wells. The remaining 98 wells had been plugged and abandoned.

Geology

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

Facilities

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

Recent and Future Activity

During 2005, we completed a proprietary 42 square mile 3-D seismic survey at East Hackberry, the first modern seismic program undertaken at this field. We believe that this 3-D seismic data enhances our probability of drilling success, and we continue to evaluate the 3-D seismic data to identify additional drilling locations. During 2010 at East Hackberry, we recompleted ten gross and net wells and drilled six gross and net land wells and two gross and net wells on water. All of the eight wells drilled during 2010 were completed as producing wells. As of March 11, 2011, we had recompleted three wells during 2011, drilled one well and were in the process of drilling two additional wells. We currently intend to drill seven to ten gross and net wells and recomplete five gross and net wells at East Hackberry during 2011.

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Production Status

In the fourth quarter of 2010, net production at East Hackberry was 157,349 BOE, or an average of 1,710 BOE per day, 96% of which was from oil and 4% of which was from natural gas. From January 1, 2011 through February 28, 2011, our average net daily production at East Hackberry was 1,899 BOE, 93% of which was from oil and 7% of which was from natural gas. The increase in production in 2011 is a result of our 2011 drilling activities.

West Hackberry Field

Location and Land

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

Area History

The first discovery well at West Hackberry was drilled in 1938 and the field was developed by Superior Oil Company, now ExxonMobil Corporation, between 1938 and 1988. The estimated cumulative oil and condensate production through 2010 was 274 MBOE and 140 Bcf of natural gas. There have been 36 wells drilled to date on our portion of West Hackberry. Currently, three are producing, 22 are shut-in and one has been converted to a saltwater disposal well. The remaining ten wells have been plugged and abandoned.

Geology

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

Production Status

In the fourth quarter of 2010, net production at West Hackberry was 3,121 BOE, or an average of 34 BOE per day. From January 1, 2011 through February 28, 2011, our average net daily production at West Hackberry was 35 BOE and was 100% oil.

Facilities

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

Permian Basin (West Texas)

Location and Land

We acquired approximately 4,100 net acres and 32 gross (16 net) producing wells in West Texas (near Midland) in the Permian Basin effective November 1, 2007. Subsequently, we acquired 10,600 additional net acres, which brought our total net acreage position in the Permian Basin to approximately 14,700 net acres as of December 31, 2010. The Permian Basin area covers a significant portion of western Texas and eastern New Mexico and is considered one of the major producing basins in the United States. The terrain in the Permian Basin is semi-arid mesquite-mixed grassland steppe. Windsor Energy LLC, an entity controlled by Wexford, is the operator of this field.

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Area History

The Permian Basin formed as an area of rapid Mississippian-Pennsylvanian subsidence in the foreland of the Ouachita Foldbelt. The Wolfcamp play was a long-established reservoir in West Texas, first found in the 1950s as wells aiming for deeper targets occasionally intersected slump blocks or reef facies with reservoir properties. Exploration with 2-D seismic located additional fields, but it was not until the use of 3-D seismic in the 1990s that the greater extent of the Wolfcamp prospects was revealed. During the late 1990s, Arco began a drilling program targeting the Spraberry formation at 10,000 feet and then drilled another 200 to 300 feet to pick up the upper part of the Wolfcamp formation. Henry Petroleum, a private firm, owned interest in the Pegusas field in Midland and Upton counties. While drilling in the same area as the Arco project, Henry Petroleum decided to drill completely through the Wolfcamp section as Devonian wells. Henry Petroleum mapped the trend and began acquiring acreage and drilling wells using multiple slick-water fracs across the entire Wolfcamp interval. In 2005, former members of Henry Petroleum s Wolfcamp team formed their own private company, ExL Petroleum, and began replicating Henry Petroleum s program. After ExL had drilled 32 productive Wolfcamp/Spraberry wells through late 2007, they decided to monetize approximately 15% of their acreage position which enabled us to participate in this play. Recent advancements in enhanced recovery techniques continue to make the basin an active play for exploration and production companies. As of December 31, 2010, we held interests in 82 gross (40 net) producing wells.

Geology

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

Wolfberry well reserves are typically approximately 80% from the Wolfcamp section and 20% from the Spraberry section. Pinnacle Energy Services, LLC, an independent petroleum engineering firm, has estimated that at December 31, 2010, proved reserves net to our interest in these assets were approximately 14.5 million BOE, of which 16% were classified as proved developed producing, or PDP. Proved undeveloped, or PUD, reserves included in this estimate were from 226 gross well locations on 40-acre units. The proved reserves are located in the Wolfcamp and Spraberry formations, which are generally characterized as long-lived, with predictable production profiles.

Production Status

In the fourth quarter of 2010, net production from the Permian field was 72,791 BOE, or an average of 791 BOE per day, 84% of which was from oil and natural gas liquids, and 16% of which was from natural gas. From January 1, 2011 through February 28, 2011, our average daily net production from our Permian acreage was 787 BOE, 87% of which was from oil and natural gas liquids and 13% of which was from natural gas. The slight production decrease was the result of the unusual sub-freezing weather conditions during January and February 2011.

Facilities

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

Recent and Future Activity

In 2010, 25 gross (11 net) wells were drilled in our Permian acreage. As of March 11, 2011, four gross (two net) wells had been recompleted and five gross (2.5 net wells) have been drilled on this acreage, three of which were waiting on completion and two were currently drilling. We have identified 226 gross future development drilling locations. We currently expect an estimated 40 to 42 gross (19 to 20 net) wells to be drilled on our acreage in 2011. The wells are expected to be drilled to approximately 10,200 feet.

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Niobrara Formation (Western Colorado)

Location and Land

Effective as of April 1, 2010, we acquired leasehold interests in the Niobrara Formation in western Colorado, and held leases for 19,172 acres as of March 1, 2011. We are the operator on the acreage.

Area History

The Niobrara Formation is a shale oil rock formation located in Colorado, Northwest Kansas, Southwest Nebraska, and Southeast Wyoming. Oil and natural gas can be found at depths of 3,000 14,000 feet and is drilled both vertically and horizontally. The Upper Cretaceous Niobrara formation has emerged as another potential crude oil resource play in various basins throughout the northern Rocky Mountain region. As with most resource plays, the Niobrara has a history of producing through conventional technology with some of the earliest production dating back to the early 1900s. Natural fracturing has played a key role in producing the Niobrara historically due to the low porosity and low permeability of the formation. Because of this, conventional production has been very localized and limited in area extent. We believe the Niobrara can be produced on a more widespread basis using today s horizontal multi-stage fracture stimulation technology where the Niobrara is thermally mature.

Geology

The Niobrara Formation oil play in northwestern Colorado is located between the Piceance Basin to the south and the Sand Wash Basin to the north. Rocks mainly consist of interbedded organic-rich shales, calcareous shales and marlstones. It is the fractured marlstone intervals locally known as the Buck Peak, Tow Creek and Wolf Mountain benches that account for the majority of the areas production. These fractured carbonate reservoirs are associated with anticlinal, synclinal and monoclinal folds, and fault zones. This proven oil accumulation is considered to be continuous in nature and lightly explored. Source rocks are predominantly oil prone and thermally mature with respect oil generation. The producing intervals are geologically equivalent to the Niobrara reservoirs of the DJ and Powder River Basins which are currently emerging as a major crude resource play.

Production Status

In the fourth quarter of 2010, net production from our Niobrara acreage was 3,380 BOE, or an average of 37 BOE per day, 100% of which was from oil. From January 1, 2011 through February 28, 2011, our average daily net production from our Niobrara acreage was 36 BOE, 100% of which was from oil.

Facilities

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

Recent and Future Activity

We recompleted one well at Niobrara during 2010. We are in the process of permitting a 60 square mile 3-D seismic survey over our Craig Dome prospect and expect to begin shooting in mid-2011. We currently intend to drill four to five gross wells at Niobrara during 2011.

Bakken

Location and Land

The Bakken Shale is located in the Williston Basin areas of western North Dakota and eastern Montana. During 2005, we purchased a 20% ownership interest in Windsor Bakken, LLC, or Bakken. The remaining interests in Bakken were owned by entities controlled by Wexford. Beginning in 2005, Bakken acquired leases on undeveloped acreage in the Williston Basin. As of December 31, 2007, Bakken had commenced participating in the drilling of some of its undeveloped acreage. Effective January 1, 2008, we acquired a direct, undivided 20% interest in Bakken s assets in redemption of our 20% interest in Bakken. During May 2009, we sold approximately 12,270 net acres and approximately 190 net BOEPD of production for approximately $13.0 million, with an effective date of April 1, 2009. During September 2009, we sold approximately 5,721 net acres for approximately $5.8 million with an effective date of July 1, 2009. As of December 31, 2010, we held approximately 900 net acres, interests in five wells and an overriding royalty interest in wells drilled prior to our sale, wells drilled subsequent to our sale and wells that might be drilled in the future.

Production Status

In the fourth quarter of 2010, net production from our Bakken acreage was 6,522 BOE, or an average of 71 BOE per day, 95% of which was from oil and natural gas liquids and 5% of which was from natural gas. From January 1, 2011 through February 28, 2011, our average net daily production from this acreage was 64 BOE, of which 93% was from oil and 7% was from natural gas.

Facilities

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

Recent and future activities

One gross well was drilled on our acreage in 2010. We have no activities currently scheduled for 2011 in the Williston Basin.

Additional Properties

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

Field	Parish	Acreage Working Interest	Overriding Royalty Interests	Producing Wells	Non-Producing Wells
Bayou Long	Iberia	3.125%	0%	0	0
Bayou Penchant	Terrebonne	3.125%	0%	1	2
Bayou Pigeon	Iberia	6.250%	0%	0	0
Deer Island	Terrebonne	6.250%	0%	0	0
Golden Meadow	Lafourche	3.125%	0%	0	0
Napoleonville	Assumption	0%	2.5%	3	0

Thailand. During 2005, we purchased a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex, at a cost of $2.4 million. The remaining interests in Tatex are owned by entities controlled by Wexford. Tatex, a privately held entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC, or APICO, an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering approximately two million acres which includes the Phu Horm Field. During

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the year ended December 31, 2010, we received $565,000 in distributions, reducing our total investment in Tatex to $1.9 million. Our investment is accounted for on the equity method. Tatex accounts for its investment in APICO using the cost method. In December 2006, first gas sales were achieved at the Phu Horm field located in northeast Thailand. Phu Horm s initial gross production was approximately 60 million cubic feet per day. For December 2010, net gas production was approximately 98 MMcf per day and condensate production was 477 barrels per day. Hess Corporation operates the field with a 35% interest. Other interest owners include APICO (35% interest), PTTEP (20% interest) and ExxonMobil (10% interest). Our gross working interest (through Tatex as a member of APICO) in the Phu Horm field is 0.7%. Due to the fact that our ownership in the Phu Horm field is indirect and Tatex s investment in APICO is accounted for by the cost method, these reserves are not included in our year-end reserve information.

During the first quarter of 2008, we purchased a 5% ownership interest in Tatex Thailand III, LLC, or Tatex III, at a cost of $850,000. In December 2009, we purchased an additional approximately 12.9% ownership interest at a cost of approximately $3.4 million bringing our total ownership interest to approximately 17.9%. Approximately 68.7% of the remaining interests in Tatex III are owned by entities controlled by Wexford. Tatex III owns a concession covering approximately one million acres. Tatex III recently completed a 3-D seismic survey on this concession. During the year ended December 31, 2010, we paid $402,000 in cash calls, bringing our total investment in Tatex III to $4.7 million. The first well drilled on our concession in 2010 was temporarily abandoned pending further scientific evaluation. A second well was drilled to a depth of 15,026 feet and logged approximately 5,000 feet of apparent possible gas saturated column. The well experienced gas shows and carried a flare measuring up to 25 feet throughout drilling below the intermediate casing point of 9,695 feet. Tatex III is currently in the process of completing the well.

Grizzly Oil Sands. During the third quarter of 2006, we, through our wholly-owned subsidiary Grizzly Holdings Inc., purchased a 24.9% interest in Grizzly. The remaining interests in Grizzly are owned by entities controlled by Wexford. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray within a few miles from other existing oil sands projects. Grizzly has approximately 534,000 acres under lease and our total net investment in Grizzly was approximately $46.5 million, including a note receivable of $20.0 million, at December 31, 2010. To date, Grizzly has drilled an aggregate of 199 core holes and three water supply test wells, tested nine separate lease blocks and conducted a seismic program. In connection with its 2010/2011 winter drilling program, Grizzly plans to drill a total of 71 core hole locations, 68 of which have been drilled to date. Upon the completion of the 2010/2011 drilling season, Grizzly will have drilled 32 locations at Thickwood Hills, 14 locations at Firebag River, 17 locations at Algar Lake, and eight total locations at Athabasca Rapids and Horse River. In March 2010, Grizzly filed an application in Alberta, Canada for the development of an 11,300 barrel per day SAGD facility at Algar Lake. Grizzly expects regulatory approval by mid-2011, followed by an anticipated construction period of 18 months leading to first production. Grizzly recently received the supplemental information request, or SIR, pertaining to its Algar Lake project application from the Alberta regulatory agencies. This is the standard process by which the Alberta regulatory agencies request additional information on all oil sands project applications. The SIR was received in a timeframe consistent with anticipated timeline for project approval. The engineering and procurement contract for Grizzly s proposed steam assisted gravity drainage facility at Algar Lake has been awarded to SNC-Lavin. Work on the detailed engineering design is underway out of Grizzly s Calgary office and the detailed design of the project is expected to be complete by April 2011. Grizzly s currently contemplated 2011 activities include the completion of the 2010/2011 core hole drilling activity and the initial preparations for the Algar Lake SAGD facility.

Competition and Markets

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These competitors may be better positioned to take advantage of industry opportunities and to

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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 demand for oil and natural gas and the level of domestic production and imports of oil, the proximity and capacity of gas pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of gas sold in interstate commerce. The oil and natural gas we produce in Louisiana is sold to purchasers who service the areas where our wells are located. We sell the majority of our oil to Shell Trading Company, or Shell. Shell takes custody of the oil at the outlet from our oil storage barge. Our production from WCBB, other than the production sold under forward sales contracts, is being sold in accordance with the Shell posted price for West Texas/New Mexico Intermediate crude plus or minus Platt s trade month average P+ value, plus or minus the Platt s HLS/WTI trade month average differential less $2.70 per barrel for transportation. During 2010, we sold 75% and 19% of our oil production to Shell and Windsor Energy Group, the operator of our Permian wells, respectively, and 50%, 32%, and 10% of our natural gas production to Windsor Energy Group, Chevron and Hilcorp Energy Company, respectively. During 2009, we sold 92% and 7% of our oil production to Shell and Windsor Energy Group, the operator of our Permian wells, respectively, and 45%, 38%, and 16% of our natural gas production to Windsor Energy Group, Chevron and Hilcorp Energy Company, respectively. During 2008, we sold 87% of our oil production to Shell and 11% to Windsor Energy Group, 100% of our natural gas liquids production to Windsor Energy Group, and 60%, 22%, and 16% of our natural gas production to Chevron, Windsor Energy Group, and Hilcorp Energy Company, respectively. We may not continue to have ready access to suitable markets for our future oil and natural gas production.

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

To mitigate the effects of commodity price fluctuations, we were party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials, for the period January 2010 through February 2010. For the period March 2010 through December 2010, we were party to forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel before transportation costs and differentials. We delivered approximately 45% of our 2010 production under these agreements.

In November 2010, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel, before transportation costs and differentials, for the period January 2011 through December 2011. Under the 2011 contracts, we have committed to deliver approximately 30% to 33% of our estimated 2011 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These forward sales contacts and fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815, *Derivatives and Hedging,* and related pronouncements.

Regulation

Regulation of Gas and Oil Production

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

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

Environmental Regulation

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

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

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

Remediation of Hazardous Substances. The Comprehensive Environmental Response, Compensation and Liability Act, as amended, also known as CERCLA or the Superfund law, and analogous state laws, generally

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imposes strict and joint and several liability, without regard to fault or legality of the original 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 at the facility. Under CERCLA and comparable state statutes, persons deemed responsible parties may be subject to strict and joint and several liability for the costs of removing or remediating previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our operations, we use materials that, if released, would be subject to CERCLA and comparable state statutes. Therefore, governmental agencies or third parties may seek to hold us responsible under CERCLA and comparable state statutes for all or part of the costs to clean up sites at which such hazardous substances have been released.

Water Discharges. The Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act , the Oil Pollution Act and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States, as well as state waters. 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. Spill prevention, control and countermeasure, or SPCC, plan requirements under federal law require appropriate containment terms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. These laws and regulations also prohibit certain activity in wetlands unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions.

The Oil Pollution Act, or OPA, is the primary federal law for oil spill liability. OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters.

Noncompliance with the Clean Water Act or OPA may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations. We believe we are in material compliance with the requirements of each of these laws.

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

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and that we hold all necessary and valid construction and operating permits for our operations. Obtaining or renewing permits has the potential to delay the development of oil and natural gas projects. Our operations may also soon be affected by rapidly emerging regulation of green house gases, such as carbon dioxide and methane, which are emitted in the course of oil and natural gas exploration and production.

Operational Hazards and Insurance

The oil business involves a variety of operating risks, including the risk of fire, explosions, blow outs, pipe failures and, in some cases, abnormally high pressure formations which could lead to environmental hazards such as oil spills, natural gas leaks and the discharge of toxic gases. If any of these should occur, we could incur legal defense costs and could be required to pay amounts due to injury, loss of life, damage or destruction to property, natural resources and equipment, pollution or environmental damage, regulatory investigation and penalties and suspension of operations.

In accordance with what we believe to be industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We insure some, but not all, of our properties for operational and hurricane related events. We currently have insurance policies that include coverage for general liability, physical damage to our oil and gas properties, operational control of certain wells, oil pollution, third party liability, workers compensation and employers liability and other coverage. Our insurance coverage includes deductibles that must be met prior to recovery. Additionally, our insurance is subject to exclusion and limitations, and there is no assurance that such coverage will fully or adequately protect us against liability from all potential consequences, damages and losses. Any of these events could cause a significant disruption to our business. For example, we experienced production interruptions in 2005 and 2006 from Hurricanes Katrina and Rita and, in 2008, from Hurricanes Gustav and Ike. A loss not fully covered by insurance could have a material adverse affect on our financial position, results of operations and cash flows.

Currently, we have general liability insurance coverage with an annual aggregate limit of up to $21.0 million which includes environmental impairment coverage for the effects of onshore and offshore pollution on third parties arising from our operations. For our offshore West Cote Blanche Bay properties, we also have a $25.0 million property physical damage policy which insures against most operational perils, such as explosions, fire, vandalism, theft, hail and windstorms, provided, however, that this policy is limited to $10.0 million for damages arising as a result of a named windstorm. In the event of a loss under this policy, we have up to $6.6 million of business interruption coverage available after a 90 day waiting period. All of our insurance coverage includes deductibles of up to $500,000 per occurrence ($1.5 million in the case of a named windstorm) that must be met prior to recovery. Additionally, our insurance is subject to customary exclusions and limitations. We reevaluate the purchase of insurance, policy terms and limits annually each May. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and we may elect to maintain minimal or no insurance coverage. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. The occurrence of a significant event, not fully insured against, could have a material adverse effect on our financial condition and results of operations.

At the depths and in the areas in which we operate, and in light of the vertical and directional drilling that we undertake, we typically do not encounter high pressures or extreme drilling conditions. Accordingly, we typically do not carry a control of well policy, although we currently have such coverage in place for two specific wells we are drilling this year. We also require all of our third party vendors to sign master service agreements in which they agree to indemnify us for injuries and deaths of the service provider s employees as well as contractors and subcontractors hired by the service provider.

We have prepared and have in place spill prevention control and countermeasure plans for each of our principal facilities at WCBB in response to federal and state requirements. The plans are reviewed annually and

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updated as necessary. As required by applicable regulations, our facilities are built with oil containment features and we own certain oil containment equipment, such as oil boom to surround drill sites and production facilities if needed. In addition, we have a national emergency response company on retainer. This company specializes in the clean up of hydrocarbons as a result of spills, blow-outs and natural disasters. This emergency response company has been involved in the clean up efforts of some of the largest oil spills along the Gulf Coast and is on call to us 24 hours a day when its services are needed. It reports that it currently owns over 164 response vehicles, 65 response vessels, 116 response trailers equipped with decontaminant supplies, personal protective equipment and other equipment used in responding to oil spills, two storage barge sets, allowing for storage of up to 248 barrels of recovered oil each, and over 20 roll-off boxes and vacuum boxes. We pay this company a retainer plus additional amounts when it provides us with clean up services. Our aggregate payments for the retainer and clean up services during 2009 and 2010 were approximately $139,000. While this company has been able to meet our service needs when required from time to time in the past, it is possible that its ability to provide services to us in the future, if and when needed, could be hindered or delayed in the event of a widespread disaster. However, in light of the depths and the areas in which we operate, and the necessity for gas lift to produce our WCBB wells due to low reservoir pressure at our WCBB field, we believe other companies would be available to us in the event our primary remediation company was unable to perform.

Headquarters and Other Facilities

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

Employees

At December 31, 2010, we had 45 employees. Certain of our employees perform management and administrative services for affiliated companies. We are reimbursed by these affiliates for the salaries and benefits of these individuals based on the estimated time they spent working for those affiliates. In addition, in the past, we have also received 100% of the COPAS overhead charges billed to these affiliated companies. For the years ended December 31, 2009 and 2008, expenses reimbursed to us under these arrangements were $0.6 million and $1.4 million, respectively, and are reflected as a reduction in our general and administrative expenses. No amounts were reimbursed to us under these arrangements in 2010. A Louisiana well servicing company provides all necessary field personnel needed to operate the WCBB and the Hackberry fields.

Available Information

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

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ITEM 1A. RISK FACTORS
Risks Related to Our Business and Industry

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

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

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

political instability or armed conflict in oil and natural gas producing regions; and

the overall economic environment.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, during the past five years, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.28 per barrel, or bbl, in December 2008 to a high of $145.31 per bbl in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $1.83 per million British thermal units, or MMBtu, in September 2009 to a high of $15.52 per MMBtu in January 2006. On March 7, 2011, the West Texas Intermediate posted price for crude oil was $105.44 per bbl and the Henry Hub spot market price of natural gas was $3.93 per MMBtu. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves, and may result in write downs of oil and natural gas properties due to ceiling test limitations.

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

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

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economic climate in the United States or abroad continues to deteriorate, demand for petroleum products could continue to diminish, which could impact the price at which we can sell our oil, natural gas and natural gas liquids, affect our vendors, suppliers and customers ability to continue operations, and ultimately adversely impact our results of operations, liquidity and financial condition.

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

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

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

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

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

There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Further, these acquisitions may be in geographic regions in which we do not currently operate, which could result in unforeseen operating difficulties and difficulties in coordinating geographically dispersed operations, personnel and facilities. In addition, if we enter into new geographic markets, we may be subject to additional and unfamiliar legal and regulatory requirements. Compliance with regulatory requirements may impose substantial additional obligations on us and our management, cause us to expend additional time and resources in compliance activities and increase our exposure to penalties or fines for non-compliance with such additional legal requirements. Completed acquisitions could require us to invest further in operational, financial and management information systems and to attract, retain, motivate and effectively manage additional employees. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

Our Canadian oil sands project is a complex undertaking and may not be completed at our estimated cost or at all.

During the third quarter of 2006, we, through our wholly-owned subsidiary Grizzly Holdings Inc., purchased a 24.9% interest in Grizzly. The remaining interests in Grizzly are owned by entities controlled by

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Wexford. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray near other oil sands development projects. Grizzly has approximately 534,000 acres under lease and our total net investment in Grizzly was approximately $46.5 million, including a note receivable of $20.0 million, at December 31, 2010. To date, Grizzly has drilled an aggregate of 199 core holes and three water supply test wells, tested nine separate lease blocks and conducted a seismic program and expects to drill an additional three core locations during the remainder of the 2010/2011 winter delineation drilling season. In 2010, Grizzly filed applications in Alberta, Canada for the development of an 11,300 barrel per day oil sand SAGD facility at Algar Lake. Grizzly expects regulatory approval by mid-2011, followed by an anticipated construction period of 18 months leading to first production. The cost of this initial facility is currently estimated to be approximately $120.0 million. This is a complex project and financing has not been secured. This project may not be completed at our estimated cost or at all.

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

The oil and natural gas industry is cyclical, which can result in shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies and personnel. When shortages occur, the costs and delivery times of rigs, equipment and supplies increase and demand for, and wage rates of, qualified drilling rig crews also rise with increases in the number of active rigs in service. In accordance with customary industry practice, we rely on independent third party service providers to provide most of the services necessary to drill new wells. Shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies, personnel, trucking services, tubulars, fracing and completion services and production equipment could delay or restrict our exploration and development operations, which in turn could impair our financial condition and results of operations.

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

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

Our proved reserves and related PV-10 as of December 31, 2010 have been reported under SEC rules that went into effect on January 1, 2010. The estimates provided in accordance with these SEC rules may change materially as a result of interpretive guidance that may be released by the SEC.

We have included in this report certain estimates of our proved reserves and related PV-10 at December 31, 2010 as prepared consistent with our and our independent reserve engineers interpretations of the SEC rules relating to disclosures of estimated natural gas and oil reserves. These rules require SEC reporting companies to prepare their reserve estimates using revised reserve definitions and revised pricing based on 12-month unweighted first-day-of-the-month average pricing. The SEC has released only limited interpretive guidance regarding reporting of reserve estimates under these rules. Accordingly, while the estimates of our proved reserves and related PV-10 at December 31, 2010 included in this report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the SEC rules, those estimates could differ materially from any estimates we might prepare applying more specific SEC interpretive guidance.

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We may be limited in our ability to book additional proved undeveloped reserves under the recent SEC rules.

One of the impacts of the recent SEC reserve rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program.

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

There are numerous uncertainties associated with estimating quantities of proved reserves and in projecting future rates of production and timing of expenditures. The reserve information included in this report represents only estimates based on reports as of December 31, 2010 prepared by Netherland, Sewell & Associates, Inc., or NSAI, with respect to our WCBB and Niobrara fields, by Pinnacle Energy Services, LLC, or Pinnacle, with respect to our assets in the Permian Basin in West Texas and by our personnel with respect to our Hackberry fields and our overriding royalty and non-operated interests. Petroleum engineering is not an exact science. Information relating to our proved oil and natural gas reserves is based upon engineering estimates. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, future site restoration and abandonment costs, the assumed effects of regulations by governmental agencies and assumptions concerning future oil and natural gas prices, future operating costs, severance and excise taxes, capital expenditures and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net cash flows expected therefrom prepared by different engineers or by the same engineers at different times may vary substantially. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

Estimates of reserves as of year-end 2010 and 2009 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2010 and 2009, respectively, in accordance with the revised guidelines of the SEC applicable to reserves estimates for such years. Estimates of reserves as of year-end 2008 were prepared using constant prices and costs in accordance with previous guidelines of the SEC based on hydrocarbon prices received on a field-by-field basis as of December 31st of such year. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties.

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 for 2010 and 2009 on average price equal to the unweighted average of prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2010 and 2009, respectively, in accordance with the revised guidelines of the SEC applicable to reserves estimates for such years. Estimated discounted future net revenue from reserves as of year-end 2008 were prepared using constant prices and costs in accordance with previous guidelines of the SEC as of December 31st of such year. 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.

As of December 31, 2010, approximately 63% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and may require successful drilling operations. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully, but these assumptions may not be accurate, and this may not occur.

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

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

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

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

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

A substantial portion of our producing properties is located in Louisiana, making us vulnerable to risks associated with operating in this region.

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

Our identified drilling locations, which are part of our anticipated future drilling plans, are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have identified over 600 drilling locations on our Louisiana, West Texas and Colorado properties. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, oil and natural gas prices, inclement weather, costs, drilling results and regulatory changes. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Operating hazards and uninsured risks may result in substantial losses.

Our operations are subject to all of the hazards and operating risks associated with drilling for and production of oil and natural gas, including the risk of fire, explosions, blowouts, pipe failure, abnormally pressured formations and environmental hazards such as oil spills, gas leaks, ruptures or discharges of toxic gases. The occurrence of any of these events could result in substantial losses to us due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. For example, in October 2006, an accident occurred north of our production facilities in the WCBB field in southern Louisiana involving two contracted vessels that were performing work on our behalf in the field. A tugboat and two barges laden with construction materials ruptured an underwater natural gas pipeline and a subsequent fire damaged the vessels. Four confirmed fatalities resulted from the accident. Several lawsuits relating to this incident were filed against us, among other parties. These lawsuits against us have all been settled.

In accordance with what we believe to be customary industry practice, we historically have maintained insurance against some, but not all, of our business risks. Our insurance may not be adequate to cover any losses or liabilities we may suffer. Also, insurance may no longer be available to us or, if it is, its availability may be at premium levels that do not justify its purchase. In addition, we understand that insurance carriers are modifying or otherwise restricting insurance coverage or ceasing to provide certain types of insurance coverage in the Gulf Coast region. We may not be able to secure additional insurance of bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. We may also be liable for environmental damage caused by previous owners of properties purchased by us, which liabilities may not be covered by insurance.

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

Our oil and natural gas operations are subject to various federal, state and local governmental regulations that may be changed from time to time in response to economic and political conditions. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells

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below actual production capacity to conserve supplies of oil and gas. In addition, the production, handling, storage, transportation, remediation, emission and disposal of oil and gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations are subject to regulation under federal, state and local laws and regulations primarily relating to protection of human health and the environment. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, permit revocations and injunctions limiting or prohibiting some or all of our operations. Moreover, 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.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the federal Safe Drinking Water Act s Underground Injection Program. While the EPA has yet to take any action enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA s recent decision. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. In addition, legislation was proposed in the recently ended 111th session of Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process, and such legislation could be introduced in the current session of Congress. Also, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances or otherwise require the public disclose of chemicals used in the hydraulic fracturing process. On March 1, 2011 a bill was introduced in the Texas Senate that would require the Railroad Commission of Texas to adopt rules requiring owners and operators of wells on which hydraulic fracturing activities been performed or other persons who had performed such activities to provide the agency written information on, among other things, the chemicals used in such activities. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to drill and produce from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings. In addition, if hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the potential impact on our business that may arise if federal or state legislation governing hydraulic fracturing is enacted into law.

The recent adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The recent adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. The U.S. Congress recently adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The new legislation was

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signed into law by the President on July 21, 2010, and requires the Commodities Futures Trading Commission, or CFTC, and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In its rulemaking under the new legislation, the CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. It is not possible at this time to predict when the CFTC will finalize these regulations. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our existing or future derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our derivative contracts in existence at that time, and increase our exposure to less creditworthy counterparties. If we reduce or change the way we use derivative instruments as a result of the legislation and regulations, our results of operations may become more volatile and its cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations or cash flows.

The proposed changes to U.S. tax laws, if adopted, could have an adverse effect on our business, financial condition, results of operations and cash flows.

The U.S. President s Fiscal Year 2012 Budget Proposal includes provisions that would, if enacted, make significant changes to U.S. tax laws. These changes include, but are not limited to, (i) eliminating the immediate deduction for intangible drilling and development costs, (ii) eliminating the deduction from income for domestic production activities relating to oil and natural gas exploration and development, and (iii) implementing certain international tax reforms. These proposed changes in the U.S. tax laws, if adopted, could adversely affect our business, financial condition, results of operations and cash flows.

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas we produce.

Many nations have agreed to limit emissions of greenhouse gases pursuant to the United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas, and refined petroleum products, are greenhouse gases, or GHGs, regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol at this time, several states or geographic regions have adopted legislation and regulations to reduce emissions of greenhouse gases. Additionally, on April 2, 2007, the U.S. Supreme Court ruled, in *Massachusetts, et al. v. EPA*, that the EPA has the authority to regulate carbon dioxide emissions from automobiles as air pollutant under the federal Clean Air Act. Thereafter, in December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because, according to the EPA, emissions of such gases contribute to warming of the earth s atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. Subsequently, the EPA adopted two sets of related rules, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources of emissions such as power plants or industrial facilities. The EPA finalized the motor vehicle rule in April 2010 and it became effective January 2011, although it does not require immediate reductions in GHG emissions. The EPA adopted the stationary source rule in May 2010, and it also became

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effective January 2011, although it remains subject of several pending lawsuits filed by industry groups. Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. More recently, in November 2010, the EPA expanded its existing GHG reporting rule to include onshore and offshore oil and natural gas production and onshore processing, transmission, storage, and distribution facilities, which may include certain of our facilities, beginning in 2012 for emissions occurring in 2011.

In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security (ACES) Act that, among other things, would have established a cap-and-trade system to regulate greenhouse gas emissions and would have required an 80% reduction in GHG emissions from sources within the United States between 2012 and 2050. The ACES Act did not pass the Senate, however, and so was not enacted by the 111th Congress. The United States Congress is likely to again consider a climate change bill in the future. Moreover, almost half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect the oil and natural gas industry. Currently, while we are subject to certain federal GHG monitoring and reporting requirements our operations are not adversely impacted by existing federal, state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

Any failure by us to comply with applicable environmental laws and regulations may result in governmental authorities taking actions that could adversely impact our operations and financial condition, including the:

- issuance of administrative, civil and criminal penalties;
- denial, suspension or revocation of necessary permits, licenses or other authorizations;
- imposition of injunctive obligations or limitations on our operations;
- requirement for additional pollution controls; and
- required performance of site investigatory, remedial or other corrective actions.

In addition, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornados and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

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.

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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 produce depends on numerous factors beyond the control of our management, including but not limited to the extent of domestic production and imports of oil, the proximity and capacity of gas pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of gas sold in interstate commerce. The oil and natural gas we produce in Louisiana is sold to purchasers who service the areas where our wells are located. We sell the majority of our oil to Shell Trading Company, or Shell. Shell takes custody of the oil at the outlet from our oil storage barge. Our production from WCBB, other than the production sold under forward sales contracts, is being sold in accordance with the Shell posted price for West Texas/New Mexico Intermediate crude plus or minus Platt s trade month average P+ value, plus or minus the Platt s HLS/WTI differential less $2.70 per barrel for transportation. During 2010, we sold 75% and 19% of our oil production to Shell and Windsor Energy Group, LLC, or Windsor, respectively and 50%, 32%, and 10% of our natural gas production to Windsor, Chevron and Hilcorp Energy Company, respectively. During 2009, we sold 92% and 7% of our oil production to Shell and Windsor, respectively, and 45%, 38%, and 16% of our natural gas production to Windsor, Chevron and Hilcorp Energy Company, respectively. During 2008, we sold 87% of our oil production to Shell and 11% to Windsor, 100% of our natural gas liquids production to Windsor, and 60%, 22%, and 16% of our natural gas production to Chevron, Windsor, and Hilcorp Energy Company, respectively. We may not continue to have ready access to suitable markets for our future oil and natural gas production.

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

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

Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month prices for 2010 and 2009 and prior to 2009, unescalated year-end prices, adjusted for any contract provisions or financial derivatives, if any, that hedge oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, less income tax effects related to differences between the book and tax basis of the oil and natural gas properties. If the net book value reduced by the related net deferred income tax liability exceeds the ceiling, an impairment or noncash writedown is required. A ceiling test impairment can give us a significant loss for a particular period. Once incurred, a write down of oil and natural gas properties is not reversible at a later date, even if oil or gas prices increase. If prices of oil, natural gas and natural gas liquids decrease, we may be required to further write down the value of our oil and gas properties. Future non-cash asset impairments could negatively affect our results of operations.

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

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not

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enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

We have entered into forward sales contracts and fixed price swaps and may in the future enter into additional contracts for a portion of our production, which may result in our making cash payments or prevent us from receiving the full benefit of increases in prices for oil and gas.

To mitigate the effects of commodity price fluctuations, we were party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials, for the period January 2010 through February 2010. For the period March 2010 through December 2010, we were party to forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel before transportation costs and differentials. In November 2010, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel, before transportation costs and differentials, for the period January 2011 through December 2011. We delivered approximately 45% of our 2010 production under these agreements. Under the 2011 contracts, we have committed to deliver approximately 30% to 33% of our estimated 2011 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. In addition, these arrangements may limit the benefit to us of increases in the price of oil. These forward sales contracts and fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815, *Derivatives and Hedging,* and related pronouncements.

A terrorist attack or armed conflict could harm our business.

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

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

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

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 largest stockholder controls a significant percentage of our common stock, and its interests may conflict with those of our other stockholders.

As of December 31, 2010, Charles E. Davidson, our largest stockholder, beneficially owned approximately 25.4% of our outstanding common stock. As a result, this stockholder acting alone is able to exercise significant influence over most matters requiring approval by our stockholders, including the election of directors and the approval of significant corporate transactions. Such a concentration of ownership may have the effect of delaying or preventing a change in control of us, including transactions in which stockholders might otherwise receive a premium for their shares over then current market prices.

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

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

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

As of December 31, 2010, we had a net operating loss, or NOL, carry forward of approximately $52.4 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 NOLs generated through the ownership change date could be limited. In general, the amount of NOLs we could use for any tax year after the date of the ownership change would be limited to the value of our stock (as of the ownership change date) multiplied by the long-term tax-exempt rate.

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

We and certain of our stockholders have registered a substantial number of shares of our common stock under a registration statement filed with the SEC. Sales of these shares of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline. In addition, sales by certain of our stockholders of their shares could impair our ability to raise capital through the sale of common or preferred stock. As of March 1, 2011, there were 44,670,930 shares of our common stock issued and outstanding, excluding 112,891 shares of unvested restricted stock awarded under our Amended and Restated 2005 Stock Incentive Plan, 30,420 shares issuable upon exercise of outstanding warrants and 433,241 shares issuable upon exercise of outstanding options to purchase our common stock granted under our Amended and Restated 2005 Stock Incentive Plan.

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

We are authorized to issue up to 5,000,000 shares of preferred stock, par value $0.01 per share. Shares of preferred stock may be issued from time to time in one or more series as our board of directors, by resolution or

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resolutions, may from time to time determine each such series to be distinctively designated. The voting powers, preferences and relative, participating, optional and other special rights, and the qualifications, limitations or restrictions, if any, of each such series of preferred stock may differ from those of any and all other series of preferred stock at any time outstanding, and, subject to certain limitations of our certificate of incorporation and the Delaware General Corporation Law, or DGCL, our board of directors may fix or alter, by resolution or resolutions, the designation, number, voting powers, preferences and relative, participating, optional and other special rights, and qualifications, limitations and restrictions thereof, of each such series preferred stock. The issuance of any such preferred stock could materially adversely affect the rights of holders of our common stock and, therefore, could reduce the value of our common stock.

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Proved Oil and Natural Gas Reserves

SEC Rule-Making Activity

In December 2008, the SEC released its final rule for Modernization of Oil and Gas Reporting. These rules require disclosure of oil and gas proved reserves by significant geographic area, using the arithmetic 12-month average beginning-of-the-month price for the year, as opposed to year-end prices as had previously been required unless contractual arrangements designate the price to be used. Other significant amendments included the following:

Disclosure of unproved reserves: probable and possible reserves may be disclosed separately on a voluntary basis.

Proved undeveloped reserve guidelines: reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time.

Reserves estimation using new technologies: reserves may be estimated through the use of reliable technology in addition to flow tests and production history.

Reserves personnel and estimation process: additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserves estimation process. We are also required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.

Non-traditional resources: the definition of oil and gas producing activities has expanded and focuses on the marketable product rather than the method of extraction.

We adopted the rules effective December 31, 2009, as required by the SEC.

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Evaluation and Review of Reserves.

Reserve estimates at December 31, 2010 were prepared by NSAI with respect to our WCBB and Niobrara fields (22% of our proved reserves at December 31, 2010), by Pinnacle with respect to our assets in the Permian Basin in West Texas (65% of our proved reserves at December 31, 2010) and by our personnel with respect to our Hackberry fields and our overriding royalty and non-operated interests (13% of our proved reserves at December 31, 2010).

NSAI and Pinnacle are independent petroleum engineering firms. Copies of their summary reserve reports are included as Exhibit 99.1 and 99.2, respectively, to this Annual Report on Form 10-K. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regards to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Our independent third-party engineers do not own an interest in any of our properties and are not employed by us on a contingent basis.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with NSAI and Pinnacle to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our WCBB and Niobrara fields and our assets in the Permian Basin, respectively. Our internal technical team members meet with NSAI and Pinnacle periodically throughout the year to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to NSAI and Pinnacle for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs. Our proved reserves attributable to our Hackberry fields and other minority interests are prepared internally by our internal staff of petroleum engineers and geoscience professionals. Our chief reserve engineer is primarily responsible for overseeing the preparation of all of our reserve estimates. He is a petroleum engineer with over 30 years of reservoir and operations experience and our geophysical staff has over 60 years combined industry experience. Our technical staff uses historical information for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs.

The preparation of our proved reserve estimates are completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- review and verification of historical production data, which data is based on actual production as reported by us;
- preparation of reserve estimates by our experienced reservoir engineers or under their direct supervision;
- review by our reservoir engineering department of all of our reported proved reserves at the close of each quarter, including the review of all significant reserve changes and all new proved undeveloped reserves additions;
- direct reporting responsibilities by our reservoir engineering department to our Chief Executive Officer; and
- verification of property ownership by our land department.

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The following table sets forth our estimated proved reserves at December 31, 2010, 2009 and 2008:

	Year Ended December 31,					
	2010		2009		2008	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Proved developed	7,230	6,068	6,165	4,325	7,072	7,187
Proved undeveloped	12,474	10,090	11,323	10,007	14,699	15,048
Total (1)	19,704	16,158	17,488	14,332	21,771	22,235

	Year Ended December 31,		
	2010	2009	2008
Total net proved oil and natural gas reserves (Mboe) (1)	22,397	19,877	25,477
PV-10 value (in millions) (2)	$ 392.6	$ 263.0	$ 126.2
Standardized measure (in millions) (3)	$ 315.5	$ 240.8	$ 126.2

(1) Estimates of reserves as of year-end 2010 and 2009 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2010 and 2009, respectively, in accordance with revised guidelines of the SEC applicable to reserves estimates as of year-end 2010 and 2009. Estimates of reserves as of year-end 2008 were prepared using constant prices and costs in accordance with previous guidelines of the SEC based on hydrocarbon prices received on a field-by-field basis as of December 31st of such year. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates.

(2) 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 certain prevailing economic conditions. The estimated future production in our reserve reports for the years ended December 31, 2010 and 2009 is priced based on the 12-month unweighted arithmetic average of the first-day-of-the month price for the period January through December of the applicable year, using $76.16 per barrel and $4.38 per MMBtu and $57.90 per barrel and 3.87 per MMBtu, respectively, and in each case adjusted by lease for transportation fees and regional price differentials. The estimated future production in our reserve report for the year ended December 31, 2008 is priced using constant year-end pricing of $41.00 per barrel and $5.71 per MMBtu and adjusted by lease for transportation fees and regional price differentials.

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

	December 31,		
	2010	2009	2008
Standardized measure of discounted future net cash flows	$ 315,487,000	$ 240,774,000	$ 126,240,000

Add: Present value of future income tax discounted at 10%	77,117,000	22,237,000	
PV-10 value	$ 392,604,000	$ 263,011,000	$ 126,240,000

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

The above table does not include proved reserves net to our interest in Tatex. For further discussion of our interest in Tatex, see Item 1. Description of Business Additional Properties.

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

Additional information regarding estimates of proved reserves, proved developed reserves and proved undeveloped reserves, or PUDs, at December 31, 2010, 2009 and 2008 and changes in proved reserves during the last three years are contained in the Supplemental Information on Oil and Gas Exploration and Production Activities, or Supplemental Information, in Note 21 to our consolidated financial statements included in this report. Also contained in the Supplemental Information are our estimates of future net cash flows and discounted future net cash flows from proved reserves. Additional information regarding our proved reserves can be found in Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations and Critical Accounting Policies and Estimates included in this report.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2010, our proved undeveloped reserves totaled 12,474 Mboe of oil and 10,090 MMcf of natural gas, for a total of 14,156 Mboe. Approximately 80% of our PUDs at year-end 2010 were located in the Permian Basin, 8% of our PUDs were located in WCBB, 10% were located in our East Hackberry field and 2% of our PUDs were located in our Niobrara field. PUDs will be converted from undeveloped to developed as the applicable wells begin production. Changes in PUDs that occurred during 2010 were primarily due to:

- Additions of 7,952 Mboe attributable to 2010 acquisitions and extensions;
- Conversion of approximately 718 Mboe attributable to PUDs into proved developed reserves;
- Positive revisions of approximately 386 Mboe in PUDs due to changes in commodity prices; and
- Exclusion of 6,455 Mboe attributable to PUD locations that were not scheduled to be drilled within the next five years.

At December 31, 2010, there were proved undeveloped reserves for four WCBB locations that have remained undeveloped for five years or more after their disclosure as proved undeveloped reserves, a decrease from the 11 PUD locations that had remained undeveloped for over five years at December 31, 2009. The reserves attributed to these locations represented approximately 2.5% of our total proved reserves at December 31, 2010 and 7.5% of our total proved reserves at December 31, 2009. We included each of these locations because we believe them to be attractive targets. They were not drilled within five years after their disclosure as proved undeveloped reserves due to the curtailment of our drilling activities in 2008 and 2009 as a

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result of the sharp decrease in commodity prices. Of the four remaining PUD locations on our books at December 31, 2010, one has already been drilled during 2011 and the other three are currently scheduled to be drilled during the summer of 2011.

Costs incurred relating to the development of PUDs were approximately $12.2 million in 2010. Estimated future development costs relating to the development of PUDs are projected to be approximately $71.3 million in 2011, $63.1 million in 2012, $52.0 million in 2013, $20.3 million in 2014 and $47.3 in 2015.

All PUD drilling locations are scheduled to be drilled prior to the end of 2015.

As of December 31, 2010, 19% of our total proved reserves were classified as proved developed non-producing.

Production, Prices, and Production Costs

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

	2010	2009	2008
Production Volumes:			
Oil (MBbls)	1,777	1,531	1,584
Gas (MMcf)	788	491	712
Natural gas liquids (MGal)	2,821	2,719	2,583
Oil equivalents (Mboe)	1,976	1,677	1,764
Average Prices:			
Oil (per Bbl)	$ 68.29(1)	$ 53.29(1)	$ 83.23(1)
Gas (per Mcf)	$ 4.40	$ 4.06	$ 9.23
Natural gas liquids (per Gal)	$ 1.00	$ 0.73	$ 1.26
Oil equivalents (per Boe)	$ 64.61	$ 51.01	$ 80.30
Production Costs:			
Average production costs (per Boe)	$ 8.92(2)	$ 9.73(2)	$ 12.96(2)
Average production taxes (per Boe)	$ 7.07	$ 5.84	$ 8.96
Total production costs (per Boe)	$ 15.99	$ 15.57	$ 21.92

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

January December 2008	$ 78.56
January December 2009	$ 55.01
January December 2010	$ 57.55

Excluding the effect of the fixed price contracts, the average oil price for 2010 would have been $78.12 per barrel and $73.45 per barrel of oil equivalent. The total volume hedged for 2010 represented approximately 45% of our total sales volumes for the year. Excluding the effect of the fixed price contracts, the average oil price for 2009 would have been $57.98 per barrel and $55.29 per barrel of oil equivalent. The total volume hedged for 2009 represented approximately 49% of our total sales volumes for the year. Excluding the net effect of the fixed price contracts, the average oil price for 2008 would have been $97.36 per barrel and $92.98 per barrel of oil equivalent. The total volume hedged for 2008 represented approximately 73% of our total sales volumes for the year.

(2) Does not include production taxes.

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The following table provides a summary of our production, average sales prices and average production costs for oil and gas fields containing 15% or more of our total proved reserves as of December 31, 2010:

	Year Ended December 31, 2010	2009	2008
WCBB			
Net Production			
Oil (MBbls)	1,176	1,209	1,220
Natural gas (MMcf)	410	192	356
NGL (Mgal)			
Total (Mboe)	1,244	1,241	1,280
Average Sales Price:			
Oil (per Bbl)	$ 62.57	$ 52.39	$ 80.20
Natural gas (per Mcf)	$ 4.44	$ 4.44	$ 10.48
NGL (per Gal)	$	$	$
Average Production Cost (per BOE)	$ 8.90	$ 8.54	$ 10.86
Permian Basin			
Net Production			
Oil (MBbls)	134	118	134
Natural gas (MMcf)	256	236	234
NGL (Mgal)	2,797	2,694	2,579
Total (Mboe)	243	221	234
Average Sales Price:			
Oil (per Bbl)	$ 76.48	$ 55.19	$ 94.42
Natural gas (per Mcf)	$ 4.21	$ 3.72	$ 7.57
NGL (per Gal)	$ 1.00	$ 0.73	$ 1.26
Average Production Cost (per BOE)	$ 9.78	$ 10.71	$ 11.59

Productive Wells and Acreage

The following table presents our total gross and net productive and non-productive wells, expressed separately for oil and gas, and the total gross and net developed and undeveloped acres as of December 31, 2010.

Field	NRI/WI (1) Percentages	Productive Oil Wells (2) Gross	Net	Productive Gas Wells Gross	Net	Non-Productive Oil Wells Gross	Net	Non-Productive Gas Wells Gross	Net	Developed Acreage (3) Gross	Net	Undeveloped Acreage (4) Gross	Net
West Cote Blanche Bay Field (5)	80.1/100	90	90	3	3	161	161	18	18	5,668	5,668		
E. Hackberry Field (6)	79.4/100	27	27			74	74			3,291	3,291	1,579	1,579
W. Hackberry Field	87.5/100	3	3			22	22			592	592		
Permian Basin	37.4/49.05	82	40							15,888	7,124	20,089	7,598
Niobrara Formation (7)	36.4/44.04	4	2			1	0.4			2,240	628	41,480	18,817
Williston Basin (8)	3.2/3.9	5	0.2							2,560	127	3,920	779
Overrides/Royalty Non-operated	Various	76	0.2	1		2							
Total		287	162.4	4	3	260	257.4	18	18	30,239	17,430	67,068	28,773

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(1) Net Revenue Interest (NRI)/Working Interest (WI).
(2) Includes nine gross and net wells at WCBB that are producing intermittently.
(3) Developed acres are acres spaced or assigned to productive wells. Approximately 36% of our acreage is developed acreage and has been perpetuated by production.
(4) E. Hackberry acreage does not include 2,868 net acres subject to a two-year exploration agreement.
(5) We have a 100% working interest (80.108% average NRI) from the surface to the base of the 13900 Sand which is located at 11,320 feet. Below the base of the 13900 Sand, we have a 40.40% non-operated working interest (29.95% NRI).
(6) NRI shown is for producing wells.
(7) The leases relating to our Niobrara Formation acreage will expire at the end of their respective primary terms unless the applicable leases are renewed or extended, we have commenced the necessary operations required by the terms of the applicable leases or we have obtained actual production from acreage subject to the applicable leases, in which event they will remain in effect until the cessation of production. Leases representing 35%, 20%, 22%, 4% and 19% of our total Niobrara acreage are currently scheduled to expire in 2011, 2012, 2013, 2014 and thereafter, respectively.
(8) NRI/WI is from wells that have been drilled or in which we have elected to participate.

Completed and Present Drilling and Recompletion Activities

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

	2010		2009		2008	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Recompletions:						
Productive	87	84	64	62.5	58	56.5
Dry						
Total	87	84	64	62.5	58	56.5
Development:						
Productive	57	42	25	18	69	27
Dry			1	1		
Total	57	42	26	19	69	27
Exploratory:						
Productive			1	1		
Dry					1	1
Total			1	1	1	1

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.

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ITEM 3. LEGAL PROCEEDINGS

The Louisiana Department of Revenue, or LDR, is disputing our severance tax payments to the State of Louisiana from the sale of oil under fixed price contracts during the years 2005 through 2007. The LDR maintains that we paid approximately $1.8 million less in severance taxes under fixed price terms than the severance taxes we would have had to pay had we paid severance taxes on the oil at the contracted market rates only. We have denied any liability to the LDR for underpayment of severance taxes and have maintained that we were entitled to enter into the fixed price contracts with unrelated third parties and pay severance taxes based upon the proceeds received under those contracts. We have maintained our right to contest any final assessment or suit for collection if brought by the State. On April 20, 2009, the LDR filed a lawsuit in the 15th Judicial District Court, Lafayette Parish, in Louisiana against our company seeking $2,275,729 in severance taxes, plus interest and court costs. We filed a response denying any liability to the LDR for underpayment of severance taxes and are defending our company in the lawsuit. The case is in the early stages of discovery.

More recently, in December 2010, the LDR filed two identical lawsuits against us in different venues to recover allegedly underpaid severance taxes on crude oil for the period January 1, 2007 through December 31, 2010, together with a claim for attorney's fees. The petitions do not make any specific claim for damages or unpaid taxes. As with the first lawsuit filed by the LDR in 2009, we have denied all liability and will vigorously defend the lawsuit. The cases are in the very early stages, and we have not yet filed a response to the recent lawsuits.

In November 2006, Cudd Pressure Control, Inc., or Cudd, filed a lawsuit against us, Great White Pressure Control LLC, or Great White, and six former Cudd employees in the 129th Judicial District Harris County, Texas. The lawsuit was subsequently removed to the United States District Court for the Southern District of Texas (Houston Division). The lawsuit alleged RICO violations and several other causes of action relating to Great White s employment of the former Cudd employees and sought unspecified monetary damages and injunctive relief. On stipulation by the parties, the plaintiff s RICO claim was dismissed without prejudice by order of the court on February 14, 2007. We filed a motion for summary judgment on October 5, 2007. The Court entered a final interlocutory judgment in favor of all defendants, including us, on April 8, 2008. On November 3, 2008, Cudd filed its appeal with the U.S. Court of Appeals for the Fifth Circuit. The Fifth Circuit vacated the district court decision finding, among other things, that the district court should not have entered summary judgment without first allowing more discovery. The case was remanded to the district court, and Cudd filed a motion to remand the case to the original state court, which motion was granted. On February 3, 2010, Cudd filed its second amended petition with the state court (a) alleging that we conspired with the other defendants to misappropriate, and misappropriated Cudd s trade secrets and caused its employees to breach their fiduciary duties, and (b) seeking unspecified monetary damages. On April 13, 2010, our motion to be dismissed from the proceeding for lack of personal jurisdiction was denied. This state court proceeding is in its initial stages. In 2011, the parties have continued with written discovery and production of documents. On February 15, 2011, Cudd filed a third amended petition seeking $26.5 million (based on a report prepared by its expert) plus disgorgement of $6.0 million in payments by Great White to the individual defendants and punitive damages. Gulfport denies these claims with respect to itself.

On July 30, 2010, six individuals and one limited liability company sued 15 oil and gas companies in Cameron Parish Louisiana for contamination across the surface of where the defendants operated in an action entitled *Reeds et al. v. BP American Production Company et al.,* 38th Judicial District. No. 10-18714. The plaintiffs original petition for damages, which did not name us as a defendant, alleges that the plaintiffs property located in Cameron Parish, Louisiana within the Hackberry oil field is contaminated as a result of historic oil and gas exploration and production activities. Plaintiffs allege that the defendants, which in addition to BP America Production Company include ExxonMobil Corporation, Shell Oil Company, ConocoPhillips Company, Sun Oil Company and Schlumberger Technology Corporation, conducted, directed and participated in various oil and gas exploration and production activities on their property which allegedly have contaminated or otherwise caused damage to the property, and have sued the defendants for alleged breaches of oil, gas and

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mineral leases, as well as for alleged negligence, trespass, failure to warn, strict liability, punitive damages, lease liability, contract liability, unjust enrichment, restoration damages, assessment and response costs and stigma damages. On December 7, 2010, we were served with a copy of the plaintiffs first supplemental and amending petition which added four additional plaintiffs and six additional defendants, including us, bringing the total number of defendants to 21. It also increased the total acreage at issue in this litigation from 240 acres to approximately 1,700 acres. In addition to the damages sought in the original petition, the plaintiffs now also seek: damages sufficient to cover the cost of conducting a comprehensive environmental assessment of all present and yet unidentified pollution and contamination of their property; the cost to restore the property to its pre-polluted original condition; damages for mental anguish and annoyance, discomfort and inconvenience caused by the nuisance created by defendants; land loss and subsidence damages and the cost of backfilling canals and other excavations; damages for loss of use of land and lost profits and income; attorney fees and expenses; and damages for evaluation and remediation of any contamination that threatens groundwater. On January 21, 2011, we filed a pleading challenging the legal sufficiency of the petitions and requesting that they either be dismissed or that plaintiffs be required to amend such petitions. Our motion is currently set to be heard on March 23, 2011.

Due to the current stages of the above litigation, the outcomes are uncertain and management cannot determine the amount of loss, if any, that may result. Litigation is inherently uncertain. Adverse decisions in one or more of the above matters could have a material adverse affect on our financial condition or results of operations.

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

ITEM 4. RESERVED

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PART II

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

Since July 14, 2006, our common stock has been quoted on The NASDAQ Global Select Market under the symbol GPOR. The following table sets forth the high and low sale prices of our common stock for the periods presented:

	Price Range of Common Stock	
	High	Low
2009		
First Quarter	$ 5.20	$ 1.50
Second Quarter	7.65	2.23
Third Quarter	8.99	5.23
Fourth Quarter	11.89	7.25
2010		
First Quarter	$ 12.68	$ 8.89
Second Quarter	15.25	10.60
Third Quarter	14.71	10.37
Fourth Quarter	22.92	13.59
2011		
First Quarter (through March 10, 2011)	$ 30.99	$ 20.00

On March 10, 2011, the last reported sale price of our common stock on The NASDAQ Global Select Market was $24.69.

Unregistered Sales of Equity Securities and Use of Proceeds

None.

Holders of Record

At the close of business on March 3, 2011, there were 340 stockholders of record holding 44,549,037 shares of our outstanding common stock. There were approximately 14,970 beneficial owners of our common stock as of March 3, 2011.

Dividend Policy

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

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ITEM 6. SELECTED FINANCIAL DATA

You should read the following selected consolidated financial data in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements and the related notes appearing elsewhere in this report. The selected consolidated statements of operations data for the fiscal years ended December 31, 2010, December 31, 2009 and December 31, 2008 and the selected consolidated balance sheet data at December 31, 2010 and December 31, 2009 are derived from our audited consolidated financial statements appearing elsewhere in this report. The selected consolidated statements of operations data for the fiscal years ended December 31, 2007 and December 31, 2006 and the selected consolidated balance sheet data at December 31, 2008, December 31, 2007 and December 31, 2006 are derived from our audited consolidated financial statements that are not included in this report. The historical data presented below is not indicative of future results. We did not pay any cash dividends on our common stock during any of the periods set forth in the following table.

	Fiscal Year Ended December 31,				
	2010	**2009**	**2008**	**2007**	**2006**
Selected Consolidated Statements of Operations Data:					
Revenues	$ 126,944,000	$ 85,262,000	$ 141,217,000	$ 105,838,000	$ 60,390,000
Costs and expenses:					
Lease operating expenses	17,614,000	16,316,000	22,856,000	16,670,000	10,670,000
Production taxes	13,966,000	9,797,000	15,813,000	12,667,000	7,366,000
Depreciation, depletion and amortization	38,907,000	29,225,000	42,472,000	29,681,000	12,652,000
Impairment of oil and natural gas properties			272,722,000		
General and administrative	6,063,000	4,992,000	6,843,000	5,802,000	3,251,000
Accretion expense	617,000	582,000	560,000	554,000	596,000
	77,167,000	60,912,000	361,266,000	65,374,000	34,535,000
Income (Loss) from Operations	49,777,000	24,350,000	(220,049,000)	40,464,000	25,855,000
Other (Income) Expense:					
Interest expense	2,761,000	2,309,000	4,762,000	3,091,000	1,956,000
Insurance recoveries		(1,050,000)	(769,000)		(3,601,000)
Settlement of fixed price contracts			(39,000,000)		
Interest income	(387,000)	(564,000)	(540,000)	(523,000)	(308,000)
	2,374,000	695,000	(35,547,000)	2,568,000	(1,953,000)
Income (Loss) before Income Taxes	47,403,000	23,655,000	(184,502,000)	37,896,000	27,808,000
Income Tax Expense	40,000	28,000		121,000	
Net Income (Loss)	47,363,000	23,627,000	(184,502,000)	37,775,000	27,808,000
Net Income (Loss) Available to Common Stockholders	47,363,000	$ 23,627,000	$ (184,502,000)	$ 37,775,000	$ 27,808,000
Net Income (Loss) Per Common Share Basic:	$ 1.08	$ 0.55	$ (4.33)	$ 1.03	$ 0.85
Net Income (Loss) Per Common Share Diluted:	$ 1.07	$ 0.55	$ (4.33)	$ 1.01	$ 0.82

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	At December 31, 2010	2009	2008	2007	2006
Selected Consolidated Balance Sheet Data:					
Total assets	$ 319,693,000	$ 227,344,000	$ 221,873,000	$ 419,137,000	$ 195,151,000
Total debt, including current maturity	$ 51,917,000	$ 52,428,000	$ 70,731,000	$ 66,533,000	$ 37,691,000
Total liabilities	$ 108,637,000	$ 102,293,000	$ 107,772,000	$ 115,015,000	$ 71,342,000
Stockholders equity	$ 211,056,000	$ 125,051,000	$ 114,101,000	$ 304,122,000	$ 123,809,000

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

Overview

We are an independent oil and natural gas exploration and production company with our principal producing properties located along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields, and in West Texas in the Permian Basin. In 2010, we acquired an acreage position in Western Colorado in the Niobrara Formation. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, and have interests in entities that operate in Southeast Asia, including the Phu Horm gas field in Thailand. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

2010 Highlights

Oil and natural gas revenues increased 49% to $127.6 million for the year ended December 31, 2010 from $85.6 million for the year ended December 31, 2009.

Net income increased 100% to $47.4 million for the year ended December 31, 2010 from $23.6 million for the year ended December 31, 2009.

Production increased 18% to approximately 1,976,000 barrels of oil equivalent, or BOE, for the year ended December 31, 2010 from approximately 1,677,000 BOE for the year ended December 31, 2009.

During 2010, we drilled 57 gross (42 net) wells, which includes 26 gross (11 net) wells drilled by our operators in the Permian Basin and Bakken, and recompleted 87 gross (84 net) wells. Of our 57 new wells drilled, 56 were completed as producing wells and one was waiting on completion.

During 2010, we acquired approximately 6,500 additional net acres in the Permian Basin, which brought our total net acreage position in the Permian Basin to approximately 14,700 net acres.

Effective as of April 1, 2010, we acquired leasehold interests in the Niobrara Formation in Colorado and held leases for 19,172 net acres as of March 1, 2011.

In May 2010, we completed an underwritten public offering of 1,668,503 shares of our common stock and received approximately $21.4 million in net proceeds, which we used to fund the acquisition of our interests in the Niobrara Formation, pay the purchase price for a portion of the additional acreage acquired by us in the Permian Basin in 2010 and for general corporate purposes.

On September 30, 2010, we entered into a new $100.0 million senior secured revolving credit facility with The Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, and Amegy Bank National Association, and repaid and terminated our existing revolving credit facility and term loan, each with Bank of America, N.A., as administrative agent, with borrowings under our new revolving credit facility. Our borrowing base under this facility was increased from $50.0 million to $65.0 million in December

2010.

Recent Developments

In February 2011, we entered into an agreement to acquire certain leasehold interests located in the Utica Shale in Ohio. The agreement also grants us an exclusive right of first refusal for a period of six months on certain additional tracts leased by the seller. Windsor, an affiliate of ours, has agreed to participate with us on a 50/50 basis in the acquisition of all of the leases described above. We will be the operator on this acreage in the Utica Shale. The purchase price for our 50% interest in the initial acreage is approximately $31.6 million, subject to certain closing adjustments. This transaction is expected to close in mid-May 2011.

Critical Accounting Policies and Estimates

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

Oil and Natural Gas Properties. We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including non-productive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. 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 the 12-month unweighted average of the first-day-of-the-month price for the period 2010 and 2009, and prior to 2009, 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, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required. 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 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 $16.8 million at December 31, 2010 and $17.5 million at December 31, 2009. These costs are reviewed quarterly by management for impairment, with the impairment provision included in the cost of oil and natural gas properties subject to amortization. Factors considered by management in its impairment assessment include our drilling results and those of other operators, the terms of oil and natural gas leases not held by production and available funds for exploration and development.

Ceiling Test. Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price for the period January December of the applicable year beginning with 2009, and prior to 2009, 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, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required. Ceiling test impairment can give us a significant loss for a particular period; however, future depletion expense would be reduced. A decline in oil and gas prices may result in an impairment of oil and gas properties. For instance, as a result of the drop in commodity prices on December 31, 2008 and subsequent reduction in our proved reserves, we recognized a ceiling test impairment of $272.7 million for the year ended December 31, 2008. If prices of oil, natural gas and natural gas liquids decline, we may be required to further write down the value of our oil and gas properties, which could negatively affect our results of operations. No ceiling test impairment was required for the year ended December 31, 2010.

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 FASB ASC 410 which requires us to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, we increase the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related long-lived asset. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.

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

Oil and Gas Reserve Quantities. Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Netherland, Sewell & Associates, Inc., Pinnacle Energy Services, LLC and to a lesser extent our personnel have prepared reserve reports of our reserve estimates at December 31, 2010 on a well-by-well basis for our properties.

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

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

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

Income Taxes. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized in the year in which realization becomes determinable. Periodically, management performs a forecast of its taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established, if in management s opinion, it is more likely than not that some portion will not be realized. At December 31, 2010, a valuation allowance of $54.4 million had been provided for deferred tax assets based on the uncertainty of future taxable income.

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

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

Derivative Instruments and Hedging Activities. We seek to reduce our exposure to unfavorable changes in oil prices by utilizing energy swaps and collars, or fixed-price contracts. We follow the provisions of FASB ASC 815, *Derivatives and Hedging*, as amended. It requires that all derivative instruments be recognized as assets or liabilities in the balance sheet, measured at fair value. We estimate the fair value of all derivative instruments using established index prices and other sources. These values are based upon, among other things, futures prices, correlation between index prices and our realized prices, time to maturity and credit risk. The values reported in the financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. Designation is established at the inception of a derivative, but re-designation is permitted. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of FASB ASC 815, changes in fair value are recognized in accumulated other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. We recognize any change in fair value resulting from ineffectiveness immediately in earnings.

To mitigate the effects of commodity price fluctuations, for the period January 2010 through February 2010, we were party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials. For the period March 2010 through December 2010, we were party to forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel, before transportation costs and differentials. In November 2010, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel, before transportation costs and differentials, for the period January 2011 through December 2011. Under the 2010 contracts, we delivered approximately 45% of our estimated 2010 production. Under the 2011 contracts, we have committed to deliver approximately 30% to 33% of our estimated 2011 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These forward sales contracts and fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements.

RESULTS OF OPERATIONS

Results of Operations

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

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

	2010	2009	2008
Production Volumes:			
Oil (MBbls)	1,777	1,531	1,584
Gas (MMcf)	788	491	712
Natural gas liquids (MGal)	2,821	2,719	2,583
Oil equivalents (Mboe)	1,976	1,677	1,764
Average Prices:			
Oil (per Bbl)	$ 68.29(1)	$ 53.29(1)	$ 83.23(1)
Gas (per Mcf)	$ 4.40	$ 4.06	$ 9.23
Natural gas liquids (per Gal)	$ 1.00	$ 0.73	$ 1.26
Oil equivalents (per Boe)	$ 64.61	$ 51.01	$ 80.30
Production Costs:			
Average production costs (per Boe)	$ 8.92(2)	$ 9.73(2)	$ 12.96(2)
Average production taxes (per Boe)	$ 7.07	$ 5.84	$ 8.96
Total production costs (per Boe)	$ 15.99	$ 15.57	$ 21.92

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

January December 2008	$ 78.56
January December 2009	$ 55.01
January December 2010	$ 57.55

Excluding the net effect of the fixed price contracts, the average oil price for 2010 would have been $78.12 per barrel and $73.45 per barrel of oil equivalent. The total volume hedged for 2010 represented approximately 45% of our total sales volumes for the year. Excluding the effect of the fixed price contracts, the average oil price for 2009 would have been $57.98 per barrel and $55.29 per barrel of oil equivalent. The total volume hedged for 2009 represented approximately 49% of our total sales volumes for the year. Excluding the net effect of the fixed price contracts, the average oil price for 2008 would have been $97.36 per barrel and $92.98 per barrel of oil equivalent. The total volume hedged for 2008 represented approximately 73% of our total sales volumes for the year.

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(2) Does not include production taxes.

From 2009 to 2010, our net equivalent oil production increased 18% from 1,677,000 barrels to 1,976,000 barrels due to increased drilling activity, the success of our drilling activities and our acquisitions of additional properties in the Permian Basin and the Niobrara Formation. From 2008 to 2009, our net equivalent oil production decreased 5% from 1,764,000 barrels to 1,677,000 barrels due to our reduced drilling activity and normal production declines. We currently estimate that our 2011 production will be between 2,200,000 and 2,400,000 BOE. However, such estimate may change based on a change in our expected drilling and recompletion activities or the changing economic climate and unforeseen events, such as hurricanes.

Comparison of the Years Ended December 31, 2010 and December 31, 2009

We reported net income of $47,363,000 for the year ended December 31, 2010, as compared to net income of $23,627,000 for the year ended December 31, 2009. This 100% increase in 2010 was due primarily to a 27% increase in realized BOE prices to $64.61 from $51.01 and an 18% increase in net production to 1,976,000 BOE, partially offset by an 8% increase in lease operating expenses, a 21% increase in general and administrative expenses and a 43% increase in production taxes.

Oil and Gas Revenues. For the year ended December 31, 2010, we reported oil and natural gas revenues of $127,636,000 as compared to oil and natural gas revenues of $85,576,000 during 2009. This $42,060,000, or 49%, increase in revenues is primarily attributable to a 27% increase in realized BOE prices to $64.61 from $51.01 and an 18% increase in net production to 1,975,576 BOE for the year ended December 31, 2010 from 1,677,474 BOE for the year ended December 31, 2009.

The following table summarizes our oil and natural gas production and related pricing for the years ended December 31, 2010 and December 31, 2009:

	Year Ended December 31,	
	2010	**2009**
Oil production volumes (MBbls)	1,777	1,531
Gas production volumes (MMcf)	788	491
Natural gas liquids production volumes (MGal)	2,821	2,719
Oil equivalents (Mboe)	1,976	1,677
Average oil price (per Bbl)	$ 68.29	$ 53.29
Average gas price (per Mcf)	$ 4.40	$ 4.06
Average natural gas liquids (per Gal)	$ 1.00	$ 0.73
Oil equivalents (per Boe)	$ 64.61	$ 51.01

Lease Operating Expenses. Lease operating expenses not including production taxes increased to $17,614,000 for 2010 from $16,316,000 for 2009. This increase is mainly a result of an increase in ad valorem taxes and expenses related to well workovers.

Production Taxes. Production taxes increased to $13,966,000 for 2010 from $9,797,000 for 2009. This increase was primarily related to a 49% increase in oil and gas revenues as a result of a 27% increase in average realized BOE price received and an 18% increase in production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $38,907,000 for 2010, and consisted of $38,600,000 in depletion on oil and natural gas properties and $307,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $29,225,000 for 2009. This increase was due to an increase in our full cost pool as a result of our capital activities and an increase in our production used to calculate our total DD&A expense.

General and Administrative Expenses. Net general and administrative expenses increased to $6,063,000 for 2010 from $4,992,000 for 2009. This $1,071,000 increase was primarily due to a $450,000 increase in franchise taxes, a $200,000 increase in legal expenses and increases related to salaries, benefits expenses partially offset by an increase in general and administrative overhead related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense increased slightly to $617,000 for 2010 from $582,000 for 2009.

Interest Expense. Interest expense increased to $2,761,000 for 2010 from $2,309,000 for 2009. This increase was due to an increase in the interest rate paid as well as the recognition of approximately $225,000 in unamortized loan fees associated with the termination of the Bank of America revolving credit facility. Effective September 30, 2010, this facility, along with the term loan with Bank of America, were repaid with borrowings under our new senior secured revolving credit agreement with The Bank of Nova Scotia, as administrative agent and letter of credit issuer and lead arranger, and Amegy Bank National Association, entered into on September 30, 2010. This increase in interest expense was partially offset by a decrease in average debt outstanding for the year ended December 31, 2010, as compared to the year ended December 31, 2009. Total debt outstanding under our new revolving credit facility was $49.5 million as of December 31, 2010, as compared to $49.9 million outstanding under our prior facilities with Bank of America as of the same date in 2009. Total weighted debt outstanding under our facilities was $46.9 million for 2010 and $59.9 million for 2009. Until September 30, 2010, amounts borrowed under our term loan and revolving credit facility with Bank of America bore interest of 3.76% and 3.25%, respectively. At December 31, 2010, amounts borrowed under our new revolving credit agreement bore interest at the Eurodollar rate of 3.77%.

Income Taxes. As of December 31, 2010, we had a net operating loss carry forward of approximately $52.4 million, in addition to numerous temporary differences, which gave rise to a deferred tax asset. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management s opinion, it is more likely than not that some portion will not be realized. At December 31, 2010, a valuation allowance of $54.4 million had been provided for deferred tax assets, with the exception of $628,000 for alternative minimum taxes. We paid $40,000 of state income tax for the year ended December 31, 2010.

Comparison of the Years Ended December 31, 2009 and December 31, 2008

We reported net income of $23,627,000 for the year ended December 31, 2009, as compared to a net loss of $184,502,000 for the year ended December 31, 2008. This net income is primarily attributable to a 29% decrease in lease operating expenses, a 27% decrease in general and administrative expenses and a 38% decrease in production taxes, partially offset by a 36% decrease in realized BOE prices to $51.01 from $80.30 and a 5% decrease in net production to 1,677,474 BOE. In addition, the net loss for 2008 was primarily attributable to an impairment charge of $272,722,000 related to the drastic decline in oil and gas prices. Further, we had $1,050,000 of insurance proceeds received during the year ended December 31, 2009 compared to insurance proceeds of $769,000 received during 2008.

Oil and Gas Revenues. For the year ended December 31, 2009, we reported oil and natural gas revenues of $85,576,000 as compared to oil and natural gas revenues of $141,650,000 during 2008. This $56,074,000, or 40%, decrease in revenues is primarily attributable to a 36% decrease in realized BOE prices to $51.01 from $80.30 and a 5% decrease in net production to 1,677,474 BOE for the year ended December 31, 2009 from 1,764,053 BOE for the year ended December 31, 2008.

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The following table summarizes our oil and natural gas production and related pricing for the years ended December 31, 2009 and December 31, 2008:

	Year Ended December 31,	
	2009	2008
Oil production volumes (MBbls)	1,531	1,584
Gas production volumes (MMcf)	491	712
Natural gas liquids production volumes (MGal)	2,719	2,583
Oil equivalents (Mboe)	1,677	1,764
Average oil price (per Bbl)	$ 53.29	$ 83.23
Average gas price (per Mcf)	$ 4.06	$ 9.23
Average natural gas liquids (per Gal)	$ 0.73	$ 1.26
Oil equivalents (per Boe)	$ 51.01	$ 80.30

Lease Operating Expenses. Lease operating expenses not including production taxes decreased to $16,316,000 for 2009 from $22,856,000 for 2008. This decrease is mainly a result of a decrease in contract labor expenses, a decrease in workovers, compressor and other equipment rentals and repairs, a decrease in the cost of chemicals and supplies and a decrease in personal property taxes. In addition, the lease operating expenses for 2008 included $3,408,000 of unreimbursed expenses related to hurricane repairs as compared to approximately $23,000 of unreimbursed expenses related to hurricane repairs in 2009.

Production Taxes. Production taxes decreased to $9,797,000 for 2009 from $15,813,000 for 2008. This decrease was primarily related to a 40% decrease in oil and gas revenues mainly as a result of the decrease in the average realized BOE price received.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense decreased to $29,225,000 for 2009, and consisted of $28,939,000 in depletion on oil and natural gas properties and $286,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $42,472,000 for 2008. This decrease was due primarily to the reduction in the book value of our oil and gas properties used to calculate depreciation, depletion and amortization expense. This reduction resulted from the drop in commodity prices reflected as of December 31, 2008 and the resulting reduction in our proved reserves which caused us to recognize a ceiling test impairment to our full cost pool of $272,722,000 for the year ended December 31, 2008.

Impairment of Oil and Gas Properties. We use the full cost method of accounting for oil and gas properties and are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of our oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price for the period of January through December 2009, and prior to 2009, unescalated year-end prices and costs, adjusted for any contract provisions or financial derivatives, if any, that hedge our oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on our balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, less income tax effects related to differences between the book and tax basis of the oil and natural gas properties. If the net book value reduced by the related net deferred income tax liability exceeds the ceiling, an impairment or noncash write-down is required. There was no impairment charge for the year ended December 31, 2009. As a result of the drop in commodity prices on December 31, 2008, we recognized a ceiling test impairment of $272,722,000 for the year ended December 31, 2008.

General and Administrative Expenses. Net general and administrative expenses decreased to $4,992,000 for 2009 from $6,843,000 for 2008. This $1,851,000 decrease was due primarily to reductions in franchise taxes as a result of the impairment mentioned in the depreciation, depletion and amortization section above which reduced our net assets used to calculate franchise taxes, a reduction in stock based compensation expenses, reductions in payroll costs including payroll taxes and related benefits mainly due to decreases in the total number of employees partially offset by a decrease in general and administrative reimbursements from our affiliates and a decrease in general and administrative overhead related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense increased slightly to $582,000 for 2009 from $560,000 for 2008.

Interest Expense. Interest expense decreased to $2,309,000 for 2009 from $4,762,000 for 2008 due to a decrease in average debt outstanding and lower interest rates on amounts borrowed under our facilities with Bank of America. Total debt outstanding under our facilities with Bank of America was $49.9 million as of December 31, 2009 and $68.1 million as of the same date in 2008. Total weighted debt outstanding under our facilities with Bank of America was $59.9 million for 2009 and $84.2 million for 2008. As of December 31, 2009, amounts borrowed under our revolving credit facility and our two term loans with Bank of America bore interest of 3.73%, 4.23% and 3.25%, respectively.

Income Taxes. As of December 31, 2009, we had a net operating loss carry forward of approximately $55.7 million, in addition to numerous temporary differences, which gave rise to a deferred tax asset. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management s opinion, it is more likely than not that some portion will not be realized. At December 31, 2009, a valuation allowance of $73.2 million had been provided for deferred tax assets, as the Company has historically had non-taxable income and has future projections of no taxable income during the carryforward period, with the exception of $533,000 related to alternative minimum taxes. We had $28,000 of state income tax expense for the year ended December 31, 2009.

Liquidity and Capital Resources

Overview. Historically, our primary sources of funds have been cash flow from our producing oil and natural gas properties, borrowings under our bank and other credit facilities and the issuance of equity securities. Our ability to access any of these sources of funds can be significantly impacted by decreases in oil and natural gas prices or our oil and gas production. During 2009, we also received proceeds from the sale of certain of our Bakken assets and, in 2010, we received net proceeds (before offering expenses) of approximately $21.6 million from the sale of our common stock in an underwritten public offering.

Net cash flow provided by operating activities was $85,835,000 for 2010, as compared to $53,299,000 for 2009. This increase was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to a 27% increase in net realized prices and an 18% increase in our net BOE production.

Net cash flow provided by operating activities was $53,299,000 for 2009, as compared to $135,323,000 for 2008. This decrease was primarily the result of a decrease in cash receipts from our oil and natural gas purchasers due to a 36% decrease in net realized prices and a 5% decrease in our net BOE production.

Net cash used in investing activities for 2010 was $105,315,000, as compared to $39,246,000 for 2009. During 2010, we spent $101,644,000 in additions to oil and natural gas properties, of which $51,356,000 was spent on our 2010 drilling and recompletion programs, $16,735,000 was spent on acquisitions in our Niobrara and Permian fields, $11,697,000 was spent on expenses attributable to the wells drilled during 2009, $3,093,000 was spent on our 2009 recompletions, $6,838,000 was spent on compressors and other facility enhancements, $1,425,000 was spent on plugging costs, $771,000 was spent on lease related costs and $3,449,000 was spent on tubulars, with the remainder attributable mainly to capitalized general and administrative expenses. In addition, we paid $3,719,000 in cash calls to Grizzly during 2010. During 2010, we used cash from operations, borrowings under our credit facilities and proceeds from our equity offering to fund our investing activities.

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Net cash used in investing activities for 2009 was $39,246,000, as compared to $136,823,000 for 2008. During the year ended December 31, 2009, we spent (a) $49,533,000 in additions to oil and natural gas properties, of which $20,296,000 was spent on our 2009 drilling and recompletion programs, $14,255,000 was spent on costs attributable to the wells drilled during 2008, $3,719,000 was spent on our 2008 recompletions, $1,191,000 was spent on barges and other facility enhancements, $866,000 was spent on plugging and abandonment activities, $2,853,000 was spent on lease related costs and $1,744,000 was spent on tubulars, with the remainder attributable mainly to capitalized general and administrative expenses, and (b) $3,813,000 on our investment in Tatex III and we loaned $4,377,000 to Grizzly. In May, September and December 2009, we received aggregate net proceeds of approximately $18,286,000 from our sale of properties in the Bakken. During the year ended December 31, 2009, we used cash from operations and proceeds from the sale of Bakken properties to fund our investing activities.

Net cash provided by financing activities for 2010 was $20,224,000 as compared to net cash used by financing activities of $18,273,000 for 2009. The 2010 amount provided by financing activities is primarily attributable to the net proceeds of $21,358,000 from our equity offering and borrowings of $52,200,000 under our new credit facility, partially offset by principal payments of $49,903,000 on borrowings under our prior credit facilities with Bank of America. We used the net proceeds of our 2010 equity offering to fund the acquisition of our interests in the Niobrara Formation, pay the purchase price for a portion of the additional acreage acquired by us in the Permian Basin in 2010 and for general corporate purposes.

The 2009 amount used by financing activities is primarily attributable to principal payments on borrowings of $18,206,000 under our credit facility with Bank of America, partially offset by $30,000 received from the exercise of stock options.

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

Credit Facility. In March 2005, we entered into a three-year secured credit agreement with Bank of America, N.A. providing for a revolving credit facility. The credit agreement was subsequently amended and restated from time to time and, among other things, the maturity date was extended to April 1, 2011. Borrowings under the revolving credit facility were subject to a borrowing base limitation, which was initially set at $18.0 million, subject to adjustment. Effective July 19, 2007, the credit facility was increased to $150.0 million and effective December 20, 2007, the amount available under the borrowing base limitation was increased to $90.0 million.

On August 31, 2009, the lender completed its periodic redetermination of our borrowing base giving consideration to our year-end 2008 and mid-year 2009 reserve information and the lender s then current pricing decks, among other factors. As a result of this redetermination, our available borrowing base was reset at $45.0 million, primarily in response to significant declines in commodity prices. Our outstanding principal balance at the effective time of this redetermination was approximately $59.0 million. The approximately $14.0 million of outstanding borrowings under the credit facility in excess of the new borrowing base was converted into a term loan as of August 31, 2009. An initial $2.0 million payment was made on the term loan at that time and we agreed to make additional monthly payments of $1.0 million commencing on September 30, 2009, with all unpaid amounts due on March 31, 2010. We paid the outstanding balance of the term loan in full in February 2010. On September 30, 2010, we repaid all borrowings under the credit facility.

Outstanding borrowings under the term loan accrued interest at the Eurodollar rate (as defined in the credit agreement) plus 4.0% or, at our option, at the base rate (which was the highest of the lender s prime rate, the Federal funds rate plus half of 1%, and the one-month Eurodollar rate plus 1%) plus 3%. Effective August 31, 2009, we also agreed to an adjustment in the commitment fees, interest rates for revolving loans and fees for letters of credit under the credit facility. Specifically, we agreed to pay (a) commitment fees ranging from 0.5% to 0.625% (an increase from 0.15% to 0.25%), (b) margin interest rates ranging from 2.75% to 3.50% for

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Eurodollar loans (an increase from 1.25% to 2.0%), (c) margin interest rates ranging from 1.75% to 2.5% for base rate loans (an increase from 1.25% to 2.0%), and (d) letter of credit fees at the margin interest rates for Eurodollar loans, in each case based on our utilization percentage. In addition, we agreed to limitations on certain dispositions and investments and to mandatory prepayments of the loans from the net cash proceeds of specified asset sales and other events.

Our obligations under the credit facility were collateralized by a lien on substantially all of our Louisiana and West Texas assets and were guaranteed by our subsidiaries. The restated credit agreement contained certain affirmative and negative covenants, including, but not limited to the following financial covenants: (a) the ratio of funded debt to EBITDAX (net income before deductions for taxes, excluding unrealized gains and losses related to trading securities and commodity hedges, plus depreciation, depletion, amortization and interest expense, plus exploration costs deducted in determining net income under full cost accounting) for a twelve-month period could not be greater than 2.00 to 1.00; and (b) the ratio of EBITDAX to interest expense for a twelve-month period could not be less than 3.00 to 1.00.

On July 10, 2006, we entered into a $5.0 million term loan agreement with Bank of America, N.A. related to the purchase of new gas compressor units. The loan began amortizing quarterly on March 31, 2007 on a straight-line basis over seven years based on the outstanding principal balance at December 31, 2006. We made quarterly principal payments of approximately $176,000. Amounts borrowed bore interest at Bank of America Prime. We made quarterly interest payments on amounts borrowed under the agreement. Our obligations under the agreement were collateralized by a lien on the compressor units. On September 30, 2010, we repaid this loan in full with borrowings under the new revolving credit agreement discussed below.

On September 30, 2010, we entered into a new $100.0 million senior secured revolving credit facility with The Bank of Nova Scotia, or Scotia Capital, as administrative agent, letter of credit issuer and lead arranger, and Amegy Bank National Association, which facility matures on September 30, 2013. The new revolving credit agreement provided for an initial borrowing base availability of $50.0 million, which was increased to $65.0 million effective December 24, 2010.

As of December 31, 2010, we had an outstanding balance of $49.5 million drawn under our new revolving credit agreement, which is included in long-term debt, net of current maturities, on our accompanying consolidated balance sheet at December 31, 2010. The amounts borrowed under our new revolving credit agreement were used to repay our outstanding indebtedness under our prior revolving credit facility ($42.0 million) and term loan ($2.5 million), each with Bank of America, N.A., as administrative agent, and for general corporate purposes. The new revolving credit agreement is secured by substantially all of our assets. Our wholly-owned subsidiaries guaranteed our obligations under the new revolving credit agreement.

Advances under the new revolving credit agreement may be in the form of either base rate loans or Eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 1.75% to 2.50%, plus (2) the highest of: (a) the federal funds rate plus 0.5%, (b) the rate of interest in effect for such day as publicly announced from time to time by agent as its prime rate, and (c) the Eurodollar rate for an interest period of one month plus 1.00%. The interest rate for Eurodollar loans is equal to (1) the applicable rate, which ranges from 2.75% to 3.50%, plus (2) the London interbank offered rate that appears on Reuters Screen LIBOR01 Page for deposits in U.S. dollars, or, if such rate is not available, the offered rate on such other page or service that displays the average British Bankers Association Interest Settlement Rate for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the London Interbank Offered Rate for deposits in U.S. dollars. At December 31, 2010, amounts borrowed under our new revolving credit agreement bore interest at the Eurodollar rate of 3.77%.

The credit agreement contains customary negative covenants including, but not limited to, restrictions on our and our subsidiaries ability to: incur indebtedness; grant liens; pay dividends and make other restricted payments; make investments; make fundamental changes; enter into swap contracts and forward sales contracts; dispose of assets; change the nature of their business; and enter into transactions with their affiliates. The negative covenants are subject to certain exceptions as specified in the credit agreement. The credit agreement also contains certain affirmative covenants, including, but not limited to the following financial covenants: (1) the ratio of funded debt to EBITDAX (net income, excluding any non-cash revenue or expense associated with swap contracts resulting from ASC 815, plus without duplication and to the extent deducted from revenues in determining net income, the sum of (a) the aggregate amount of consolidated interest expense for such period, (b) the aggregate amount of income, franchise, capital or similar tax expense (other than ad valorem taxes) for such period, (c) all amounts attributable to depletion, depreciation, amortization and asset or goodwill impairment or writedown for such period, (d) all other non-cash charges, (e) non-cash losses from minority investments, (f) actual cash distributions received from minority investments, (g) to the extent actually reimbursed by insurance, expenses with respect to liability on casualty events or business interruption, and (h) all reasonable transaction expenses related to dispositions and acquisitions of assets, investments and debt and equity offering, and less non-cash income attributable to equity income from minority investments) for a twelve-month period may not be greater than 2.00 to 1.00; and (2) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. We were in compliance with all covenants at December 31, 2010.

In connection with our scheduled spring 2011 borrowing base redetermination completed in March 2011, Scotia Capital has advised us that it has approved an increase to our borrowing base from the current level of $65.0 million to $85.0 million. In addition, Scotia has given us a commitment letter providing for an amendment to our credit facility which would, among other things, increase the maximum commitment to $350.0 million, provide for an $85.0 million current borrowing base, extend the maturity date to April 2015 and reduce our average credit spread by 75 basis points per annum from current levels. Both the increase in the borrowing base to $85.0 million and the other proposed amendments to our existing credit facility will require the approval of our other current lender and the addition of one or more additional lenders to our bank group. As a result, we cannot assure you that we will be able to amend our existing credit facility on the terms described above.

During 2010, in conjunction with the repayment of the Bank of America revolving credit facility on September 30, 2010, we expensed approximately $225,000 in unamortized loan fees associated with this facility, which is included in interest expense in our consolidated statements of operations for the year ended December 31, 2010.

We used the proceeds of our borrowings under the credit facilities for the development of our oil and natural gas properties and other capital expenditures, acquisition opportunities and for other general corporate purposes.

Building Loans. In June 2004, we purchased the office building we occupy in Oklahoma City, Oklahoma, for $3.7 million. One loan associated with this building matured in March 2006 and bore interest at the rate of 6% per annum, while the other loan matures in June 2011 and bears interest at the rate of 6.5% per annum. The remaining building loan requires monthly interest and principal payments of approximately $23,000 and is secured by the Oklahoma City office building and associated land. As of December 31, 2010, approximately $2.4 million was outstanding on this loan.

Capital Expenditures. Our recent capital commitments have been primarily for the execution of our drilling programs, to fund Grizzly s delineation drilling program and for acquisitions, primarily in the Permian Basin and the Niobrara Formation. Our strategy is to continue to (1) increase cash flow generated from our operations by undertaking new drilling, workover, sidetrack and recompletion projects to exploit our existing properties, subject to economic and industry conditions, and (2) explore acquisition and disposition opportunities. We have upgraded our infrastructure and our existing facilities in Southern Louisiana with the goal of increasing operating efficiencies and volume capacities and lowering lease operating expenses. These upgrades were also intended to better enable our facilities to withstand future hurricanes with less damage. Additionally, we completed the reprocessing of 3-D seismic data in one of our principal properties, WCBB and shot 3-D seismic for the first time in our Hackberry field. The new and reprocessed data enables our geophysicists to continue to generate new prospects and enhance existing prospects in the intermediate zones in the fields, thus creating a portfolio of new drilling opportunities. In addition, with our acquisition of strategic assets in the Permian Basin in West Texas, we are required to pay 50% of all drilling costs for drilling activity on such properties. To combat significant declines in the commodity prices during the second half of 2008, management undertook a series of actions aimed at reducing capital spending and operating costs. As a result, we reduced our drilling and other capital activities to a minimum in the fourth quarter of 2008, releasing all rigs in Southern Louisiana and the Permian and only selectively participating in wells in the Bakken. During 2009, we were not bound by lease obligations and long term capital commitments relating to the exploration or development of our oil and gas properties. As a result of the then current economic conditions, we initially reduced our estimated capital activities and aggressively sought price concessions from our service providers until such time costs were reduced to more appropriate levels. In June 2009, we restarted our drilling programs. We commenced our 2010 drilling programs during March 2010.

In our December 31, 2010 reserve reports, 63% of our net reserves were categorized as proved undeveloped. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved developed reserves, or both. To realize reserves and increase production, we must continue our exploratory drilling, undertake other replacement activities or use third parties to accomplish those activities.

Our inventory of prospects includes approximately 29 proved undeveloped drilling locations at WCBB. The drilling schedule used in our December 31, 2010 reserve report anticipates that all of those wells will be drilled by 2013. During 2010, we recompleted 72 wells and drilled 23 wells, all of which were completed as producers, at WCBB for an aggregate cost of $40.9 million. From January 1, 2011 through March 11, 2011, we recompleted twelve existing wells and drilled two wells at our WCBB field. We currently intend to spend a total of approximately $36.0 to $38.0 million to drill 20 to 24 wells and recomplete 60 wells in our WCBB field during 2011.

In our East Hackberry field, in 2010, we recompleted ten existing wells and drilled eight wells, all of which were completed as producers, for an aggregate cost of $20.0 million. From January 1, 2011 through March 11, 2011, we recompleted three existing wells and drilled three wells, two of which are currently drilling, at our East Hackberry field. We currently intend to drill seven to ten wells and recomplete five wells in our East Hackberry field in 2011. Total capital expenditures for our East Hackberry field during 2011 are estimated at $24.0 to $26.0 million.

In the Permian Basin, our booked inventory of prospects includes 226 gross (113 net) future development drilling locations. During 2010, 25 gross (11 net) wells were drilled on this acreage, of which 24 gross (10.7 net) were completed as producers and one gross (0.5 net) well was waiting on completion. Our aggregate capital expenditures in the Permian Basin were $29.0 million in 2010, which includes acreage acquisitions. From January 1, 2011 through March 11, 2011, four gross (two net) wells were recompleted and five gross (2.5 net) wells were drilled on this acreage, three of which are waiting on completion and two of which are currently drilling. We currently anticipate that our capital requirements to drill a total of 40 to 42 gross (19 to 20 net) wells and recomplete ten gross (five net) wells in the Permian Basin in West Texas will be approximately $37.0 to $39.0 million.

In the Niobrara Formation in Western Colorado, effective April 1, 2010, we acquired leasehold interests for a total of approximately $7.6 million. In addition, we recompleted one existing well and acquired additional acreage for an aggregate cost, including acquisition costs, of approximately $8.1 million in 2010. We are in the process of permitting a 60 square mile 3-D seismic survey and expect to begin shooting in mid-2011. We currently anticipate that our total capital expenditures in the Niobrara Formation will be approximately $4.0 million in 2011 relating to the seismic survey and drilling of four to five gross wells.

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During the third quarter of 2006, we purchased a 24.9999% interest in Grizzly. During 2010, we paid Grizzly $3.7 million in cash calls. As of December 31, 2010, our net investment in Grizzly was approximately $26.5 million. In addition, we have loaned Grizzly $20.0 million including interest and net of foreign currency adjustments as of December 31, 2010. Our capital requirements in 2011 for this project are currently estimated to be approximately $25.6 million, primarily for the expenses associated with the initial preparations of the Algar Lake SAGD facility and planned drilling activity.

Capital expenditures in 2010 relating to our interest in Thailand were approximately $400,000. Capital expenditures in 2011 relating to our interest in Thailand are expected to be approximately $1.0 million, which we believe will be mostly funded from our share of production from the Phu Horm field.

Our total capital expenditures for 2011 are currently estimated to be $127.0 million to $133.0 million, excluding our anticipated acquisition in the Utica Shale. This is an increase from the $85.8 million spent in 2010 due to improved commodity pricing and cost environment. We intend to continue to monitor pricing and cost developments and make adjustments to our future capital expenditure programs as warranted.

We believe that our cash on hand and cash flow from operations will be sufficient to meet our normal recurring operating needs and our WCBB, Hackberry, Permian Basin, Niobrara and Grizzly capital requirements for the next twelve months. Although we currently anticipate significant free cash flow during 2011, in the event we elect to further expand or accelerate our drilling programs, complete acquisitions (including our anticipated acquisition in the Utica Shale) or accelerate our Canadian oil sands project, we may be required to obtain additional funds which we would seek to do through traditional borrowings, offerings of debt or equity securities or other means, including the sale of assets. We regularly evaluate new acquisition opportunities. Needed capital may not be available to us on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to delay or curtail implementation of our business plan or not be able to complete acquisitions that may be favorable to us.

Commodity Price Risk

The volatility of the energy markets makes it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, during the past five years, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.28 per barrel, or bbl, in December 2008 to a high of $145.31 per barrel in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $1.83 per million British thermal units, or MMBtu, in September 2009 to a high of $15.52 per MMBtu in January 2006. On March 7, 2011, the West Texas Intermediate posted price for crude oil was $105.44 per barrel and the Henry Hub spot market price of natural gas was $3.93 per MMBtu. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves, and may result in write downs of oil and natural gas properties due to ceiling test limitations.

To mitigate the effects of commodity price fluctuations, for the period January 2010 through February 2010, we were party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials. For the period March 2010 through December 2010, we were party to forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel, before transportation costs and differentials. In November 2010, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel, before transportation costs and differentials, for the period January 2011 through December 2011. Under the 2010 contracts, we delivered approximately 45% of our 2010 production. Under the 2011 contacts, we have committed to deliver approximately 30% to 33% of our estimated 2011 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These forward sales contracts and fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements.

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Commitments

In connection with the acquisition in 1997 of the remaining 50% interest in the WCBB properties, we assumed the seller s (Chevron) obligation to contribute approximately $18,000 per month through March 2004, to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until abandonment obligations to Chevron have been fulfilled. Beginning in 2009, we can access the trust for use in plugging and abandonment charges associated with the property. As of December 31, 2010, the plugging and abandonment trust totaled approximately $3,129,000. At December 31, 2010, we have plugged 311 wells at WCBB since we began our plugging program in 1997, which management believes fulfills our current minimum plugging obligation.

Contractual and Commercial Obligations

The following table sets forth our contractual and commercial obligations at December 31, 2010.

	Payment due by period (1)				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Short-term and long-term debt	$ 51,917,000	$ 2,417,000	$ 49,500,000	$	$
Asset retirement obligations	10,845,000	635,000	1,334,000	816,000	8,060,000
Total	$ 62,762,000	$ 3,052,000	$ 50,834,000	$ 816,000	$ 8,060,000

(1) Does not include estimated interest of $1,970,000 less than one year and $3,312,000 1-3 years and short-term derivative instruments of $4,720,000 less than one year.

New Accounting Pronouncements

In December 2008, the SEC published a final rule, Modernization of Oil and Gas Reporting. The new rule permits the use of new technologies to determine proved reserves if those technologies have been demonstrated to lead to reliable conclusions about reserve volumes. The new requirements also will allow companies to disclose their probable and possible reserves. In addition, the new disclosure requirements require companies to (a) report the independence and qualifications of its reserve preparer, (b) file reports when a third party is relied upon to prepare reserve estimates or conducts a reserve audit, and (c) report oil and gas reserves using an average price based upon the prior 12-month period rather than year end prices. The new requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. Early adoption is not permitted in quarterly reports prior to the first annual report in which the revised disclosures are required. We adopted this final rule as of December 31, 2009. The adoption of the rule resulted in a lower price used in reserve calculations and a decrease in 2009 reserves. Updated disclosures are included in Item 2. Properties Proved Oil and Natural Gas Reserves and Note 21 to our consolidated financial statements included in this report.

In January 2010, the FASB issued Accounting Standards Update 2010-03, Oil and Gas Reserve Estimation and Disclosures (currently codified in FASB ASC Topic 932, Extractive Activities Oil & Gas), or FASB ASC 932. The purpose of the amendments in this Update is to align the oil and gas reserve estimation and disclosure requirements of FASB ASC 932 with the requirements in the SEC s final rule, Modernization of Oil and Gas Reporting. The amendments to FASB ASC 932 are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. We adopted FASB ASC 932 effective December 31, 2009, the impact of which is noted above.

In January 2010, the FASB issued Accounting Standards Update 2010-06, Improving Disclosures about Fair Value Measurements, which provides amendments to FASB ASC Topic 820, Fair Value Measurements and Disclosure, (FASB ASC 820). FASB ASC 820 requires additional disclosures about (a) the different classes of assets and liabilities measured at fair value, (b) the valuation techniques and inputs used, (c) the activity in Level 3 fair value measurements, and (d) significant transfers between Levels 1, 2 and 3. The updated guidance is effective for annual and interim periods beginning after December 15, 2009. We adopted FASB ASC 820 effective January 1, 2010. The adoption did not have a material impact on our consolidated financial statements.

In December 2010, the FASB issued Accounting Standards Update 2010-29, Business Combinations: Disclosure of Supplementary Pro Forma Information for Business Combinations (currently codified in FASB ASC Topic 805, Business Combinations), or FASB ASC 805. The purpose of the amendments in this update is to specify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The amendments in this update also expand the supplemental pro forma disclosures under FASB ASC 805 to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The amendments to FASB ASC 805 are effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. The adoption did not have an immediate impact on our consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors, including: worldwide and domestic supplies of oil and natural gas; the level of prices, and expectations about future prices, of oil and natural gas; the cost of exploring for, developing, producing and delivering oil and natural gas; the expected rates of declining current production; weather conditions, including hurricanes, that can affect oil and natural gas operations over a wide area; the level of consumer demand; the price and availability of alternative fuels; technical advances affecting energy consumption; risks associated with operating drilling rigs; the availability of pipeline capacity; the price and level of foreign imports; domestic and foreign governmental regulations and taxes; the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls; political instability or armed conflict in oil and natural gas producing regions; and the overall economic environment.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, during the past five years, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.28 per barrel, or bbl, in December 2008 to a high of $145.31 per barrel in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $1.83 per million British thermal units, or MMBtu, in September 2009 to a high of $15.52 per MMBtu in January 2006. On March 7, 2011, the West Texas Intermediate posted price for crude oil was $105.44 per barrel and the Henry Hub spot market price of natural gas was $3.93 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.

For the period January 2010 through February 2010, we were party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials. For the period March 2010 through December 2010, we were party to forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel, before transportation costs and differentials. In November 2010, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel, before transportation costs and differentials, for the period January 2011 through December 2011. Under the 2010 contracts, we delivered approximately 45% of our 2010 production. Under the 2011 contracts, we have committed to deliver approximately 30% to 33% of our estimated 2011 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These forward sales contracts and fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements. At December 31, 2010, we had a net liability derivative position of $4.7 million related to our fixed price swaps. Utilizing actual derivative contractual volumes, a 10% increase in underlying commodity prices would have reduced the fair value of these instruments by approximately $6.8 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by $6.8 million. However, any realized derivative gain or loss would be substantially offset by a decrease of increase, respectively, in the actual sales value of production covered by the derivative instrument.

Our new revolving credit facility is structured under floating rate terms, as advances under this facility may be in the form of either base rate loans or Eurodollar loans. As such, our interest expense is sensitive to fluctuations in the prime rates in the U.S. or, if the Eurodollar rates are elected, the Eurodollar rates. At December 31, 2010, amounts borrowed under our new revolving credit agreement bore interest at the Eurodollar rate of 3.77%. Based on the current debt structure, a 1% increase in interest rates would increase interest expense by approximately $495,000 per year, based on $49.5 million outstanding under our credit facility as of December 31, 2010. As of December 31, 2010, we did not have any interest rate swaps to hedge our interest risks.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

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

As of December 31, 2010, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Vice President and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. Based upon our evaluation, our Chief Executive Officer and Vice President and Chief Financial Officer have concluded that as of December 31, 2010, 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.

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Management s Report on Internal Control Over Financial Reporting

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

Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in *Internal Control Integrated Framework*, management did not identify any material weaknesses in our internal control over financial reporting and concluded that our internal control over financial reporting was effective as of December 31, 2010.

Grant Thornton LLP, the independent registered public accounting firm that audited our financial statements for the year ended December 31, 2010 included with this Annual Report on Form 10-K, has also audited our internal control over financial reporting as of December 31, 2010, as stated in their accompanying report.

/s/ James D. Palm
Name: James D. Palm
Title: Chief Executive Officer

/s/ Michael G. Moore
Name: Michael G. Moore
Title: Chief Financial Officer

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Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders

Gulfport Energy Corporation:

We have audited internal control over financial reporting of Gulfport Energy Corporation and Subsidiaries (the Company) as of December 31, 2010, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, Gulfport Energy Corporation and Subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Gulfport Energy Corporation and Subsidiaries as of December 31, 2010 and 2009, and the related consolidated statements of operations, stockholders equity and comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2010 and our report dated March 14, 2011 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

March 14, 2011

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

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

ITEM 11. EXECUTIVE COMPENSATION

For information concerning Item 11 Executive Compensation, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

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

For information concerning Item 12 Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

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

For information concerning Item 13 Certain Relationships and Related Transactions, and Director Independence, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission with 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

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

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

List the following documents filed as part of this report:

Exhibit Number	Description
2.1	Purchase and Sale Agreement, dated as of November 28, 2007, by and among Ambrose Energy I, Ltd. and each of the other persons, which are listed as a party seller, and Windsor Permian (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 24, 2007).
2.2	Second Amendment to the Purchase and Sale Agreement, dated as of December 18, 2007, by and among Ambrose Energy I, Ltd., each of the other parties which are listed as a party seller, Windsor Permian and Gulfport (incorporated by reference to Exhibit 2.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 24, 2007).
3.1	Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
3.2	Certificate of Amendment No. 1 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.2 to Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 6, 2009).
3.3	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 12, 2006).
4.1	Form of Common Stock certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.2	Form of Warrant Agreement (incorporated by reference to Exhibit 10.4 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.3	Registration Rights Agreement, dated as of February 23, 2005, by and among the Company, Southpoint Fund LP, a Delaware limited partnership, Southpoint Qualified Fund LP, a Delaware limited partnership and Southpoint Offshore Operating Fund, LP, a Cayman Islands exempted limited partnership (incorporated by reference to Exhibit 10.7 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2005).
4.4	Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.3 of Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on November 11, 2005).
4.5	Amendment No. 1, dated February 14, 2006, to the Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.15 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2006).
10.1+	Amended and Restated 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
10.2+	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.2 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).

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Exhibit Number	Description
10.3+	Form of Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.3 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
10.4+	Employment Agreement, dated as of May 18, 1999 and effective as of June 1, 1999, by and between the Company and Mike Liddell (incorporated by reference to Exhibit 10.5 of Amendment No. 1 to Form 10-KSB/A, File No. 000-19514, filed by the Company with the SEC on May 11, 2007).
10.5+	Summary of Oral Employment Agreement with James D. Palm (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 7, 2010).
10.5	Credit Agreement, dated as of September 30, 2010, by and among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, and Amegy Bank National Association (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 6, 2010).
10.6	Amendment, dated as of December 24, 2010, to the Credit Agreement by and among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, and Amegy Bank National Association (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 28, 2010).
14	Code of Ethics (incorporated by reference to Exhibit 14 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 14, 2006).
21*	Subsidiaries of the Registrant.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
23.3*	Consent of Pinnacle Energy Services, LLC
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
99.1*	Report of Netherland, Sewell & Associates, Inc.
99.2*	Report of Pinnacle Energy Services, LLC.

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

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SIGNATURES

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

Date: March 14, 2011

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 14, 2011	By:	/s/ JAMES D. PALM **James D. Palm** **Chief Executive Officer and Director** **(Principal Executive Officer)**
Date: March 14, 2011	By:	/s/ MIKE LIDDELL **Mike Liddell** **Chairman of the Board and Director**
Date: March 14, 2011	By:	/s/ MICHAEL G. MOORE **Michael G. Moore** **Vice President and Chief Financial Officer** **(Principal Financial and Accounting Officer)**
Date: March 14, 2011	By:	/s/ DONALD DILLINGHAM **Donald Dillingham** **Director**
Date: March 14, 2011	By:	/s/ DAVID L. HOUSTON **David L. Houston** **Director**
Date: March 14, 2011	By:	/s/ SCOTT E. STRELLER **Scott E. Streller** **Director**

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders

Gulfport Energy Corporation:

We have audited the accompanying consolidated balance sheets of Gulfport Energy Corporation and Subsidiaries (the Company) as of December 31, 2010 and 2009, and the related consolidated statements of operations, stockholders equity and comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Gulfport Energy Corporation and Subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1, the Company changed its method of estimating oil and gas reserves and related disclosures in 2009.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Gulfport Energy Corporation and Subsidiaries internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 14, 2011 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

March 14, 2011

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GULFPORT ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(Amounts rounded to nearest thousand)

	December 31, 2010	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$ 2,468,000	$ 1,724,000
Accounts receivable oil and gas	14,952,000	9,492,000
Accounts receivable related parties	573,000	136,000
Prepaid expenses and other current assets	1,732,000	2,047,000
Total current assets	19,725,000	13,399,000
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $16,778,000 and $17,521,000 excluded from amortization in 2010 and 2009, respectively	747,344,000	628,849,000
Other property and equipment	7,609,000	7,182,000
Accumulated depletion, depreciation, amortization and impairment	(512,822,000)	(473,915,000)
Property and equipment, net	242,131,000	162,116,000
Other assets:		
Equity investments	33,021,000	32,006,000
Note receivable related party	20,006,000	15,920,000
Other assets	4,182,000	3,370,000
Total other assets	57,209,000	51,296,000
Deferred tax asset	628,000	533,000
Total assets	$ 319,693,000	$ 227,344,000
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 41,155,000	$ 20,977,000
Asset retirement obligation current	635,000	635,000
Short-term derivative instruments	4,720,000	18,735,000
Current maturities of long-term debt	2,417,000	2,842,000
Total current liabilities	48,927,000	43,189,000
Asset retirement obligation long-term	10,210,000	9,518,000
Long-term debt, net of current maturities	49,500,000	49,586,000
Total liabilities	108,637,000	102,293,000
Commitments and contingencies (Notes 18 and 19)		
Preferred stock, $.01 par value; 5,000,000 authorized, 30,000 authorized as redeemable 12% cumulative preferred stock, Series A; 0 issued and outstanding		

Stockholders' equity:		
Common stock $.01 par value, 100,000,000 authorized, 44,645,435 issued and outstanding in 2010 and 42,696,409 in 2009	446,000	427,000
Paid-in capital	296,253,000	273,901,000
Accumulated other comprehensive income (loss)	(1,768,000)	(18,039,000)
Retained earnings (accumulated deficit)	(83,875,000)	(131,238,000)
Total stockholders' equity	211,056,000	125,051,000
Total liabilities and stockholders' equity	$ 319,693,000	$ 227,344,000

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(Amounts rounded to nearest thousand)

	Year Ended December 31, 2010	2009	2008
Revenues:			
Oil and condensate sales	$ 121,350,000	$ 81,587,000	$ 131,825,000
Gas sales	3,468,000	1,992,000	6,570,000
Natural gas liquid sales	2,818,000	1,997,000	3,255,000
Other income (expense)	(692,000)	(314,000)	(433,000)
	126,944,000	85,262,000	141,217,000
Costs and expenses:			
Lease operating expenses	17,614,000	16,316,000	22,856,000
Production taxes	13,966,000	9,797,000	15,813,000
Depreciation, depletion, and amortization	38,907,000	29,225,000	42,472,000
Impairment of oil and gas properties			272,722,000
General and administrative	6,063,000	4,992,000	6,843,000
Accretion expense	617,000	582,000	560,000
	77,167,000	60,912,000	361,266,000
INCOME (LOSS) FROM OPERATIONS	49,777,000	24,350,000	(220,049,000)
OTHER (INCOME) EXPENSE:			
Interest expense	2,761,000	2,309,000	4,762,000
Settlement of fixed price contracts			(39,000,000)
Insurance proceeds		(1,050,000)	(769,000)
Interest income	(387,000)	(564,000)	(540,000)
	2,374,000	695,000	(35,547,000)
INCOME (LOSS) BEFORE INCOME TAXES	47,403,000	23,655,000	(184,502,000)
INCOME TAX EXPENSE	40,000	28,000	
NET INCOME (LOSS)	$ 47,363,000	$ 23,627,000	$ (184,502,000)
NET INCOME (LOSS) PER COMMON SHARE:			
Basic	$ 1.08	$ 0.55	$ (4.33)
Diluted	$ 1.07	$ 0.55	$ (4.33)

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

(Amounts rounded to nearest thousand)

	Common Stock		Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
	Shares	Amount				
Balance at January 1, 2008	42,453,587	$ 424,000	$ 271,807,000	$ 2,254,000	$ 29,637,000	$ 304,122,000
Net loss					(184,502,000)	(184,502,000)
Other Comprehensive Income (Loss):						
Foreign currency translation adjustment				(7,057,000)		(7,057,000)
Total Comprehensive Income (Loss)						(191,559,000)
Stock Compensation			1,056,000			1,056,000
Issuance of Restricted Stock	41,493					
Issuance of Common Stock through exercise of options	144,121	2,000	480,000			482,000
Balance at December 31, 2008	42,639,201	426,000	273,343,000	(4,803,000)	(154,865,000)	114,101,000
Net income					23,627,000	23,627,000
Other Comprehensive Income (Loss):						
Foreign currency translation adjustment				5,499,000		5,499,000
Change in fair value of derivative instruments				(13,422,000)		(13,422,000)
Reclassification of derivative contracts				(5,313,000)		(5,313,000)
Total Comprehensive Income (Loss)						10,391,000
Stock Compensation			529,000			529,000
Issuance of Restricted Stock	43,458					
Issuance of Common Stock through exercise of options	13,750	1,000	29,000			30,000
Balance at December 31, 2009	42,696,409	427,000	273,901,000	(18,039,000)	(131,238,000)	125,051,000
Net income					47,363,000	47,363,000
Other Comprehensive Income (Loss):						
Foreign currency translation adjustment				2,255,000		2,255,000
Change in fair value of derivative instruments				(4,720,000)		(4,720,000)
Reclassification of derivative contracts				18,736,000		18,736,000
Total Comprehensive Income (Loss)						63,634,000
Stock Compensation			492,000			492,000
Issuance of Common Stock in public offering, net of related expenses of $210,000	1,668,503	17,000	21,341,000			21,358,000
Issuance of Common Stock through exercise of warrants	173,109	2,000	204,000			206,000
Issuance of Restricted Stock	58,525					
Issuance of Common Stock through exercise of options	48,889		315,000			315,000

Balance at December 31, 2010	44,645,435	$ 446,000	$ 296,253,000	$ (1,768,000)	$ (83,875,000)	$ 211,056,000

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOW

(Amounts rounded to nearest thousand)

	Year Ended December 31,		
	2010	**2009**	**2008**
Cash flows from operating activities:			
Net income (loss)	$ 47,363,000	$ 23,627,000	$ (184,502,000)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Accretion of discount Asset Retirement Obligation	617,000	582,000	560,000
Depletion, depreciation and amortization	38,907,000	29,225,000	42,472,000
Impairment of oil and gas properties			272,722,000
Stock-based compensation expense	295,000	317,000	634,000
Loss from equity investments	977,000	706,000	656,000
Interest income note receivable	(267,000)	(547,000)	(410,000)
Deferred income tax benefit	(95,000)	120,000	(653,000)
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(5,460,000)	3,051,000	(2,033,000)
(Increase) decrease in accounts receivable related party	(437,000)	965,000	1,107,000
Decrease (increase) in prepaid expenses	315,000	(1,002,000)	301,000
Increase in other asset	(75,000)		
Increase (decrease) in accounts payable and accrued liabilities	4,948,000	(3,686,000)	5,328,000
Settlement of asset retirement obligation	(1,253,000)	(59,000)	(859,000)
Net cash provided by operating activities	85,835,000	53,299,000	135,323,000
Cash flows from investing activities:			
Deductions (additions) to cash held in escrow	8,000	8,000	(40,000)
Additions to other property, plant and equipment	(427,000)	(14,000)	(60,000)
Additions to oil and gas properties	(101,644,000)	(49,533,000)	(126,030,000)
Proceeds from sale of oil and gas properties	304,000	18,286,000	
Advances on note receivable to related party	(2,877,000)	(4,377,000)	(10,519,000)
Contributions to investment in Grizzly Oil Sands ULC	(842,000)		(151,000)
Distributions from investment in Tatex Thailand II, LLC	565,000	197,000	862,000
Contributions to investment in Tatex Thailand III, LLC	(402,000)	(3,813,000)	(885,000)
Net cash used in investing activities	(105,315,000)	(39,246,000)	(136,823,000)
Cash flows from financing activities:			
Principal payments on borrowings	(52,711,000)	(18,303,000)	(25,802,000)
Borrowings on line of credit	52,200,000		30,000,000
Loan commitment fees	(1,144,000)		
Proceeds from issuance of common stock, net of offering costs of $210,000 for 2010, and exercise of stock options	21,879,000	30,000	482,000
Net cash provided by (used in) financing activities	20,224,000	(18,273,000)	4,680,000
Net (decrease) increase in cash and cash equivalents	744,000	(4,220,000)	3,180,000
Cash and cash equivalents at beginning of period	1,724,000	5,944,000	2,764,000
Cash and cash equivalents at end of period	$ 2,468,000	$ 1,724,000	$ 5,944,000
Supplemental disclosure of cash flow information:			
Interest payments	$ 1,949,000	$ 2,300,000	$ 4,898,000
Income tax payments	$ 40,000	$ 543,000	$ 135,000

Supplemental disclosure of non-cash transactions:			
Capitalized stock based compensation	$ 197,000	$ 212,000	$ 422,000
Asset retirement obligation capitalized	$ 1,328,000	$ 361,000	$ 934,000
Dissolution of interest in Windsor Bakken, LLC	$	$	$ 2,468,000
Foreign currency translation gain (loss) on investment in Grizzly Oil Sands ULC	$ 1,313,000	$ 3,656,000	$ (5,281,000)
Foreign currency translation gain (loss) on note receivable related party	$ 942,000	$ 1,843,000	$ (1,776,000)

See accompanying notes to consolidated financial statements.

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(Amounts rounded to nearest thousand)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business

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

Cash and Cash Equivalents

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

Principles of Consolidation

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

Accounts Receivable

The Company s accounts receivable oil and gas primarily are from companies in the oil and gas industry. The majority of its receivables are from two purchasers of the Company s oil and gas and one operator of certain of the Company s properties. Credit is extended based on evaluation of a customer s payment history and, generally, collateral is not required. Accounts receivable are due within 30 days and are stated at amounts due from customers, net of an allowance for doubtful accounts when the Company believes collection is doubtful. Accounts outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company s previous loss history, the customer s current ability to pay its obligation to the Company, amounts which may be obtained by an offset against production proceeds due the customer and the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. No allowance was deemed necessary at December 31, 2010 and December 31, 2009.

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. Under the full cost method of accounting, the Company is 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 the 12-month unweighted average of the first-day-of-the-month price for 2010 and 2009, and prior to 2009, unescalated year-end prices and costs, adjusted for any contract provisions or financial derivatives, if any, that hedge the Company s oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement

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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, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required.

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 $16,778,000 and $17,521,000 at December 31, 2010 and December 31, 2009, respectively. These costs are reviewed quarterly by management for impairment. If impairment has occurred, the portion of cost in excess of the current value is transferred to the cost of oil and gas properties subject to amortization. Factors considered by management in its impairment assessment include drilling results by Gulfport and other operators, the terms of oil and gas leases not held by production, and available funds for exploration and development.

The Company accounts for its abandonment and restoration liabilities under FASB ASC Topic 410, *Asset Retirement and Environmental Obligations* (FASB ASC 410), which requires the Company to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, the Company increases the carrying amount of oil and natural gas properties by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is included in capitalized costs and depreciated consistent with depletion of reserves. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.

Other Property and Equipment

Depreciation of other property and equipment is provided on a straight-line basis over estimated useful lives of the related assets, which range from 3 to 30 years.

Foreign Currency

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

December 31, 2007	$ 2,254,000
December 31, 2008	$ (4,803,000)
December 31, 2009	$ 696,000
December 31, 2010	$ 2,952,000

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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 13.

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.

The company adopted the provisions of FASB ASC Topic 740 as of January 1, 2007. The Company is subject to U.S. federal income tax as well as income tax of multiple jurisdictions. The Company s 1996 2009 U.S. federal and state income tax returns remain open to examination by tax authorities, due to net operating losses. As of December 31, 2010, the Company has no unrecognized tax benefits that would have a material impact on the effective rate. The Company recognizes interest and penalties related to income tax matters as interest expense and general and administrative expenses, respectively. For the year ended December 31, 2010, there is no interest or penalties associated with uncertain tax positions in the Company s consolidated financial statements.

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, 2010 and 2009 because the Company has no imbalances. Oil revenues are recognized when ownership transfers, which occurs in the month produced.

Investments Equity Method

Investments in entities greater than 20% and less than 50% are accounted for under the equity method. Under the equity method, the Company s share of investees earnings or loss is recognized in the statement of operations. The Company reviews its investments to determine if a loss in value which is other than a temporary decline has occurred. If such loss has occurred, the Company recognizes an impairment provision. There was no impairment of equity method investments at December 31, 2010 or 2009.

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Accounting for Stock-Based Compensation

The Company accounts for stock-based compensation in accordance with the provisions of FASB ASC Topic 718, *Compensation Stock Compensation* (FASB ASC 718). FASB ASC 718 requires share-based payments to employees, including grants of employee stock options, to be recognized as equity or liabilities at the fair value on the date of grant and to be expensed over the applicable vesting period.

Accounting for Derivative Instruments and Hedging Activities

The Company may seek to reduce its exposure to unfavorable changes in oil prices by utilizing energy swaps and collars, or fixed-price contracts. The Company follows the provisions of FASB ASC 815, *Derivatives and Hedging* (FASB ASC 815) as amended. It requires that all derivative instruments be recognized as assets or liabilities in the statement of financial position, measured at fair value.

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

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 FASB ASC 815, changes in fair value are recognized in accumulated other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value resulting from ineffectiveness is recognized immediately in earnings.

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, the realization of deferred tax assets and the realization of future net operating loss carryforwards available as reductions of income tax expense. The estimate of the Company s oil and gas reserves is used to compute depletion, depreciation, amortization and impairment of oil and gas properties.

Recent Accounting Pronouncements

In December 2008, the Securities and Exchange Commission published a Final Rule, *Modernization of Oil and Gas Reporting*. The new rule permits the use of new technologies to determine proved reserves if those technologies have been demonstrated to lead to reliable conclusions about reserve volumes. The new requirements also will allow companies to disclose their probable and possible reserves. In addition, the new disclosure requirements require companies to (a) report the independence and qualifications of its reserve

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preparer, (b) file reports when a third party is relied upon to prepare reserve estimates or conducts a reserve audit, and (c) report oil and gas reserves using an average price based upon the prior 12 month period rather than year end prices. The new requirements were effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. The Company adopted the Final Rule as of December 31, 2009. The adoption of the rule resulted in a lower price used in reserve calculations and a decrease in 2009 reserves. See Item 2. Properties and Note 21 for further discussion of the impact of implementation.

In January 2010, the FASB issued Accounting Standards Update 2010-03, *Oil and Gas Reserve Estimation and Disclosures* (currently codified in FASB ASC Topic 932, *Extractive Activities Oil & Gas*) (FASB ASC 932). The purpose of the amendments in this Update is to align the oil and gas reserve estimation and disclosure requirements of FASB ASC 932 with the requirements in the Security and Exchange Commission s Final Rule, *Modernization of Oil and Gas Reporting.* The amendments to FASB ASC 932 are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. The impact of the adoption of FASB ASC 932 is noted above.

In January 2010, the FASB issued Accounting Standards Update 2010-06, *Improving Disclosures about Fair Value Measurements,* which provides amendments to FASB ASC Topic 820, *Fair Value Measurements and Disclosure* (FASB ASC 820). FASB ASC 820 requires additional disclosures about (a) the different classes of assets and liabilities measured at fair value, (b) the valuation techniques and inputs used, (c) the activity in Level 3 fair value measurements, and (d) significant transfers between Levels 1, 2 and 3. The updated guidance is effective for annual and interim periods beginning after December 15, 2009. The Company adopted FASB ASC 820 effective January 1, 2010. The adoption did not have a material impact on the Company s consolidated financial statements.

In December 2010, the FASB issued Accounting Standards Update 2010-29, *Business Combinations: Disclosure of Supplementary Pro Forma Information for Business Combinations* (currently codified in FASB ASC Topic 805, *Business Combinations*) (FASB ASC 805). The purpose of the amendments in this update is to specify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The amendments in this update also expand the supplemental pro forma disclosures under FASB ASC 805 to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The amendments to FASB ASC 805 are effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. The adoption did not have an immediate impact on the Company s consolidated financial statements.

2. ACQUISITIONS

On June 15, 2010, Gulfport acquired an ownership interest in certain oil and gas properties located in the Niobrara Formation of Colorado, including three gross producing wells for a cash price of approximately $7.75 million. The effective date of the acquisition was April 1, 2010. The total purchase price for the acquired assets, as adjusted at closing on June 15, 2010, was $7.7 million, which was recorded as oil and natural gas properties on the accompanying December 31, 2010 consolidated balance sheet. This amount includes an adjustment for the results of operations of the assets between the April 1, 2010 effective date and the June 15, 2010 closing date. The Company may adjust the purchase price for any post closing adjustments. The results of operations from

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these properties were included in the December 31, 2010 consolidated statement of operations for the period from June 16, 2010 through December 31, 2010. No pro forma financials for this acquisition are disclosed as the acquisition was not deemed significant to the Company.

During May 2010, Gulfport acquired a 50% interest in 4,979 gross (2,489 net) undeveloped acres in the Permian Basin for approximately $7.6 million.

Gulfport funded these transactions predominately through a 1.7 million common share offering completed in May of 2010. The Company received net proceeds (before offering expenses) of approximately $21.6 million from the equity offering, as discussed below in Note 8.

3. ACCOUNTS RECEIVABLE RELATED PARTIES

Included in the accompanying December 31, 2010 and December 31, 2009 consolidated balance sheets are amounts receivable from related parties of the Company. These receivables represent amounts billed by the Company for general and administrative functions, such as accounting, human resources, legal, and technical support, performed by Gulfport s personnel on behalf of these related parties. These services are solely administrative in nature and for entities in which the Company has no property interests. The amounts reimbursed to the Company for these services are for the purpose of Gulfport recovering costs associated with the services and do not include the assessment of any fees or other amounts beyond the estimated costs of performing such services. At December 31, 2010 and December 31, 2009, these receivables totaled $573,000 and $136,000, respectively. The Company recorded $593,000 and $1,363,000 for the years ended December 31, 2009 and 2008, respectively, for general and administrative functions which are reflected as a reduction of general and administrative expenses in the consolidated statements of operations and include the amounts under service contracts discussed below. No amounts were reimbursed for general and administrative functions for the year ended December 31, 2010.

The Company is or has been a party to administrative service agreements with Caliber Development Company, LLC, Great White Energy Services LLC, and Diamondback Energy Services LLC. Under these agreements, the Company s services include accounting, human resources, legal and technical support. The services provided and the fees for such services can be amended by mutual agreement of the parties. Each of these administrative service agreements has a three-year term, and upon expiration of that term the agreements will continue on a month-to-month basis until cancelled by either party with at least 30 days prior written notice. Each administrative service agreement is terminable (1) by the counterparty at any time with at least 30 days prior written notice to the Company and (2) by either party if the other party is in material breach and such breach has not been cured within 30 days of receipt of written notice of such breach.

The Company is also a party to administrative service agreements with Stampede Farms LLC, Grizzly Oil Sands ULC, Everest Operations Management LLC and Tatex Thailand III, LLC. Under these agreements, the Company s services include professional and technical support and office space. The services provided and the fees for such services can be amended by mutual agreement of the parties. Each of these administrative service agreements has a two-year term, and upon expiration of that term such agreement will continue on a month-to-month basis until cancelled by either party to such agreement with at least 60 days prior written notice. Each administrative service agreement is terminable (1) by the counterparty at any time with at least 30 days prior written notice to the Company and (2) by either party if the other party is in material breach and such breach has not been cured within 30 days of receipt of written notice of such breach.

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The Company was reimbursed the following amounts by the specified entities in consideration for its administrative services for the years ended December 31, 2010, 2009 and 2008. These amounts are reflected as a reduction of general and administrative expenses in the consolidated statements of operations. Wexford Capital LP (Wexford) controls and/or owns a greater than 10% interest in each of these entities. Affiliates of Wexford own approximately 25% of Gulfport s outstanding stock.

Agreement		December 31,		
Effective Date	Entity	2010	2009	2008
2/9/2005	Caliber Development Company, LLC*	$	$	$ 60,000
7/22/2006	Great White Energy Services LLC		61,000	83,000
9/26/2006	Diamondback Energy Services LLC*			10,000
3/1/2008	Stampede Farms LLC			159,000
3/1/2008	Grizzly Oil Sands ULC **		20,000	368,000
3/1/2008	Everest Operations Management LLC		508,000	154,000
3/1/2008	Tatex Thailand III, LLC			

* Agreement was terminated effective December 10, 2008.

** Agreement was terminated effective December 31, 2010.

For the year ended December 31, 2009, the Company was also reimbursed approximately $2,000 and $1,000 by Stampede Farms LLC and Everest Operations Management LLC, respectively, and approximately $20,000 and $26,000, respectively, for the year ended December 31, 2008, for office space under the administrative service agreements, which is included in other income (expense) in the consolidated statements of operations. For the year ended December 31, 2010, the Company was reimbursed approximately $20,000 by Orange Leaf Holdings, LLC, an affiliate of Gulfport, for office space which is included in other income (expense) in the consolidated statements of operations.

Effective July 1, 2008, the Company entered into an acquisition team agreement with Everest Operations Management LLC (Everest) to identify and evaluate potential oil and gas properties in which the Company and Everest may wish to invest. Upon a successful closing of an acquisition or divestiture, the party identifying the acquisition or divestiture is entitled to receive a fee from the other party and its affiliates, if applicable, participating in such closing. The fee is equal to 1% of the party s proportionate share of the acquisition or divestiture consideration. The agreement may be terminated by either party upon 30 days notice.

Effective April 1, 2010, the Company entered into an area of mutual interest agreement with Windsor Niobrara LLC (Windsor Niobrara), an entity controlled by Wexford, to jointly acquire oil and gas leases on certain lands located in Northwest Colorado for the purpose of exploring, exploiting and producing oil and gas from the Niobrara Formation. The agreement provides that each party must offer the other party the right to participate in such acquisitions on a 50%/50% basis. The parties also agreed, subject to certain exceptions, to share third-party costs and expenses in proportion to their respective participating interests and pay certain other fees as provided in the agreement. In connection with this agreement, Gulfport and Windsor Niobrara also entered into a development agreement, effective as of April 1, 2010, pursuant to which the Company and Windsor Niobrara agreed to jointly develop the contract area, and Gulfport agreed to act as the operator under the terms of a joint operating agreement.

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4. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of December 31, 2010 and 2009 are as follows:

	December 31, 2010	December 31, 2009
Oil and natural gas properties	$ 747,344,000	$ 628,849,000
Office furniture and fixtures	3,277,000	2,996,000
Building	4,049,000	3,926,000
Land	283,000	260,000
Total property and equipment	754,953,000	636,031,000
Accumulated depletion, depreciation, amortization and impairment	(512,822,000)	(473,915,000)
Property and equipment, net	$ 242,131,000	$ 162,116,000

At December 31, 2008, the net book value of the Company s oil and natural gas properties, less related deferred income taxes, was above the calculated ceiling as a result of reduced commodity prices at December 31, 2008. As a result, the Company was required to record an impairment of its oil and natural gas properties under the full cost method of accounting in the amount of $272.7 million for the year ended December 31, 2008. No impairment of oil and natural gas properties was required for the years ended December 31, 2010 and December 31, 2009.

Included in oil and natural gas properties at December 31, 2010 and December 31, 2009 is the cumulative capitalization of $18,126,000 and $14,009,000, respectively, in general and administrative costs incurred and capitalized to the full cost pool. General and administrative costs capitalized to the full cost pool represent management s estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All general and administrative costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized general and administrative costs were approximately $4,117,000, $3,395,000 and $4,645,000 for the years ended December 31, 2010, 2009 and 2008, respectively.

The following is a summary of Gulfport s oil and gas properties not subject to amortization as of December 31, 2010:

	Costs Incurred in 2010	2009	2008	Prior to 2008	Total
Acquisition costs	$ 9,950,000	$ 1,163,000	$ 5,000	$ 638,000	$ 11,756,000
Exploration costs	2,692,000	155,000	1,069,000	1,106,000	5,022,000
Development costs					

Total oil and gas properties not subject to amortization	$ 12,642,000	$ 1,318,000	$ 1,074,000	$ 1,744,000	$ 16,778,000

At December 31, 2010, approximately $5,022,000 of oil and gas properties related to the Company s Belize properties is excluded from amortization as it relates to non-producing properties. In addition, approximately

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$8,595,000 of non-producing leasehold costs resulting from the Company s acquisition of West Texas Permian properties, $301,000 of non-producing leasehold costs related to the Company s Bakken properties and $1,727,000 of non-producing leasehold costs related to the Company s Colorado properties are excluded from amortization at December 31, 2010. Approximately $1,089,000 of non-producing leasehold costs related to the Company s Southern Louisiana assets and $44,000 of non-producing leasehold costs related to other projects are also excluded from amortization. At December 31, 2009, approximately $17,521,000 of non-producing leasehold costs was not subject to amortization.

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

A reconciliation of the asset retirement obligation for the years ended December 31, 2010 and 2009 is as follows:

	December 31,	
	2010	**2009**
Asset retirement obligation, beginning of period	$ 10,153,000	$ 9,269,000
Liabilities incurred	1,328,000	361,000
Liabilities settled	(1,253,000)	(59,000)
Accretion expense	617,000	582,000
Asset retirement obligation as of end of period	10,845,000	10,153,000
Less current portion	635,000	635,000
Asset retirement obligation, long-term	$ 10,210,000	$ 9,518,000

5. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of December 31, 2010 and 2009:

	December 31,	
	2010	**2009**
Investment in Tatex Thailand II, LLC	$ 1,907,000	$ 2,485,000
Investment in Tatex Thailand III, LLC	4,660,000	4,482,000
Investment in Grizzly Oil Sands ULC	26,454,000	25,039,000
	$ 33,021,000	$ 32,006,000

Tatex Thailand II, LLC

During 2005, the Company purchased a 23.5% ownership interest in Tatex Thailand II, LLC (Tatex) at a cost of $2,400,000. The remaining interests in Tatex are owned by entities controlled by Wexford. Tatex, a non-public entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC (APICO), an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering approximately two million acres which includes the Phu Horm Field. During 2010, Gulfport received $565,000 in distributions, reducing its total investment in Tatex (including previous investments) to $1,907,000. The loss on equity investment related to Tatex was immaterial for the years ended December 31, 2010, 2009 and 2008.

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Tatex Thailand III, LLC

During the first quarter of 2008, the Company purchased a 5% ownership interest in Tatex Thailand III, LLC (Tatex III) at a cost of $850,000. In December 2009, the Company purchased an additional approximately 12.9% ownership interest at a cost of approximately $3,385,000 bringing its total ownership interest to approximately 17.9%. Approximately 68.7% of the remaining interests in Tatex III are owned by entities controlled by Wexford. During the year ended December 31, 2010, Gulfport paid $402,000 in cash calls, bringing its total investment in Tatex III to $4,660,000. The Company recognized a loss on equity investment of $224,000, $207,000 and $9,000 for the years ended December 31, 2010, 2009 and 2008, respectively, which is included in other income (expense) in the consolidated statements of operations.

Grizzly Oil Sands ULC

During the third quarter of 2006, the Company, through its wholly owned subsidiary Grizzly Holdings Inc., purchased a 24.9999% interest in Grizzly Oil Sands ULC (Grizzly), a Canadian unlimited liability company, for approximately $8.2 million. The remaining interests in Grizzly are owned by entities controlled by Wexford. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray near other oil sands development projects. Grizzly has drilled core holes and water supply test wells in nine separate lease blocks for feasibility of oil production and conducted a seismic program, but has not commenced development of operations. As of December 31, 2010 and 2009, Gulfport s net investment in Grizzly was $26,454,000 and $25,039,000, respectively. Grizzly s functional currency is the Canadian dollar. The Company s investment in Grizzly was increased by $1,313,000 and $3,656,000 as a result of a currency translation gain for the years ended December 31, 2010 and 2009. The Company recognized a loss on equity investment of $740,000, $498,000 and $639,000 for the years ended December 31, 2010, 2009 and 2008, respectively, which is included in other income (expense) in the consolidated statements of operations.

The Company, through its wholly owned subsidiary Grizzly Holdings Inc., entered into a loan agreement with Grizzly effective January 1, 2008, under which Grizzly may borrow funds from the Company. Borrowed funds initially bore interest at LIBOR plus 400 basis points and had an original maturity date of December 31, 2012. Effective April 1, 2010, the loan agreement was amended to modify the interest rate to 0.69% and change the maturity date to December 31, 2011. Effective October 15, 2010, the loan agreement was further amended to change the maturity date to the original maturity date of December 31, 2012. Interest is paid on a paid-in-kind basis by increasing the outstanding balance of the loan. The Company loaned Grizzly approximately $2,877,000 during the year ended December 31, 2010. The Company recognized interest income of approximately $267,000, $547,000 and $410,000 for the years ended December 31, 2010, 2009 and 2008, respectively, which is included in interest income in the consolidated statements of operations. The note balance was increased by approximately $942,000 and $1,843,000 as a result of a currency translation gain for the years ended December 31, 2010 and 2009, respectively. The total $20,006,000 due from Grizzly is included in note receivable related party on the accompanying consolidated balance sheets.

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The table below summarizes financial information for Grizzly as of December 31, 2010, 2009 and 2008:

	December 31,		
	2010	**2009**	**2008**
Current assets	$ 3,277,000	$ 2,064,000	$ 1,481,000
Noncurrent assets	$ 188,786,000	$ 164,043,000	$ 125,024,000
Current liabilities	$ 3,708,000	$ 1,585,000	$ 2,663,000
Noncurrent liabilities	$ 81,089,000	$ 64,365,000	$ 36,397,000
Gross revenue	$	$	$
Loss from continuing operations	$ 3,234,000	$ 1,992,000	$ 2,595,000
Net loss	$ 3,234,000	$ 1,991,000	$ 2,557,000

6. OTHER ASSETS

Other assets consist of the following as of December 31, 2010 and 2009:

	December 31,	
	2010	**2009**
Plugging and abandonment escrow account on the WCBB properties (Note 18)	$ 3,129,000	$ 3,136,000
Certificates of Deposit securing letter of credit	275,000	200,000
Prepaid drilling costs	7,000	30,000
Loan commitment fees	767,000	
Deposits	4,000	4,000
	$ 4,182,000	$ 3,370,000

7. LONG-TERM DEBT

A break-down of long-term debt as of December 31, 2010 and 2009 is as follows:

	December 31,	
	2010	**2009**
Revolving credit agreement (1)	$ 49,500,000	$ 45,000,000
Term loans (1)		4,903,000
Building loans (2)	2,417,000	2,525,000
Less: current maturities of long term debt	(2,417,000)	(2,842,000)

Debt reflected as long term	$ 49,500,000	$ 49,586,000

Maturities of long-term debt as of December 31, 2010 are as follows:

2011	$ 2,417,000
2012	
2013	49,500,000
2014	
2015	
Thereafter	
Total	$ 51,917,000

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(1) In March 2005, Gulfport entered into a three-year secured credit agreement with Bank of America, N.A. providing for a revolving credit facility. The credit agreement was subsequently amended and restated from time to time and, among other things, the maturity date was extended to April 1, 2011. Borrowings under the revolving credit facility were subject to a borrowing base limitation, which was initially set at $18.0 million, subject to adjustment. Effective July 19, 2007, the credit facility was increased to $150.0 million and effective December 20, 2007, the amount available under the borrowing base limitation was increased to $90.0 million.

On August 31, 2009, the lender completed its periodic redetermination of the Company s borrowing base giving consideration to the Company s year-end 2008 and mid-year 2009 reserve information and the lender s then current pricing decks, among other factors. As a result of this redetermination, the Company s available borrowing base was reset at $45.0 million, primarily in response to significant declines in commodity prices. The Company s outstanding principal balance at the effective time of this redetermination was approximately $59.0 million. The approximately $14.0 million of outstanding borrowings under the credit facility in excess of the new borrowing base was converted into a term loan as of August 31, 2009. An initial $2.0 million payment was made on the term loan at that time and the Company agreed to make additional monthly payments of $1.0 million commencing on September 30, 2009, with all unpaid amounts due on March 31, 2010. The Company paid the outstanding balance of the term loan in full in February 2010.

Outstanding borrowings under the term loan accrued interest at the Eurodollar rate (as defined in the credit agreement) plus 4.0% or, at the option of the Company, at the base rate (which was the highest of the lender s prime rate, the Federal funds rate plus half of 1%, and the one-month Eurodollar rate plus 1%) plus 3%. Effective August 31, 2009, the Company also agreed to an adjustment in the commitment fees, interest rates for revolving loans and fees for letters of credit under the credit facility. Specifically, the Company agreed to pay (a) commitment fees ranging from 0.5% to 0.625% (an increase from 0.15% to 0.25%), (b) margin interest rates ranging from 2.75% to 3.50% for Eurodollar loans (an increase from 1.25% to 2.0%), (c) margin interest rates ranging from 1.75% to 2.5% for base rate loans (an increase from 1.25% to 2.0%), and (d) letter of credit fees at the margin interest rates for Eurodollar loans, in each case based on the Company s utilization percentage. In addition, the Company agreed to limitations on certain dispositions and investments and to mandatory prepayments of the loans from the net cash proceeds of specified asset sales and other events.

The Company s obligations under the credit facility were collateralized by a lien on substantially all of the Company s Louisiana and West Texas assets and were guaranteed by its subsidiaries. The restated credit agreement contained certain affirmative and negative covenants, including, but not limited to the following financial covenants: (a) the ratio of funded debt to EBITDAX (net income before deductions for taxes, excluding unrealized gains and losses related to trading securities and commodity hedges, plus depreciation, depletion, amortization and interest expense, plus exploration costs deducted in determining net income under full cost accounting) for a twelve-month period could not be greater than 2.00 to 1.00; and (b) the ratio of EBITDAX to interest expense for a twelve-month period could not be less than 3.00 to 1.00.

On September 30, 2010, the Company entered into a $100 million senior secured revolving credit agreement with The Bank of Nova Scotia, as administrative agent and letter of credit issuer and lead arranger, and Amegy Bank National Association. The new revolving credit facility matures on September 30, 2013 and has an initial borrowing base availability of $50.0 million, which was increased to $65.0 million effective December 24, 2010. As of December 31, 2010, the Company had an outstanding balance of $49.5 million drawn under the credit agreement, which is included in long-term debt, net of current maturities, on the accompanying consolidated balance sheets. The amounts borrowed under the credit agreement were used to repay all of the Company s

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outstanding indebtedness under its prior revolving credit facility ($42.0 million) and term loan ($2.5 million), each with Bank of America, N.A., as administrative agent, and for general corporate purposes. The new credit agreement is secured by substantially all of the Company s assets. The Company s wholly-owned subsidiaries guaranteed the obligations of the Company under the credit agreement.

Advances under the credit agreement may be in the form of either base rate loans or eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 1.75% to 2.50%, plus (2) the highest of: (a) the federal funds rate plus 0.5%, (b) the rate of interest in effect for such day as publicly announced from time to time by agent as its prime rate, and (c) the eurodollar rate for an interest period of one month plus 1.00%. The interest rate for eurodollar loans is equal to (1) the applicable rate, which ranges from 2.75% to 3.50%, plus (2) the London interbank offered rate that appears on Reuters Screen LIBOR01 Page for deposits in U.S. dollars, or, if such rate is not available, the offered rate on such other page or service that displays the average British Bankers Association Interest Settlement Rate for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the London Interbank Offered Rate for deposits in U.S. dollars. At December 31, 2010, amounts borrowed under the credit agreement bore interest at the Eurodollar rate (3.77%).

The credit agreement contains customary negative covenants including, but not limited to, restrictions on the Company s and its subsidiaries ability to: incur indebtedness; grant liens; pay dividends and make other restricted payments; make investments; make fundamental changes; enter into swap contracts and forward sales contracts; dispose of assets; change the nature of their business; and enter into transactions with their affiliates. The negative covenants are subject to certain exceptions as specified in the credit agreement. The credit agreement also contains certain affirmative covenants, including, but not limited to the following financial covenants: (1) the ratio of funded debt to EBITDAX (net income, excluding any non-cash revenue or expense associated with swap contracts resulting from ASC 815, plus without duplication and to the extent deducted from revenues in determining net income, the sum of (a) the aggregate amount of consolidated interest expense for such period, (b) the aggregate amount of income, franchise, capital or similar tax expense (other than ad valorem taxes) for such period, (c) all amounts attributable to depletion, depreciation, amortization and asset or goodwill impairment or writedown for such period, (d) all other non-cash charges, (e) non-cash losses from minority investments, (f) actual cash distributions received from minority investments, (g) to the extent actually reimbursed by insurance, expenses with respect to liability on casualty events or business interruption, and (h) all reasonable transaction expenses related to dispositions and acquisitions of assets, investments and debt and equity offering, and less non-cash income attributable to equity income from minority investments) for a twelve-month period may not be greater than 2.00 to 1.00; and (2) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. The Company was in compliance with all covenants at December 31, 2010.

In conjunction with the repayment of the Bank of America credit facilities on September 30, 2010, the Company expensed approximately $225,000 in unamortized loan fees associated with the Bank of America revolving credit facility, which is included in interest expense in the accompanying consolidated statements of operations.

On July 10, 2006, Gulfport entered into a $5 million term loan agreement with Bank of America, N.A. related to the purchase of new gas compressor units. The loan began amortizing quarterly on March 31, 2007 on a straight-line basis over seven years based on the outstanding principal balance at December 31, 2006. The Company made quarterly principal payments of approximately $176,000. Amounts borrowed bore interest at

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Bank of America Prime. The Company made quarterly interest payments on amounts borrowed under the agreement. The Company s obligations under the agreement were collateralized by a lien on the compressor units. On September 30, 2010, the Company repaid this loan in full with borrowings under the new credit agreement discussed above.

(2) In June 2004, the Company purchased the office building it occupies in Oklahoma City, Oklahoma, for $3.7 million. One loan associated with this building matured in March 2006 and bore interest at the rate of 6% per annum, while the other loan matures in June 2011 and bears interest at the rate of 6.5% per annum. The remaining building loan requires monthly interest and principal payments of approximately $23,000 and is secured by the Oklahoma City office building and associated land.

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

Options

The Company sponsors the 1999 Stock Option Plan (the Plan), which is administered by the Compensation Committee (the Committee) of the Board of Directors of the Company. Under the terms of the Plan, the Committee could determine: to which eligible participants options shall be granted, the number of shares covered by such options, the purchase price or exercise price of such options, the vesting period of such options and the exercisable period of such options. Eligible participants are defined as all directors of the Company, all officers of the Company and all key employees of the Company with a customary work week of at least 40 hours in the employ of the Company. The maximum number of shares for which options could be granted under the Plan, as adjusted for changes in capitalization which have taken place since the Plan s adoption, was 883,000. The Company has granted 627,337 options for the purchase of shares of the Company s common stock under the Plan as of December 31, 2010. No additional securities will be issued under the Plan other than upon exercise of options that are outstanding.

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

On April 20, 2006, the Company amended and restated the 2005 Plan to (i) include (a) Incentive Stock Options, (b) Nonstatutory Stock Options, (c) Restricted Awards (Restricted Stock and Restricted Stock Units), (d) Performance Awards and (e) Stock Appreciation Rights and (ii) increase the maximum aggregate amount of common stock that may be issued under the 2005 Plan from 1,904,606 shares to 3,000,000 shares, including the 627,337 shares underlying options granted to employees under the Plan prior to adoption of the 2005 Plan. As of December 31, 2010, the Company has granted 997,269 options for the purchase of shares of the Company s common stock under the 2005 Plan.

Restricted Stock

On March 13, 2008, the Company granted 6,666 shares of restricted common stock of the Company, of which 740 shares vested on April 1, 2008 with the remaining shares vesting over 36 equal monthly installments

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beginning on May 1, 2008. On August 6, 2008, the Company granted 2,000 shares of restricted common stock of the Company. The shares vest over twelve equal quarterly installments beginning on September 17, 2008. On September 15, 2008, the Company granted 10,000 shares of restricted common stock of the Company. The shares vest over twelve equal quarterly installments beginning on September 17, 2008. On December 5, 2008, the Company granted 66,667 shares of restricted common stock of the Company. The shares vest over twelve equal quarterly installments beginning on December 17, 2008.

On November 3, 2009, the Company granted 13,332 shares of restricted common stock of the Company. The shares vest over twelve equal quarterly installments beginning on December 17, 2009.

On March 8, 2010, the Company granted 66,667 shares of restricted common stock of the Company to employees of the Company at a fair value of approximately $662,000. The shares vest over twelve substantially equal quarterly installments beginning on March 18, 2010. On November 3, 2010, the Company granted 45,000 shares of restricted common stock of the Company to employees of the Company at a fair value of approximately $783,000. The shares vest annually over five years, with 3,000 vesting the first year, 6,000 vesting the second year, 9,000 vesting the third year, 12,000 vesting the fourth year, and 15,000 vesting the fifth year. All shares of restricted common stock of the Company were granted under the amended and restated 2005 Plan.

Sale of Common Stock

On May 19, 2010, the Company sold 1,481,481 shares of its common stock in an underwritten public offering at a public offering price of $13.50 per share less the underwriting discount. On May 25, 2010, the Company sold an additional 187,022 shares of common stock at the public offering price less the underwriting discount in connection with the underwriters partial exercise of the over-allotment option granted to them by the Company. The Company received the aggregate net proceeds of approximately $21.6 million from the sale of these shares after deducting the underwriting discount and before offering expenses. A portion of the net proceeds from the offering was used to fund the Company s Niobrara Formation and Permian Basin acquisitions as discussed in Note 2. The remaining net proceeds from this offering were used for general corporate purposes, including expenditures associated with the Company s 2010 drilling programs.

Private Placement Offering

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

The 2,322,962 Warrants issued have a term of ten years and a current exercise price of $1.19 per share of common stock subject to adjustment. The Company granted to holders of the Warrants certain demand and piggyback registration rights with respect to shares of common stock issuable upon exercise of the Warrants. The Company considered the valuation of the Warrants and did not consider them materially significant. The Company had 9,050 Warrants outstanding at December 31, 2010 which can be converted into 30,420 shares of common stock.

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9. STOCK-BASED COMPENSATION

During the years ended December 31, 2010, 2009 and 2008, the Company s stock-based compensation cost was $492,000, $529,000 and $1,056,000, respectively, of which the Company capitalized $197,000, $212,000 and $422,000, respectively, relating to its exploration and development efforts, which reduced basic and diluted earnings per share by $0.01 and $0.01 for the years ended December 31, 2010 and December 31, 2009, respectively.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option valuation model. Expected volatilities are based on the historical volatility of the market price of Gulfport s common stock over a period of time ending on the grant date. Based upon historical experience of the Company, the expected term of options granted is equal to the vesting period plus one year. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of the grant. The 2005 Plan provides that all options must have an exercise price not less than the fair value of the Company s common stock on the date of the grant.

No stock options were issued during the years ended December 31, 2010, 2009 and 2008.

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

A summary of the status of stock options and related activity for the years ended December 31, 2010, 2009 and 2008 are presented below:

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Options outstanding at December 31, 2007	674,390	$ 6.22	6.97	$ 8,098,000
Granted				
Exercised	(144,121)	3.34		1,694,000
Forfeited/expired	(7,889)	6.17		
Options outstanding at December 31, 2008	522,380	7.01	6.24	$ (1,599,000)
Granted				
Exercised	(13,750)	2.20		71,000
Forfeited/expired				
Options outstanding at December 31, 2009	508,630	7.14	5.38	$ 2,192,000
Granted				
Exercised	(48,889)	6.46		545,000
Forfeited/expired	(1,500)	2.00		

Options outstanding at December 31, 2010	458,241	$	7.23	4.48	$	6,621,000
Options exercisable at December 31, 2010	458,241	$	7.23	4.48	$	6,621,000

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Unrecognized compensation expense as of December 31, 2010 related to outstanding stock options and restricted shares was $1,329,000. The expense is expected to be recognized over a weighted average period of 2.21 years. The following table summarizes information about the stock options outstanding at December 31, 2010:

Exercise Price	Number Outstanding	Weighted Average Remaining Life (in years)	Number Exercisable
$2.00		0.00	
$3.36	222,241	4.06	222,241
$9.07	36,000	4.69	36,000
$11.20	200,000	4.92	200,000
	458,241		458,241

The following table summarizes restricted stock activity for the twelve months ended December 31, 2010, 2009 and 2008:

	Number of Unvested Restricted Shares	Weighted Average Grant Date Fair Value
Unvested shares as of December 31, 2007	59,033	$ 13.94
Granted	85,333	5.64
Vested	(41,493)	11.97
Forfeited	(9,417)	15.84
Unvested shares as of December 31, 2008	93,456	$ 7.04
Granted	13,332	$ 8.08
Vested	(43,458)	8.16
Forfeited	(3,086)	15.77
Unvested shares as of December 31, 2009	60,244	$ 6.01
Granted	111,667	$ 12.94
Vested	(58,525)	8.17
Forfeited		
Unvested shares as of December 31, 2010	113,386	$ 11.72

10. INSURANCE PROCEEDS

In May 2008, the Company received insurance proceeds of approximately $769,000 related to damages incurred resulting from a 2006 barge accident in its WCBB field. The costs associated with repairing the field were expensed to lease operating expenses as incurred in 2006 and 2007. The Company recognized the insurance proceeds in other (income) expense in the accompanying consolidated statements of operations.

In March 2009, the Company received insurance proceeds of approximately $1,050,000 related to damages incurred in its WCBB field as a result of Hurricane Ike in 2008. The costs associated with repairing the field were

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expensed to lease operating expenses as incurred in 2008 and 2009. The Company recognized the insurance proceeds in other (income) expense in the accompanying consolidated statements of operations. In September and October 2009, the Company received additional insurance proceeds of approximately $994,000 related to damages incurred in the WCBB field as a result of Hurricane Ike and related debris removal. As the costs related to these repairs and debris removal were incurred in 2009 and expensed to lease operating expense, the Company recognized the insurance proceeds in lease operating expenses in the accompanying consolidated statements of operations.

11. FAIR VALUE OF FINANCIAL INSTRUMENTS

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

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

12. INCOME TAXES

The income tax provision consists of the following:

	2010	2009	2008
Current:			
State	$ 40,000	$ 28,000	$
Federal	95,000	32,000	653,000
Deferred:			
State			
Federal	(95,000)	(32,000)	(653,000)
Total income tax expense provision	$ 40,000	$ 28,000	$

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

	2010	2009	2008
Income (loss) before income taxes	$ 47,403,000	$ 23,655,000	$ (184,502,000)
Expected income tax at statutory rate	16,591,000	8,279,000	(64,576,000)
State income taxes	2,378,000	1,370,000	(7,033,000)
Other differences	(111,000)	(891,000)	(527,000)
Changes in valuation allowance	(18,818,000)	(8,730,000)	72,136,000

Income tax expense recorded	$	40,000	$	28,000	$

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The tax effects of temporary differences and net operating loss carryforwards, which give rise to deferred tax assets and liabilities at December 31, 2010, 2009 and 2008 are estimated as follows:

	2010	2009	2008
Deferred tax assets:			
Net operating loss carryforward	$ 20,967,000	$ 22,268,000	$ 23,810,000
Oil and gas property basis difference	32,054,000	49,638,000	57,789,000
FASB ASC 718 compensation expense	347,000	341,000	238,000
Investment in pass through entities	722,000	528,000	
AMT credit	693,000	598,000	718,000
Non-oil and gas property basis difference	279,000	316,000	118,000
Total deferred tax assets	55,062,000	73,689,000	82,673,000
Deferred tax liabilities:			
Oil and gas property basis difference			
Investment in pass through entities			134,000
Unrealized gain on hedging activities			
Total deferred tax liabilities			134,000
Total deferred tax asset	55,062,000	73,689,000	82,539,000
Valuation allowance	(54,434,000)	(73,156,000)	(81,886,000)
Net deferred tax asset	$ 628,000	$ 533,000	$ 653,000

The Company has an available tax net operating loss carryforward estimated at approximately $52,417,000 as of December 31, 2010. This carryforward will begin to expire in the year 2018. A valuation allowance has been provided at December 31, 2010, 2009 and 2008 because it is management s belief, based upon the Company s past history of no taxable income and future projections of no taxable income during the carryforward period, it is more likely than not the net deferred tax assets will not be realized.

The Company had income tax expense of $40,000 and $28,000 related to state income tax for the years ended December 31, 2010 and 2009, respectively.

13. EARNINGS PER SHARE

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

	2010		2009		2008	
	Income	Shares	Income	Shares	Income	Shares

			Per Share			Per Share			Per Share
Basic:									
Net income (loss)	$ 47,363,000	43,863,190	$ 1.08	$ 23,627,000	42,667,581	$ 0.55	$ (184,502,000)	42,599,611	$ (4.33)
Effect of dilutive securities:									
Stock options and awards		392,902			350,067				
Diluted:									
Net income	$ 47,363,000	44,256,092	$ 1.07	$ 23,627,000	43,017,648	$ 0.55	$ (184,502,000)	42,599,611	$ (4.33)

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For the year ended December 31, 2009, options to purchase 64,889 shares at $9.07 per share and 200,000 shares at $11.20 per share were excluded from the calculation of dilutive earnings per share because they were anti-dilutive. For the year ended December 31, 2008, all options were excluded from the calculation of dilutive earnings per share because the Company had a net loss and, therefore, the effect would have been anti-dilutive. There were no potential shares of common stock that were considered anti-dilutive for the year ended December 31, 2010.

14. HEDGING ACTIVITIES

Oil Price Hedging Activities

The Company seeks to reduce its exposure to unfavorable changes in oil prices, which are subject to significant and often volatile fluctuation, by entering into forward sales contracts or fixed price swaps. These contracts allow the Company to predict with greater certainty the effective oil prices to be received for hedged production and benefit operating cash flows and earnings when market prices are less than the fixed prices provided in the contracts. However, the Company will not benefit from market prices that are higher than the fixed prices in the contracts for hedged production.

The Company accounts for its oil derivative instruments as cash flow hedges for accounting purposes under FASB ASC 815 and related pronouncements. All derivative contracts are marked to market each quarter end and are included in the accompanying consolidated balance sheets as derivative assets and liabilities.

At December 31, 2010, the fair value of derivative liabilities related to the fixed price swaps is as follows:

Short-term derivative instruments liability	$ 4,720,000

At December 31, 2009, the fair value of derivative liabilities related to the forward sales contracts is as follows:

Short-term derivative instruments liability	$ 18,735,000

All forward sales contracts and fixed price swaps have been executed in connection with the Company s oil price hedging program. For forward sales contracts and fixed price swaps qualifying as cash flow hedges pursuant to FASB ASC 815, the realized contract price is included in oil sales in the period for which the underlying production was hedged.

For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of FASB ASC 815, changes in fair value are recognized in accumulated other comprehensive income until the hedged item is recognized in earnings. Amounts reclassified out of accumulated other comprehensive income into earnings as a component of oil and condensate sales for the years ended December 31, 2010 and 2009 are presented below.

	Year ended December 31,	
	2010	**2009**
(Reduction) addition to oil and condensate sales	($ 18,736,000)	$ 5,313,000

The Company expects to reclassify $4,720,000 out of accumulated other comprehensive income into earnings as a component of oil and condensate sales during the year ended December 31, 2011 related to fixed price swaps.

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Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value resulting from ineffectiveness is recognized immediately in earnings. The Company did not recognize into earnings any amount related to hedge effectiveness for the year ended December 31, 2010 related to the 2010 hedges as these hedges were deemed to be perfectly effective. The Company did not recognize into earnings any amount related to hedge ineffectiveness for the year ended December 31, 2010 related to the 2011 hedges, however, these hedges could be considered ineffective in future periods.

During the fourth quarter of 2010, the Company entered into fixed price swap contracts for 2011 with the purchaser of the Company s WCBB oil and another financial institution. The Company will 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 prices as defined in each contract. The Company s fixed price swap contracts are tied to the commodity prices on the New York Mercantile Exchange (NYMEX). The Company will receive the fixed price amount stated in the contract and pay to its counterparty the current market price for oil as listed on the NYMEX West Texas Index (WTI). However, due to the geographic location of the Company s assets and the cost of transporting oil to another market, the amount that the Company receives when it actually sells its oil differs from the index price. At December 31, 2010, the Company had the following fixed price swaps in place:

	Daily Volume (Bbls/day	Weighted Average Price
January December 2011	2,000	$ 86.96

In 2009, the Company was party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $55.17 per barrel, before transportation costs and differentials, for the period April 2009 to August 2009. The Company also was party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials, for the period September 2009 to December 2009. For the period January 2010 through February 2010, the Company was party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials. For the period March 2010 through December 2010, the Company was party to forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel, before transportation costs and differentials.

In the first quarter of 2009, the Company terminated forward sales contracts for 3,000 barrels per day of March 2009 production for approximately $1.5 million and terminated forward sales contracts for 3,000 barrels per day in the second quarter of 2009 for $476,000. For the year ended December 31, 2009, approximately $2.0 million related to such terminations is included in oil and condensate sales on the accompanying consolidated statements of operations. There were no contracts in place which were accounted for as hedges at December 31, 2008.

The Company delivered approximately 45% of its 2010 production under forward sales contracts.

15. FAIR VALUE MEASUREMENTS

The Company adopted FASB ASC 820 for all financial assets and liabilities measured at fair value on a recurring basis. The Company adopted FASB ASC 820 effective January 1, 2009 for all non-financial assets and liabilities. FASB ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer

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a liability (exit price) in an orderly transaction between market participants at the measurement date. The statement establishes market or observable inputs as the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The statement requires fair value measurements be classified and disclosed in one of the following categories:

Level 1 Quoted prices in active markets for identical assets and liabilities.

Level 2 Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active and model-derived valuations whose inputs are observable or whose significant value drivers are observable.

Level 3 Significant inputs to the valuation model are unobservable.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

The following tables summarizes the Company s financial and nonfinancial liabilities by FASB ASC 820 valuation level as of December 31, 2010 and 2009:

	As of December 31, 2010		
	Level 1	**Level 2**	**Level 3**
Assets:			
Fixed price swaps	$	$	$
Liabilities:			
Fixed price swaps	$	$ 4,720,000	$

	As of December 31, 2009		
	Level 1	**Level 2**	**Level 3**
Assets:			
Forward sales contracts	$	$	$
Liabilities:			
Forward sales contracts	$	$ 18,735,000	$

The estimated fair value of the Company s fixed price swap contracts was based upon forward commodity prices based on quoted market prices, adjusted for differentials.

The Company estimates asset retirement obligations pursuant to the provisions of FASB ASC Topic 410, *Asset Retirement and Environmental Obligations* (FASB ASC 410). The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. See Note 4 for further discussion of the Company s asset retirement obligations. Asset retirement obligations incurred during the twelve months ended December 31, 2010 were approximately $1,328,000.

16. OPERATING LEASES

In October 2006, the Company began leasing the Louisiana building that it owns to an unrelated party. The cost of the building totaled approximately $217,000 and accumulated depreciation amounted to approximately

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$97,000 as of December 31, 2010. The lease commenced on October 15, 2006 and was extended to expire on October 14, 2011, with equal monthly installments of $10,500. The future minimum lease payments to be received are as follows:

Fiscal year ending December 31, 2011	$ 100,000

17. RELATED PARTY TRANSACTIONS

In the ordinary course of business, the Company conducts business activities with certain entities affiliated with its largest stockholder.

Windsor Energy Group, LLC (WEG), an entity controlled by Wexford, operates the Permian Basin wells in West Texas. At December 31, 2010 and 2009, the Company owed WEG approximately $5,871,000 and $1,631,000, respectively, related to reimbursement for services provided. Approximately $2,386,000 and $2,368,000 of services provided by WEG are included in lease operating expenses in the consolidated statements of operations for the years ended December 31, 2010 and 2009, respectively. Approximately $21,666,000 and $8,063,000 related to services performed by WEG are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2010 and 2009, respectively.

Athena Construction LLC (Athena), an entity controlled by Wexford, performs services for the Company at its WCBB and Hackberry fields. At December 31, 2010 and December 31, 2009, the Company owed Athena approximately $791,000 and $836,000, respectively, related to these services. Approximately $438,000 and $709,000 of services provided by Athena are included in lease operating expenses in the consolidated statements of operations for the years ended December 31, 2010 and 2009, respectively. Approximately $2,554,000 and $1,286,000 related to services performed by Athena are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2010 and 2009, respectively.

Great White Directional Services LLC (Directional), an entity controlled by Wexford, performs services for the Company at its WCBB and Hackberry fields. At December 31, 2010 and December 31, 2009, the Company owed Directional approximately $952,000 and $699,000, respectively, related to these services. Approximately $3,008,000 and $1,064,000 relating to services performed by Directional are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2010 and 2009, respectively.

Great White Pressure Control (Pressure Control), an entity controlled by Wexford, performs services for the Company at its WCBB field. At December 31, 2010, the Company owed Pressure Control approximately $80,000, related to these services. No amounts were owed to Pressure Control at December 31, 2009. Approximately $80,000 of services performed by Pressure Control is included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2010. No services were performed by Pressure Control in 2009.

Black Fin P&A, LLC (Black Fin), an entity controlled by Wexford, performs services for the Company at its WCBB field. No amounts were owed to Black Fin at December 31, 2010. Approximately $826,000 of services performed by Black Fin is included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2010. No services were performed by Black Fin in 2009.

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18. COMMITMENTS

Plugging and Abandonment Funds

In connection with the acquisition in 1997 of the remaining 50% interest in the WCBB properties, the Company assumed the seller s (Chevron) obligation to contribute approximately $18,000 per month through March 2004, to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until abandonment obligations to Chevron have been fulfilled. Beginning in 2009, the Company can access the trust for use in plugging and abandonment charges associated with the property. As of December 31, 2010, the plugging and abandonment trust totaled approximately $3,129,000. At December 31, 2010, the Company has plugged 311 wells at WCBB since it began its plugging program in 1997, which management believes fulfills its current minimum plugging obligation.

Texaco Global Settlement

Pursuant to the terms of a global settlement between Texaco and the State of Louisiana which includes the State Lease No. 50 portion of Gulfport s East Hackberry field, Gulfport was obligated to commence drilling a well or other qualifying development operation on certain non-producing acreage in the field prior to March 1998. Because of prevailing market conditions during 1998, the Company believed it was commercially impractical to shoot seismic or commence drilling operations on the subject property. As a result, Gulfport agreed to surrender approximately 440 non-producing acres in this field to the State of Louisiana. At December 31, 2010, Gulfport was in the process of releasing these properties to the State of Louisiana.

Contributions to 401(k) Plan

Gulfport sponsors a 401(k) and Profit Sharing plan under which eligible employees may contribute up to 15% of their total compensation through salary deferrals. Also under these plans, the Company will make a contribution each calendar year on behalf of each employee equal to at least 3% of his or her salary, regardless of the employee s participation in salary deferrals. During the years ended December 31, 2010, 2009 and 2008, Gulfport incurred $316,000, $279,000 and $651,000, respectively, in contributions expense related to this plan.

Employment Agreement

In May 1999, Gulfport entered into an employment agreement with its Chairman of the Board. The original term of the agreement expired on May 31, 2004, but automatically renews for successive terms of one year unless Gulfport or the Chairman elects otherwise. The employment agreement calls for an annual salary of $200,000, subject to adjustment for cost of living increases.

The Company is party to an oral agreement with the Company s Chief Executive Officer, with respect to his compensation and benefits, pursuant to which he is entitled to an annual salary of $200,000 and, at the discretion of the Company s board of directors, an annual cash incentive bonus. The compensation committee of the Board of Directors may make upward adjustments to this salary.

19. CONTINGENCIES

The Louisiana Department of Revenue (LDR) is disputing Gulfport s severance tax payments to the State of Louisiana from the sale of oil under fixed price contracts during the years 2005 to 2007. The LDR maintains

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that Gulfport paid approximately $1,800,000 less in severance taxes under fixed price terms than the severance taxes Gulfport would have had to pay had it paid severance taxes on the oil at the contracted market rates only. Gulfport has denied any liability to the LDR for underpayment of severance taxes and has maintained that it was entitled to enter into the fixed price contracts with unrelated third parties and pay severance taxes based upon the proceeds received under those contracts. Gulfport has maintained its right to contest any final assessment or suit for collection if brought by the State. On April 20, 2009, the LDR filed a lawsuit in the 15th Judicial District Court, Lafayette Parish, in Louisiana against Gulfport seeking $2,275,729 in severance taxes, plus interest and court costs. Gulfport filed a response denying any liability to the LDR for underpayment of severance taxes and is defending itself in the lawsuit.

In December 2010, the LDR filed two identical lawsuits against Gulfport in different venues to recover allegedly underpaid severance taxes on crude oil for the period January 1, 2007 through December 31, 2010, together with a claim for attorney's fees. The petitions do not make any specific claim for damages or unpaid taxes. As with the first lawsuit filed by LDR in 2009, Gulfport denies all liability and will vigorously defend the lawsuit. The cases are in the early stages, and Gulfport has not yet filed a response to the recent lawsuits.

Other Litigation

In November 2006, Cudd Pressure Control, Inc. (Cudd) filed a lawsuit against Gulfport, Great White Pressure Control LLC (Great White) and six former Cudd employees in the 129th Judicial District Harris County, Texas. The lawsuit was subsequently removed to the United States District Court for the Southern District of Texas (Houston Division). The lawsuit alleged RICO violations and several other causes of action relating to Great White s employment of the former Cudd employees and sought unspecified monetary damages and injunctive relief. On stipulation by the parties, the plaintiff s RICO claim was dismissed without prejudice by order of the court on February 14, 2007. Gulfport filed a motion for summary judgment on October 5, 2007. The court entered a final interlocutory judgment in favor of all defendants, including Gulfport, on April 8, 2008. On November 3, 2008, Cudd filed its appeal with the U.S. Court of Appeals for the Fifth Circuit. The Fifth Circuit vacated the district court decision finding, among other things, that the district court should not have entered summary judgment without first allowing more discovery. The case was remanded to the district court, and Cudd filed a motion to remand the case to the original state court, which motion was granted. On February 3, 2010, Cudd filed its second amended petition with the state court (a) alleging that Gulfport conspired with the other defendants to misappropriate, and misappropriated, Cudd s trade secrets and caused its employees to breach their fiduciary duties, and (b) seeking unspecified monetary damages. On April 13, 2010, Gulfport s motion to be dismissed from the proceeding for lack of personal jurisdiction was denied. This state court proceeding is in its initial stages. In 2011, the parties have continued with written discovery and production of documents. Cudd filed a third amended petition seeking $26.5 million (based on a report prepared by its expert) plus disgorgement of $6 million in payments by Great White to the individual defendants and punitive damages. Gulfport denies these claims with respect to itself.

On July 30, 2010, six individuals and one limited liability company sued 15 oil and gas companies in Cameron Parish Louisiana for contamination across the surface of where the defendants operated in an action entitled *Reeds et al. v. BP American Production Company et al.,* 38th Judicial District. No. 10-18714. The plaintiffs original petition for damages, which did not name Gulfport as a defendant, alleges that the plaintiffs property located in Cameron Parish, Louisiana within the Hackberry oil field is contaminated as a result of historic oil and gas exploration and production activities. Plaintiffs allege that the defendants, which in addition to BP America Production Company include ExxonMobil Corporation, Shell Oil Company, ConocoPhillips Company, Sun Oil Company and Schlumberger Technology Corporation, conducted, directed and participated in various oil and gas

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exploration and production activities on their property which allegedly have contaminated or otherwise caused damage to the property, and have sued the defendants for alleged breaches of oil, gas and mineral leases, as well as for alleged negligence, trespass, failure to warn, strict liability, punitive damages, lease liability, contract liability, unjust enrichment, restoration damages, assessment and response costs and stigma damages. On December 7, 2010, Gulfport was served with a copy of the plaintiffs first supplemental and amending petition which added four additional plaintiffs and six additional defendants, including Gulfport, bringing the total number of defendants to 21. It also increased the total acreage at issue in this litigation from 240 acres to approximately 1,700 acres. In addition to the damages sought in the original petition, the plaintiffs now also seek: damages sufficient to cover the cost of conducting a comprehensive environmental assessment of all present and yet unidentified pollution and contamination of their property; the cost to restore the property to its pre-polluted original condition; damages for mental anguish and annoyance, discomfort and inconvenience caused by the nuisance created by defendants; land loss and subsidence damages and the cost of backfilling canals and other excavations; damages for loss of use of land and lost profits and income; attorney fees and expenses and damages for evaluation and remediation of any contamination that threatens groundwater. On January 21, 2011, Gulfport filed a pleading challenging the legal sufficiency of the petitions and requesting that they either be dismissed or that plaintiffs be required to amend such petitions. Gulfport s motion is currently set to be heard on March 23, 2011.

Due to the current stages of the LDR, Cudd and Reed litigation, the outcome is uncertain and management cannot determine the amount of loss, if any, that may result. Litigation is inherently uncertain. Adverse decisions in one or more of the above matters could have a material adverse effect on the Company s financial condition or results of operations.

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

Concentration of Credit Risk

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

The Company maintains cash balances at several banks. Accounts at each institution are insured by the Federal Deposit Insurance Corporation up to $250,000. At December 31, 2010, Gulfport held cash in excess of insured limits in these banks totaling $1,986,000.

During the year ended December 31, 2010, Gulfport sold approximately 75% and 19% of its oil production to Shell Trading Company (Shell) and WEG, respectively, and 50%, 32% and 10% of its natural gas production to WEG, Chevron, and Hilcorp Energy Company (Hilcorp), respectively. During the year ended December 31, 2009, Gulfport sold approximately 92% and 7% of its oil production to Shell and WEG, respectively, 100% of its natural gas liquids production to WEG, and 45%, 38%, and 16% of its natural gas production to WEG, Chevron, and Hilcorp, respectively. During the year ended December 31, 2008, Gulfport sold approximately 87% and 11% of its oil production to Shell and WEG, respectively, 100% of its natural gas liquids production to WEG, and 60%, 22%, and 16% of its natural gas production to Chevron, WEG, and Hilcorp, respectively.

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Forward Sales Contracts

The Company was party to forward sales contracts for the sale of 3,500 barrels of production per day for the months of January 2008 through May 2008 at a weighted average daily price of $70.29 per barrel before transportation costs. For June 2008, the Company had agreements to sell 3,500 barrels of production per day at a weighted average daily price of $71.69 per barrel before transportation costs. For the month of July 2008, the Company had agreements to sell 3,500 barrels of production per day at a weighted average daily price of $85.89 per barrel before transportation costs. For August 2008, Gulfport had agreements to sell 3,500 barrels of production per day at a weighted average daily price of $86.81 per barrel before transportation costs. For the periods September 2008 through December 2008, the Company entered into forward sales contracts for the sale of 3,500 barrels of production per day at a weighted average daily price of $86.60 per barrel before transportation costs. For the period of January 2009 through December 2009, the Company entered into agreements to sell 3,000 barrels of production per day at a weighted average daily price of $89.06 per barrel before transportation costs. These contracts were originally designated as normal sales of production under FASB ASC 815, based on the Company s intent to physically deliver the production quantities under the contract terms, and exempted from the provisions of FASB ASC 815.

In December 2008, the Company terminated the 2009 forward sales contracts in exchange for $39.0 million cash, which is included in other (income) expense on the accompanying consolidated statements of operations. As a result of this cash settlement, beginning in 2009, the Company is required to account for similar contracts under the provisions of FASB ASC 815 until a reasonable period passes and the Company redevelops a past history of physical delivery under fixed price contracts without net cash settlement. See Note 14 for further discussion of the Company s 2009 and 2010 forward sales contracts.

20. LITIGATION TRUST ENTITY

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

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

On January 20, 1998, Gulfport and the Litigation Trust entered into a Clarification Agreement whereby the rights to pursue various claims reserved by Gulfport under the plan of reorganization were assigned to the Litigation Trust. In connection with this agreement, the Litigation Trust agreed to reimburse the Company $100,000 for legal fees Gulfport had incurred in connection with these claims. As additional consideration for the contribution of this claim to the Litigation Trust, Gulfport is entitled to 20% to 80% of the net proceeds from these claims.

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In December 2009, the Company received a final distribution from the Litigation Trust of approximately $234,000. No proceeds were received from the Litigation Trust for the years ended December 31, 2010 or 2008.

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

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

Capitalized Costs Related to Oil and Gas Producing Activities

	2010	2009
Proven properties	$ 730,566,000	$ 610,778,000
Unproven properties	11,756,000	15,192,000
	742,322,000	625,970,000
Accumulated depreciation, depletion, amortization and impairment reserve	(509,248,000)	(470,649,000)
Net capitalized costs	$ 233,074,000	$ 155,321,000

Costs Incurred in Oil and Gas Property Acquisition and Development Activities

	2010	2009	2008
Acquisition	$ 17,627,000	$ 1,885,000	$ 2,468,000
Development of proved undeveloped properties	64,652,000	28,652,000	64,643,000
Exploratory		502,000	9,764,000
Recompletions	16,917,000	8,980,000	16,877,000
Capitalized asset retirement obligation	1,328,000	361,000	934,000
Total	$ 100,524,000	$ 40,380,000	$ 94,686,000

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Results of Operations for Producing Activities

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

	2010	2009	2008
Revenues	$ 127,636,000	$ 85,576,000	$ 141,650,000
Production costs	(31,580,000)	(26,113,000)	(38,669,000)
Impairment of oil and gas assets			(272,722,000)
Depletion	(38,600,000)	(28,939,000)	(42,194,000)
	57,456,000	30,524,000	(211,935,000)
Income tax expense			
Current	40,000	28,000	
Deferred			
	40,000	28,000	
Results of operations from producing activities	$ 57,416,000	$ 30,496,000	$ (211,935,000)
Depletion per barrel of oil equivalent (BOE)	$ 19.54	$ 17.25	$ 23.92

Oil and Gas Reserves (Unaudited)

The following table presents estimated volumes of proved developed and undeveloped oil and gas reserves as of December 31, 2010, 2009 and 2008 and changes in proved reserves during the last three years. The 2010 and 2009 reserve reports use an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2010 and 2009, in accordance with revised guidelines of the SEC applicable to reserves estimates as of year-end 2009. Estimates of reserves as of year-end 2008 were prepared using constant prices and costs in accordance with previous guidelines of the SEC based on hydrocarbon prices received on a field-by-field basis as of December 31, 2008. Volumes for oil are stated in thousands of barrels (MBbls) and volumes for gas are stated in millions of cubic feet (MMcf). The prices used for the 2010 reserve report are $76.16 per barrel and $4.38 per MMbtu, adjusted by lease for transportation fees and regional price differentials, and for oil and gas reserves, respectively. The prices used at December 31, 2009 and 2008 for reserve report purposes are $57.90 per barrel and $3.87 per MMbtu and $41.00 per barrel and $5.71 per MMbtu, respectively.

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

	2010		2009		2008	
	Oil	Gas	Oil	Gas	Oil	Gas
Proved Reserves						
Beginning of the period	17,488	14,332	21,771	22,235	25,115	24,259
Purchases in oil and gas reserves in place	3,913	3,482	1,728	1,135	77	26
Extensions and discoveries	5,574	5,303	2,614	2,874	1,315	1,965
Sales of oil and gas reserves in place			(736)	(282)		
Revisions of prior reserve estimates	(5,426)	(6,171)	(6,294)	(11,139)	(3,091)	(3,303)
Current production	(1,845)	(788)	(1,595)	(491)	(1,645)	(712)
End of period	19,704	16,158	17,488	14,332	21,771	22,235
Proved developed reserves	7,230	6,068	6,165	4,325	7,072	7,187

The Company experienced downward reserve revisions in estimated proved reserves in 2010. These downward revisions were primarily the result of the application of the five-year schedule for the development of proved undeveloped reserves required by the SEC s Modernization of Oil and Gas Reporting Final Rule, which resulted in the elimination of proved undeveloped reserves that remained undeveloped beyond such five-year schedule. The Company experienced downward reserve revisions in estimated proved reserves in 2009. These downward revisions were primarily the result of application of the five-year schedule for the development of proved undeveloped reserves required by the SEC s Modernization of Oil and Gas Reporting Final Rule. The Company experienced downward reserve revisions in estimated proved reserves in 2008. These downward revisions were primarily a result of year end commodity prices utilized for the reserve estimate decreasing from $92.50 per barrel and $6.80 per MMbtu at December 31, 2007 to $41.00 per barrel and $5.71 per MMbtu at December 31, 2008.

Discounted Future Net Cash Flows (Unaudited)

The following tables present the estimated future cash flows, and changes therein, from Gulfport s proven oil and gas reserves as of December 31, 2010, 2009 and 2008 using an unweighted average first-of-the-month price for the period January through December for 2010 and 2009 and the applicable year end price for 2008.

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

	Year ended December 31,		
	2010	2009	2008
Future cash flows	$ 1,479,295,000	$ 1,005,029,000	$ 1,023,056,000
Future development and abandonment costs	(301,651,000)	(209,975,000)	(299,362,000)
Future production costs	(305,814,000)	(236,003,000)	(376,176,000)
Future production taxes	(136,323,000)	(97,841,000)	(109,478,000)
Future income taxes	(159,171,000)	(50,229,000)	
Future net cash flows	576,336,000	410,981,000	238,040,000
10% discount to reflect timing of cash flows	(260,849,000)	(170,207,000)	(111,800,000)
Standardized measure of discounted future net cash flows	$ 315,487,000	$ 240,774,000	$ 126,240,000

In order to develop its proved undeveloped reserves according to the drilling schedule used by the engineers in Gulfport s reserve report, the Company will need to spend $71,320,000, $63,100,000 and $52,038,000 during years 2011, 2012 and 2013, respectively.

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

	Year ended December 31,		
	2010	2009	2008
Sales and transfers of oil and gas produced, net of production costs	$ (96,056,000)	$ (59,463,000)	$ (102,981,000)
Net changes in prices, production costs, and development costs	122,147,000	183,426,000	(662,004,000)
Acquisition of oil and gas reserves in place	63,043,000	20,981,000	376,000
Extensions and discoveries	88,227,000	32,638,000	7,801,000
Revisions of previous quantity estimates, less related production costs	(89,155,000)	(77,531,000)	(13,480,000)
Sales of reserves in place		(13,185,000)	
Accretion of discount	24,077,000	12,624,000	66,830,000
Net changes in income taxes	(54,879,000)	(22,238,000)	152,949,000
Change in production rates and other	17,309,000	37,282,000	8,454,000
Total change in standardized measure of discounted future net cash flows	$ 74,713,000	$ 114,534,000	$ (542,055,000)

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GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2010, 2009 AND 2008

(Amounts rounded to nearest thousand)

22. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table summarizes quarterly financial data for the years ended December 31, 2010 and 2009:

	2010			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$ 27,355,000	$ 28,875,000	$ 33,181,000	$ 37,533,000
Income from operations	10,526,000	11,004,000	13,468,000	14,779,000
Income tax expense		40,000		
Net income	9,981,000	10,389,000	12,678,000	14,315,000
Income per share:				
Basic	$ 0.23	$ 0.24	$ 0.28	$ 0.32
Diluted	$ 0.23	$ 0.24	$ 0.28	$ 0.32

	2009			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$ 17,784,000	$ 20,514,000	$ 22,071,000	$ 24,893,000
Income from operations	2,214,000	5,410,000	7,130,000	9,596,000
Income tax expense		28,000		
Net income	2,733,000	5,078,000	6,674,000	9,142,000
Income per share:				
Basic	$ 0.06	$ 0.12	$ 0.16	$ 0.21
Diluted	$ 0.06	$ 0.12	$ 0.16	$ 0.21

23. SUBSEQUENT EVENTS (Unaudited)

In February 2011, the Company entered into an agreement to acquire certain leasehold interests located in the Utica Shale in Ohio. The agreement also grants the Company an exclusive right of first refusal for a period of six months on certain additional tracts leased by the seller. Windsor, an affiliate of the Company, has agreed to participate with the Company on a 50/50 basis in the acquisition of all leases described above. Gulfport will be the operator on this acreage in the Utica Shale. The purchase price for the Company s 50% interest in the initial acreage is approximately $31,625,000, subject to certain closing adjustments. This transaction is expected to close in mid-May 2011.

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EXHIBIT INDEX

Exhibit Number	Description
2.1	Purchase and Sale Agreement, dated as of November 28, 2007, by and among Ambrose Energy I, Ltd. and each of the other persons, which are listed as a party seller, and Windsor Permian (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 24, 2007).
2.2	Second Amendment to the Purchase and Sale Agreement, dated as of December 18, 2007, by and among Ambrose Energy I, Ltd., each of the other parties which are listed as a party seller, Windsor Permian and Gulfport (incorporated by reference to Exhibit 2.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 24, 2007).
3.1	Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
3.2	Certificate of Amendment No. 1 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.2 to Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 6, 2009).
3.3	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 12, 2006).
4.1	Form of Common Stock certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.2	Form of Warrant Agreement (incorporated by reference to Exhibit 10.4 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.3	Registration Rights Agreement, dated as of February 23, 2005, by and among the Company, Southpoint Fund LP, a Delaware limited partnership, Southpoint Qualified Fund LP, a Delaware limited partnership and Southpoint Offshore Operating Fund, LP, a Cayman Islands exempted limited partnership (incorporated by reference to Exhibit 10.7 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2005).
4.4	Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.3 of Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on November 11, 2005).
4.5	Amendment No. 1, dated February 14, 2006, to the Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.15 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2006).
10.1+	Amended and Restated 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
10.2+	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.2 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
10.3+	Form of Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.3 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).

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Exhibit Number	Description
10.4+	Employment Agreement, dated as of May 18, 1999 and effective as of June 1, 1999, by and between the Company and Mike Liddell (incorporated by reference to Exhibit 10.5 of Amendment No. 1 to Form 10-KSB/A, File No. 000-19514, filed by the Company with the SEC on May 11, 2007).
10.5+	Summary of Oral Employment Agreement with James D. Palm (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 7, 2010).
10.5	Credit Agreement, dated as of September 30, 2010, by and among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, and Amegy Bank National Association (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 6, 2010).
10.6	Amendment, dated as of December 24, 2010, to the Credit Agreement by and among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, and Amegy Bank National Association (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 28, 2010).
14	Code of Ethics (incorporated by reference to Exhibit 14 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 14, 2006).
21*	Subsidiaries of the Registrant.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
23.3*	Consent of Pinnacle Energy Services, LLC
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
99.1*	Report of Netherland, Sewell & Associates, Inc.
99.2*	Report of Pinnacle Energy Services, LLC.

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