GULFPORT ENERGY CORP
Form 10-Q
November 07, 2008
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

FOR THE QUARTERLY PERIOD ENDED September 30, 2008

OR

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

Commission File Number 000-19514

Gulfport Energy Corporation

(Exact Name of Registrant As Specified in Its Charter)

Delaware	**73-1521290**
(State or Other Jurisdiction of Incorporation or Organization)	**(IRS Employer Identification Number)**
14313 North May Avenue, Suite 100	
Oklahoma City, Oklahoma	**73134**
(Address of Principal Executive Offices)	**(Zip Code)**

(405) 848-8807

(Registrant Telephone Number, Including Area Code)

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

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

Large Accelerated Filer ¨ Accelerated Filer x Non-Accelerated Filer ¨ Smaller Reporting Company ¨

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

As of October 31, 2008, 42,627,456 shares of common stock were outstanding.

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CONSOLIDATED BALANCE SHEETS

	(Unaudited) September 30, 2008	December 31, 2007
Assets		
Current assets:		
Cash and cash equivalents	$ 4,511,000	$ 2,764,000
Accounts receivable - oil and gas	8,951,000	10,510,000
Accounts receivable - related parties	455,000	2,208,000
Prepaid expenses and other current assets	1,366,000	1,346,000
Total current assets	15,283,000	16,828,000
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $39,505,000 and $37,278,000 excluded from amortization in 2008 and 2007, respectively	574,120,000	484,487,000
Other property and equipment	7,165,000	7,108,000
Accumulated depletion, depreciation and amortization	(158,408,000)	(129,496,000)
Property and equipment, net	422,877,000	362,099,000
Other assets		
Equity investments	29,405,000	33,822,000
Other assets	6,851,000	6,388,000
Note receivable - related party	9,511,000	
Total other assets	45,767,000	40,210,000
Total assets	$ 483,927,000	$ 419,137,000
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 35,169,000	$ 39,848,000
Asset retirement obligation - current	480,000	480,000
Current maturities of long-term debt	813,000	808,000
Total current liabilities	36,462,000	41,136,000
Asset retirement obligation - long-term	8,775,000	8,154,000
Long-term debt, net of current maturities	95,120,000	65,725,000
Total liabilities	140,357,000	115,015,000
Commitments and contingencies (Note 13)		
Preferred stock, $.01 par value; 5,000,000 authorized, 30,000 authorized as redeemable 12% cumulative preferred stock, Series A; 0 issued and outstanding		
Stockholders equity:		
Common stock - $.01 par value, 55,000,000 authorized, 42,624,723 issued and outstanding in 2008 and 42,453,587 in 2007	426,000	424,000

Paid-in capital	273,103,000	271,807,000
Accumulated other comprehensive income (loss)	(95,000)	2,254,000
Retained earnings	70,136,000	29,637,000
Total stockholders equity	343,570,000	304,122,000
Total liabilities and stockholders equity	$ 483,927,000	$ 419,137,000

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Revenues:				
Gas sales	$ 1,337,000	$ 1,500,000	$ 5,612,000	$ 3,993,000
Oil and condensate sales	34,354,000	28,472,000	95,636,000	71,360,000
Natural gas liquids sales	1,216,000		2,784,000	
Other income (expense)	(176,000)	3,000	(381,000)	12,000
	36,731,000	29,975,000	103,651,000	75,365,000
Costs and expenses:				
Lease operating expenses	6,362,000	4,008,000	14,906,000	11,127,000
Production taxes	3,970,000	3,547,000	11,398,000	9,017,000
Depreciation, depletion, and amortization	9,392,000	7,845,000	28,912,000	20,128,000
General and administrative	1,748,000	1,192,000	5,270,000	3,427,000
Accretion expense	140,000	138,000	417,000	415,000
	21,612,000	16,730,000	60,903,000	44,114,000
INCOME FROM OPERATIONS:	15,119,000	13,245,000	42,748,000	31,251,000
OTHER (INCOME) EXPENSE:				
Interest expense	1,172,000	654,000	3,402,000	1,979,000
Insurance proceeds			(769,000)	
Interest income	(180,000)	(114,000)	(404,000)	(343,000)
	992,000	540,000	2,229,000	1,636,000
INCOME BEFORE INCOME TAXES	14,127,000	12,705,000	40,519,000	29,615,000
INCOME TAX EXPENSE:	20,000	4,000	20,000	57,000
NET INCOME	$ 14,107,000	$ 12,701,000	$ 40,499,000	$ 29,558,000
NET INCOME PER COMMON SHARE:				
Basic	$ 0.33	$ 0.34	$ 0.95	$ 0.82
Diluted	$ 0.33	$ 0.33	$ 0.94	$ 0.80

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

Consolidated Statements of Stockholders Equity and Comprehensive Income

(Unaudited)

	Common Stock		Additional	Accumulated Other	Retained Earnings	Total
	Shares	Amount	Paid-in Capital	Comprehensive Income (Loss)	(Accumulated Deficit)	Stockholders Equity
Balance at January 1, 2008	42,453,587	$ 424,000	$ 271,807,000	$ 2,254,000	$ 29,637,000	$ 304,122,000
Net income					40,499,000	40,499,000
Other Comprehensive Income:						
Foreign currency translation adjustment				(2,349,000)		(2,349,000)
Total Comprehensive Income						38,150,000
Stock Compensation			816,000			816,000
Issuance of Restricted Stock	27,015					
Issuance of Common Stock through exercise of options	144,121	2,000	480,000			482,000
Balance at September 30, 2008	42,624,723	$ 426,000	$ 273,103,000	$ (95,000)	$ 70,136,000	$ 343,570,000
Balance at January 1, 2007	33,659,759	$ 337,000	$ 131,610,000	$	$ (8,138,000)	$ 123,809,000
Net income					29,558,000	29,558,000
Other Comprehensive Income:						
Foreign currency translation adjustment				2,094,000		2,094,000
Total Comprehensive Income						31,652,000
Stock Compensation			875,000			875,000
Issuance of Common Stock in public offerings, net of related expenses of $572,000	4,047,500	40,000	62,786,000			62,826,000
Issuance of Restricted Stock	26,946					
Issuance of Common Stock through exercise of options	210,398	2,000	866,000			868,000
Balance at September 30, 2007	37,944,603	$ 379,000	$ 196,137,000	$ 2,094,000	$ 21,420,000	$ 220,030,000

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION

Consolidated Statements of Cash Flows

(Unaudited)

	Nine Months Ended September 30, 2008	2007
Cash flows from operating activities:		
Net income	$ 40,499,000	$ 29,558,000
Adjustments to reconcile net income to net cash provided by operating activities:		
Accretion of discount - Asset Retirement Obligation	417,000	415,000
Depletion, depreciation and amortization	28,912,000	20,128,000
Stock-based compensation expense	490,000	639,000
Loss from equity investments	540,000	109,000
Interest income - note receivable	(290,000)	
Changes in operating assets and liabilities:		
Decrease (increase) in accounts receivable	1,559,000	(1,588,000)
Decrease in accounts receivable - related party	1,753,000	380,000
Increase in prepaid expenses	(20,000)	(793,000)
Increase (decrease) in accounts payable and accrued liabilities	1,727,000	(740,000)
Settlements of asset retirement obligation	(324,000)	(872,000)
Net cash provided by operating activities	75,263,000	47,236,000
Cash flows from investing activities:		
Additions to cash held in escrow	(36,000)	(95,000)
Additions to other property, plant and equipment	(57,000)	(385,000)
Additions to oil and gas properties	(92,993,000)	(102,757,000)
Proceeds from sale of oil and gas properties		500,000
Note receivable - related party	(9,708,000)	
Investment in Grizzly Oil Sands ULC	(151,000)	(12,374,000)
Investment in Tatex Thailand II, LLC	432,000	(88,000)
Investment in Tatex Thailand III, LLC	(885,000)	
Investment in Windsor Bakken, LLC		(127,000)
Net cash used in investing activities	(103,398,000)	(115,326,000)
Cash flows from financing activities:		
Principal payments on borrowings	(600,000)	(46,959,000)
Borrowings on note payable	30,000,000	46,500,000
Proceeds from issuance of common stock, net of offering costs of $0 and $572,000, and exercise of stock options	482,000	63,694,000
Net cash provided by financing activities	29,882,000	63,235,000
Net increase (decrease) in cash and cash equivalents	1,747,000	(4,855,000)
Cash and cash equivalents at beginning of period	2,764,000	6,627,000
Cash and cash equivalents at end of period	$ 4,511,000	$ 1,772,000
Supplemental disclosure of cash flow information:		
Interest payments	$ 3,534,000	$ 2,378,000

Supplemental disclosure of non-cash transactions:		
Capitalized stock based compensation	$ 326,000	$ 236,000
Asset retirement obligation capitalized	$ 528,000	$ 292,000

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

These consolidated financial statements have been prepared by Gulfport Energy Corporation (the Company or Gulfport) without audit, pursuant to the rules and regulations of the Securities and Exchange Commission, and reflect all adjustments which, in the opinion of management, are necessary for a fair presentation of the results for the interim periods, on a basis consistent with the annual audited consolidated financial statements. All such adjustments are of a normal recurring nature. Certain information, accounting policies, and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been omitted pursuant to such rules and regulations, although the Company believes that the disclosures are adequate to make the information presented not misleading. These consolidated financial statements should be read in conjunction with the consolidated financial statements and the summary of significant accounting policies and notes thereto included in the Company s most recent annual report on Form 10-K. Results for the three month and nine month periods ended September 30, 2008 are not necessarily indicative of the results expected for the full year.

1. ACQUISITIONS

On December 20, 2007, Gulfport closed on the acquisition of an ownership interest in certain oil and gas properties located in the Permian Basin of West Texas, including approximately 4,100 net acres with 32 gross producing wells from ExL Petroleum, LP and 12 other sellers for a cash price of approximately $85 million. The effective date of the acquisition was November 1, 2007. The total purchase price for the assets, as adjusted at the original closing on December 20, 2007, was $85.2 million, which was recorded as oil and natural gas properties on the accompanying December 31, 2007 consolidated balance sheet. This amount includes an adjustment for the results of operations of the assets between the November 1, 2007 effective date and the December 20, 2007 closing date. The final post closing adjustments occurred 90 days from the original closing date of December 20, 2007, or March 20, 2008, and the purchase price was adjusted accordingly. The total adjusted purchase price for the assets was $83.8 million.

2. ACCOUNTS RECEIVABLE RELATED PARTY

Included in the accompanying September 30, 2008 and December 31, 2007 consolidated balance sheets are amounts receivable from affiliates of the Company. These receivables represent amounts billed by the Company for general and administrative functions, such as accounting, human resources, legal, and technical support, performed by Gulfport s personnel on behalf of the affiliates. These services are solely administrative in nature and for entities in which the Company has no property interests. The amounts reimbursed to the Company for these services are for the purpose of Gulfport recovering costs associated with the services and do not include the assessment of any fees or other amounts beyond the estimated costs of performing such services. At September 30, 2008 and December 31, 2007, these receivable amounts totaled $455,000 and $2,208,000, respectively. The Company was reimbursed $74,000 and $1,176,000 for the three months and nine months ended September 30, 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. For the three months and nine months ended September 30, 2007, the Company was reimbursed $3,047,000 and $9,685,000, respectively.

The Company is a party to administrative service agreements with Caliber Development Company, LLC, Great White Energy Services LLC and Diamondback Energy Services LLC. Under the 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 administrative service agreement has a three-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 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 a party to administrative service agreements with Stampede Farms LLC, Grizzly Oil Sands ULC, Everest Operations Management LLC and Tatex Thailand III, LLC. Under the 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

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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.

The Company was reimbursed the amounts specified in the table below in consideration for the services under agreements referenced above for the three months and nine months ended September 30, 2008 and 2007. These amounts are reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

Agreement Effective Date	Entity	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
2/9/2005	Caliber Development Company, LLC	$	$ 343,000	$ 60,000	$ 735,000
7/22/2006	Great White Energy Services LLC	15,000	19,000	68,000	729,000
9/26/2006	Diamondback Energy Services LLC		5,000	10,000	5,000
3/1/2008	Stampede Farms LLC			159,000	
3/1/2008	Grizzly Oil Sands ULC	28,000	243,000	353,000	542,000
3/1/2008	Everest Operations Management LLC				
3/1/2008	Tatex Thailand III, LLC				

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. Under the agreement, Gulfport and Everest each formed an acquisition team staffed by their respective employees who will devote all or a specified portion of their time to acquisition team activities. Each party will bill the other party on a quarterly basis for 50% of any budgeted expenses incurred during the quarter. Upon a successful closing of an acquisition, each participating party shall pay a fee to the acquiring party equal to 1% of its proportionate share of the acquisition consideration. The agreement has a one year term unless earlier terminated by either party upon 30 days notice. The Company has accrued $134,000 of acquisition team costs payable to Everest for the three months ended September 30, 2008, which is included in accounts payable and accrued liabilities in the accompanying consolidated balance sheet. The Company has accrued $110,000 of acquisition team costs receivable from Everest for the three months ended September 30, 2008, which is included in accounts receivable related parties in the accompanying consolidated balance sheet.

3. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation and amortization as of September 30, 2008 and December 31, 2007 are as follows:

	September 30, 2008	December 31, 2007
Oil and gas properties	$ 574,120,000	$ 484,487,000
Office furniture and fixtures	2,979,000	2,922,000
Building	3,926,000	3,926,000
Land	260,000	260,000
Total property and equipment	581,285,000	491,595,000
Accumulated depletion, depreciation, amortization and impairment reserve	(158,408,000)	(129,496,000)
Property and equipment, net	$ 422,877,000	$ 362,099,000

Included in oil and gas properties at September 30, 2008 is the cumulative capitalization of $9,481,000 in general and administrative costs incurred and capitalized to the full cost pool. General and administrative costs capitalized to the full cost pool represent management s estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All general and administrative costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized general and administrative costs were approximately

$1,165,000 and $3,512,000 for the three months and nine months ended September 30, 2008, respectively, and $410,000 and $1,203,000 for the three months and nine months ended September 30, 2007, respectively.

At September 30, 2008, approximately $2,476,000 of oil and gas properties related to the Company s Belize properties was excluded from amortization as they relate to non-producing properties. In addition, approximately $31,288,000 of non-producing leasehold costs resulting from the Company s acquisition of West Texas Permian properties was excluded from amortization at September 30, 2008. Approximately $5,741,000 of non-producing leasehold costs related to the Company s Southern Louisiana, West Texas, and Williston Basin assets was also excluded from amortization at September 30, 2008.

A reconciliation of the asset retirement obligation for the nine months ended September 30, 2008 and 2007 is as follows:

	September 30, 2008	September 30, 2007
Asset retirement obligation, beginning of period	$ 8,634,000	$ 8,858,000
Liabilities incurred	528,000	292,000
Liabilities settled	(324,000)	(872,000)
Accretion expense	417,000	415,000
Asset retirement obligation as of end of period	9,255,000	8,693,000
Less current portion	480,000	480,000
Asset retirement obligation, long-term	$ 8,775,000	$ 8,213,000

4. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of September 30, 2008 and December 31, 2007.

	September 30, 2008	December 31, 2007
Investment in Tatex Thailand II, LLC	$ 3,115,000	$ 3,553,000
Investment in Tatex Thailand III, LLC	877,000	
Investment in Windsor Bakken, LLC		2,468,000
Investment in Grizzly Oil Sands ULC	25,413,000	27,801,000
	$ 29,405,000	$ 33,822,000

Tatex Thailand II, LLC

During 2005, the Company purchased a 23.5% ownership interest in Tatex Thailand II, LLC (Tatex) at a cost of $2,400,000. The remaining interests in Tatex are owned by entities controlled by Wexford Capital LLC (Wexford), an affiliate of Gulfport. Tatex, a non-public entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC (APICO), an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering three million acres which includes the Phu Horm Field. During the nine months ended September 30, 2008, Gulfport received $482,000 in distributions and paid $50,000 in cash calls, bringing its total investment in Tatex (including previous investments) to $3,115,000. The Company recognized a loss on equity investment of $6,000 for the nine months ended September 30, 2008 which is included in other income (expense) in the consolidated statements of operations. The loss on equity investment related to Tatex was immaterial for the nine months ended September 30, 2007.

Tatex Thailand III, LLC

During the first quarter of 2008, the Company purchased a 5% ownership interest in Tatex Thailand III, LLC (Tatex III) at a cost of $850,000. Approximately 68.7% of the remaining interests in Tatex III are owned by entities controlled by Wexford, an affiliate of Gulfport. During the nine months ended September 30, 2008, Gulfport paid $35,000 in cash calls, bringing its total investment in Tatex III to $877,000. The Company recognized a loss on equity investment of $8,000 for the three months and nine months ended September 30, 2008 which is included in other income (expense) in the consolidated statements of operations.

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Windsor Bakken, LLC

During 2005, the Company purchased a 20% ownership interest in Windsor Bakken, LLC (Bakken). The remaining interests in Bakken are owned by entities controlled by Wexford, an affiliate of Gulfport. In 2005 and 2006, Bakken acquired leases on undeveloped acreage in the Williston Basin areas of western North Dakota and eastern Montana. Effective January 1, 2008, the Company acquired a direct, undivided 20% interest in Bakken s assets in redemption of its 20% interest in Bakken. As a result, the Company recognized $2,468,000 of oil and natural gas assets which is included in oil and natural gas properties on the accompanying consolidated balance sheets.

Grizzly Oil Sands ULC

During the third quarter of 2006, the Company, through its wholly owned subsidiary Grizzly Holdings Inc., purchased a 24.9999% interest in Grizzly Oils Sands ULC (Grizzly), a Canadian unlimited liability company, for approximately $8.2 million. The remaining interests in Grizzly are owned by entities controlled by Wexford, an affiliate of Gulfport. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray near other oil sands development projects. Grizzly has drilled core holes to evaluate the feasibility of oil production in five separate lease blocks but has not commenced development of operations. As of September 30, 2008, Gulfport s net investment in Grizzly was $25,413,000. Grizzly s functional currency is the Canadian dollar. The Company s investment in Grizzly was decreased by $1,031,000 and $1,862,000 as a result of a currency translation loss for the three months and nine months ended September 30, 2008, respectively. The Company recognized a loss on equity investment of $217,000 and $526,000 for the three months and nine months ended September 30, 2008, respectively, and $47,000 and $83,000 for the three months and nine months ended September 30, 2007, 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 the agreement, Grizzly may borrow funds from the Company. Borrowed funds bear interest at LIBOR plus 400 basis points. Interest is paid on a paid-in-kind basis by increasing the outstanding balance of the loan. The loan matures on December 31, 2012. The Company loaned Grizzly approximately $9,708,000 during the nine months ended September 30, 2008. The Company recognized interest income of approximately $156,000 and $290,000 for the three months and nine months ended September 30, 2008, respectively, which is included in interest income in the consolidated statements of operations. The note balance was decreased by approximately $357,000 and $487,000 as a result of a currency translation loss for the three months and nine months ended September 30, 2008, respectively. The total $9,511,000 due from Grizzly is included in note receivable related party on the accompanying consolidated balance sheets.

5. OTHER ASSETS

Other assets consist of the following as of September 30, 2008 and December 31, 2007:

	September 30, 2008	December 31, 2007
Plugging and abandonment escrow account on the WCBB properties (Note 13)	$ 3,140,000	$ 3,104,000
Certificates of Deposit securing letter of credit	200,000	200,000
Prepaid drilling costs	427,000	
Deposits	3,084,000	3,084,000
	$ 6,851,000	$ 6,388,000

The Company is required to prepay certain drilling costs. Approximately $38,000 of the total $427,000 of prepaid drilling costs were paid to Windsor Energy Group LLC, an entity controlled by Wexford, an affiliate of Gulfport, as operator of certain wells in the Bakken and Permian areas.

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6. LONG-TERM DEBT

A breakdown of long-term debt as of September 30, 2008 and December 31, 2007 is as follows:

	September 30, 2008	December 31, 2007
Reducing credit agreement (1)	$ 89,521,000	$ 59,521,000
Term loan (1)	3,764,000	4,294,000
Building loans (2)	2,648,000	2,718,000
Less: current maturities of long term debt	(813,000)	(808,000)
Debt reflected as long term	$ 95,120,000	$ 65,725,000

Maturities of long-term debt as of September 30, 2008 are as follows:

2009	$ 813,000
2010	90,341,000
2011	3,157,000
2012	714,000
2013	714,000
Thereafter	194,000
Total	$ 95,933,000

(1) On March 11, 2005, Gulfport entered into a three-year secured reducing credit agreement providing for a $30.0 million revolving credit facility with Bank of America, N.A. Borrowings under the revolving credit facility are subject to a borrowing base limitation, which was initially set at $18.0 million, subject to adjustment. On November 1, 2005, the amount available under the borrowing base limitation was increased to $23.0 million and was redetermined without change on May 30, 2006. On December 19, 2006, the amount available under the borrowing base limitation was increased to $30.0 million. Effective July 19, 2007, the credit facility was increased to $150.0 million and the amount available under the borrowing base limitation was increased to $60.0 million. On December 20, 2007, the amount available under the borrowing base limitation was increased to $90.0 million and the Eurodollar interest rate, which the Company elected to use on March 28, 2008, was reduced by 0.75%. In addition, the maturity date was extended from March 31, 2009 to March 31, 2010. The Company makes quarterly interest payments on amounts borrowed under the facility. Amounts borrowed under the credit facility bear interest at the Eurodollar rate plus 2.00% (5.72% at September 30, 2008). The Company s obligations under the credit facility are collateralized by a lien on substantially all of the Company s Louisiana and West Texas assets. The credit facility contains certain affirmative and negative covenants, including, but not limited to, the following financial covenants: (a) the ratio of funded debt to EBITDAX (net income before deductions for taxes, excluding unrealized gains and losses related to trading securities and commodity hedges, plus depreciation, depletion, amortization and interest expense, plus exploration costs deducted in determining net income under full cost accounting) for a twelve month period may not be greater than 2.00 to 1.00; and (b) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. The Company was in compliance with all covenants at September 30, 2008. As of September 30, 2008, approximately $89.5 million was outstanding under this facility, which is included in long-term debt, net of current maturities on the accompanying consolidated balance sheet.

On July 10, 2006, Gulfport entered into a $5.0 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. The Company makes quarterly principal payments of approximately $176,000. Amounts borrowed bear interest at Bank of America prime (5.00% at September 30, 2008). The Company makes quarterly interest payments on amounts borrowed under the agreement. The Company s obligations under the agreement are collateralized by a lien on the compressor units. As of September 30, 2008, approximately $3.8 million was outstanding under this agreement.

(2) In June 2004, the Company purchased the office building it occupies in Oklahoma City, Oklahoma, for $3.7 million. One loan associated with this building matured in March 2006 and bore interest at the rate of 6% per annum, while

the other loan matures in June 2011 and bears interest at the rate of 6.5% per annum. In addition, the building loans included a loan related to a building in Lafayette, Louisiana, purchased in 1996 to be used as the Company s Louisiana headquarters. This loan bore interest at the rate of 5.75% per annum. The Company paid this loan in full during the third quarter of 2007, in advance of its February 2008 maturity date. The remaining building loan requires monthly interest and principal payments of approximately $23,000 and is collateralized by the Oklahoma City office building and associated land.

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

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 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. All shares of restricted common stock of the Company were granted under the Amended and Restated 2005 Stock Incentive Plan (the 2005 Plan).

8. STOCK-BASED COMPENSATION

During the three months and nine months ended September 30, 2008, the Company s stock-based compensation expense was $266,000 and $816,000, respectively, of which the Company capitalized $106,000 and $326,000, respectively, relating to its exploration and development efforts. During the three months and nine months ended September 30, 2007, the Company s stock-based compensation expense was $294,000 and $875,000, respectively, of which the Company capitalized $79,000 and $236,000, respectively, relating to its exploration and development efforts. Stock based compensation expense included in general and administrative expense reduced basic and diluted earnings per share by $0.00 and $0.01 each for the three months and nine months ended September 30, 2008, respectively, and by $0.01 and $0.02 each for the three months and nine months ended September 30, 2007, respectively. Options and restricted common stock are reported as share based payments and their fair value is amortized to expense using the straight-line method over the vesting period. The shares of stock issued once the options are exercised will be from authorized but unissued common stock.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option valuation model that uses certain assumptions. 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 nine months ended September 30, 2008 and 2007.

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 nine months ended September 30, 2008 is presented below:

	Shares	Average Exercise Price per Share	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		

Forfeited/expired	(7,889)		6.17		
Options outstanding at September 30, 2008	522,380	$	7.01	6.49	$ 1,576,000
Options exercisable at September 30, 2008	303,028	$	9.37	6.58	$ 207,000

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Unrecognized compensation expense as of September 30, 2008 related to outstanding stock options and restricted shares was $832,000. The expense is expected to be recognized over a weighted average period of 1.44 years.

The following table summarizes information about the stock options outstanding at September 30, 2008:

Exercise Price	Number Outstanding	Weighted Average Remaining Life (in years)	Number Exercisable
$ 2.00	23,250	1.10	23,250
$ 3.36	234,241	6.31	26,000
$ 9.07	64,889	6.94	64,889
$11.20	200,000	7.17	188,889
	522,380		303,028

The following table summarizes restricted stock activity for the nine months ended September 30, 2008:

	Number of Unvested Restricted Shares	Weighted Average Grant Date Fair Value
Unvested shares as of December 31, 2007	59,033	$ 13.94
Granted	18,666	11.38
Vested	(27,015)	13.28
Forfeited	(8,167)	16.43
Unvested shares as of September 30, 2008	42,517	$ 12.75

9. EARNINGS PER SHARE

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

	For the three months ended September 30, 2008			2007		
	Income	Shares	Per Share	Income	Shares	Per Share
Basic:						
Net income	$ 14,107,000	42,620,332	$ 0.33	$ 12,701,000	37,671,681	$ 0.34
Effect of dilutive securities:						
Stock options and awards		441,499			678,533	
Diluted:						
Net income	$ 14,107,000	43,061,831	$ 0.33	$ 12,701,000	38,350,214	$ 0.33

	For the nine months ended September 30, 2008			2007		
	Income	Shares	Per Share	Income	Shares	Per Share
Basic:						
Net income	$ 40,499,000	42,589,277	$ 0.95	$ 29,558,000	36,048,327	$ 0.82
Effect of dilutive securities:						
Stock options and awards		472,106			673,416	
Diluted:						
Net income	$ 40,499,000	43,061,383	$ 0.94	$ 29,558,000	36,721,743	$ 0.80

There were no potential shares of common stock that were considered anti-dilutive during the three month and nine month periods ended September 30, 2008 and 2007.

10. OTHER COMPREHENSIVE INCOME

Other comprehensive income for the three months and nine months ended September 30, 2008 and 2007 is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Net income	$ 14,107,000	$ 12,701,000	$ 40,499,000	$ 29,558,000
Other comprehensive income (loss):				
Foreign currency translation adjustment	(1,388,000)	3,020,000	(2,349,000)	2,094,000
Total comprehensive income	$ 12,719,000	$ 15,721,000	$ 38,150,000	$ 31,652,000

11. NEW ACCOUNTING STANDARDS

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

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115.* SFAS No. 159 permits companies to choose to measure certain financial instruments and other items at fair value. The objective is to improve financial reporting by providing companies with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Unrealized gains and losses on any items for which the Company elects the fair value measurement option would be reported in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. The Company adopted SFAS No. 159 effective January 1, 2008. The adoption did not have a material impact on the Company s consolidated financial statements.

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

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

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

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*. SFAS No. 162 identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America (the GAAP hierarchy). This statement is effective November 15, 2008 (60 days following the SEC s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, *The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles)*. The Company is currently assessing the impact, if any, of the adoption of SFAS No. 162.

12. 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 $81,000 as of September 30, 2008. The lease commenced on October 15, 2006 and expires October 14, 2009, with equal monthly installments of $10,500. The future minimum lease payments to be received are as follows:

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

13. COMMITMENTS AND CONTINGENCIES

Plugging and Abandonment Funds

In connection with its 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 September 30, 2008, the plugging and abandonment trust totaled approximately $3,140,000, including interest received during 2008 of approximately $40,000. The Company has plugged 253 wells at WCBB since it began its plugging program in 1997, which management believes fulfills its current minimum plugging obligation.

The Louisiana State Mineral Board (LSMB) disputed Gulfport s royalty payments to the State of Louisiana resulting from the sale of oil under fixed price contracts. The LSMB maintained that Gulfport paid approximately $1,400,000 less in royalties under the fixed price contracts than the royalties Gulfport would have had to pay had it sold the oil at prevailing market rates. Gulfport denied any liability to the LSMB for underpayment of royalties and maintained that it was entitled to enter into the fixed price contracts with unrelated third parties and pay royalties based upon the sales proceeds from those contracts. Gulfport met with the Louisiana Attorney General on several occasions and reached a mutual settlement. In accordance with the settlement, Gulfport paid $250,000 during the second quarter of 2008, all of which was previously accrued in accounts payable and accrued liabilities in the accompanying consolidated balance sheets. Under the settlement, all future royalties will be paid at market price, regardless of the presence of fixed price contracts. The settlement was approved by the LSMB during its February 2008 session and executed on April 1, 2008, effectively closing the matter.

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 through 2007. The LDR maintains that Gulfport paid approximately $1,799,000 less in severance taxes under the fixed price contracts than the severance taxes

Gulfport would have had to pay had it sold the oil at prevailing market rates. 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 sales proceeds from those contracts. Gulfport is currently awaiting response from the LDR.

Other Litigation

In November 2006, Cudd Pressure Control, Inc. (Cudd) filed a lawsuit against Gulfport and Great White Pressure Control LLC, an affiliate of the Company, among others, in the 129th Judicial District Harris County, Texas. The lawsuit was subsequently removed to the United States District Court for the Southern District of Texas (Houston Division). The lawsuit alleges RICO violations and several other causes of action relating to an affiliate company s employment of several former Cudd employees. The defendants in the suit are Ronnie Roles, Rocky Roles, Steve Winters, Bert Ballard, Nelson Britton, Michael Fields, Steve Bickle, Great White Pressure Control LLC and Gulfport. On stipulation by the parties, the plaintiff s RICO claim was dismissed without prejudice by order of the court on February 14, 2007. Co-defendant Steve Bickle was dismissed from the case on July 18, 2007. The Company 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. The judgment also allowed Gulfport to apply for attorney s fees. The Court entered a final judgment on June 5, 2008, in favor of all defendants, including Gulfport. On June 6, 2008, Cudd filed a notice of appeal to the U.S. Court of Appeals.

On July 27, 2007, Robotti & Company, LLC filed a putative class action lawsuit in the Court of Chancery for the State of Delaware in and for Kent County, Delaware. The lawsuit seeks damages for an alleged breach of fiduciary duty by Gulfport and its directors in connection with the pricing of the 2004 rights offering. The Company received service of this matter on August 10, 2007. By mutual agreement of the parties, Gulfport was not required to respond until notified by the plaintiff, which was received on January 16, 2008. Plaintiff filed an amended complaint on January 15, 2008, and Gulfport filed a motion to dismiss in early February 2008 and filed the brief in support of said motion on April 29, 2008. The court held a hearing on October 3, 2008 regarding Gulfport s motion to dismiss and motion to stay, ultimately deciding to allow the plaintiff to file a second amended complaint.

In July 2007, Michael Tripkovich filed suit in the 16th Judicial District Court of the Parish of St. Martin, Louisiana, against 113 entities, including Gulfport, alleging his contraction of chronic myeloid leukemia (CML) was caused by exposure to various substances while maintaining natural gas compressors over a nineteen year period. Gulfport was served on July 23, 2007 and filed a response denying the plaintiff s claims. The suit is currently in discovery. Gulfport has no record that Mr. Tripkovich was ever employed by the Company. No other deadlines have been set at this time.

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

On October 13, 2006, Athena Construction LLC (Athena) filed a limitation action in the United States District Court for the Eastern District of Louisiana, alleging that all losses and damages as a result of the pipeline incident were incurred without fault on its part. Furthermore, Athena claims the benefit of the limitation of liability provided for in 42 U.S.C. § 183 and seeks an injunction restraining filing commencement and further prosecution in any court of any lawsuit against Athena related to the pipeline incident. The limitation of liability action was subsequently transferred to the United States District Court for the Western District of Louisiana, which is where the case remains pending. On December 20, 2006, 4-K Marine LLC, as owner of the M/V Miss Megan, and Central Boat Rentals, Inc., as operator of the M/V Miss Megan also filed a limitation action in the Western District. On January 10, 2007, the Athena and the 4-K/Central Boat limitation proceedings were consolidated by order of the court. On May 5, 2007, Diamondback Energy Services LLC (Diamondback), an affiliate of Gulfport, filed an intervener with the Court to become a party to the suit. The remaining parties filed claims on July 9, 2007, which included claims by Nicholas Aucoin, one of the initial responders to the scene of the accident. On May 2, 2008, Gulfport reached a settlement with Athena and Diamondback. The settlement provided reimbursement to Gulfport for pipeline repair costs incurred as a result of the October 2006 accident.

On October 15, 2007, Brian Dumesnil filed suit in the 16th Judicial District Court for the Parish of St. Mary, Louisiana, against Gulfport, Chevron USA, Chevron Texaco Pipeline Holdings, Chevron Natural Gas, Diamondback and the Estate of Timothy Tauzin. Mr. Dumesnil was employed by Athena and was on the Athena barge at the time of the accident. He is seeking unspecified sums as a result of the alleged negligence of defendants and injuries incurred following the October 12, 2006 accident. This case settled on

September 11, 2008.

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Due to the early stages of certain of the above 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.

Forward Sales Contracts

The Company was a 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 period of September 2008 through December 2008, the Company has 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 has 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 require physical delivery of production quantities and are exempted from the provisions of SFAS 133 as normal sales of production.

14. INSURANCE PROCEEDS

In May 2008, the Company received insurance proceeds of approximately $769,000 related to damages incurred resulting from the 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.

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ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with the Management s Discussion and Analysis of Financial Condition and Results of Operations section and audited consolidated financial statements and related notes thereto included in our Annual Report on Form 10-K and with the unaudited consolidated financial statements and related notes thereto presented in this Quarterly Report on Form 10-Q.

Disclosure Regarding Forward-Looking Statements

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. All statements other than statements of historical facts included in this report 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 statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate in the circumstances. However, whether actual results and developments will conform with our expectations and predictions is subject to a number of risks and uncertainties, general economic, market or business conditions, the opportunities (or lack thereof) that may be presented to and pursued by us, competitive actions by other oil and natural gas companies, changes in laws or regulations, hurricanes and other natural disasters and other factors, including those listed in the Risk Factors section of our most recent Annual Report on Form 10-K, many of which are beyond our control. Consequently, all of the forward-looking statements made in this report are qualified by these cautionary statements, and we cannot assure you that the actual results or developments anticipated by us will be realized or, even if realized, that they will have the expected consequences to or effects on us, our business or operations. We have no intention, and disclaim any obligation, to update or revise any forward-looking statements, whether as a result of new information, future results or otherwise.

Overview

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

Third quarter 2008 Highlights and Other 2008 Developments

Revenues. Oil and natural gas revenues increased 23%, or $6,935,000, to $36,907,000 for the three months ended September 30, 2008 from $29,972,000 for the three months ended September 30, 2007.

Net Income. Net income increased 11% to $14,107,000 for the three months ended September 30, 2008 from $12,701,000 for the three months ended September 30, 2007.

Production. Production decreased 9% to 400,000 barrels of oil equivalent, or BOE, for the three months ended September 30, 2008 from 440,000 BOE for the three months ended September 30, 2007 due primarily to the impact of Hurricanes Gustav and Ike.

Tatex Entities. During 2005, we purchased a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex. The remaining interests in Tatex are owned by entities controlled by Wexford Capital, LLC, or Wexford, an affiliate of ours. Tatex, a privately held entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC, or APICO, an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering three million acres which includes the Phu Horm Field. During 2008, we purchased a 5% ownership interest in Tatex Thailand III, LLC, or Tatex III, at a cost of $850,000. Approximately 68.7% of the remaining interests in Tatex III are owned by entities and individuals affiliated with Wexford.

Windsor Bakken, LLC. During 2005, we purchased a 20% ownership interest in Windsor Bakken, LLC, or Bakken. The remaining interests in Bakken are owned by entities controlled by Wexford. In 2006, Bakken acquired leases on undeveloped acreage in the Williston Basin areas of western North Dakota and eastern

Montana, which we refer to as the contract area. Effective January 1, 2008, we acquired a direct, undivided 20% interest in Bakken s assets in redemption of our 20% interest in Bakken. In addition, effective January 1, 2008, we entered into an area of mutual interest agreement with Bakken and Windsor Dakota LLC, or Windsor Dakota, to jointly acquire oil and gas leases on certain lands located in North Dakota and Montana for the purpose of exploring, exploiting and producing oil and gas from the Bakken Shale. In connection with this agreement, we, Bakken, Windsor Dakota and Windsor Energy Group, L.L.C., as the operator, also entered into an exploration agreement, effective as of January 1, 2008, pursuant to which we, Bakken and Windsor Dakota agreed to jointly evaluate, explore, exploit and develop the contract area, and Windsor Energy Group, L.L.C. agreed to act as the operator under the terms of a joint operating agreement, effective as of March 4, 2008. Windsor Energy Group, LLC and Windsor Dakota LLC are entities controlled by Wexford.

Reserves. As of December 31, 2007, we had 29.2 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 $821 million and associated standardized measure of discounted future net cash flows of approximately $668.3 million. Our total, proved reserve quantities were 86% oil at December 31, 2007.

2008 Production and Drilling Activity

During the three months ended September 30, 2008, our total net production was 361,000 barrels of oil, 135,000 thousand cubic feet of gas, or Mcf, and 695,000 gallons of liquids, for a total 400,000 BOE, compared to 404,000 barrels of oil, 218,000 Mcf of gas and no liquids, for a total 440,000 BOE, for the three months ended September 30, 2007. Our total net production averaged approximately 4,352 BOE per day during the three months ended September 30, 2008 compared to 4,787 BOE per day during the same period in 2007. This nine percent decrease is primarily due to the impact of Hurricanes Gustav and Ike.

WCBB. As of October 31, 2008, we had drilled eight wells, seven of which were producing and one was non-productive. We had also recompleted 43 wells. We do not intend to drill any more wells during 2008. We intend to recomplete approximately 50 existing wells during 2008.

Aggregate net production from the WCBB field during the three months ended September 30, 2008 was 270,000 BOE, or 2,935 BOE per day, approximately 96% of which was from oil and 4% of which was from natural gas. During October 2008, our average daily net production at WCBB was approximately 3,333 BOE, 99% of which was from oil and 1% of which was from natural gas. The increase in October production is primarily due to production being restored after Hurricanes Gustav and Ike.

East Hackberry Field. As of October 31, 2008 at East Hackberry, we had drilled five wells, all five of which were producing. We had also recompleted five existing wells as of that date. We do not intend to drill any more wells during 2008.

Aggregate net production from the East Hackberry field during the three months ended September 30, 2008 was approximately 44,000 BOE, or 481 BOE per day, 95% of which was from oil and 5% of which was from natural gas. During October 2008, our average daily net production at East Hackberry was approximately 844 BOE, 94% of which was from oil and 6% of which was from natural gas. The increase in October production is primarily due to production being restored after Hurricanes Gustav and Ike.

West Hackberry Field. Aggregate net production from the West Hackberry field during the three months ended September 30, 2008 was approximately 3,000 BOE, or 34 BOE per day. For the three days of production beginning on October 29, 2008 our average daily net production at West Hackberry was approximately 36 BOE. Production was not restored to the field after Hurricanes Gustav and Ike until October 29, 2008.

West Texas. On December 20, 2007, we completed the acquisition of strategic assets in West Texas in the Permian Basin for approximately $85 million, with an effective date of November 1, 2007. The final post-closing adjustments occurred on March 20, 2008, which was 90 days after the original closing date of December 20, 2007, and the purchase price was adjusted accordingly. The total adjusted purchase price for the assets was $83.8 million. Through this transaction, we acquired 4,100 net acres with production at the time of acquisition from 32 gross wells, predominately from the Wolfcamp formation. At December 31, 2007, Pinnacle Energy Services LLC, an independent petroleum engineering firm, estimated that proved reserves net to our interest in these assets were approximately 6.6 million BOE, of which 19.5% were classified as proved developed producing, or PDP. Proved undeveloped, or PUD, reserves included in this estimate were from 92 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. We expect that approximately 31 gross wells, including one well spud in 2007 and completed in 2008 and one Henry Petroleum operated well, will be drilled in 2008. The wells are expected to be drilled to approximately 10,400 feet at an estimated

average gross completed well cost of $2.0 million. As of October 31, 2008 at Permian, 30 gross wells have been drilled, including one well spud in 2007 and completed in 2008 and one Henry Petroleum operated well. Twenty seven of those wells have been completed, and three wells are awaiting completion. In addition, one well is currently being drilled in the field.

Aggregate net production from the Permian field during the three months ended September 30, 2008 was approximately 64,000 BOE, or 692 BOE per day. During October 2008, average daily net production at Permian was approximately 781 BOE, of which approximately 59% was oil, 25% was natural gas liquids and 16% was natural gas.

Bakken. As of October 31, 2008, we had participated, or committed to participate, in approximately 50 gross wells, which include 29 wells in Mountrail County, with an average working interest of 2.8%. Windsor Energy, the operator of our acreage, drilled and completed the first and second Windsor Energy operated wells. We own an approximately 15.5% working interest in the first well and approximately 3.9% working interest in the second well. Windsor Energy is now drilling its third operated well with the same rig. In addition, a second rig has been contracted and will commence drilling during November 2008. We currently hold approximately 17,660 net acres, which include approximately 4,660 acres in Mountrail County, in the Bakken play.

Aggregate net production from the Bakken play during the three months ended September 30, 2008 was approximately 19,000 BOE, or 202 BOE per day. For October 2008, average daily net production in Bakken was approximately 278 BOE.

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 associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. Net capitalized costs are limited to the estimated future net revenues, after income taxes, discounted at 10% per year, from proven oil and natural gas reserves and the cost of the properties not subject to amortization. Such capitalized costs, including the estimated future development costs and site remediation costs, if any, are depleted by an equivalent units-of-production method, converting gas to barrels at the ratio of six Mcf of gas to one barrel of oil. No gain or loss is recognized upon the disposal of oil and natural gas properties unless such dispositions significantly alter the relationship between capitalized costs and proven oil and natural gas reserves. Oil and natural gas properties not subject to amortization consist of the cost of undeveloped leaseholds and totaled $39,505,000 at September 30, 2008 and $37,278,000 at December 31, 2007. These costs are reviewed periodically by management for impairment, with the impairment provision included in the cost of oil and natural gas properties subject to amortization. Factors considered by management in its impairment assessment include our drilling results and those of other operators, the terms of oil and natural gas leases not held by production and available funds for exploration and development.

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

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

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

The fair value of the liability associated with these retirement obligations is determined using significant assumptions, including current estimates of the plugging and abandonment or retirement, annual inflations of these costs, the productive life of the asset and our risk adjusted cost to settle such obligations discounted using our credit adjusted 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. and Pinnacle Energy Services, LLC have prepared reserve reports on approximately 79% of our reserve estimates on a well-by-well basis for our properties. Our personnel have prepared reserve reports on 21% of our reserve estimates.

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 the Securities and Exchange Commission, or SEC, guidelines. The accuracy of our reserve estimates is a function of many factors including the following:

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

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

Income Taxes. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized in the year in which realization becomes determinable. Periodically, management performs a forecast of its taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established, if in management s opinion, it is more likely than not that some portion will not be realized. At December 31, 2007, a valuation allowance of $9,750,000 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.

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

The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. Designation is established at the inception of a derivative, but re-designation is permitted. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of SFAS 133, changes in fair value are recognized in accumulated other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. We recognize any change in fair value resulting from ineffectiveness immediately in earnings.

To mitigate the effects of commodity price fluctuations, we were 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, we 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, we 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, we 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 period of September 2008 through December 2008, we have entered into forward sales contracts for the sale of 3,500 barrels of production per day during such period at a weighted average daily price of $86.60 per barrel before transportation costs. Under these agreements, we have committed to deliver approximately 75% of our estimated production for January through December 2008. For the period of January 2009 through December 2009, we 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. 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 above the contracted prices. These contracts require physical delivery of production quantities and are exempted from the provisions of SFAS 133 as normal sales of production.

RESULTS OF OPERATIONS

Comparison of the Three Months Ended September 30, 2008 and 2007

We reported net income of $14,107,000 for the three months ended September 30, 2008, as compared to $12,701,000 for the three months ended September 30, 2007. This 11% increase in net income was due primarily to a 35% increase in realized BOE prices to $92.19 from $68.05 offset by a 9% decrease in net production to 400,000 BOE for the quarter ended September 30, 2008 from 440,000 BOE for the quarter ended September 30, 2007. This 9% decrease in net production is due to the impact of Hurricanes Gustav and Ike.

Oil and Gas Revenues. For the three months ended September 30, 2008, we reported oil, natural gas and liquid revenues of $36,907,000 as compared to oil and natural gas revenues of $29,972,000 during the same period in 2007. This $6,935,000, or 23%, increase in revenues is primarily attributable to a 35% increase in realized BOE prices to $92.19 from $68.05 offset by a 9% decrease in net production to 400,000 BOE for the quarter ended September 30, 2008 from 440,000 BOE for the quarter ended September 30, 2007.

The following table summarizes our oil and natural gas production and related pricing for the three months ended September 30, 2008, as compared to the three months ended September 30, 2007:

	Three Months Ended September 30,	
	2008	**2007**
Oil production volumes (MBbls)	361	404
Gas production volumes (MMcf)	135	218
Liquid production volumes (Gallons)	695	
Oil Equivalents (Mboe)	400	440

	Three Months Ended September 30, 2008	2007
Average oil price (per Bbl)	$ 95.08	$ 70.46
Average gas price (per Mcf)	$ 9.91	$ 6.88
Average liquids price (per gallon)	$ 1.75	$
Oil Equivalents (per Mboe)	$ 92.19	$ 68.05

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to $6,362,000 for the three months ended September 30, 2008 from $4,008,000 for the same period in 2007. This increase is a result of the LOE related to the Permian property acquisition in December 2007, hurricane related repairs of approximately $700,000, a $500,000 increase in Louisiana property taxes, increases in workovers on existing wells, repairs to compressors and other equipment and an increase in chemicals and salt water disposals costs.

Production Taxes. Production taxes increased to $3,970,000 for the three months ended September 30, 2008 from $3,547,000 for the same period in 2007. This increase was directly related to a 23% increase in oil and gas revenues as a result of the 35% increase in the average realized BOE price received offset by a 9% decrease in production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased to $9,392,000 for the three months ended September 30, 2008, and consisted of $9,322,000 in depletion on oil and natural gas properties and $70,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $7,845,000 for the three months ended September 30, 2007. This increase was due primarily to an increase in our oil and natural gas property costs associated with our 2008 drilling and recompletion programs.

General and Administrative Expenses. Net general and administrative expenses increased to $1,748,000 for the three months ended September 30, 2008 from $1,192,000 for the same period in 2007. This increase was due primarily to an increase in payroll costs and related benefits, increases in franchise taxes and accounting services from the implementation and ongoing services needed for compliance with Section 404 of the Sarbanes-Oxley Act of 2002 and a decrease in general and administrative reimbursements from our affiliates. These increases were 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 remained relatively unchanged at $140,000 for the three months ended September 30, 2008 as compared to $138,000 for the same period in 2007.

Interest Expense. Interest expense increased to $1,172,000 for the three months ended September 30, 2008 from $654,000 for the same period in 2007 due primarily to an increase in average debt outstanding. Total debt outstanding under our facilities with Bank of America was $93.3 million as of September 30, 2008 and $34.5 million as of the same date in 2007. Total weighted average debt outstanding under our facilities with Bank of America was $90.8 million for the three months ended September 30, 2008 and $27.0 million as of the same date in 2007.

Income Taxes. As of September 30, 2008, we had a net operating loss carry forward of approximately $93.0 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 September 30, 2008, a valuation allowance of $9.8 million had been provided for deferred tax assets. We had $20,000 of income tax expense for the three months ended September 30, 2008.

Comparison of the Nine Months Ended September 30, 2008 and 2007

We reported net income of $40,499,000 for the nine months ended September 30, 2008, as compared to $29,558,000 for the nine months ended September 30, 2007. This 37% increase in net income was due primarily to a 31% increase in realized BOE prices to $82.05 from $62.58 and a 5% increase in net production to 1,268,000 BOE for the nine months ended September 30, 2008 from 1,204,000 BOE for the same period in 2007.

Oil and Gas Revenues. For the nine months ended September 30, 2008, we reported oil, natural gas and liquid revenues of $104,032,000 as compared to oil and natural gas revenues of $75,353,000 during the same period in 2007. This $28,679,000, or 38%, increase in revenues is primarily attributable to a 31% increase in realized BOE prices to $82.05 from $62.58 and a 5% increase in net production to 1,268,000 BOE for the nine months ended September 30, 2008 from 1,204,000 BOE for the same period in 2007.

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The following table summarizes our oil and natural gas production and related pricing for the nine months ended September 30, 2008, as compared to the nine months ended September 30, 2007:

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Oil production volumes (MBbls)	1,132	1,116
Gas production volumes (MMcf)	559	531
Liquid production volumes (Gallons)	1,805	
Oil Equivalents (Mboe)	1,268	1,204
Average oil price (per Bbl)	$ 84.50	$ 63.97
Average gas price (per Mcf)	$ 10.04	$ 7.51
Average liquids price (per gallon)	$ 1.54	$
Oil Equivalents (per Mboe)	$ 82.05	$ 62.58

Lease Operating Expenses. Lease operating expenses not including production taxes increased to $14,906,000 for the nine months ended September 30, 2008 from $11,127,000 for the same period in 2007. This increase is a result of the LOE related to the Permian property acquisition in December 2007, hurricane related repairs of approximately $700,000, a $800,000 increase in Louisiana property taxes, increases in workovers on existing wells, repairs to compressors and other equipment and an increase in chemicals and salt water disposals costs.

Production Taxes. Production taxes increased to $11,398,000 for the nine months ended September 30, 2008 from $9,017,000 for the same period in 2007. This increase was directly related to a 38% increase in oil and gas revenues as a result of the 31% increase in the average realized BOE price received and a 5% increase in production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased to $28,912,000 for the nine months ended September 30, 2008, and consisted of $28,705,000 in depletion on oil and natural gas properties and $207,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $20,128,000 for the nine months ended September 30, 2007. This increase was due primarily to an increase in our production and an increase in our oil and natural gas property costs associated with our 2008 drilling programs.

General and Administrative Expenses. Net general and administrative expenses increased to $5,270,000 for the nine months ended September 30, 2008 from $3,427,000 for the same period in 2007. This increase was due primarily to increases in payroll costs and related benefits, increases in franchise taxes, an increase in accounting services from the implementation and ongoing services needed for compliance with Section 404 of the Sarbanes-Oxley Act of 2002 and a decrease in general and administrative reimbursements from our affiliates. These increases were 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 remained relatively unchanged at $417,000 for the nine months ended September 30, 2008 as compared to $415,000 for the same period in 2007.

Interest Expense. Interest expense increased to $3,402,000 for the nine months ended September 30, 2008 from $1,979,000 for the same period in 2007 due primarily to an increase in average debt outstanding. Total debt outstanding under our facilities with Bank of America was $93.3 million as of September 30, 2008 and $34.5 million as of the same date in 2007. Total weighted average debt outstanding under our facilities with Bank of America was $82.0 million for the nine months ended September 30, 2008 and $27.9 million as of the same date in 2007.

Income Taxes. As of September 30, 2008, we had a net operating loss carry forward of approximately $93.0 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 September 30, 2008, a valuation allowance of $9.8 million had been provided for deferred tax assets. We had $20,000 in income tax expense for the nine months ended September 30, 2008.

Liquidity and Capital Resources

Overview. Historically, our primary sources of funds have been cash flow from our producing oil and natural gas properties, the issuance of equity securities and borrowings under our bank and other credit facilities. Our ability to access any of these sources of funds can be significantly impacted by decreases in oil and natural gas prices or oil and natural gas production.

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Net cash flow provided by operating activities was $75,263,000 for the nine months ended September 30, 2008 as compared to net cash flow provided by operating activities of $47,236,000 for the same period in 2007. This increase was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to a 31% increase in net realized prices as well as a 5% increase in our net BOE production.

Net cash used in investing activities for the nine months ended September 30, 2008 was $103,398,000 as compared to $115,326,000 for the same period in 2007. During the nine months ended September 30, 2008, we spent $92,993,000 in additions to oil and natural gas properties, of which $47,865,000 was spent on our 2008 drilling and recompletion programs, $27,354,000 was spent on expenses attributable to the wells drilled and recompleted during 2007, $4,596,000 was spent on new compressors, $1,397,000 was spent on activity in Belize, $799,000 was spent on our new storage barge, $2,774,000 was spent on facilities, $1,129,000 was spent on plugging activities, with the remainder attributable mainly to capitalized general and administrative expenses. During the nine months ended September 30, 2008, we also made capital investments of $151,000 and loans of $9,708,000 to Grizzly. In addition, we also paid $885,000 for investments in Tatex III and received distributions of $482,000 and paid $50,000 related to our investment in Tatex Thailand II, LLC. During the nine months ended September 30, 2008, we used cash from operations and borrowings under our credit facility to fund our investing activities.

Net cash provided by financing activities for the nine months ended September 30, 2008 was $29,882,000 as compared to $63,235,000 for the same period in 2007. The 2008 amount provided by financing activities is primarily attributable to borrowings of $30,000,000 under our credit facility with Bank of America and $482,000 from the exercise of stock options. Net cash provided by financing activities were used for general corporate purposes. The 2007 amount provided by financing activities is primarily attributable to net proceeds of approximately $63,694,000 from the sale of shares of our common stock on February 5, 2007, May 22, 2007, and July 25, 2007 after deducting the underwriting discount and offering expenses and the exercise of stock options, and borrowings of $46,500,000 on our credit facility with Bank of America offset by principal payments of $46,959,000 from the proceeds of equity offerings.

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

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

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

Credit Facility. On March 11, 2005, we entered into a three-year secured reducing credit agreement providing for a $30.0 million revolving credit facility with Bank of America, N.A. Borrowings under the revolving credit facility are subject to a borrowing base limitation, which was initially set at $18.0 million, subject to adjustment. On November 1, 2005, the amount available under the borrowing base limitation was increased to $23.0 million and was redetermined without change on May 30, 2006. On December 19, 2006, the amount available under the borrowing base limitation was increased to $30.0 million. Effective July 19, 2007, the credit facility was increased to $150.0 million and the amount available under the borrowing base limitation was increased to $60.0 million. On December 20, 2007, the amount available under the borrowing base limitation was increased to $90.0 million and the Eurodollar interest rate, which we elected to use on March 28, 2008, was reduced by 0.75%. In addition, the maturity date was extended from March 31, 2009 to March 31, 2010. We make quarterly interest payments on amounts borrowed under the facility. Amounts borrowed under the credit facility bear interest at the Eurodollar rate plus 2.00% (5.72% at September 30, 2008). Our obligations under the credit facility are collateralized by a lien on substantially all of our Louisiana and West Texas assets.

The credit facility contains certain affirmative and negative covenants, including, but not limited to, the following financial covenants: (a) the ratio of funded debt to EBITDAX (net income before deductions for taxes, excluding unrealized gains and losses related to trading securities and commodity hedges, plus depreciation, depletion, amortization and interest expense, plus exploration costs deducted in determining net income under full cost accounting) for a twelve-month period may not be greater than 2.00 to 1.00; and (b) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. We were in compliance with all covenants at September 30, 2008. As of September 30, 2008, approximately $89.5 million was outstanding under this facility, which is included in long-term debt, net of current maturities on the accompanying consolidated balance sheet. We have used the proceeds of our borrowings under the credit facility for the exploration of our oil and natural gas properties and other capital expenditures, acquisition opportunities, and for other general corporate purposes.

On July 10, 2006, we entered into a $5.0 million term loan agreement with Bank of America, N.A. related to the purchase of new gas compressor units. The loan began amortizing quarterly on March 31, 2007 on a straight-line basis over seven years based on the outstanding principal balance at December 31, 2006. Amounts borrowed bear interest at Bank of America prime (5.0% at September 30, 2008). We make quarterly interest payments on amounts borrowed under the agreement. Our obligations under the agreement are collateralized by a lien on the compressor units. As of September 30, 2008, approximately $3.8 million was outstanding under this agreement.

Building Loans. We had three loans associated with two of our buildings. One loan, in the original principal amount of $115,000, related to a building in Lafayette, Louisiana, that we purchased in 1996 to be used as our Louisiana headquarters. This loan bore interest at the rate of 5.75% per annum. We repaid this loan in full during the third quarter of 2007. In addition, in June 2004 we purchased the office building we occupy in Oklahoma City, Oklahoma, for $3,700,000. One of the two loans 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 and is collateralized by the Oklahoma City office building and associated land**.**

Capital Expenditures. Our 2008 capital commitments have been primarily for the development of our proved reserves in Southern Louisiana, West Texas and North Dakota and to fund Grizzly s delineation drilling program. Our strategy is to (1) increase cash flow generated from our operations by undertaking new drilling, workover, sidetrack and recompletion projects to exploit our existing properties and (2) explore other acquisition opportunities. We have upgraded our infrastructure and our existing facilities with the goal of increasing operating efficiencies and volume capacities and lowering lease operating expenses. Additionally, the reprocessing of 3-D seismic data in one of our principal properties, WCBB, enables our geophysicists to continue to generate new prospects and enhance existing prospects in the intermediate zones in the field, thus creating a portfolio of new drilling opportunities.

In our December 31, 2007 reserve reports, 72% 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.

Our inventory of prospects includes approximately 111 drilling locations at WCBB. The drilling schedule used in our December 31, 2007 reserve report anticipates that all of those wells will be drilled by 2019. From January 1, 2008 through October 31, 2008, we drilled eight wells and recompleted 43 existing wells at our WCBB field. Capital expenditures for drilling, recompletion and other activities in our WCBB field for 2008 activities are estimated to be between $38.0 million and $42.0 million.

In our East Hackberry field, from January 1, 2008 through October 31, 2008, we drilled five wells and recompleted five wells. Capital expenditures for our East Hackberry field for 2008 activities are estimated at $21.0 million to $23.0 million.

During the third quarter of 2006, we purchased a 24.9999% interest in Grizzly. As of September 30, 2008, our net investment in Grizzly was approximately $25.4 million. In addition, the Company loaned Grizzly approximately $9,708,000 during the nine months ended September 30, 2008. Capital requirements in 2008, which are funded through loans to Grizzly, are estimated to be approximately $10.0 million, primarily for the expenses associated with Grizzly s 2007/2008 fifty-five well core hole drilling program, a seismic program and additional lease acquisitions.

Capital expenditures in 2008 relating to our interests in Thailand are expected to be approximately $1.0 million, which we believe will be mostly offset from our share of production from the Phu Horm field.

Capital expenditures in 2008 relating to our interest in the Bakken Shale in the Williston Basin are expected to be approximately $10.0 million.

Capital expenditures for 2008 for our properties in the Permian Basin in West Texas purchased on December 20, 2007 are estimated to be between $28.0 million and $30.0 million. We have identified 178 gross future development drilling locations. We currently expect that approximately 31 gross wells, including one well spud in 2007 and completed in 2008 and one Henry Petroleum operated well, will be drilled in 2008.

Our total capital expenditures for 2008 are currently estimated to be $108.0 million to $116.0 million. We believe that our cash on hand and cash flow from operations will be sufficient to meet our normal recurring operating needs, debt service obligations, and our WCBB, Hackberry, Bakken, Permian Basin and Grizzly capital requirements for the next twelve months. In the event we elect to further expand or accelerate our drilling programs, pursue acquisitions or accelerate our Canadian oil sands project, we may be required to obtain additional funds which we may do so through traditional borrowings, offerings of debt or equity securities or other means, including the sale of assets. Needed capital may not be available to us on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to delay or curtail implementation of our business plan or not be able to complete acquisitions that may be favorable to us.

Commodity Price Risk

To mitigate the effects of commodity price fluctuations, we were 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, we 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, we 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, we 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. We have entered into forward sales contracts for the sale of 3,500 barrels of production per day during the period of September 2008 through December 2008 at a weighted average daily price of $86.60 per barrel before transportation costs. Under these agreements we have committed to deliver approximately 75% of our estimated production for January through December 2008. For the period of January through December 2009, we 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. 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 above the contracted prices. These contracts require physical delivery of production quantities and are exempted from the provisions of SFAS 133 as normal sales of production. In addition, these arrangements may limit the benefit to us of increases in the price of oil.

Commitments

In connection with the acquisition in 1997 of the remaining 50% interest in the WCBB properties, we assumed the seller s (Chevron) obligation to contribute approximately $18,000 per month through March 2004 to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until abandonment obligations to Chevron have been fulfilled. Beginning in 2009, we can access the trust for use in plugging and abandonment charges associated with the property. As of September 30, 2008, the plugging and abandonment trust totaled approximately $3,140,000, including interest received during 2008 of approximately $40,000. At September 30, 2008, we had plugged 253 wells at WCBB since we began our plugging program in 1997, which management believes fulfills our current minimum plugging obligation.

New Accounting Pronouncements

SFAS No. 157

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

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SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115*. SFAS No. 159 permits companies to choose to measure certain financial instruments and other items at fair value. The objective is to improve financial reporting by providing companies with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Unrealized gains and losses on any items for which we elect the fair value measurement option would be reported in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We adopted SFAS No. 159 effective January 1, 2008. The adoption did not have a material impact on our consolidated financial statements.

SFAS No. 141(R)

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

SFAS No. 160

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

SFAS No. 161

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

SFAS No. 162

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*. SFAS No. 162 identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America (the GAAP hierarchy). This statement is effective November 15, 2008 (60 days following the SEC s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, *The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles).* We are currently assessing the impact, if any, of the adoption of SFAS No. 162.

ITEM 3. QUALITATIVE AND QUANTITATIVE 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, over the last four years, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.83 per barrel, or bbl, in January 2004 to a high of $145.29 per bbl on July 3, 2008. The Henry Hub spot market price of natural gas has ranged from a low of $4.20 per million British thermal units, or MMBtu, in October 2006 to a high of $15.39 per MMBtu in December 2005. Any substantial and prolonged 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, we entered into forward sales contracts. We were 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, we 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, we 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, we 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 months of September 2008 through December 2008, we have 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. Under these agreements, we have committed to deliver approximately 75% of our estimated production for January through December 2008. For the period of January 2009 through December 2009, we 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. 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 above the contracted prices. These contracts require physical delivery of production quantities and are exempted from the provisions of SFAS 133 as normal sales of production. In addition, these arrangements may limit the benefit to us of increases in the price of oil.

Our credit facility and term loan with Bank of America are structured under floating rate terms and, as such, our interest expense is sensitive to fluctuations in the interest rates. Borrowings under our revolving credit facility with Bank of America bear interest at the Eurodollar rate (which we elected to use on March 28, 2008) plus 2% (5.72% at September 30, 2008). Borrowings under our term loan with Bank of America bear interest at Bank of America prime (5.00% at September 30, 2008). Based on the current debt structure, a 1% increase in interest rates would increase interest expense by approximately $933,000 per year, based on an aggregate of $93.3 million outstanding under our credit facilities as of September 30, 2008. As of September 30, 2008, we did not have any interest rate swaps to hedge our interest risks.

ITEM 4. 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 September 30, 2008, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Vice President and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 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 September 30, 2008, our disclosure controls and procedures are effective.

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

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The Louisiana State Mineral Board, or LSMB, disputed our royalty payments to the State of Louisiana resulting from the sale of oil under fixed price contracts. The LSMB maintained that we paid approximately $1,400,000 less in royalties under the fixed price contracts than the royalties we would have had to pay had we sold the oil at prevailing market rates. We denied any liability to the LSMB for underpayment of royalties and maintained that we were entitled to enter into the fixed price contracts with unrelated third parties and pay royalties based upon the sales proceeds from those contracts. We met with the Attorney General on several occasions and reached a mutual settlement. In accordance with the settlement, we paid $250,000 during the second quarter of 2008, all of which was previously accrued in accounts payable and accrued liabilities in the accompanying consolidated balance sheets. Under the settlement, all future royalties will be paid at market price, regardless of the presence of fixed price contracts. The settlement was approved during the LSMB s February 2008 session and executed on April 1, 2008, effectively closing the matter.

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 $1,799,000 less in Louisiana severance taxes under the fixed price contracts than the severance taxes we would have had to pay had we sold the oil at prevailing market rates. We 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 sales proceeds from those contracts. We are currently awaiting response from the LDR.

Litigation

In November 2006, Cudd Pressure Control, Inc., or Cudd, filed a lawsuit against us and Great White Pressure Control LLC, an affiliate of ours, among others, in the 129th Judicial District Harris County, Texas. The lawsuit was subsequently removed to the United States District Court for the Southern District of Texas (Houston Division). The lawsuit alleges RICO violations and several other causes of action relating to an affiliate company s employment of several former Cudd employees and seeks unspecified monetary damages and injunctive relief. The defendants in the suit are Ronnie Roles, Rocky Roles, Steve Winters, Bert Ballard, Nelson Britton, Michael Fields, Steve Bickle, Great White Pressure Control LLC, and us. On stipulation by the parties, the plaintiff s RICO claim was dismissed without prejudice by order of the court on February 14, 2007. Co-defendant Steve Bickle was dismissed from the case on July 18, 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. The judgment also allowed us to apply for attorney s fees. The Court entered a final judgment on June 5, 2008, in favor of all defendants, including us. On June 6, 2008, Cudd filed a notice of appeal to the U.S. Court of Appeals.

On July 27, 2007, Robotti & Company, LLC filed a putative class action lawsuit in the Court of Chancery for the State of Delaware in and for Kent County, Delaware. The lawsuit seeks damages for an alleged breach of fiduciary duty by us and our directors in connection with the pricing of the 2004 rights offering. We received service of this matter on August 10, 2007. By mutual agreement of the parties, we were not required to respond until notified by the plaintiff, which was received on January 16, 2008. Plaintiff filed an amended complaint on January 15, 2008, and we filed a motion to dismiss in early February 2008 and filed the brief in support of said motion on April 29, 2008. The court held a hearing on October 3, 2008 regarding our motion to dismiss and motion to stay, ultimately deciding to allow the plaintiff to file a second amended complaint.

In July 2007, Michael Tripkovich filed suit in the 16th Judicial District Court of the Parish of St. Martin, Louisiana, against 113 entities, including us, alleging his contraction of chronic myeloid leukemia (CML) was caused by exposure to various substances while maintaining natural gas compressors over a nineteen year period. We were served on July 23, 2007 and filed a response denying plaintiff s claims. The suit is currently in discovery. We have no record that Mr. Tripkovich was ever employed by our company. No other deadlines have been set at this time.

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 behalf of us in the field. A tugboat, the M/V Miss Megan, and two barges laden with construction materials ruptured an underwater natural gas pipeline and a subsequent fire damaged the vessels. Six fatalities resulted from the accident. The following lawsuits relating to this incident are currently pending before the courts:

On October 13, 2006, Athena Construction LLC, or Athena, filed a limitation action in the United States District Court for the Eastern District of Louisiana, alleging that all losses and damages as a result of the pipeline incident were incurred without fault on its part. Furthermore, Athena claims the benefit of the limitation of liability provided for in

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42 U.S.C. § 183 and seeks an injunction restraining filing commencement and further prosecution in any court of any lawsuit against Athena related to the pipeline incident. The limitation of liability action was subsequently transferred to the United States District Court for the Western District of Louisiana, which is where the case remains pending. On December 20, 2006, 4-K Marine LLC, as owner of the M/V Miss Megan, and Central Boat Rentals, Inc., as operator of the M/V Miss Megan also filed a limitation action in the Western District. On January 10, 2007, the Athena and the 4-K/Central Boat limitation proceedings were consolidated by order of the court. On May 5, 2007, Diamondback Energy, an affiliate of ours, filed an intervener with the Court to become a party to the suit. The remaining parties filed claims on July 9, 2007, which included claims by Nicholas Aucoin, one of the initial responders to the scene of the accident. On May 2, 2008, we reached a settlement with Athena and Diamondback. The settlement provided reimbursement to us for pipeline repair costs incurred as a result of the October 2006 accident.

On October 15, 2007, Brian Dumesnil filed suit in the 16th Judicial District Court for the Parish of St. Mary, Louisiana, against us, Chevron USA, Chevron Texaco Pipeline Holdings, Chevron Natural Gas, Diamondback Energy Services and the Estate of Timothy Tauzin. Mr. Dumesnil was employed by Athena and was on the Athena barge at the time of the accident. He is seeking unspecified sums as a result of the alleged negligence of defendants and injuries incurred following the October 12, 2006 accident. This case settled on September 11, 2008.

Due to the early stages of certain of the above 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 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 1A. RISK FACTORS

See risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2007.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

(a) None.

(b) Not Applicable.

(c) We do not have a share repurchase program, and during the three months ended September 30, 2008, we did not purchase any shares of our common stock.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

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

None.

ITEM 5. OTHER INFORMATION

(a) None.

(b) None.

ITEM 6. EXHIBITS

Exhibit Number	Description
3.1	Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
3.2	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to 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).

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

* Filed herewith.

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SIGNATURES

Pursuant to the requirements of the Securities and Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Date: November 7, 2008

GULFPORT ENERGY CORPORATION

/s/ James D. Palm
James D. Palm
Chief Executive Officer

/s/ Michael G. Moore
Michael G. Moore
Chief Financial Officer

Exhibit Index

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