

GULFPORT ENERGY CORP
Form 10-Q
August 14, 2007
Table of Contents

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 JUNE 30, 2007

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
(State or Other Jurisdiction of
Incorporation or Organization)

73-1521290
(IRS Employer

Identification Number)

14313 North May Avenue, Suite 100

Oklahoma City, Oklahoma
(Address of Principal Executive Offices)

73134
(Zip Code)

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(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 No

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

Large Accelerated Filer Accelerated Filer Non-Accelerated Filer

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

As of August 13, 2007, 37,930,877 shares of common stock were outstanding.

Table of Contents

GULFPORT ENERGY CORPORATION

TABLE OF CONTENTS

	Page
<u>PART I FINANCIAL INFORMATION</u>	
Item 1. Consolidated Financial Statements:	
<u>Consolidated Balance Sheets at June 30, 2007 (unaudited) and December 31, 2006</u>	1
<u>Consolidated Statements of Operations for the Three and Six Months Ended June 30, 2007 and 2006 (unaudited)</u>	2
<u>Consolidated Statements of Stockholders' Equity and Comprehensive Income for the Six Months Ended June 30, 2007 and 2006 (unaudited)</u>	3
<u>Consolidated Statements of Cash Flows for the Six Months Ended June 30, 2007 and 2006 (unaudited)</u>	4
<u>Notes to Consolidated Financial Statements (unaudited)</u>	5
Item 2. <u>Management's Discussion and Analysis of Financial Condition and Results of Operations</u>	15
Item 3. <u>Quantitative and Qualitative Disclosures About Market Risk</u>	24
Item 4. <u>Controls and Procedures</u>	25
<u>PART II OTHER INFORMATION</u>	
Item 1. <u>Legal Proceedings</u>	26
Item 1A. <u>Risk Factors</u>	27
Item 2. <u>Unregistered Sales of Equity Securities and Use of Proceeds</u>	27
Item 3. <u>Defaults Upon Senior Securities</u>	28
Item 4. <u>Submission of Matters to a Vote of Security Holders</u>	28
Item 5. <u>Other Information</u>	28
Item 6. <u>Exhibits</u>	28
<u>Signatures</u>	30

Table of Contents**CONSOLIDATED BALANCE SHEETS**

	(Unaudited) June 30, 2007	December 31, 2006
Assets		
Current assets:		
Cash and cash equivalents	\$ 2,137,000	\$ 6,627,000
Accounts receivable - oil and gas	10,639,000	7,585,000
Insurance settlement receivables		541,000
Accounts receivable - related parties	3,462,000	4,202,000
Prepaid expenses and other current assets	2,808,000	972,000
Total current assets	19,046,000	19,927,000
Property and equipment:		
Oil and natural gas properties, full-cost accounting, \$1,536,000 and \$1,459,000 excluded from amortization in 2007 and 2006, respectively	320,736,000	250,838,000
Other property and equipment	6,949,000	6,651,000
Accumulated depletion, depreciation and amortization	(112,098,000)	(99,815,000)
Property and equipment, net	215,587,000	157,674,000
Other assets	23,881,000	17,550,000
Total assets	\$ 258,514,000	\$ 195,151,000
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable and accrued liabilities	\$ 34,786,000	\$ 24,793,000
Asset retirement obligation - current	480,000	480,000
Current maturities of long-term debt	827,000	835,000
Total current liabilities	36,093,000	26,108,000
Asset retirement obligation - long-term	7,940,000	8,378,000
Long-term debt, net of current maturities	31,625,000	36,856,000
Total liabilities	75,658,000	71,342,000
Commitments and contingencies (Note 12)		
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, 36,906,620 issued and outstanding in 2007 and 33,659,759 in 2006	369,000	337,000
Paid-in capital	174,694,000	131,610,000
Accumulated other comprehensive loss	(926,000)	
Retained earnings (accumulated deficit)	8,719,000	(8,138,000)
Total stockholders equity	182,856,000	123,809,000

Total liabilities and stockholders equity	\$ 258,514,000	\$ 195,151,000
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See accompanying notes to consolidated financial statements.

Table of Contents

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Revenues:				
Gas sales	\$ 1,385,000	\$ 504,000	\$ 2,493,000	\$ 1,047,000
Oil and condensate sales	23,634,000	13,845,000	42,888,000	17,751,000
Other income (expense)	(10,000)	11,000	9,000	17,000
	25,009,000	14,360,000	45,390,000	18,815,000
Costs and expenses:				
Lease operating expenses	3,942,000	2,255,000	7,119,000	3,606,000
Production taxes	3,025,000	1,921,000	5,470,000	2,486,000
Depreciation, depletion, and amortization	6,613,000	2,743,000	12,283,000	3,736,000
General and administrative	1,154,000	513,000	2,235,000	1,514,000
Accretion expense	139,000	149,000	277,000	298,000
	14,873,000	7,581,000	27,384,000	11,640,000
INCOME FROM OPERATIONS:	10,136,000	6,779,000	18,006,000	7,175,000
OTHER (INCOME) EXPENSE:				
Interest expense	685,000	397,000	1,325,000	668,000
Business interruption insurance recoveries		(614,000)		(3,269,000)
Interest income	(119,000)	(63,000)	(229,000)	(111,000)
	566,000	(280,000)	1,096,000	(2,712,000)
INCOME BEFORE INCOME TAXES	9,570,000	7,059,000	16,910,000	9,887,000
INCOME TAX EXPENSE:			53,000	
NET INCOME	\$ 9,570,000	\$ 7,059,000	\$ 16,857,000	\$ 9,887,000
NET INCOME PER COMMON SHARE:				
Basic	\$ 0.27	\$ 0.22	\$ 0.48	\$ 0.31
Diluted	\$ 0.26	\$ 0.21	\$ 0.47	\$ 0.29

See accompanying notes to consolidated financial statements.

Table of Contents**GULFPORT ENERGY CORPORATION****Consolidated Statements of Stockholders Equity and Comprehensive Income****(Unaudited)**

	Common Stock		Additional	Accumulated Other Comprehensive Income	Accumulated Deficit	Total Stockholders Equity
	Stock	Amount	Paid-in Amount			
Balance at January 1, 2007	33,659,759	\$ 337,000	\$ 131,610,000	\$	\$ (8,138,000)	\$ 123,809,000
Net income					16,857,000	16,857,000
Other Comprehensive Income:						
Foreign currency translation adjustment				(926,000)		(926,000)
Total Comprehensive Income						15,931,000
Stock Compensation			581,000			581,000
Issuance of Common Stock in public offerings, net of related expenses of \$350,000	3,047,500	30,000	41,789,000			41,819,000
Issuance of Restricted Stock	17,796					
Issuance of Common Stock through exercise of options	181,565	2,000	714,000			716,000
Balance at June 30, 2007	36,906,620	\$ 369,000	\$ 174,694,000	\$ (926,000)	\$ 8,719,000	\$ 182,856,000
Balance at January 1, 2006	32,168,203	\$ 322,000	\$ 119,192,000	\$ 759,000	\$ (35,946,000)	\$ 84,327,000
Net income					9,887,000	9,887,000
Other Comprehensive Income:						
Unrealized loss on hedges				(2,961,000)		(2,961,000)
Deferred gain on settled contracts				30,000		30,000
Loss on hedging ineffectiveness				163,000		163,000
Reclassification adjustment on settled hedges				(527,000)		(527,000)
Total Comprehensive Income						6,592,000
Stock Compensation			368,000			368,000
Issuance of Common Stock in public offering, net of related expenses of \$479,000	790,000	8,000	9,964,000			9,972,000
Issuance of Restricted Stock	1,583					
Issuance of Common Stock through exercise of warrants	12,171					
Issuance of Common Stock through exercise of options	6,332		18,000			18,000
Balance at June 30, 2006	32,978,289	\$ 330,000	\$ 129,542,000	\$ (2,536,000)	\$ (26,059,000)	\$ 101,277,000

See accompanying notes to consolidated financial statements.

Table of Contents**GULFPORT ENERGY CORPORATION****Consolidated Statements of Cash Flows****(Unaudited)**

	Six Months Ended June 30,	
	2007	2006
Cash flows from operating activities:		
Net income	\$ 16,857,000	\$ 9,887,000
Adjustments to reconcile net income to net cash provided by operating activities:		
Accretion of discount - Asset Retirement Obligation	277,000	298,000
Depletion, depreciation and amortization	12,283,000	3,736,000
Stock-based compensation expense	424,000	368,000
Loss from equity investments	63,000	
Unrealized loss on hedge ineffectiveness		163,000
Changes in operating assets and liabilities:		
Increase in accounts receivable	(3,054,000)	(5,110,000)
Decrease in business interruption insurance settlement receivable		1,710,000
Decrease in accounts receivable - related party	740,000	311,000
Increase in prepaid expenses	(1,836,000)	(286,000)
Increase in accounts payable and accrued liabilities	2,000	1,784,000
Increase in deferred hedge gains		30,000
Settlements of asset retirement obligation	(872,000)	(537,000)
Net cash provided by operating activities	24,884,000	12,354,000
Cash flows from investing activities:		
Additions to cash held in escrow	(63,000)	(51,000)
Additions to other property, plant and equipment	(298,000)	(262,000)
Additions to oil and gas properties	(59,551,000)	(23,142,000)
Proceeds from sale of oil and gas properties	500,000	
Investment in Grizzly Oil Sands ULC	(7,220,000)	
Investment in Tatex Thailand II, LLC	(34,000)	(439,000)
Investment in Windsor Bakken, LLC	(4,000)	(1,339,000)
Net cash used in investing activities	(66,670,000)	(25,233,000)
Cash flows from financing activities:		
Principal payments on borrowings	(30,739,000)	(10,752,000)
Borrowings on note payable	25,500,000	18,500,000
Proceeds from issuance of common stock, net of offering costs of \$350,000 and \$479,000, and exercise of stock options	42,535,000	9,990,000
Net cash provided by financing activities	37,296,000	17,738,000
Net increase (decrease) in cash and cash equivalents	(4,490,000)	4,859,000
Cash and cash equivalents at beginning of period	6,627,000	2,119,000
Cash and cash equivalents at end of period	\$ 2,137,000	\$ 6,978,000
Supplemental disclosure of cash flow information:		
Interest payments	\$ 1,776,000	\$ 668,000

Supplemental disclosure of non-cash transactions:

Capitalized stock based compensation	\$	157,000	\$	
Asset retirement obligation capitalized	\$	157,000	\$	217,000

See accompanying notes to consolidated financial statements.

Table of Contents**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-KSB. Results for the three month and six month periods ended June 30, 2007 are not necessarily indicative of the results expected for the full year.

1. INSURANCE SETTLEMENT RECEIVABLE

The Company sustained damage to both its Hackberry field located in Cameron Parish, Louisiana and its West Cote Blanche Bay (WCBB) field located in St. Mary Parish, Louisiana as a result of Hurricane Rita in September 2005. As of June 30, 2007, the Company had incurred costs of \$14,388,000 relating to the damage to the fields and facilities. Of this amount, \$250,000 represents insurance deductible amounts that were expensed to lease operating expenses in 2005. The Company received \$8,396,000 in insurance proceeds related to physical damage, of which \$541,000 was received in the first quarter of 2007, which are reflected as investing activity in the consolidated statements of cash flows. Approximately \$5,634,000 of costs incurred during 2006 and the first quarter of 2007 related to equipment and facilities replacement costs which will not be reimbursed by insurance and are included in the full cost pool. Approximately \$108,000 previously included in insurance settlement receivables was not collected and was expensed in 2006. At June 30, 2007, the Company had collected all outstanding insurance receivable amounts related to physical damage.

The Company maintained business interruption insurance to cover lost production revenue in the event of shut-in production. The business interruption insurance began 60 days after the occurrence of the insurable event, subject to a daily limit of \$45,000 and had a maximum coverage of 180 days. Coverage began on November 24, 2005 for shut-in production caused by Hurricane Rita. For the three months and six months ended June 30, 2006, the Company recognized \$614,000 and \$3,269,000, respectively, of business interruption insurance proceeds in other income in the consolidated statements of operations. As of June 30, 2006, the Company had received proceeds of \$4,979,000 (\$1,710,000 of which was accrued in 2005) related to business interruption for the period of November 24, 2005 to May 1, 2006. Such recoveries are presented as operating cash flows in the consolidated statements of cash flows. All business interruption recoveries were collected in 2006.

2. ACCOUNTS RECEIVABLE RELATED PARTY

Included in the accompanying June 30, 2007 and December 31, 2006 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 June 30, 2007 and December 31, 2006, this receivable amount totaled \$3,462,000 and \$4,202,000, respectively. The Company was reimbursed \$2,847,000 and \$6,638,000 for the three months and six months ended June 30, 2007, 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 six months ended June 30, 2006, the Company was reimbursed \$2,566,000 and \$4,562,000, respectively.

Effective September 29, 2006, the Company entered into an administrative services agreement with Diamondback Energy Services LLC (Diamondback). Under the agreement, the Company's services for Diamondback include accounting, human resources, legal and technical support. The services provided to Diamondback and the fees for such services can be amended by mutual agreement of the parties. The administrative services agreement has a three-year term,

Table of Contents

and upon expiration of that term the agreement will continue on a month-to-month basis until cancelled by either party with at least 30 days prior written notice. The administrative services agreement is terminable (1) by Diamondback at any time with at least 30 days prior written notice to the Company and (2) by either party if the other party is in material breach and such breach has not been cured within 30 days of receipt of written notice of such breach. The Company was reimbursed approximately \$403,000 and \$778,000 in consideration for those services during the three months and six months ended June 30, 2006, respectively. No amounts were reimbursed during the three months and six months ended June 30, 2007. These amounts are reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

Effective July 22, 2006, the Company entered into an administrative services agreement with Great White Energy Services LLC (Great White). Under the agreement, the Company's services for Great White include accounting, human resources, legal and technical support. The services provided to Great White and the fees for such services can be amended by mutual agreement of the parties. The administrative services agreement has a three-year term, and upon expiration of that term the agreement will continue on a month-to-month basis until cancelled by either party with at least 30 days prior written notice. The administrative services agreement is terminable (1) by Great White at any time with at least 30 days prior written notice to the Company and (2) by either party if the other party is in material breach and such breach has not been cured within 30 days of receipt of written notice of such breach. The Company was reimbursed approximately \$24,000 and \$710,000 in consideration for those services during the three months and six months ended June 30, 2007, respectively, and \$92,000 during the three months and six months ended June 30, 2006. These amounts are reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

3. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depreciation, depletion and amortization as of June 30, 2007 and December 31, 2006 are as follows:

	June 30, 2007	December 31, 2006
Oil and gas properties	\$ 320,736,000	\$ 250,838,000
Office furniture and fixtures	2,763,000	2,465,000
Building	3,926,000	3,926,000
Land	260,000	260,000
Total property and equipment	327,685,000	257,489,000
Accumulated depreciation, depletion, amortization and impairment reserve	(112,098,000)	(99,815,000)
Property and equipment, net	\$ 215,587,000	\$ 157,674,000

Included in oil and gas properties at June 30, 2007 is the cumulative capitalization of \$4,721,000 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 \$408,000 and \$793,000 for the three months and six months ended June 30, 2007, respectively, and \$177,000 and \$419,000 for the three months and six months ended June 30, 2006, respectively.

Table of Contents

A reconciliation of the asset retirement obligation for the six months ended June 30, 2007 and 2006 is as follows:

	June 30, 2007	June 30, 2006
Asset retirement obligation, beginning of period	\$ 8,858,000	\$ 8,609,000
Liabilities incurred	157,000	217,000
Liabilities settled	(872,000)	(537,000)
Accretion expense	277,000	298,000
Asset retirement obligation as of end of year	8,420,000	8,587,000
Less current portion	480,000	480,000
Asset retirement obligation, long-term	\$ 7,940,000	\$ 8,107,000

4. OTHER ASSETS

Other assets consist of the following as of June 30, 2007 and December 31, 2006:

	June 30, 2007	December 31, 2006
Plugging and abandonment escrow account on the WCBB properties (Note 12)	\$ 3,046,000	\$ 2,983,000
Investment in Tatex Thailand II, LLC	3,499,000	3,465,000
Investment in Windsor Bakken, LLC	2,410,000	2,433,000
Investment in Grizzly Oil Sands ULC	14,722,000	8,465,000
Certificates of Deposit securing letter of credit	200,000	200,000
Deposits	4,000	4,000
	\$ 23,881,000	\$ 17,550,000

Tatex Thailand II, LLC

During 2005, the Company purchased a 23.5% ownership interest in Tatex Thailand II, LLC (Tatex) at a cost of \$2,400,000. The remaining interests in Tatex are owned by other entities controlled by Wexford Capital LLC, an affiliate of Gulfport. Tatex, a non-public entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC (APICO), an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering three million acres which includes the Phu Horm Field. During the six months ended June 30, 2007, Gulfport paid \$34,000 in cash calls, bringing its total investment in Tatex (including previous investments) to \$3,499,000.

Windsor Bakken, LLC

During 2005, the Company purchased a 20% ownership interest in Windsor Bakken, LLC (Bakken). The remaining interests in Bakken are owned by other entities controlled by Wexford Capital LLC, an affiliate of Gulfport. In 2005 and 2006, Bakken acquired leases on undeveloped acreage in the Williston Basin areas of western North Dakota and eastern Montana. As of June 30, 2007, Gulfport's net investment in Bakken was \$2,410,000. As of June 30, 2007, Bakken has not yet commenced drilling of its undeveloped acreage.

Grizzly Oil Sands ULC

During the third quarter of 2006, the Company, through its wholly owned subsidiary Grizzly Holdings Inc., purchased a 25% interest in Grizzly Oils Sands ULC (Grizzly), a Canadian unlimited liability company, for approximately \$8.2 million. The remaining interests in Grizzly are owned by other entities controlled by Wexford Capital LLC, an affiliate of Gulfport. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray within a few miles of other existing oil sands projects. Grizzly has commenced drilling of core holes for feasibility of oil production in three separate lease blocks but has not commenced development of

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operations. As of June 30, 2007, Gulfport's net investment in Grizzly was \$14,722,000. Grizzly's functional currency is the Canadian dollar. The Company's investment in Grizzly was reduced by \$821,000 and \$926,000 as a result of a currency translation loss for the three months and six months ended June 30, 2007, respectively.

Table of Contents**5. LONG-TERM DEBT**

A breakdown of long-term debt as of June 30, 2007 and December 31, 2006 is as follows:

	June 30, 2007	December 31, 2006
Reducing credit agreement (1)	\$ 25,020,000	\$ 29,848,000
Term loan (1)	4,647,000	5,000,000
Building loans (2)	2,785,000	2,843,000
Less: current maturities of long term debt	(827,000)	(835,000)
Debt reflected as long term	\$ 31,625,000	\$ 36,856,000

Maturities of long-term debt as of June 30, 2007 are as follows:

2008	\$ 827,000
2009	25,832,000
2010	818,000
2011	3,185,000
2012	714,000
Thereafter	1,076,000
Total	\$ 32,452,000

(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. The credit facility has a term of three years and all principal amounts of revolving loans outstanding under the credit facility, together with all accrued and unpaid interest and fees were to be due and payable on March 11, 2008. The maturity date was subsequently amended to March 31, 2009. The Company makes quarterly interest payments on amounts borrowed under the facility. Amounts borrowed under the credit facility bear interest at Bank of America Prime plus 0.25% (8.5% at June 30, 2007). The Company's obligations under the credit facility are collateralized by a lien on substantially all of the Company's assets. The credit facility contains certain affirmative and negative covenants, including, but not limited to the following financial covenants: (a) the ratio of current assets to current liabilities may not be less than 1.00 to 1.00; (b) the ratio of funded debt to EBITDAX (net income before deductions for taxes, excluding unrealized gains and losses related to trading securities and commodity hedges, plus depreciation, depletion, amortization and interest expense, plus exploration costs deducted in determining net income under full cost accounting) for a twelve month period may not be greater than 2.00 to 1.00; and (c) the ratio of EBITDAX to interest expense for a twelve month period may not be less than 3.00 to 1.00. The Company was not in compliance with the current ratio covenant at June 30, 2007; however, a waiver was obtained from the lender. As of June 30, 2007, approximately \$25.0 million was outstanding under this facility, which is included in long-term debt, net of current maturities on the accompanying consolidated balance sheet. The Company has used the proceeds of borrowings under the credit facility for the exploration of oil and natural gas properties and other capital expenditures, acquisition opportunities, repair of damaged facilities and for other general corporate purposes.

On July 10, 2006, Gulfport entered into a \$5 million term loan agreement with Bank of America, N.A. related to the purchase of new gas compressor units. The loan amortizes quarterly beginning March 31, 2007 on a straight-line basis over seven years based on the outstanding principal balance at December 31, 2006. Amounts borrowed bear interest at Bank of America Prime (8.25% at June 30, 2007). 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 June 30, 2007, approximately \$4.6 million was outstanding under this agreement, of which \$714,000 and \$3,933,000 are included in current maturities of long-term debt and long-term debt, net of current maturities, respectively, on the accompanying consolidated balance sheet.

Table of Contents

(2) In June 2004 the Company purchased the office building it occupies in Oklahoma City, Oklahoma, for \$3,700,000. One loan associated with this building matured in March 2006 and bore interest at the rate of 6% per annum, while the other loan matures in June 2011 and bears interest at the rate of 6.5% per annum. In addition, the building loans include \$22,000 related to a building in Lafayette, Louisiana, purchased in 1996 to be used as the Company's Louisiana headquarters. This loan matures in February of 2008 and bears interest at the rate of 5.75% per annum. All building loans require monthly interest and principal payments and are collateralized by the respective land and buildings.

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

Sale of Common Stock

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

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

Restricted Stock

On April 1, 2007, the Company issued 16,389 shares of restricted common stock of the Company. These shares vest monthly over a three year period. On May 15, 2007, the Company issued 10,000 shares of restricted common stock of the Company. These shares vest in equal monthly installments over a three year period.

7. STOCK-BASED COMPENSATION

On January 1, 2006, the Company changed its method of accounting for share-based compensation from the APB No. 25 intrinsic-value accounting method to the fair value recognition provisions of SFAS No. 123(R). During the three months and six months ended June 30, 2007, the Company's stock-based compensation expense was \$313,000 and \$581,000, respectively, of which the Company capitalized \$85,000 and \$157,000, respectively, relating to its exploration and development efforts. During the three months and six months ended June 30, 2006, the Company's stock-based compensation expense was \$202,000 and \$368,000, respectively, of which the Company capitalized \$55,000 and \$88,000, respectively, relating to its exploration and development efforts. Stock based compensation expense reduced basic and diluted earnings per share by \$0.01 and \$0.01 each for the three months and six months ended June 30, 2007, respectively and by \$0.00 and \$0.01 for the three months and six months ended June 30, 2006. Options and restricted common stock are reported as share based payments and their fair value is amortized to expense using the straight-line method over the vesting period. The shares of stock issued once the options are exercised will be from authorized but unissued common stock.

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

Table of Contents

No stock options were issued during the six months ended June 30, 2007. The following table provides information relating to outstanding stock options for the six months ended June 30, 2006:

	June 30, 2006
Expected volatility	40.9%
Expected life in years	4.0
Weighted average risk free interest rate	4.0%

The Company has not declared dividends and does not intend to do so in the foreseeable future, and thus did not use a dividend yield. The Company did not include forfeitures in its assumptions. 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 six months ended June 30, 2007 is presented below:

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Options outstanding at December 31, 2006	967,233	\$ 5.54	7.76	\$ 7,782,000
Granted				
Exercised	(181,565)	3.94		1,840,000
Forfeited/expired	(38,666)	3.36		
Options outstanding at June 30, 2007	747,002	\$ 6.05	7.43	\$ 10,382,000
Options exercisable at June 30, 2007	254,196	\$ 7.22	6.72	\$ 3,244,000

Unrecognized compensation expense as of June 30, 2007 related to outstanding stock options and restricted shares was \$2,210,000. The expense is expected to be recognized over a weighted average period of 1.62 years.

The following table summarizes information about the stock options outstanding at June 30, 2007:

Exercise Price	Weighted Average	
	Number Outstanding	Remaining Life (in years)
\$ 2.00	63,418	2.35
\$ 3.36	391,695	7.56
\$ 9.07	91,889	8.19
\$ 11.20	200,000	8.42
	747,002	
		254,196

The following table summarizes restricted stock activity for the six months ended June 30, 2007:

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	Number of Unvested Restricted Shares	Weighted Average Grant Date Fair Value
Unvested shares as of December 31, 2006	69,518	\$ 12.81
Granted	26,389	14.28
Vested	(17,796)	12.94
Forfeited		
Unvested shares as of June 30, 2007	78,111	\$ 13.28

Table of Contents**8. 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 June 30,					
	2007			2006		
	Income	Shares	Per Share	Income	Shares	Per Share
Basic:						
Net income	\$ 9,570,000	35,891,902	\$ 0.27	\$ 7,059,000	32,636,144	\$ 0.22
Effect of dilutive securities:						
Stock options and awards		700,446			1,222,475	
Diluted:						
Net income	\$ 9,570,000	36,592,348	\$ 0.26	\$ 7,059,000	33,858,619	\$ 0.21

	For the six months ended June 30,					
	2007			2006		
	Income	Shares	Per Share	Income	Shares	Per Share
Basic:						
Net income	\$ 16,857,000	35,221,924	\$ 0.48	\$ 9,887,000	32,408,098	\$ 0.31
Effect of dilutive securities:						
Stock options and awards		663,790			1,226,114	
Diluted:						
Net income	\$ 16,857,000	35,885,714	\$ 0.47	\$ 9,887,000	33,634,212	\$ 0.29

Options to purchase 200,000 shares at \$11.20 per share and 40,000 shares at \$12.17 per share were excluded from the calculation of dilutive earnings per share for the three month and six month periods ended June 30, 2006 because they were anti-dilutive. There were no potential shares of common stock that were considered anti-dilutive during the three month or six month periods ended June 30, 2007.

9. OTHER COMPREHENSIVE INCOME

Other comprehensive income for the three months and six months ended June 30, 2007 and 2006 is as follows:

	Three Months Ended		Six Months Ended June 30,	
	June 30, 2007	June 30, 2006	June 30, 2007	June 30, 2006
Net income	\$ 9,570,000	\$ 7,059,000	\$ 16,857,000	\$ 9,887,000
Other comprehensive income (loss):				
Foreign currency translation adjustment	(821,000)		(926,000)	
Unrealized loss on hedges		(1,520,000)		(2,961,000)
Deferred gain on settled contracts		(47,000)		30,000
Loss on hedging ineffectiveness		119,000		163,000
Reclassification of settled contracts		411,000		(527,000)
Total comprehensive income	\$ 8,749,000	\$ 6,022,000	\$ 15,931,000	\$ 6,592,000

10. NEW ACCOUNTING STANDARDS

The Company adopted FASB Interpretation Number 48, *Accounting for Uncertainty in Income Taxes* an interpretation of FASB Statement No. 109, as of January 1, 2007. The adoption of this Interpretation had no effect on the Company's consolidated financial statements. The Company is subject to U.S. federal income tax as well as income tax of multiple state jurisdictions. The Company's 2003-2006 U.S. federal and state income tax returns remain open to examination by the Internal Revenue Service. The Company is continuing its practice of recognizing interest and/or penalties related to income tax matters as general and administrative expenses.

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

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115*. SFAS No. 159 permits companies to choose to measure

Table of Contents

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

11. OPERATING LEASES

The Company began leasing the Louisiana building that it owns in October 2006 to an unrelated party. The cost of the building totaled approximately \$217,000 and accumulated depreciation amounted to approximately \$72,000 as of June 30, 2007. 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	
2007	\$ 63,000
2008	126,000
2009	94,500
	\$ 283,500

12. COMMITMENTS AND CONTINGENCIES*Plugging and Abandonment Funds*

In connection with the acquisition in 1997 of the remaining 50% interest in the WCBB properties, the Company assumed the seller's (Chevron) obligation to contribute approximately \$18,000 per month through March 2004, to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until abandonment obligations to Chevron have been fulfilled. Beginning in 2009, the Company can access the trust for use in plugging and abandonment charges associated with the property. As of June 30, 2007, the plugging and abandonment trust totaled approximately \$3,046,000, including interest received during 2007 of approximately \$67,000. The Company has plugged 231 wells at WCBB since it began its plugging program in 1997, which management believes fulfills its minimum plugging obligation through March 31, 2007.

The Louisiana State Mineral Board (LSMB) is disputing Gulfport's royalty payments to the State of Louisiana resulting from the sale of oil under fixed price contracts. The LSMB maintains that Gulfport paid approximately \$1,400,000 less in royalties under the fixed price contracts than the royalties Gulfport would have had to pay had it sold the oil at prevailing market rates. Gulfport has denied any liability to the LSMB for underpayment of royalties and has maintained that it was entitled to enter into the fixed price contracts with unrelated third parties and pay royalties based upon the sales proceeds from those contracts. Gulfport met with the Attorney General on several occasions and recently reached a mutual settlement. The settlement requires Gulfport to pay \$250,000, which has been accrued in accounts payable and accrued liabilities in the accompanying consolidated balance sheet, and all future royalties will be paid at market price, regardless of the presence of fixed price contracts. Gulfport is currently working with the Attorney General to finalize the agreement and expect to receive approval during the Mineral Board's September 2007 meeting.

Other Litigation

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

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

Table of Contents

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 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 case against Gulfport was stayed by order of the court on July 31, 2007. The court further ordered co-defendant, Great White Pressure Control, to move for summary judgment by August 24, 2007. Cudd was ordered to respond by September 14, 2007. The next pretrial conference is set for September 24, 2007.

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 alleges a 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, and is currently working to respond accordingly.

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, an affiliate of Gulfport, filed an intervener with the Court to become a party to the suit. All claims related to the death of Mr. Timothy Tauzin were dismissed by order of the court on June 8, 2007 and June 12, 2007 following successful settlement negotiations. Mr. Tauzin was an employee of Central Boat Rentals and was the captain of the tug boat involved in the accident. 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. A record hearing has been set for August 13, 2007, to discuss the status of the consolidated matters. No other deadlines have been set.

On October 16, 2006, a lawsuit was filed in the 16th Judicial District Court for the Parish of St. Mary, Louisiana against Gulfport, Athena, and Central Boat seeking compensatory and punitive damages for claims related to the death of the plaintiff's husband, a crewmember on the Athena barge. The suit alleges that the husband's death was caused by the defendants' negligence and the unseaworthiness of the barge to which he was assigned. Pursuant to the Blanket Time Charter between Gulfport and Central Boat, Central Boat tendered the defense and indemnification of the lawsuit to Gulfport. On November 2, 2006, all proceedings were stayed as a result of the limitation of liability action discussed above.

On October 22, 2006, a lawsuit was filed in United States District Court for the Southern District of Texas, Galveston Division against Gulfport, Central Boat, Diamondback Energy Services LLC, an affiliate of Gulfport, Chevron Pipeline Company, Chevron USA, Inc., and ChevronTexaco Pipeline Holdings, Inc. This lawsuit is a result of the death of three individuals. These individuals were employed by Athena and were on the Athena barge at the time of the accident. The plaintiffs seek compensatory and punitive damages as a result of the alleged negligence of defendants. Central Boat has tendered the defense and indemnification of this lawsuit to Gulfport. On April 30, 2007, an order was filed transferring the case to the Western District of Louisiana. No deadlines have been set.

On February 2, 2007, a lawsuit was filed in the United States District Court for the Western District of Louisiana, Lafayette Division against Chevron Pipeline Company, Chevron USA Inc., Chevron Texaco Pipeline Holdings, Inc., Chevron Natural Gas Services Inc., Diamondback Energy Services LLC, an affiliate of Gulfport, and Gulfport. The suit was filed on behalf of April Hummel, individually and as the representative of the minor, Aleya Hummel, the surviving child of Terry Abraham, who died in the accident.

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On March 27, 2007, the Company filed its answer. No other deadlines have been set.

On January 11, 2007, plaintiffs Janet Rink, individually and as the personal representative of the Estate of Kenneth Rink, Tysie Rink and Scott Rink filed a lawsuit in the United States District Court for the Western District of Louisiana against defendants Chevron Pipeline Company, Chevron USA, Inc., ChevronTexaco Pipeline Holdings, Inc., Chevron Natural Gas Services, Inc., the Company and Diamondback Energy Services LLC, an affiliate of Gulfport. All parties reached a mutually agreeable settlement on June 27, 2007 and are currently working to document the settlement, release, and dismissal of this action.

Table of Contents

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

Forward Sales Contracts

In the second quarter of 2007, the Company entered into forward sales contracts for the sale of 3,000 barrels of production per day for the month of June 2007 at a weighted average daily price of \$69.84 per barrel before transportation costs. For the period of July 2007 through May 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 \$70.31 per barrel before transportation costs. For the month of June 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 \$71.21 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.

13. SUBSEQUENT EVENTS

In July 2007, the Company sold 1,000,000 shares of common stock in an underwritten offering at an offering price to the public of \$22.00 per share. The Company received the net proceeds of approximately \$21.2 million from the sale of these shares on July 25, 2007 after deducting the underwriting discount and before offering expenses. In connection with the offering, a selling stockholder granted the underwriter a 30-day option to purchase up to an additional 150,000 shares of common stock to cover over-allotments. The Company will not receive any proceeds from the sale of shares of common stock by the selling stockholder in the event the underwriter exercises the over-allotment option in whole or in part.

Table of Contents

**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-KSB 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 Annual Report on Form 10-KSB, 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 properties located along the Louisiana Gulf Coast. Our operations are concentrated in two fields: West Cote Blanche Bay, or WCBB, and the Hackberry fields. We also hold ownership interests in entities that operate in Southeast Asia, Canada and the Williston Basin area of western North Dakota and eastern Montana. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

In 2006, at our WCBB field we drilled 27 wells and recompleted 18 existing wells for a total cost to date of \$45.3 million. Of our 27 new wells drilled at WCBB in 2006, 24 were completed as producing wells and three were non-productive. During 2007, we intend to drill 26 to 28 wells and recomplete 30 to 35 existing wells at our WCBB field for an estimated aggregate cost of \$50 million. From January 1, 2007 through August 9, 2007, at WCBB we drilled 14 new wells of which eleven were productive, one was waiting on completion, and two were non-productive.

During 2005, we completed a 3-D seismic shoot at our East Hackberry field. In 2006, we drilled one well in East Hackberry. From January 1, 2007 through August 9, 2007, at East Hackberry we drilled five wells in Lake Calcasieu and three wells on land. Four wells are producing and four are in the process of completion. We are currently drilling our ninth East Hackberry well of 2007.

As of December 31, 2006, we had 23.2 million barrels of oil equivalent, or MBOE, of proved reserves.

Recent Developments

Current Production. During the six months ended June 30, 2007, our total net production was 712,000 barrels of oil and 313,000 thousand cubic feet of gas, or Mcf, or 764,000 BOE, compared to 279,000 barrels of oil and 192,000 Mcf of gas, or 311,000 BOE, for the six months ended June 30, 2006. Our total net production averaged approximately 4,220 BOE per day during the six months ended June 30, 2007, compared to 1,730 BOE per day during the same period in 2006. Production for the six months ended June 30, 2006 was negatively impacted by the damage caused by Hurricane Rita, as production from our wells at WCBB was not fully restored until later in 2006.

Table of Contents

WCBB. From January 1, 2007 through August 9, 2007, we drilled 14 new wells of which eleven were productive, one was waiting on completion, and two were non-productive. The eleven productive wells, with total depths ranging from 6,107 to 10,464 feet, have approximately 1,520 feet of aggregate apparent net pay. As of August 9, 2007, we are currently drilling our fifteenth and sixteenth 2007 well at WCBB.

Aggregate net production from the WCBB field during the six months ended June 30, 2007 was 701,000 BOE, 94% of which was from oil and 6% of which was from natural gas. In July 2007, average daily net production at WCBB was approximately 4,567 BOE, 93% of which was from oil and 7% of which was from natural gas.

East Hackberry Field. During 2005, we completed a proprietary 42 square mile 3-D seismic survey at East Hackberry. Given that drilling activities at the East Hackberry field prior to our acquisition of the field in 1997 were undertaken without the benefit of modern seismic information, we believe that the acquired 3-D seismic data has enhanced our probability of drilling success. We continue to evaluate the 3-D seismic data to identify additional drilling locations. From January 1, 2007 through August 9, 2007, we drilled eight wells and are in the process of drilling our ninth East Hackberry well of 2007. Four of the wells are producing and four are in the process of completion. Drilling activity in this field will target measured depths ranging from approximately 8,000 to 13,000 feet using directional drilling techniques. We have now completed the installation of our new production barge facility and are currently producing four wells into the facility. We recently added an additional 1,000 acres to our East Hackberry leasehold and now hold approximately 7,500 acres in the field. We anticipate that our total capital expenditures at East Hackberry during 2007 will be approximately \$60 million to \$70 million.

Aggregate net production from the East Hackberry field during the six months ended June 30, 2007 was 38,000 BOE, 90% of which was from oil and 10% of which was from natural gas. In July 2007, average daily net production at East Hackberry was approximately 752 BOE, 68% of which was from oil and 32% of which was from natural gas.

West Hackberry Field. There have been 36 wells drilled to date on our portion of West Hackberry. Currently, three are producing, 24 are shut-in and one has been converted to a saltwater disposal well. The remaining eight wells have been plugged and abandoned.

Aggregate net production from the West Hackberry field during the six months ended June 30, 2007 was 9,000 BOE. In July 2007, average daily net production at West Hackberry was approximately 54 BOE.

Insurance Coverage. We sustained damage to both our Hackberry field located in Cameron Parish, Louisiana and our WCBB field located in St. Mary Parish, Louisiana as a result of Hurricane Rita in September 2005. As of June 30, 2007, we had incurred costs of \$14,388,000 relating to the damage to the fields and facilities. Of this amount, \$250,000 represents insurance deductible amounts that were expensed to lease operating expenses in 2005. We received \$8,396,000 in insurance proceeds related to physical damage, of which \$541,000 was received in the first quarter of 2007, which are reflected as investing activity in the consolidated statements of cash flows. Approximately \$5,634,000 of costs incurred during 2006 and 2007 related to equipment and facilities replacement costs which will not be reimbursed by insurance and is included in the full cost pool. Approximately \$108,000 previously included in insurance settlement receivables was not collected and was expensed in fourth quarter 2006. We had collected all outstanding insurance receivable amounts related to physical damage insurance as of the end of the first quarter 2007.

We also maintained business interruption insurance to cover lost production revenue in the event of shut-in production. The business interruption insurance began 60 days after the occurrence of the insurable event, subject to a daily limit of \$45,000 and had a maximum coverage of 180 days. Coverage began on November 24, 2005 for shut-in production caused by Hurricane Rita. For the three months and six months ended June 30, 2006, we recognized \$614,000 and \$3,269,000, respectively, of business interruption insurance proceeds in other income in the consolidated statements of operations. As of June 30, 2006, we had received proceeds of \$4,979,000 (\$1,710,000 of which was accrued in 2005) related to business interruption for the period of November 24, 2005 to May 1, 2006. Such recoveries are presented as operating cash flows in the consolidated statements of cash flows. All business interruption recoveries were collected in 2006.

During May 2007 we placed both our physical damage and business interruption insurance coverage with new carriers. We now have a total of \$10,000,000 in coverage which may be used in whole or in part on either physical damage or business interruption or any combination thereof. In addition, we separately insure our new barge production facility in our East Hackberry field.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. The preparation of these consolidated financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in Note 1 to our consolidated financial statements included in our annual report on Form 10-KSB for the fiscal year ended

Table of Contents

December 31, 2006, filed with the SEC on April 2, 2007. 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 \$1,536,000 at June 30, 2007 and \$1,459,000 at December 31, 2006. These costs are reviewed periodically by management for impairment, with the impairment provision included in the cost of oil and natural gas properties subject to amortization. Factors considered by management in its impairment assessment include our drilling results and those of other operators, the terms of oil and natural gas leases not held by production and available funds for exploration and development.

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

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

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

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

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

Table of Contents

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

the quality and quantity of available data;

the interpretation of that data;

the accuracy of various mandated economic assumptions; and

the judgments of the individuals preparing the estimates.

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

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

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

The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. Designation is established at the inception of a derivative, but re-designation is permitted. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of SFAS 133, changes in fair value are recognized in accumulated other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. We recognize any change in fair value resulting from ineffectiveness immediately in earnings. As of June 30, 2007, we had entered into forward sales contracts for the sale of 3,000 barrels of production per day for the month of June 2007 at a weighted average daily price of \$69.84 per barrel before transportation costs. For the period of July 2007 through May 2008, we have entered

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into forward sales contracts for the sale of 3,500 barrels of production per day at a weighted average daily price of \$70.31 per barrel before transportation costs. For the month of June 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 \$71.21 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.

Table of Contents**RESULTS OF OPERATIONS****Comparison of the Three Months Ended June 30, 2007 and 2006**

We reported net income of \$9,570,000 for the three months ended June 30, 2007, as compared to \$7,059,000 for the three months ended June 30, 2006. This 36% increase in net income was due primarily to a 71% increase in net production to 396,000 BOE for the quarter ended June 30, 2007 from 232,000 BOE for the same period in 2006.

Oil and Gas Revenues. For the three months ended June 30, 2007, we reported oil and gas revenues of \$25,019,000 compared to oil and gas revenues of \$14,349,000 during the same period in 2006. This \$10,670,000, or 74%, increase in revenues is primarily attributable to a 71% increase in net production to 396,000 BOE for the quarter ended June 30, 2007 from 232,000 BOE for the same period in 2006. Production for the same period in the 2006 period was negatively impacted by the damage caused by Hurricane Rita, as production from our wells at WCBB was not fully restored until later in 2006.

The following table summarizes our oil and natural gas production and related pricing for the three months ended June 30, 2007 and 2006:

	Three Months Ended June 30,	
	2007	2006
Oil production volumes (MBbls)	370	215
Gas production volumes (MMcf)	155	100
Average oil price (per Bbl)	\$ 63.88	\$ 64.37
Average gas price (per Mcf)	\$ 8.91	\$ 5.03

Lease Operating Expenses. Lease operating expenses not including production taxes increased to \$3,942,000 for the three months ended June 30, 2007 from \$2,255,000 for the same period in 2006. Since our WCBB facilities continued to be shut in until late in the first quarter of 2006 due to the impact of Hurricane Rita, much of the costs normally associated with our lease operating expenses were instead spent on restoration and repair activities for the second quarter of 2006. Lease operating expenses for the second quarter of 2007 increased due to increases in labor costs and non-recurring repairs and were partially offset by a reduction in lease operating expenses attributable to our interest in the Marquiss field which we sold during February 2007.

Production Taxes. Production taxes increased to \$3,025,000 for the six months ended June 30, 2007 from \$1,921,000 for the same period in 2006. This increase was directly related to a 74% increase in oil and gas revenues as a result of the increase in production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased to \$6,613,000 for the three months ended June 30, 2007, and consisted of \$6,500,000 in depletion on oil and natural gas properties and \$113,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of \$2,743,000 for the three months ended June 30, 2006. This increase was due primarily to an increase in our production, an increase in our oil and natural gas property costs associated with our 2006 and 2007 drilling programs and an increase in our future developments costs.

General and Administrative Expenses. Net general and administrative expenses increased to \$1,154,000 for the three months ended June 30, 2007 from \$513,000 for the same period in 2006. This increase was due primarily to general increases in payroll costs and related benefits, increases in the total number of employees and increases in the effect of SFAS No. 123(R), *Share Based Payment*. These increases were partially offset by an increase in general and administrative reimbursements from our affiliates.

Accretion Expense. Accretion expense decreased to \$139,000 for the three months ended June 30, 2007 from \$149,000 for the same period in 2006. Although there was a larger obligation at the beginning of 2007 than there was at the beginning of 2006 resulting from the addition of future abandonment obligations on new wells drilled during 2006, the effect of the increase on the larger obligations was more than offset by the effect of the sale of the Marquiss properties in February 2007.

Table of Contents

Interest Expense. Interest expense increased to \$685,000 for the three months ended June 30, 2007 from \$397,000 for the same period in 2006 due to an increase in average debt outstanding. Total debt outstanding under our facility with Bank of America was \$25.0 million as of June 30, 2007 and \$15.1 million as of the same date in 2006.

Income Taxes. As of June 30, 2007, we had a net operating loss carry forward of approximately \$95.9 million, in addition to numerous temporary differences, which gave rise to a deferred tax asset. Periodically, management performs a forecast of our 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 June 30, 2007, a valuation allowance of \$25.6 million had been provided for deferred tax assets. We had no income tax expense for the three months ended June 30, 2007.

As of June 30, 2006, we had a net operating loss carry forward of approximately \$100.1 million, in addition to numerous temporary differences, which gave rise to a deferred tax asset. At June 30, 2006, a valuation allowance of \$38.0 million had been provided for deferred tax assets. We had no income tax expense due to a change in the valuation allowance for deferred income taxes for the three months ended June 30, 2006.

Comparison of the Six Months Ended June 30, 2007 and 2006

We reported net income of \$16,857,000 for the six months ended June 30, 2007, compared to \$9,887,000 for the six months ended June 30, 2006. This 71% increase in net income was due primarily to a 145% increase in net production to 764,000 BOE for the six months ended June 30, 2007 from 311,000 BOE for the same period in 2006.

Oil and Gas Revenues. For the six months ended June 30, 2007, we reported oil and gas revenues of \$45,381,000, compared to oil and gas revenues of \$18,798,000 during the same period in 2006. This \$26,583,000, or 141%, increase in revenues is primarily attributable to a 145% increase in net production to 764,000 BOE for the six months ended June 30, 2007 from 311,000 BOE for the same period in 2006. Production in the 2006 period was negatively impacted by the damage caused by Hurricane Rita, as production from our wells at WCBB was not fully restored until later in 2006.

The following table summarizes our oil and natural gas production and related pricing for the six months ended June 30, 2007 and 2006:

	Six Months Ended June 30,	
	2007	2006
Oil production volumes (MBbls)	712	279
Gas production volumes (MMcf)	313	192
Average oil price (per Bbl)	\$ 60.28	\$ 63.53
Average gas price (per Mcf)	\$ 7.96	\$ 5.45

Lease Operating Expenses. Lease operating expenses not including production taxes increased to \$7,119,000 for the six months ended June 30, 2007 from \$3,606,000 for the same period in 2006. Since our WCBB facilities continued to be shut in until late in the first quarter of 2006 due to the impact of Hurricane Rita, much of the costs normally associated with our lease operating expenses were instead spent on restoration and repair activities for the second quarter of 2006. Lease operating expenses for the six months ended June 30, 2007 increased due to increases in labor costs and non-recurring repairs and were partially offset by a reduction in lease operating expenses attributable to our interest in the Marquiss field which we sold during February 2007.

Production Taxes. Production taxes increased to \$5,470,000 for the six months ended June 30, 2007 from \$2,486,000 for the same period in 2006. This increase was directly related to a 141% increase in oil and gas revenues as a result of the increase in production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased to \$12,283,000 for the six months ended June 30, 2006, and consisted of \$12,063,000 in depletion on oil and natural gas properties and \$220,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of \$3,736,000 for the six months ended June 30, 2006. This increase was due primarily to an increase in our production, an increase in our oil and natural gas property costs associated with our 2006 and 2007 drilling programs and an increase in our future developments costs.

Table of Contents

General and Administrative Expenses. Net general and administrative expenses increased to \$2,235,000 for the six months ended June 30, 2007 from \$1,514,000 for the same period in 2006. This increase was due primarily to general increases in payroll costs and related benefits, increases in the total number of employees and increases in the effect of SFAS No. 123(R), *Share Based Payment*. These increases were partially offset by an increase in general and administrative reimbursements from our affiliates and a decrease in legal expenses and corporate fees.

Accretion Expense. Accretion expense decreased to \$277,000 for the six months ended June 30, 2007 from \$298,000 for the same period in 2006. Although there was a larger obligation at the beginning of 2007 than there was at the beginning of 2006 resulting from the addition of future abandonment obligations on new wells drilled during 2006, the effect of the increase on the larger obligations was more than offset by the effect of the sale of the Marquiss properties in February 2007.

Interest Expense. Interest expense increased to \$1,325,000 for the six months ended June 30, 2007 from \$668,000 for the same period in 2006 due to an increase in average debt outstanding. Total debt outstanding under our facility with Bank of America was \$25.0 million as of June 30, 2007 and \$15.1 million as of the same date in 2006.

Income Taxes. As of June 30, 2007, we had a net operating loss carry forward of approximately \$95.9 million, in addition to numerous temporary differences, which gave rise to a deferred tax asset. Periodically, management performs a forecast of our 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 June 30, 2007, a valuation allowance of \$25.6 million had been provided for deferred tax assets. We had only a slight income tax expense of \$53,000 during the six months ended June 30, 2007 related to the payment of alternative minimum taxes. Although we have substantial net operating loss carryforwards, these cannot be used to offset alternative minimum tax liabilities.

As of June 30, 2006, we had a net operating loss carry forward of approximately \$100.1 million, in addition to numerous temporary differences, which gave rise to a deferred tax asset. At June 30, 2006, a valuation allowance of \$38.0 million had been provided for deferred tax assets. We had no income tax expense due to a change in the valuation allowance for deferred income taxes for the three months ended June 30, 2006.

Liquidity and Capital Resources

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

Net cash flow provided by operating activities was \$24,884,000 for the six months ended June 30, 2007 as compared to net cash flow provided by operating activities of \$12,354,000 for the same period in 2006. This increase was primarily the result of an increase in cash receipts from our oil and gas purchasers due to a 145% increase in net production, partially offset by increases in cash paid for lease operating expenses and production taxes.

Net cash used in investing activities for the six months ended June 30, 2007 was \$66,670,000 as compared to \$25,233,000 for the same period in 2006. During the six months ended June 30, 2007, we spent \$59,551,000 in additions to oil and natural gas properties, of which \$29,063,000 was spent on our 2007 drilling program, \$11,940,000 was spent on expenses attributable to the wells drilled during 2006, \$8,050,000 was spent on our new Hackberry barge facilities, \$2,813,000 was spent on additions to oil and natural gas properties due to Hurricane Rita with the remainder attributable mainly to capitalized general and administrative expenses. During the first six months of 2007, we used cash from operations, proceeds from the sale of 3,047,500 shares of our common stock and borrowings under our credit facility to fund our investing activities.

Net cash provided by financing activities for the six months ended June 30, 2007 was \$37,296,000 as compared to \$17,738,000 for the same period in 2006. The 2007 amount provided by financing activities is primarily attributable to borrowings of \$25,500,000 under our credit facility with Bank of America and aggregate proceeds of approximately

Table of Contents

\$42.5 million from the sale of shares of our common stock in February 2007 and May 2007, after deducting the underwriting discount and before offering expenses and from the exercise of stock options. Net proceeds were used to pay down existing debt under our credit facility with Bank of America. The 2006 amount provided by financing activities is attributable to draws of \$18,500,000 on our credit facility with Bank of America and proceeds of \$9,990,000 from the issuance of common stock in our May 2006 underwritten public offering and the exercise of stock options.

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

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

In July 2007, we sold 1,000,000 shares of our common stock in an underwritten offering at an offering price to the public of \$22.00 per share. We received the net proceeds of approximately \$21.2 million from our sale of these shares on July 25, 2007 after deducting the underwriting discount and before offering expenses. In connection with the offering, a selling stockholder granted the underwriter a 30-day option to purchase up to an additional 150,000 shares of our common stock to cover over-allotments. We will not receive any proceeds from the sale of shares of our common stock by the selling stockholder in the event the underwriter exercises the over-allotment option in whole or in part.

Credit Facility. On March 11, 2005, we entered into a three-year secured revolving credit agreement, as amended, providing for a revolving credit facility with Bank of America, N.A. Borrowings under the revolving credit facility are subject to a borrowing base limitation, which was initially set at \$18.0 million, subject to adjustment. On November 1, 2005, the amount available under the borrowing base limitation was increased to \$23.0 million and was redetermined without change on May 30, 2006. On December 19, 2006, the amount available under the borrowing base limitation was increased to \$30.0 million. Effective July 19, 2007, the credit facility increased to \$150.0 million and the amount available under the borrowing base limitation was increased to \$60.0 million. The credit facility has a term of three years and all principal amounts of revolving loans outstanding under the credit facility, together with all accrued and unpaid interest and fees will be due and payable on March 11, 2008. The maturity date was subsequently amended to March 31 2009. We make quarterly interest payments on amounts borrowed under the facility, which amounts bear interest at Bank of America prime plus 0.25% (8.5% at June 30, 2007). Our obligations under the credit facility are collateralized by a lien on substantially all of our assets.

The credit facility contains certain affirmative and negative covenants, including, but not limited to the following financial covenants: (a) the ratio of current assets to current liabilities may not be less than 1.00 to 1.00; (b) the ratio of funded debt to EBITDAX (net income before deductions for taxes, excluding unrealized gains and losses related to trading securities and commodity hedges, plus depreciation, depletion, amortization and interest expense, plus exploration costs deducted in determining net income under full cost accounting) for a twelve-month period may not be greater than 2.00 to 1.00; and (c) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. The Company was not in compliance with the current ratio covenant at June 30, 2007; however, a waiver was obtained from the lender. As of June 30, 2007, approximately \$25.0 million was outstanding under this facility, which is included in long-term debt, net of current maturities on the accompanying consolidated balance sheet. We have used the proceeds of our borrowings under the credit facility for the exploration of our oil and natural gas properties and other capital expenditures, acquisition opportunities, replacement of facilities and equipment due to Hurricane Rita and for other general corporate purposes.

On July 10, 2006, we entered into a \$5.0 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 (8.25% at June 30, 2007). 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 June 30, 2007, approximately \$4.6 million was outstanding under this agreement, of which \$714,000 and \$3,933,000 are included in current maturities of long-term debt and long-term debt, net of current maturities, respectively, on our accompanying consolidated balance sheet.

Table of Contents

Building Loans. We have three loans associated with two of our buildings. One loan, in the original principal amount of \$115,000, related to a building in Lafayette, Louisiana, that we purchased in 1996 to be used as our Louisiana headquarters. This loan matures in February 2008 and bears interest at the rate of 5.75% per annum. In addition, in June 2004 we purchased the office building we occupy in Oklahoma City, Oklahoma for \$3.7 million. One of the two loans associated with this building, with an original principal amount of \$389,000, matured in March 2006 and bore interest at a rate of 6% per annum. The other loan associated with this building, with an original principal amount of \$3.0 million, matures in June 2011 and bears interest at a rate of 6.5% per annum. All building loans require monthly interest and principal payments and are collateralized by the respective land and buildings.

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

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

Our inventory of prospects includes approximately 118 drilling locations at WCBB. The drilling schedule used in our December 31, 2006 reserve report anticipates that all of those wells will be drilled by 2016. From January 1, 2007 through August 9, 2007, we drilled 14 wells and recompleted 37 existing wells at our WCBB field. We currently intend to spend a total of approximately \$60 million in our WCBB field during 2007.

In our East Hackberry field, from January 1, 2007 through August 9, 2007, we drilled eight exploratory wells, are currently drilling one well and currently intend to drill three to five additional wells during 2007. Total capital expenditures for our East Hackberry field are estimated at \$60 million to \$70 million for 2007.

During the third quarter of 2006, we purchased a 25% interest in Grizzly Oils Sands ULC, or Grizzly, a Canadian unlimited liability company. The remaining interests in Grizzly are owned by other entities controlled by Wexford Capital LLC, an affiliate of ours. During 2006, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray within a few miles of other existing oil sands projects. As of June 30, 2007, our net investment in Grizzly was approximately \$14,722,000. Capital requirements in 2007 for this project are currently estimated to be approximately \$8.0 million, primarily for the expenses associated with our recently completed 62 well core hole drilling program and additional lease acquisitions.

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

Our total capital expenditures for 2007 are currently estimated to be \$120.0 million to \$130.0 million. We believe that our cash on hand, cash flow from operations, proceeds from issuance of equity, and borrowings under our credit facility will be sufficient to meet our normal recurring operating needs, debt service obligations, and our WCBB capital requirements for the next twelve months. With the added Hackberry activity or in the event we elect to further expand or accelerate our drilling programs, pursue acquisitions or accelerate our Canadian oil sands project, we will be required to obtain additional funds which we may do so through traditional borrowings, offerings of debt or equity securities or other means, including the sale of assets. Needed capital may not be available to us on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to delay or curtail implementation of our business plan or not be able to complete acquisitions that may be favorable to us.

Commodity Price Risk

To mitigate the effects of commodity price fluctuations, during the second quarter of 2007, we entered into agreements to sell 3,000 barrels of production per day for the month of June 2007 at a weighted average daily price of

Table of Contents

\$69.84 per barrel before transportation costs. For the period of July 2007 through May 2008, we have agreements to sell 3,500 barrels of production per day at a weighted average daily price of \$70.31 per barrel before transportation costs. For the month of June 2008 we have agreements to sell 3,500 barrels of production per day at a weighted average daily price of \$71.21 per barrel before transportation costs. Under these agreements we have committed to deliver approximately 71% of our estimated production for June through December 2007. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These 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 June 30, 2007, the plugging and abandonment trust totaled approximately \$3,046,000, including interest received during 2007 of approximately \$67,000. We have plugged 231 wells at WCBB since we began our plugging program in 1997, which management believes fulfills our minimum plugging obligation through March 31, 2007.

New Accounting Pronouncements

We adopted FASB Interpretation Number 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109*, as of January 1, 2007. The adoption of this Interpretation had no effect on our consolidated financial statements. We are subject to U.S. federal income tax as well as income tax of multiple state jurisdictions. Our 2003-2006 U.S. federal and state income tax returns remain open to examination by the Internal Revenue Service. We are continuing our practice of recognizing interest and/or penalties related to income tax matters as general and administrative expenses.

SFAS 157

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

SFAS No. 159

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

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.

Table of Contents

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, over the last three years, the West Texas Intermediate posted price for crude oil has ranged from a low of \$30.83 per barrel, or bbl, in January 2004 to a high of \$71.17 per bbl in July 2006. The Henry Hub spot market price of natural gas has ranged from a low of \$4.20 per million British thermal units, or MMBtu, in October 2006 to a high of \$13.93 per MMBtu in October 2005. Until recently, these prices have generally been at historically high levels. On June 30, 2007, the West Texas Intermediate posted price for crude oil was \$67.40 per bbl for crude oil and the Henry Hub spot market price of natural gas was \$6.795 per MMBtu. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves, and may result in write downs of oil and natural gas properties due to ceiling test limitations. To mitigate the effects of commodity price fluctuations, in the second quarter of 2007, we entered into forward sales contracts to deliver 3,000 barrels of production per day for the month of June 2007 at a weighted average daily price of \$69.84 per barrel before transportation costs. For the period of July 2007 through May 2008, we have committed to 3,500 barrels of production per day at a weighted average daily price of \$70.31 per barrel before transportation costs. For the month of June 2008, we have agreements to sell 3,500 barrels of production per day at a weighted average daily price of \$71.21 per barrel before transportation costs. Under these agreements we have committed to deliver approximately 71% of our estimated production for June through December 2007. Such arrangements, however, may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. In addition, these arrangements may limit the benefit to us of increases in the price of oil.

Our credit facility and term loan with Bank of America are structured under floating rate terms and, as such, our interest expense is sensitive to fluctuations in the prime rates in the U.S. Borrowings under our revolving credit facility with Bank of America bear interest at Bank of America prime plus 0.25% (8.5% at June 30, 2007). Borrowings under our term loan with Bank of America bear interest at Bank of America prime (8.25% at June 30, 2007). Based on the current debt structure, a 1% increase in interest rates would increase interest expense by approximately \$250,000 per year, based on an aggregate of \$25 million outstanding under our credit facilities as of June 30, 2007. As of June 30, 2007, 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 we are required to disclose 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 our management, including the Chief Executive Officer and Vice President and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

As of June 30, 2007, an evaluation was performed under the supervision and with the participation of our management, including the 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 June 30, 2007, 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 the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

Table of Contents**PART II. OTHER INFORMATION****ITEM 1. LEGAL PROCEEDINGS**

The Louisiana State Mineral Board is disputing our royalty payments to the State of Louisiana resulting from the sale of oil under fixed price contracts. The Board maintains that we paid approximately \$1,400,000 less in royalties under the fixed price contracts than the royalties we would have had to pay had we sold the oil at prevailing market rates. We have denied any liability to the Board for underpayment of royalties and have maintained that we were entitled to enter into the fixed price contracts with unrelated third parties and pay royalties based upon the sales proceeds from those contracts. Over the past several months, we met with the Attorney General on several occasions and recently reached a mutual settlement. The settlement requires Gulfport to pay \$250,000, which has been accrued in our financial statements, and all future royalties will be paid at market price, regardless of the presence of fixed price contracts. We are currently working with the Attorney General to finalize the agreement and expect to receive approval during the Mineral Board's September 2007 meeting.

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

On October 13, 2006, Athena Construction LLC, or Athena, the owner of the two barges, filed a limitation action in the United States District Court for the Eastern District of Louisiana, alleging that all losses and damages as a result of the pipeline incident were incurred without fault on its part. Furthermore, Athena claims the benefit of the limitation of liability provided for in 42 U.S.C. § 183 and seeks an injunction restraining the commencement and prosecution of any further lawsuits against Athena, which are related to the pipeline incident. The limitation of liability action was subsequently transferred to the United States District Court for the Western District of Louisiana, where the case is pending. On December 20, 2006, 4-K Marine LLC, as owner of the M/V Miss Megan, and Central Boat Rentals, Inc., as operator of the M/V Miss Megan also filed a limitation action in the Western District. On January 10, 2007, the Athena and the 4-K/Central Boat limitation proceedings were consolidated by order of the Court. On May 5, 2007 Diamondback Energy Services LLC, one of our affiliates, filed an intervener with the Court to become a party to the suit. All claims related to the death of Mr. Timothy Tauzin were dismissed by order of the court on June 8, 2007 and June 12, 2007 following successful settlement negotiations. Mr. Tauzin was an employee of Central Boat Rentals and was the captain of the tug boat involved in the accident. 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. A record hearing has been set for August 13, 2007, to discuss the status of the consolidated matters. No other deadlines have been set.

On October 16, 2006, a lawsuit was filed in the 16th Judicial District Court for the Parish of St. Mary, Louisiana against us, Athena and Central Boat seeking compensatory and punitive damages for claims related to the death of the plaintiff's husband, a crewmember on the Athena barge. The suit alleges that the husband's death was caused by the defendants' negligence and the unseaworthiness of the barge to which he was assigned. Under the Blanket Time Charter between Central Boat, and us Central Boat tendered the defense and indemnification of the lawsuit to us. On November 2, 2006, all proceedings were stayed as a result of the limitation of liability action discussed above.

On October 22, 2006, a lawsuit was filed in United States District Court for the Southern District of Texas, Galveston Division against us, Central Boat, Diamondback Energy Services LLC, one of our affiliates, Chevron Pipeline Company, Chevron USA, Inc., and ChevronTexaco Pipeline Holdings, Inc. This lawsuit is a result of the death of three individuals employed by Athena and on the barge at the time of the accident. The plaintiffs seek compensatory and punitive damages as a result of the alleged negligence of defendants. Central Boat has tendered the defense and indemnification of this lawsuit to us. On April 30, 2007, an order was filed transferring the case to the Western District of Louisiana. At this time, no deadlines have been set.

On February 2, 2007, a lawsuit was filed in the United States District Court for the Western District of Louisiana, Lafayette Division against Chevron Pipeline Company, Chevron USA Inc., Chevron Texaco Pipeline Holdings, Inc., Chevron Natural Gas Services Inc., Diamondback Energy Services LLC, one of our affiliates, and us. The suit was filed on behalf of April Hummel, individually and as the representative of the minor, Aleya Hummel, the surviving child of Terry Abraham, who died in the accident. On March 27, 2007

we filed our answer. No other deadlines have been set.

Table of Contents

On January 11, 2007, plaintiffs Janet Rink, individually and as the personal representative of the Estate of Kenneth Rink, Tysie Rink and Scott Rink filed a lawsuit in the United States District Court for the Western District of Louisiana against defendants Chevron Pipeline Company, Chevron USA, Inc., ChevronTexaco Pipeline Holdings, Inc., Chevron Natural Gas Services, Inc., us and Diamondback Energy Services LLC, one of our affiliates. All parties reached a mutually agreeable settlement on June 27, 2007, and are currently working to document the settlement, release and dismissal of this action.

In November 2006, Cudd Pressure Control, Inc., or Cudd, filed a lawsuit 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, as well as conspiracy to misappropriate trade secrets to secure breach of fiduciary duty, misappropriation of trade secrets and unfair competition relating to an affiliate company's employment of several former Cudd employees and seeks unspecified monetary damages and injunctive relief. The defendants in the suit are Ronnie Roles, Rocky Roles, Steve Winters, Bert Ballard, Nelson Britton, Michael Fields, Steve Bickle, Great White Pressure Control LLC, one of our affiliates, and us. On stipulation by the parties, the plaintiff's RICO claim was dismissed without prejudice by order of the court on February 14, 2007. Co-defendant, Steve Bickle, was dismissed from the case on July 18, 2007. The case against us was stayed by order of the Court on July 31, 2007. The Court further ordered co-defendant, Great White Pressure Control, to move for summary judgment by August 24, 2007. Plaintiff, Cudd Pressure Control, was ordered to respond by September 14, 2007. The next pretrial conference is set for September 24, 2007.

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 alleges a 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, and are currently working to respond accordingly.

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

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

ITEM 1A. RISK FACTORS.

There have been no material changes from risk factors as previously disclosed in our Annual Report on Form 10-KSB for the year ended December 31, 2006.

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 six months ended June 30, 2007, we did not purchase any shares of our common stock.

Table of Contents**ITEM 3. DEFAULTS UPON SENIOR SECURITIES**

Not applicable.

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

(a) The Company held its Annual Meeting of Stockholders on June 13, 2007.

(b) Mike Liddell, Robert E. Brooks, David L. Houston, James D. Palm and Scott E. Streller were each elected to continue to serve as directors of the Company until the 2008 Annual Meeting of Stockholders of the Company and until their respective successors are elected and qualified.

(c) Two proposals were approved by the Company's stockholders at the 2007 Annual Meeting, with the following vote tabulation:

Proposal 1 Election of Directors.

Directors	For	Withheld
Mike Liddell	29,084,192	568,409
Robert E. Brooks	29,094,559	558,042
David L. Houston	29,094,559	558,042
James D. Palm	29,092,145	560,456
Scott E. Streller	29,083,529	569,072

Proposal No. 2 To ratify the appointment of Grant Thornton LLP as the Company's independent auditors for the fiscal year ending December 31, 2007.

	For	Against	Abstain
Ratification of auditors	29,209,053	443,484	64

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	Bylaws (incorporated by reference to Exhibit 3.2 to Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on December 1, 1997).
4.1	Form of Common Stock certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
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).

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- 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).

Table of Contents

- 4.4 Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.3 of Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on November 11, 2005).
- 4.5 Amendment No. 1, dated February 14, 2006, to the Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.15 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2006).
- 10.1 Second Amendment to Credit Agreement, dated as of July 19, 2007, between the Company and Bank of America, N.A. (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 19, 2007).
- 10.2 Note dated July 19, 2007 issued by the Company for the benefit of Bank of America, N.A. (incorporated by reference to Exhibit 10.2 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 19, 2007).
- 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.

Table of Contents

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: August 14, 2007

GULFPORT ENERGY CORPORATION

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

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

Table of Contents

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