GULFPORT ENERGY CORP
Form 10-Q
November 05, 2013
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

ý QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED September 30, 2013
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	73134
(Address of Principal Executive Offices)	(Zip Code)

(405) 848-8807
(Registrant Telephone Number, Including Area Code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨

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

Large Accelerated Filer	x	Accelerated Filer	¨

Non-Accelerated Filer	¨	Smaller Reporting Company	¨

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

As of November 1, 2013, 77,584,405 shares of common stock were outstanding.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2013	December 31, 2012
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$95,466	$167,088
Accounts receivable—oil and gas	47,673	25,615
Accounts receivable—related parties	29,797	34,848
Prepaid expenses and other current assets	4,634	1,506
Deferred tax asset	787	—
Short-term derivative instruments	1,633	664
Note receivable - related party	875	—
Total current assets	180,865	229,721
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $952,697 and $626,295 excluded from amortization in 2013 and 2012, respectively	2,253,605	1,611,090
Other property and equipment	10,164	8,662
Accumulated depletion, depreciation, amortization and impairment	(747,698)	(665,884)
Property and equipment, net	1,516,071	953,868
Other assets:		
Equity investments ($242,174 and $151,317 attributable to fair value option in 2013 and 2012, respectively)	500,679	381,484
Derivative instruments	127	—
Other assets	12,827	13,295
Total other assets	513,633	394,779
Total assets	$2,210,569	$1,578,368
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$179,357	$110,244
Asset retirement obligation—current	780	60
Short-term derivative instruments	4,808	10,442
Current maturities of long-term debt	156	150
Total current liabilities	185,101	120,896
Long-term derivative instrument	962	—
Asset retirement obligation—long-term	13,988	13,215
Deferred tax liability	93,957	18,607
Long-term debt, net of current maturities	298,992	298,888
Other non-current liabilities	—	354
Total liabilities	593,000	451,960
Commitments and contingencies (Note 11)		
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, 200,000,000 authorized, 77,584,405 issued and outstanding in 2013 and 67,527,386 in 2012	775	674

Paid-in capital	1,399,803	1,036,245
Accumulated other comprehensive loss	(4,841)	(3,429)
Retained earnings	221,832	92,918
Total stockholders’ equity	1,617,569	1,126,408
Total liabilities and stockholders’ equity	$2,210,569	$1,578,368

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
	(In thousands, except share data)			
Revenues:				
Oil and condensate sales	$52,972	$58,609	$167,051	$187,633
Gas sales	10,755	973	19,014	2,127
Natural gas liquid sales	5,100	874	7,828	2,374
Other income	425	81	793	189
	69,252	60,537	194,686	192,323
Costs and expenses:				
Lease operating expenses	7,297	6,638	18,347	18,201
Production taxes	7,071	6,974	20,381	22,228
Midstream transportation, processing and marketing	3,622	96	5,940	183
Depreciation, depletion, and amortization	30,691	25,377	81,814	70,424
General and administrative	5,259	3,098	14,571	9,370
Accretion expense	180	176	529	529
(Gain) loss on sale of assets	(5)	—	567	—
	54,115	42,359	142,149	120,935
INCOME FROM OPERATIONS	15,137	18,178	52,537	71,388
OTHER (INCOME) EXPENSE:				
Interest expense	2,602	1,003	9,365	1,630
Interest income	(70)	(6)	(211)	(37)
(Income) loss from equity method investments	(51,322)	1,165	(162,640)	1,793
	(48,790)	2,162	(153,486)	3,386
INCOME BEFORE INCOME TAXES	63,927	16,016	206,023	68,002
INCOME TAX EXPENSE	23,400	15,514	77,109	15,514
NET INCOME	$40,527	$502	$128,914	$52,488
NET INCOME PER COMMON SHARE:				
Basic	$0.52	$0.01	$1.70	$0.94
Diluted	$0.52	$0.01	$1.69	$0.93
Weighted average common shares outstanding—Basic	77,554,386	55,692,664	75,955,040	55,658,507
Weighted average common shares outstanding—Diluted	77,931,738	56,291,792	76,374,107	56,174,581

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
Net income	$40,527	$502	$128,914	$52,488
Foreign currency translation adjustment	3,894	5,320	(5,786)	3,394
Change in fair value of derivative instruments (1)	630	(19,251)	(444)	(11,678)
Reclassification of settled contracts (2)	1,617	185	4,818	646
Other comprehensive income (loss)	6,141	(13,746)	(1,412)	(7,638)
Comprehensive income	$46,668	$(13,244)	$127,502	$44,850

(1) Net of $0.4 million and $(0.3) million in taxes for the three and nine months ended September 30, 2013, respectively. No taxes were recorded in the three and nine months ended September 30, 2012.

(2) Net of $1.0 million and $3.0 million in taxes for the three and nine months ended September 30, 2013, respectively. No taxes were recorded in the three and nine months ended September 30, 2012.

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(Unaudited)

	Common Stock		Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Stockholders' Equity
	Shares	Amount				
	(In thousands, except share data)					
Balance at January 1, 2013	67,527,386	$674	$1,036,245	$ (3,429)	$92,918	$1,126,408
Net income	—	—	—	—	128,914	128,914
Other Comprehensive Loss	—	—	—	(1,412)	—	(1,412)
Stock Compensation	—	—	4,619	—	—	4,619
Issuance of Common Stock in public offerings, net of related expenses	9,812,500	99	357,541	—	—	357,640
Issuance of Restricted Stock	119,519	1	(1)	—	—	—
Issuance of Common Stock through exercise of options	125,000	1	1,399			1,400
Balance at September 30, 2013	77,584,405	$775	$1,399,803	$ (4,841)	$221,832	$1,617,569
Balance at January 1, 2012	55,621,371	$556	$604,584	$ 2,663	$24,547	$632,350
Net income	—	—	—	—	52,488	52,488
Other Comprehensive Loss	—	—	—	(7,638)	—	(7,638)
Stock Compensation	—	—	3,427	—	—	3,427
Issuance of Restricted Stock	96,331	1	(1)	—	—	—
Balance at September 30, 2012	55,717,702	$557	$608,010	$ (4,975)	$77,035	$680,627

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30,	
	2013	2012
	(In thousands)	
Cash flows from operating activities:		
Net income	$128,914	$52,488
Adjustments to reconcile net income to net cash provided by operating activities:		
Accretion of discount—Asset Retirement Obligation	529	529
Depletion, depreciation and amortization	81,814	70,424
Stock-based compensation expense	2,771	2,056
(Gain) loss from equity investments	(162,265)	1,793
Interest income - note receivable	(13)	(2)
Unrealized loss on derivative instruments	1,311	100
Deferred income tax expense	77,107	15,514
Amortization of loan commitment fees	750	405
Amortization of note discount and premium	221	—
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	(22,058)	3,199
Decrease (increase) in accounts receivable—related party	5,051	(6,184)
Increase in prepaid expenses	(3,128)	(1,461)
Increase in accounts payable and accrued liabilities	30,833	28,017
Settlement of asset retirement obligation	(807)	(1,002)
Net cash provided by operating activities	141,030	165,876
Cash flows from investing activities:		
Deductions to cash held in escrow	8	8
Additions to other property and equipment	(1,502)	(599)
Additions to oil and gas properties	(608,270)	(269,177)
Proceeds from sale of other property and equipment	—	140
Advances on note receivable to related party	(875)	—
Proceeds from sale of investments	74,544	—
Contributions to equity method investments	(34,936)	(118,975)
Distributions from equity method investments	203	710
Net cash used in investing activities	(570,828)	(387,893)
Cash flows from financing activities:		
Principal payments on borrowings	(111)	(12,103)
Borrowings on line of credit	—	153,000
Debt issuance costs and loan commitment fees	(753)	(497)
Proceeds from issuance of common stock, net of offering costs	359,040	—
Net cash provided by financing activities	358,176	140,400
Net decrease in cash and cash equivalents	(71,622)	(81,617)
Cash and cash equivalents at beginning of period	167,088	93,897
Cash and cash equivalents at end of period	$95,466	$12,280
Supplemental disclosure of cash flow information:		
Interest payments	$12,618	$941

Income tax payments	$2,751	$255
Supplemental disclosure of non-cash transactions:		
Capitalized stock based compensation	$1,848	$1,371
Asset retirement obligation capitalized	$1,771	$1,711
Interest capitalized	$9,013	$—
Foreign currency translation (loss) gain on investment in Grizzly Oil Sands ULC	$(5,786)	$3,394

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

These consolidated financial statements have been prepared by Gulfport Energy Corporation (the “Company” or “Gulfport”) without audit, pursuant to the rules and regulations of the Securities and Exchange Commission (the "SEC"), and reflect all adjustments which, in the opinion of management, are necessary for a fair presentation of the results for the interim periods, on a basis consistent with the annual audited consolidated financial statements. All such adjustments are of a normal recurring nature. Certain information, accounting policies, and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been omitted pursuant to such rules and regulations, although the Company believes that the disclosures are adequate to make the information presented not misleading. These consolidated financial statements should be read in conjunction with the consolidated financial statements and the summary of significant accounting policies and notes thereto included in the Company's most recent annual report on Form 10-K. Results for the three and nine month periods ended September 30, 2013 are not necessarily indicative of the results expected for the full year.

1. ACQUISITIONS

Beginning in February 2011, the Company entered into agreements to acquire certain leasehold interests located in the Utica Shale in Ohio. Certain of the agreements also granted the Company an exclusive right of first refusal for a period of six months to acquire certain additional tracts leased by the seller. Affiliates of Gulfport initially participated with the Company on a 50/50 basis in the acquisition of all leases described above. On December 17, 2012, Gulfport entered into a definitive agreement to purchase approximately 30,000 net acres in the Utica Shale in Eastern Ohio for approximately $302.0 million. On December 19, 2012, the parties amended that agreement to provide for Gulfport's acquisition of approximately 7,000 additional net acres for approximately $70.0 million, resulting in a total purchase price of approximately $372.0 million, subject to certain adjustments. This transaction closed on December 24, 2012. At closing, approximately $53.9 million of the purchase price was placed in escrow pending completion of title review after the closing. Gulfport funded this acquisition with a portion of the net proceeds from its common stock offering that closed on December 24, 2012 (with a second closing for the underwriters' purchase of 900,000 shares pursuant to their over-allotment option on January 7, 2013). The Company received aggregate net proceeds of approximately $460.7 million from this equity offering, as discussed below in Note 7.

On February 15, 2013, the Company completed an acquisition of approximately 22,000 net acres in the Utica Shale in Eastern Ohio. The purchase price was approximately $220.0 million, subject to certain adjustments. At closing, approximately $33.6 million of the purchase price was placed in escrow pending completion of title review after the closing. Gulfport funded this acquisition with a portion of the net proceeds from its common stock offering that closed on February 15, 2013. The Company received aggregate net proceeds of approximately $325.8 million from this equity offering. In the February 2013 transaction, the Company acquired an additional approximately 16.2% interest in these leases, increasing its working interest in the acreage to 93.8%. All of the acreage included in these transactions was nonproducing at the time of the applicable transaction and the Company is the operator of all of this acreage, subject to existing development and operating agreements between the parties. These acquisitions excluded the seller's interest in 14 existing wells and 16 proposed future wells together with certain acreage surrounding these wells.

In May 2013, both escrow accounts terminated and an aggregate of $10.0 million was returned to the Company. The balance of the escrow accounts was distributed to the seller based on the results of the title review.

2. ACCOUNTS RECEIVABLE—RELATED PARTIES

Included in the accompanying consolidated balance sheets as of September 30, 2013 and December 31, 2012 are amounts receivable from related parties of the Company. These receivables consist primarily of amounts billed by the Company to related parties as operator of such parties' Colorado and Ohio oil and natural gas properties. At September 30, 2013 and December 31, 2012, these receivables totaled $29.8 million and $34.8 million, respectively. Effective July 1, 2008, the Company entered into an acquisition team agreement with Everest Operations Management LLC ("Everest") to identify and evaluate potential oil and gas properties in which the Company and Everest or its affiliates may wish to invest. Upon a successful closing of an acquisition or divestiture, the party identifying the acquisition or divestiture is entitled to receive a fee from the other party and its affiliates, if applicable, participating in such closing. The fee is equal to 1% of the party’s proportionate share of the acquisition or divestiture consideration. The agreement may be terminated by either party upon 30 days notice. Affiliates of Everest were billed approximately $0.4 million and $0.9 million under this acquisition

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team agreement during the three and nine months ended September 30, 2012, respectively, which amounts are reflected as a reduction of general and administrative expenses in the consolidated statements of operations. Amounts billed under the acquisition team agreement during the three and nine months ended September 30, 2013 were immaterial.

3. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of September 30, 2013 and December 31, 2012 are as follows:

	September 30, 2013	December 31, 2012
	(In thousands)	
Oil and natural gas properties	$2,253,605	$1,611,090
Office furniture and fixtures	5,576	4,476
Building	4,176	3,926
Land	412	260
Total property and equipment	2,263,769	1,619,752
Accumulated depletion, depreciation, amortization and impairment	(747,698)	(665,884)
Property and equipment, net	$1,516,071	$953,868

Included in oil and natural gas properties at September 30, 2013 is the cumulative capitalization of $42.2 million 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 $3.5 million and $9.6 million for the three and nine months ended September 30, 2013, respectively, and $2.0 million and $6.2 million for the three and nine months ended September 30, 2012, respectively.

The following table summarizes the Company’s non-producing properties excluded from amortization by area at September 30, 2013:

	September 30, 2013
	(In thousands)
Colorado	$6,160
Bakken	312
Southern Louisiana	914
Ohio	945,261
Other	50
	$952,697

At December 31, 2012, approximately $626.3 million of non-producing leasehold costs was not subject to amortization.

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

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A reconciliation of the Company's asset retirement obligation for the nine months ended September 30, 2013 and 2012 is as follows:

	September 30, 2013	September 30, 2012
	(In thousands)	
Asset retirement obligation, beginning of period	$13,275	$12,653
Liabilities incurred	1,771	1,711
Liabilities settled	(807)	(1,002)
Accretion expense	529	529
Asset retirement obligation as of end of period	14,768	13,891
Less current portion	780	60
Asset retirement obligation, long-term	$13,988	$13,831

On May 7, 2012, the Company entered into a contribution agreement with Diamondback Energy Inc. ("Diamondback"). Under the terms of the contribution agreement, the Company agreed to contribute to Diamondback, prior to the closing of the Diamondback initial public offering ("Diamondback IPO"), all its oil and natural gas interests in the Permian Basin (the "Contribution"). The Contribution was completed on October 11, 2012. At the closing of the Contribution, Diamondback issued to the Company (i) 7,914,036 shares of Diamondback common stock and (ii) a promissory note for $63.6 million, which was repaid to the Company at the closing of the Diamondback IPO on October 17, 2012. This aggregate consideration was subject to a post-closing cash adjustment based on changes in the working capital, long-term debt and certain other items of Diamondback O&G LLC, formerly Windsor Permian LLC ("Diamondback O&G"), as of the date of the Contribution. In January 2013, the Company received an additional payment from Diamondback of approximately $18.6 million as a result of this post-closing adjustment. Diamondback O&G is a wholly-owned subsidiary of Diamondback. Under the contribution agreement, the Company is generally responsible for all liabilities and obligations with respect to the contributed properties arising prior to the Contribution and Diamondback is responsible for such liabilities and obligations with respect to the contributed properties arising after the Contribution.

In connection with the Contribution, the Company and Diamondback entered into an investor rights agreement under which the Company has the right, for so long as it beneficially owns more than 10% of Diamondback's outstanding common stock, to designate one individual as a nominee to serve on Diamondback's board of directors. Such nominee, if elected to Diamondback's board, will also serve on each committee of the board so long as he or she satisfies the independence and other requirements for service on the applicable committee of the board. So long as the Company has the right to designate a nominee to Diamondback's board and there is no Gulfport nominee actually serving as a Diamondback director, the Company has the right to appoint one individual as an advisor to the board who shall be entitled to attend board and committee meetings. The Company is also entitled to certain information rights and Diamondback granted the Company certain demand and "piggyback" registration rights obligating Diamondback to register with the SEC any shares of Diamondback common stock that the Company owns. Immediately upon completion of the Contribution, the Company owned a 35% equity interest in Diamondback, rather than leasehold interests in the Company's Permian Basin acreage. Upon completion of the Diamondback IPO in October 2012, Gulfport owned approximately 21.4% of Diamondback's outstanding common stock. As of September 30, 2013, Gulfport owned approximately 12.1% of Diamondback's outstanding common stock. Following the Contribution, the Company accounts for its interest in Diamondback as an equity investment. See also Note 4, " Equity Investments - Diamondback Energy, Inc."

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4. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of September 30, 2013 and December 31, 2012:

	September 30, 2013	December 31, 2012
	(In thousands)	
Investment in Tatex Thailand II, LLC	$—	$203
Investment in Tatex Thailand III, LLC	10,871	8,657
Investment in Grizzly Oil Sands ULC	189,943	172,766
Investment in Bison Drilling and Field Services LLC	12,559	13,518
Investment in Muskie Holdings LLC	8,650	7,320
Investment in Timber Wolf Terminals LLC	870	878
Investment in Windsor Midstream LLC	10,379	9,503
Investment in Stingray Pressure Pumping LLC	17,755	13,265
Investment in Stingray Cementing LLC	3,345	3,110
Investment in Blackhawk Midstream LLC	—	—
Investment in Stingray Logistics LLC	978	947
Investment in Diamondback Energy LLC	242,174	151,317
Investment in Stingray Energy Services LLC	3,155	—
	$500,679	$381,484

Tatex Thailand II, LLC

The Company has a 23.5% indirect ownership interest in Tatex Thailand II, LLC (“Tatex”). The remaining indirect interests in Tatex are owned by entities controlled by Wexford Capital LP ("Wexford"). Tatex holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC (“APICO”), an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering approximately 243,000 acres which includes the Phu Horm Field. During the three and nine months ended September 30, 2013, Gulfport received $0.2 million and $0.6 million, respectively, in distributions from Tatex and recognized $0.2 million and $0.4 million in distribution income for the same periods, which is included in (income) loss from equity method investments in the consolidated statements of operations.

Tatex Thailand III, LLC

The Company has a 17.9% ownership interest in Tatex Thailand III, LLC ("Tatex III"). Approximately 68.7% of the remaining interests in Tatex III are owned by entities controlled by Wexford. During the nine months ended September 30, 2013, the Company paid cash cash calls of $2.4 million, and had a total net investment in Tatex III of $10.9 million at September 30, 2013. The Company recognized a loss on equity investment of $0.1 million and $0.2 million for the three and nine months ended September 30, 2013, respectively. The Company recognized an immaterial loss on equity investment related to Tatex III during the three months ended September 30, 2012 and a loss of $0.2 million for the nine months ended September 30, 2012, which is included in (income) loss from equity method investments in the consolidated statements of operations.

Grizzly Oil Sands ULC

The Company, through its wholly owned subsidiary Grizzly Holdings Inc. ("Grizzly Holdings"), owns a 24.9999% interest in Grizzly Oil Sands ULC ("Grizzly"), a Canadian unlimited liability company. The remaining interest in Grizzly is owned by certain investment funds managed by Wexford. As of September 30, 2013, Grizzly had approximately 800,000 acres under lease in the Athabasca and Peace River oil sands regions of Alberta, Canada. During the nine months ended September 30, 2013, Gulfport paid $25.1 million in cash calls increasing its total net investment in Grizzly to $189.9 million at September 30, 2013. Grizzly’s functional currency is the Canadian dollar. The Company's investment in Grizzly was increased by $3.9 million as a result of a foreign currency translation gain and decreased by $5.8 million as a result of a foreign currency translation loss for the three and nine months ended

September 30, 2013, respectively, and increased by $5.3 million and $3.4 million as a result of a foreign currency translation gain for the three and nine months ended September 30, 2012. The Company recognized a loss on equity investment of $0.8 million and $2.1 million for the three and nine months ended September 30, 2013, respectively, and a loss of $0.3 million and $0.9 million for the three and nine months ended September

30, 2012, respectively, which is included in (income) loss from equity method investments in the consolidated statements of operations.

Bison Drilling and Field Services LLC

During the third quarter of 2011, the Company purchased a 25% ownership interest in Bison Drilling and Field Services LLC (“Bison”). In April 2012, the Company increased its ownership interest in Bison to 40% for a payment of $6.2 million, The remaining interests in Bison are owned by entities controlled by Wexford. Bison owns and operates drilling rigs. During the nine months ended September 30, 2013, Gulfport paid $0.3 million in cash calls, increasing its total net investment in Bison to $12.6 million. The Company recognized a loss on its equity investment in Bison of $1.3 million and $1.3 million for the three and nine months ended September 30, 2013, respectively. The Company recognized a loss on equity investment of $0.1 million and a gain on equity investment of $0.2 million, for the three and nine months ended September 30, 2012, respectively, which is included in (income) loss from equity method investments in the consolidated statements of operations.

The Company entered into a loan agreement with Bison effective May 15, 2012, under which Bison may borrow funds from the Company. Interest accrues at LIBOR plus 0.28% or 8%, whichever is lower, and shall be paid on a paid-in-kind basis by increasing the outstanding balance of the loan. The loan has a maturity date of January 31, 2015. The Company loaned Bison $1.6 million during the first nine months of 2012, all of which was repaid by Bison during the third quarter of 2012.

Muskie Holdings LLC

During the fourth quarter of 2011, the Company purchased a 25% ownership interest in Muskie Proppant LLC (“Muskie”), formerly known as Muskie Holdings LLC. The remaining interests in Muskie are owned by entities controlled by Wexford. Muskie holds certain rights in a lease covering land in Wisconsin for mining oil and natural gas fracture grade sand. During the nine months ended September 30, 2013, Gulfport paid $2.2 million in cash calls, increasing its total net investment in Muskie to $8.7 million. The Company recognized a loss on equity investment of $0.1 million and $0.9 million for the three and nine months ended September 30, 2013, respectively, and a loss of $0.1 million and $0.2 million for the three and nine months ended September 30, 2012, respectively, which is included in (income) loss from equity method investments in the consolidated statements of operations.

The Company entered into a loan agreement with Muskie effective July 1, 2013, for $0.9 million. Interest accrues at Prime plus 2.5%. The loan has a maturity date of July 31, 2014. As of September 30, 2013, the outstanding balance on the loan is included in notes receivable-related party on the accompanying consolidated balance sheets.

Timber Wolf Terminals LLC

During the first quarter of 2012, the Company and entities controlled by or affiliated with Wexford formed Timber Wolf Terminals LLC (“Timber Wolf”). The Company has a 50% interest in Timber Wolf and its initial investment during 2012 was $1.0 million. Timber Wolf will operate a crude/condensate terminal and a sand transloading facility in Ohio. The loss on equity investment related to Timber Wolf was immaterial for the three and nine months ended September 30, 2013 and 2012.

Windsor Midstream LLC

During the first quarter of 2012, the Company purchased a 22.5% ownership interest in Windsor Midstream LLC (“Midstream”) at a cost of $7.0 million. The remaining interests in Midstream are owned by entities controlled by Wexford. Midstream owns a 28.4% interest in MidMar Gas LLC, a gas processing plant in West Texas. During the nine months ended September 30, 2013, Gulfport paid an immaterial amount in net cash calls to Midstream, bringing its total net investment in Midstream to $10.4 million. The Company recognized income on equity investment of $0.9 million for the nine months ended September 30, 2013, and income on equity investment of $0.1 million and $0.2 million for the three and nine months ended September 30, 2012, respectively, which is included in (income) loss from equity method investments in the consolidated statements of operations. Income on equity investment for the three months ended September 30, 2013, was immaterial.

Stingray Pressure Pumping LLC

During the second quarter of 2012, the Company and certain individuals and entities primarily affiliated with Wexford formed Stingray Pressure Pumping LLC ("Stingray Pressure"). The Company's initial interest is 50%. Stingray Pressure provides well completion services. During the nine months ended September 30, 2013, the Company paid $1.8 million in cash calls, increasing its total net investment in Stingray Pressure to $17.8 million. After intercompany profit eliminations, the

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Company recognized income on equity investment of $0.3 million and $0.7 million for the three and nine months ended September 30, 2013. The Company recognized a loss on equity investment of $0.4 million and $0.5 million for the three and nine months ended September 30, 2012, respectively, which is included in (income) loss from equity method investments in the consolidated statements of operations.

Stingray Cementing LLC

During the second quarter of 2012, the Company and certain individuals and entities primarily affiliated with Wexford formed Stingray Cementing LLC ("Stingray Cementing"). The Company's initial interest is 50%. Stingray Cementing provides well cementing services. During the nine months ended September 30, 2013, the Company did not pay any cash calls related to Stingray Cementing. The Company recognized an immaterial loss, after intercompany profit eliminations, on equity investment related to Stingray Cementing during the three and nine months ended September 30, 2013. The loss on equity investment related to Stingray Cementing was immaterial for the three and nine months ended September 30, 2012.

Blackhawk Midstream LLC

During the second quarter of 2012, the Company and an entity controlled by Wexford formed Blackhawk Midstream LLC ("Blackhawk"). The Company has an initial 50% interest. Blackhawk coordinates gathering, compression, processing and marketing activities for the Company in connection with the development of its Utica Shale acreage. During the nine months ended September 30, 2013, the Company paid $0.3 million in cash calls related to Blackhawk. The Company recognized a loss on equity investment related to Blackhawk of $0.2 million and $0.3 million for the three and nine months ended September 30, 2013, respectively. The Company recognized a loss on equity investment of $0.1 million and $0.4 million for the three and nine months ended September 30, 2012, respectively, which is included in (income) loss from equity method investments in the consolidated statements of operations.

Stingray Logistics LLC

During the fourth quarter of 2012, the Company and certain individuals and entities affiliated with Wexford formed Stingray Logistics LLC ("Stingray Logistics"). The Company's initial interest is 50%. Stingray Logistics provides well services. The Company recognized an immaterial loss on equity investment related to Stingray Logistics during the three and nine months ended September 30, 2013, which is included in (income) loss from equity method investments in the consolidated statements of operations.

Diamondback Energy, Inc.

As noted above in Note 3, on May 7, 2012, the Company entered into a contribution agreement with Diamondback. Under the terms of the contribution agreement, the Company agreed to contribute to Diamondback, prior to the closing of the Diamondback IPO, all its oil and natural gas interests in the Permian Basin. The Contribution was completed on October 11, 2012. At the closing of the Contribution, Diamondback issued to the Company (i) 7,914,036 shares of Diamondback common stock and (ii) a promissory note for $63.6 million, which was repaid to the Company at the closing of the Diamondback IPO on October 17, 2012. Following the closing of the Diamondback IPO, the Company owned approximately 21.4% of Diamondback's outstanding common stock for an initial investment in Diamondback of $138.5 million. On June 24, 2013, the Company sold 1,951,781 shares of its Diamondback common stock for net proceeds of $65.1 million in an underwritten public offering in which certain entities controlled by Wexford also participated as selling stockholders. On July 5, 2013, the underwriters purchased an additional 282,755 shares of Diamondback common stock from Gulfport pursuant to an option to purchase additional shares from the selling stockholders granted to the underwriters resulting in net proceeds to the Company of

$9.4 million. The shares were sold to the public at $34.75 per share. As of September 30, 2013, the Company owned approximately 12.1% of Diamondback's outstanding common stock.

The Company accounts for its interest in Diamondback as an equity method investment and has elected the fair value option of accounting for this investment. The Company valued its investment in Diamondback using the quoted closing market price of Diamondback's stock on September 30, 2013 of $42.64 per share multiplied by the number of outstanding shares of Diamondback's stock held by the Company. The value of the Company's investment in Diamondback was approximately $242.2 million at September 30, 2013. The Company recognized an aggregate gain of approximately $52.9 million and $165.4 million on its investment in Diamondback for the three and nine months ended September 30, 2013, respectively, which is included in (income) loss from equity method investments in the consolidated statements of operations.

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The table below summarizes balance sheet information for Diamondback as of September 30, 2013 and December 31, 2012:

	September 30, 2013	December 31, 2012
	(In thousands)	
Current assets	$91,915	$50,275
Noncurrent assets	$1,373,981	$556,426
Current liabilities	$109,451	$79,232
Noncurrent liabilities	$533,507	$65,401

The table below summarizes the results of operations for Diamondback for the three and nine months ended September 30, 2013 and 2012, respectively:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
Gross revenue	$57,791	$16,814	$132,094	$49,195
Income from operations	$29,423	$4,086	$57,468	$15,130
Net income	$14,596	$452	$34,463	$15,553

Stingray Energy Services LLC

During the first quarter of 2013, the Company purchased a 50% ownership in Stingray Energy Services LLC ("Stingray Energy") at a cost of $2.2 million. The remaining interests in Stingray Energy are owned by certain individuals and entities primarily affiliated with Wexford. Stingray Energy provides rental tools for land-based oil and natural gas drilling, completion and workover activities as well as the transfer of fresh water to wellsites. Other than its initial investment, the Company paid cash calls of $0.7 million during the three and nine months ended September 30, 2013. After intercompany profit eliminations, the Company recognized income on equity investment of $0.2 million and $0.1 million for the three and nine months ended September 30, 2013, respectively, which is included in (income) loss from equity method investments in the consolidated statements of operations.

5. OTHER ASSETS

Other assets consist of the following as of September 30, 2013 and December 31, 2012:

	September 30, 2013	December 31, 2012
	(In thousands)	
Plugging and abandonment escrow account on the WCBB properties (Note 11)	$3,105	$3,113
Certificates of Deposit securing letter of credit	275	275
Prepaid drilling costs	527	515
Loan commitment fees	8,889	9,388
Pipeline imbalance receivable	27	—
Deposits	4	4
	$12,827	$13,295

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6. LONG-TERM DEBT

Long-term debt consisted of the following items as of September 30, 2013 and December 31, 2012:

	September 30, 2013	December 31, 2012
	(In thousands)	
Revolving credit agreement (1)	$—	$—
Building loans (2)	2,033	2,143
7.75% senior unsecured notes due 2020 (3)	300,000	300,000
Unamortized original issue (discount) premium, net (4)	(2,885)	(3,105)
Less: current maturities of long term debt	(156)	(150)
Debt reflected as long term	$298,992	$298,888

The Company capitalized approximately $3.5 million and $9.0 million in interest expense to undeveloped oil and natural gas properties during the three and nine months ended September 30, 2013, respectively. There was no interest expense capitalized during the three and nine months ended September 30, 2012, respectively.

(1) On September 30, 2010, the Company entered into a $100.0 million senior secured revolving credit agreement with The Bank of Nova Scotia, as administrative agent and letter of credit issuer and lead arranger, and Amegy Bank National Association ("Amegy Bank"). The revolving credit facility initially matured on September 30, 2013 and had an initial borrowing base availability of $50.0 million, which was increased to $65.0 million effective December 24, 2010. The amounts borrowed under the credit agreement were used to repay all of the Company’s outstanding indebtedness under its prior revolving credit facility ($42.0 million) and term loan ($2.5 million), each with Bank of America, N.A., as administrative agent, and for general corporate purposes. The credit agreement is secured by substantially all of the Company’s assets. The Company’s wholly-owned subsidiaries guaranteed the obligations of the Company under the credit agreement.

On May 3, 2011, the Company entered into a first amendment to the revolving credit agreement with The Bank of Nova Scotia, Amegy Bank, KeyBank National Association (“KeyBank”) and Société Générale. Pursuant to the terms of the first amendment, KeyBank and Société Générale were added as additional lenders, the maximum amount of the facility was increased to $350.0 million, the borrowing base was increased to $90.0 million, certain fees and rates payable by the Company under the credit agreement were decreased, and the maturity date was extended until May 3, 2015. On October 31, 2011, the Company entered into additional amendments to its revolving credit facility pursuant to which, among other things, the borrowing base under this facility was increased to $125.0 million.

Effective May 2, 2012, the Company entered into a fourth amendment to its revolving credit facility under which, among other things, the borrowing base was increased to $155.0 million and Credit Suisse, Deutsche Bank Trust Company Americas and Iberiabank were added as additional lenders and Société Générale left the bank group.

On October 9, 2012 and October 17, 2012, the Company entered into a fifth amendment and a sixth amendment, respectively, to the revolving credit agreement. The fifth amendment modified certain covenants in the credit agreement to permit the Company to issue senior unsecured notes in an aggregate principal amount of up to $300.0 million and provided for a reduction in the borrowing base to an amount to be determined upon the completion of any senior unsecured notes issuance. The sixth amendment lowered the applicable rate set forth in the credit agreement (i) from a range of 1.00% to 1.75% to a range of 0.75% to 1.50% for the base rate loans and (ii) from a range of 2.00% to 2.75% to a range of 1.75% to 2.50% for the eurodollar rate loans and letters of credit. The sixth amendment lowered the commitment fees for Level 1 and Level 2 usage levels, in each case, from 0.50% per annum to 0.375% per annum. Also, effective as of October 17, 2012, in connection with the Company's completion of the offering of $250.0 million 7.75% senior unsecured notes due 2020, (the "October Notes"), the repayment of all outstanding amounts under the revolving credit agreement with the proceeds of the October Notes, and the contribution of Gulfport’s oil and natural gas interests in the Permian Basin to Diamondback discussed in Note 3 above, Gulfport’s borrowing base under the credit agreement was reduced to $45.0 million until the next borrowing base redetermination.

On December 18, 2012, the Company entered into a seventh amendment to the revolving credit agreement under which the Company was permitted to issue $50.0 million 7.75% senior unsecured notes due 2020 (the "December Notes") under the same indenture as the October Notes (collectively, the "Notes"), and upon the issuance of the December Notes, the borrowing base under the revolving credit agreement was reduced from $45.0 million to $40.0 million until the next borrowing base redetermination.

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On June 6, 2013, the Company entered into an eighth amendment to the revolving credit agreement. The eighth amendment lowered the applicable rate set forth in the revolving credit agreement (i) from a range of 1.75% to 2.50% to a range of 1.50% to 2.50% for eurodollar rate loans and (ii) from a range of 0.75% to 1.50% to a range of 0.50% to 1.50% for base rate loans. Additionally, the eighth amendment extended the maturity date from May 3, 2015 to June 6, 2018, provided for an increase in the borrowing base from $40.0 million to $50.0 million, and amended certain other provisions. As of September 30, 2013, the Company had no balance outstanding under the revolving credit agreement.

Advances under the credit agreement, as amended, may be in the form of either base rate loans or eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 0.50% to 1.50%, plus (2) the highest of: (a) the federal funds rate plus 0.50%, (b) the rate of interest in effect for such day as publicly announced from time to time by agent as its "prime rate," and (c) the eurodollar rate for an interest period of one month plus 1.00%. The interest rate for eurodollar loans is equal to (1) the applicable rate, which ranges from 1.50% to 2.50%, plus (2) the London interbank offered rate that appears on Reuters Screen LIBOR01 Page for deposits in U.S. dollars, or, if such rate is not available, the offered rate on such other page or service that displays the average British Bankers Association Interest Settlement Rate for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the "London Interbank Offered Rate" for deposits in U.S. dollars.

The credit agreement contains customary negative covenants including, but not limited to, restrictions on the Company's and its subsidiaries' ability to:

- incur indebtedness;
- grant liens;
- pay dividends and make other restricted payments;
- make investments;
- make fundamental changes;
- enter into swap contracts and forward sales contracts;
- dispose of assets;
- change the nature of their business; and
- enter into transactions with affiliates.

The negative covenants are subject to certain exceptions as specified in the credit agreement. The credit agreement also contains certain affirmative covenants, including, but not limited to the following financial covenants:

(i) the ratio of funded debt to EBITDAX (net income, excluding any non-cash revenue or expense associated with swap contracts resulting from ASC 815, plus without duplication and to the extent deducted from revenues in determining net income, the sum of (a) the aggregate amount of consolidated interest expense for such period, (b) the aggregate amount of income, franchise, capital or similar tax expense (other than ad valorem taxes) for such period, (c) all amounts attributable to depletion, depreciation, amortization and asset or goodwill impairment or writedown for such period, (d) all other non-cash charges, (e) non-cash losses from minority investments, (f) actual cash distributions received from minority investments, (g) to the extent actually reimbursed by insurance, expenses with respect to liability on casualty events or business interruption, and (h) all reasonable transaction expenses related to dispositions and acquisitions of assets, investments and debt and equity offerings, and less non-cash income attributable to equity income from minority investments) for a twelve-month period may not be greater than 2.00 to 1.00; and

(ii) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00.

The Company was in compliance with all covenants at September 30, 2013.

(2) In March 2011, the Company entered into a new building loan agreement for the office building it occupies in Oklahoma City, Oklahoma. The new loan agreement refinanced the $2.4 million outstanding under the previous building loan agreement. The new agreement matures in February 2016 and bears interest at the rate of 5.82% per annum. The new building loan requires monthly interest and principal payments of approximately $22,000 and is collateralized by the Oklahoma City office building and associated land.

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(3) On October 17, 2012, the Company issued $250.0 million in aggregate principal amount of October Notes to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act, (the "October Notes Offering") under an indenture among the Company, its subsidiary guarantors and Wells Fargo Bank, National Association, as the trustee, (the "senior note indenture"). On December 21, 2012, the Company issued an additional $50.0 million in aggregate principal amount of December Notes to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act ("the December Notes Offering"). The December Notes were issued as additional securities under the senior note indenture. The October Notes Offering and the December Notes Offering are collectively referred to as the "Notes Offerings". The Company used a portion of the net proceeds from the October Notes Offering to repay all amounts outstanding at such time under its revolving credit facility. The Company used the remaining net proceeds of October Notes Offering and the net proceeds of the December Notes Offering for general corporate purposes, which included funding a portion of its 2013 capital development plan.

Under the senior note indenture, interest on the Notes accrues at a rate of 7.75% per annum on the outstanding principal amount from October 17, 2012, payable semi-annually on May 1 and November 1 of each year, commencing on May 1, 2013. The Notes are the Company's senior unsecured obligations and rank equally in the right of payment with all of the Company's other senior indebtedness and senior in right of payment to any future subordinated indebtedness. All of the Company's existing and future restricted subsidiaries that guarantee the Company's secured revolving credit facility or certain other debt guarantee the Notes; provided, however, that the Notes are not guaranteed by Grizzly Holdings, Inc. and will not be guaranteed by any of the Company's future unrestricted subsidiaries. The Company may redeem some or all of the Notes at any time on or after November 1, 2016, at the redemption prices listed in the senior note indenture. Prior to November 1, 2016, the Company may redeem the Notes at a price equal to 100% of the principal amount plus a “make-whole” premium. In addition, prior to November 1, 2015, the Company may redeem up to 35% of the aggregate principal amount of the Notes with the net proceeds of certain equity offerings, provided that at least 65% of the aggregate principal amount of the Notes initially issued remains outstanding immediately after such redemption.

(4) The October Notes were issued at a price of 98.534% resulting in a gross discount of $3.7 million and an effective rate of 8.000%. The December Notes were issued at a price of 101.000% resulting in a gross premium of $0.5 million and an effective rate of 7.531%. The premium and discount are being amortized using the effective interest method.

7. COMMON STOCK OPTIONS, WARRANTS AND CHANGES IN CAPITALIZATION

Sale of Common Stock

On December 24, 2012, the Company completed the sale of an aggregate of 11,750,000 shares of its common stock in an underwritten public offering (including the partial exercise of a 1,650,000 share over-allotment option granted to the underwriters, which option was initially exercised to the extent of 750,000 shares) at a public offering price of $38.00 per share less the underwriting discount. The underwriters subsequently exercised their option to purchase the remaining 900,000 additional shares of common stock subject to the over-allotment option in a second closing, which occurred on January 7, 2013. The Company received aggregate net proceeds from both closings of approximately $460.7 million from the sale of these shares after deducting the underwriting discount and before offering expenses. The Company used a portion of these net proceeds to fund the acquisition of approximately 37,000 net acres in the Utica Shale in Eastern Ohio, as described above in Note 1, and for general corporate purposes, including the funding of a portion of its 2013 capital development plan.

On February 15, 2013, the Company completed the sale of an aggregate of 8,912,500 shares of its common stock in an underwritten public offering at a public offering price of $38.00 per share less the underwriting discount. The Company received aggregate net proceeds of approximately $325.8 million from the sale of these shares after deducting the underwriting discount and before offering expenses. The Company used a portion of the net proceeds from this equity offering to fund its acquisition of additional Utica Shale acreage as described in Note 1, and intends to use the balance for general corporate purposes, including the funding of a portion of its 2013 capital development plan.

8. STOCK-BASED COMPENSATION

During the three and nine months ended September 30, 2013, the Company’s stock-based compensation cost was $1.6 million and $4.6 million, respectively, of which the Company capitalized $0.6 million and $1.8 million, respectively, relating to its exploration and development efforts. During the three and nine months ended September 30, 2012, the Company's stock-based compensation cost was $1.2 million and $3.4 million, respectively, of which the Company capitalized $0.5 million and $1.4 million, respectively, relating to its exploration and development efforts.

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

No stock options were issued during the nine months ended September 30, 2013 and 2012.

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

A summary of the status of stock options and related activity for the nine months ended September 30, 2013 is presented below:

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (In thousands)
Options outstanding at December 31, 2012	335,241	$6.37	2.39	$10,678
Granted	—	—		
Exercised	(125,000)	11.20		$4,797
Forfeited/expired	—	—		
Options outstanding at September 30, 2013	210,241	$3.50	1.32	$12,792
Options exercisable at September 30, 2013	210,241	$3.50	1.32	$12,792

The following table summarizes information about the stock options outstanding at September 30, 2013:

Exercise Price	Number Outstanding	Weighted Average Remaining Life (in years)	Number Exercisable
$3.36	205,241	1.31	205,241
$9.07	5,000	1.94	5,000
	210,241		210,241

The following table summarizes restricted stock activity for the nine months ended September 30, 2013:

	Number of Unvested Restricted Shares	Weighted Average Grant Date Fair Value
Unvested shares as of December 31, 2012	245,831	$31.88
Granted	209,500	38.98
Vested	(119,519)	35.58
Forfeited	(8,500)	38.54
Unvested shares as of September 30, 2013	327,312	$34.90

Unrecognized compensation expense as of September 30, 2013 related to outstanding stock options and restricted shares was $10.0 million. The expense is expected to be recognized over a weighted average period of 1.66 years.

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9. EARNINGS PER SHARE

Reconciliations of the components of basic and diluted net income per common share for the three and nine months ended September 30, 2013 and 2012 are presented in the tables below:

	Three Months Ended September 30,					
	2013			2012		
	Income	Shares	Per Share	Income	Shares	Per Share
	(In thousands, except share data)					
Basic:						
Net income	$40,527	77,554,386	$0.52	$502	55,692,664	$0.01
Effect of dilutive securities:						
Stock options and awards	—	377,352		—	599,128	
Diluted:						
Net income	$40,527	77,931,738	$0.52	$502	56,291,792	$0.01

	Nine Months Ended September 30,					
	2013			2012		
	Income	Shares	Per Share	Income	Shares	Per Share
	(In thousands, except share data)					
Basic:						
Net income	$128,914	75,955,040	$1.70	$52,488	55,658,507	$0.94
Effect of dilutive securities:						
Stock options and awards	—	419,067		—	516,074	
Diluted:						
Net income	$128,914	76,374,107	$1.69	$52,488	56,174,581	$0.93

There were no potential shares of common stock that were considered anti-dilutive for the three and nine months ended September 30, 2013 and 2012.

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10. NEW ACCOUNTING STANDARDS

In February 2013, the FASB issued Accounting Standards Update ("ASU") No. 2013-02, "Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income," which requires additional information about amounts reclassified out of accumulated other comprehensive income by component. This ASU requires the presentation, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under GAAP to be reclassified in their entirety to net income, a cross-reference to other disclosures required under GAAP that provide additional detail about those amounts. The requirements of this ASU are effective prospectively for reporting periods beginning after December 15, 2012 with early adoption permitted. The Company adopted the provisions of this ASU for reporting periods in 2013. Adoption of this ASU had no impact on the Company's financial position or results of operations.

11. COMMITMENTS AND CONTINGENCIES

Plugging and Abandonment Funds

In connection with the Company's acquisition in 1997 of the remaining 50% interest in its 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 could access the trust for use in plugging and abandonment charges associated with the property, although it has not yet done so. As of September 30, 2013, the plugging and abandonment trust totaled approximately $3.1 million. At September 30, 2013, the Company had plugged 354 wells at WCBB since it began its plugging program in 1997, which management believes fulfills its current minimum plugging obligation.

Employment Agreements

Effective November 1, 2012, the Company entered into employment agreements with its executive officers, each with an initial three-year term that expires on November 1, 2015 subject to automatic one-year extensions unless terminated by either party to the agreement at least 90 days prior to the end of the then current term. These agreements provide for minimum salary and bonus levels which are subject to review and potential increase by the Compensation Committee and/or the Board of Directors, as well as participation in the Company's Amended and Restated 2005 Stock Incentive Plan (or other equity incentive plans that may be put in place for the benefit of employees) and other employee benefits. The aggregate minimum commitment for future salaries and bonuses at September 30, 2013 was approximately $4.7 million.

Grizzly

On October 5, 2012, the Company entered into an agreement with Grizzly in which it committed to make monthly payments from October 2012 to May 2013 to fund the construction and development of the Algar Lake facility. The Company also agreed to fund its proportionate share of any unfunded cost overruns. The remaining aggregate commitment including the Company's share of cost overruns at September 30, 2013 was approximately $6.1 million.

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Operating Leases

The Company leases office facilities under non-cancellable operating leases exceeding one year. Future minimum lease commitments under these leases at September 30, 2013 are as follows:

	September 30, 2013 (In thousands)
Remaining 2013	$45
2014	179
2015	127
2016	68
2017	34
Total	$453

Litigation

The Louisiana Department of Revenue (“LDR”) is disputing Gulfport’s severance tax payments to the State of Louisiana from the sale of oil under fixed price contracts during the years 2005 to 2007. The LDR maintains that Gulfport paid approximately $1.8 million less in severance taxes under fixed price terms than the severance taxes Gulfport would have had to pay had it paid severance taxes on the oil at the contracted market rates only. Gulfport has denied any liability to the LDR for underpayment of severance taxes and has maintained that it was entitled to enter into the fixed price contracts with unrelated third parties and pay severance taxes based upon the proceeds received under those contracts. Gulfport has maintained its right to contest any final assessment or suit for collection if brought by the State. On April 20, 2009, the LDR filed a lawsuit in the 15th Judicial District Court, Lafayette Parish, in Louisiana against Gulfport seeking $2.3 million in severance taxes, plus interest and court costs. Gulfport filed a response denying any liability to the LDR for underpayment of severance taxes and is defending itself in the lawsuit. The LDR had taken no further action on this lawsuit since filing its petition other than propounding discovery requests to which Gulfport has responded. Since serving discovery requests on the LDR and receiving the LDR's responses in 2012, there has been no further activity on the case and no trial date has been set.

In December 2010, the LDR filed two identical lawsuits against Gulfport in different venues to recover allegedly underpaid severance taxes on crude oil for the period January 1, 2007 through December 31, 2010, together with a claim for attorney’s fees. The petitions do not make any specific claim for damages or unpaid taxes. As with the first lawsuit filed by the LDR in 2009, Gulfport denies all liability and will vigorously defend the lawsuit. The cases are in the early stages, and Gulfport has not yet filed a response to the recent lawsuits. The LDR filed motions to stay the lawsuits before Gulfport filed any responsive pleadings. Although there had been no activity on either of these lawsuits for years, the LDR recently moved to dismiss one of the identical lawsuits it filed in the 19th Judicial District Court in 2010, amended the petition it filed in the 15th Judicial District Court in 2010, and served discovery requests on Gulfport. The LDR asserts that Gulfport underpaid severance taxes by nearly $12 million from 2007 to 2010. The LDR also asserts that Gulfport owes an additional $4.4 million and may be subject to additional penalties. The LDR's claims are still in their infancy and there has been no formal discovery. Gulfport maintains that the LDR's claims are not well-grounded in fact or law and intends to aggressively defend the lawsuits.

Other Litigation

On July 30, 2010, six individuals and one limited liability company sued 15 oil and gas companies in Cameron Parish Louisiana for surface contamination in areas where the defendants operated in an action entitled Reeds et al. v. BP American Production Company et al.,38th Judicial District. No. 10-18714. The plaintiffs’ original petition for damages, which did not name Gulfport as a defendant, alleges that the plaintiffs’ property located in Cameron Parish, Louisiana within the Hackberry oil field is contaminated as a result of historic oil and gas exploration and production activities. The plaintiffs allege that the defendants conducted, directed and participated in various oil and gas exploration and production activities on their property which allegedly have contaminated or otherwise caused damage to the property, and have sued the defendants for alleged breaches of oil, gas and mineral leases, as well as for alleged negligence, trespass, failure to warn, strict liability, punitive damages, lease liability, contract liability, unjust enrichment, restoration damages, assessment and response costs and stigma damages. On December 7, 2010, Gulfport was served with a copy of the plaintiffs' first supplemental and amending petition which added four additional plaintiffs and six additional defendants, including Gulfport, bringing the total number of defendants to 21. It also increased the total acreage at issue in this litigation from 240 acres to approximately 1,700 acres. In addition to the damages sought in the original petition, the plaintiffs now also seek: damages sufficient to cover the cost of conducting a comprehensive environmental assessment of all present and yet unidentified pollution and contamination of their property; the cost to restore the property to its pre-polluted original condition; damages for mental anguish and annoyance, discomfort and inconvenience caused by the nuisance created by defendants; land loss and subsidence damages and the cost of backfilling canals and other excavations; damages for loss of use of land and lost profits and income; attorney fees and expenses and damages for evaluation and remediation of any contamination that threatens groundwater. In addition to Gulfport, current defendants include ExxonMobil Oil Corporation, Mobil Exploration & Producing North America Inc., Chevron U.S.A. Inc., The Superior Oil Company, Union Oil Company of California, BP America Production Company, Tempest Oil Company, Inc., ConocoPhillips Company, Continental Oil Company, WM. T. Burton Industries, Inc., Freeport Sulphur Company, Eagle Petroleum Company, U.S. Oil of Louisiana, M&S Oil Company, and Empire Land Corporation, Inc. of Delaware. On January 21, 2011, Gulfport filed a pleading challenging the legal sufficiency of the petitions on several grounds and requesting that they either be dismissed or that plaintiffs be required to amend such petitions. In response to the pleadings filed by Gulfport and similar pleadings filed by other defendants, the plaintiffs filed a third amending petition with exhibits which expands the description of the property at issue, attaches numerous aerial photos and identifies the mineral leases at issue. In response, Gulfport and numerous defendants re-urged their pleadings challenging the legal sufficiency of the petitions. Some of the defendants' grounds for challenging the plaintiffs' petitions were heard by the court on May 25, 2011 and were denied. The court signed the written judgment on December 9, 2011. Gulfport noticed its intent to seek supervisory review on December 19, 2011 and the trial court fixed a return date of January 11, 2012 for the filing of the writ application. Gulfport filed its supervisory writ, which was denied by the Louisiana Third Circuit Court of Appeal and the Louisiana Supreme Court. Gulfport has been active in serving discovery requests and responding to discovery requests from the plaintiffs. The parties engaged in a non-binding mediation in July 2013 to discuss settlement and settlement discussions are on-going. At this time, the parties are continuing to conduct discovery and no expert reports have been issued. The trial date has been continued to July 2014.

Due to the early stages of the LDR and Reed litigation, the outcome is uncertain and management cannot determine the amount of loss, if any, that may result. In each case, management has determined the possibility of loss is remote. However, litigation is inherently uncertain. Adverse decisions in one or more of the above matters could have a material adverse effect on the Company's financial condition or results of operations and management cannot determine the amount of loss, if any, that may result.

The Company has been named as a defendant in various other lawsuits related to its business. In each such case, management has determined that the possibility of loss is remote. The resolution of these matters is not expected to have a material adverse effect on the Company's financial condition or results of operations in future periods.

12. HEDGING ACTIVITIES

Oil Price Hedging Activities

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

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

During 2012 and 2013, the Company entered into fixed price swap contracts for 2013 through 2016 with four financial institutions. The Company's fixed price swap contracts are tied to the commodity prices on the International Petroleum Exchange ("IPE") and NYMEX. The Company will receive the fixed price amount stated in the contract and pay to its counterparty the current market price as listed on the IPE for Brent Crude and the NYMEX WTI for oil and on the NYMEX Henry Hub for natural gas. At September 30, 2013, the Company had the following fixed price swaps in place:

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	Daily Volume (Bbls/day)	Weighted Average Price
October - December 2013	5,000	$99.86
January - March 2014	4,000	$104.75
April - December 2014	2,000	$101.50
	Daily Volume (MMBtu/day)	Weighted Average Price
October - December 2013	10,000	$4.00
January - December 2014	20,000	$3.98
January 2015 - March 2016	15,000	$3.97
April 2016	5,000	$3.90

At September 30, 2013 the fair value of derivative assets related to the fixed price swaps was as follows:

	(In thousands)
Short-term derivative instruments - asset	$1,633
Long-term derivative instruments - asset	$127
Short-term derivative instruments - liability	$4,808
Long-term derivative instruments - liability	$962

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

For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of FASB ASC 815, changes in fair value are recognized in accumulated other comprehensive income (loss) until the hedged item is recognized in earnings. Amounts reclassified out of accumulated other comprehensive income (loss) into earnings as a component of oil and condensate sales for the nine months ended September 30, 2013 and 2012 are presented below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)		(In thousands)	
Reduction to oil and condensate sales	$(1,617)	$(185)	$(4,818)	$(646)

The Company expects to reclassify $2.6 million out of accumulated other comprehensive income (loss) into earnings as a component of oil and condensate and gas sales during the remainder of the year ended December 31, 2013 related to fixed price swaps.

Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value resulting from ineffectiveness is recognized immediately in earnings. The Company recognized a loss of $6.7 million and $1.3 million related to hedge ineffectiveness for the three and nine months ended September 30, 2013, respectively, which is included in oil and condensate and gas sales in the consolidated statements of operations. This loss was comprised of a loss of $3.0 million and a gain of $5.2 million related to hedge ineffectiveness for the three and nine months ended September 30, 2013, respectively, partially offset by a loss of $3.6 million and $6.5 million related to the amortization of other comprehensive income for the three and nine months ended September 30, 2013, respectively. The Company recognized a loss of $0.2 million and $0.1 million related to hedge ineffectiveness for the three and nine months ended September 30, 2012, respectively, which is included in oil and condensate sales in the consolidated statements of operations.

FAIR VALUE MEASUREMENTS

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The Company records certain financial and non-financial assets and liabilities on the balance sheet at fair value in accordance with FASB ASC 820. FASB ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. The statement establishes market or observable inputs as the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The statement requires fair value measurements be classified and disclosed in one of the following categories:

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

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

Level 3 – Significant inputs to the valuation model are unobservable.

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

The following tables summarize the Company’s financial and non-financial liabilities by FASB ASC 820 valuation level as of September 30, 2013:

	As of September 30, 2013		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets:			
Fixed price swaps	$—	$1,760	$—
Equity investment in Diamondback	242,174	—	—
Liabilities:			
Fixed price swaps	$—	$5,770	$—

The estimated fair value of the Company’s fixed price swap contracts was based upon forward commodity prices based on quoted market prices, adjusted for differentials. See Note 12 for further discussion of the Company's hedging activities. The estimated fair value of the Company's equity investment in Diamondback was based upon the public closing share price of Diamondback's common stock as of September 30, 2013.

The Company estimates asset retirement obligations pursuant to the provisions of FASB ASC Topic 410, “Asset Retirement and Environmental Obligations” (“FASB ASC 410”). The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. See Note 3 for further discussion of the Company’s asset retirement obligations. Asset retirement obligations incurred during the nine months ended September 30, 2013 were approximately $1.8 million.

14. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amounts on the accompanying consolidated balance sheet for cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and current debt are carried at cost, which approximates market value due to their short-term nature. Long-term debt related to the building loan is carried at cost, which approximates market value based on the borrowing rates currently available to the Company with similar terms and maturities.

At September 30, 2013, the carrying value of the outstanding debt represented by the Notes was $297.1 million, including the remaining unamortized discount of approximately $3.3 million related to the October Notes and the remaining unamortized premium of approximately $0.4 million related to the December Notes. Based on the quoted market price, the fair value of the Notes was determined to be approximately $315.4 million at September 30, 2013.

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

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15. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

On October 17, 2012 and December 21, 2012, the Company issued an aggregate of $300.0 million of its 7.750% Senior Notes. The Notes are guaranteed on a senior unsecured basis by all existing consolidated subsidiaries that guarantee the Company's secured revolving credit facility or certain other debt (the "Guarantors"). The Notes are not guaranteed by Grizzly Holdings, Inc., (the "Non-Guarantor"). The Guarantors are 100% owned by Gulfport, (the "Parent") and the guarantees are full, unconditional, joint and several. There are no significant restrictions on the ability of the Parent or the Guarantors to obtain funds from each other in the form of a dividend or loan.

The following condensed consolidating balance sheets, statements of operations, statements of comprehensive income (loss) and statements of cash flows are provided for the Parent, the Guarantors and the Non-Guarantor and include the consolidating adjustments and eliminations necessary to arrive at the information for the Company on a condensed consolidated basis. The information has been presented using the equity method of accounting for the Parent's ownership of the Guarantors and the Non-Guarantor.

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CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	September 30, 2013				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$93,996	$1,469	$ 1	$—	$95,466
Accounts receivable - oil and gas	47,143	530	—	—	47,673
Accounts receivable - related parties	26,421	3,376	—	—	29,797
Accounts receivable - intercompany	18,419	—	—	(18,419)	—
Prepaid expenses and other current assets	4,634	—	—	—	4,634
Deferred tax asset	787	—	—	—	787
Short-term derivative instruments	1,633	—	—	—	1,633
Note receivable - related party	875	—	—	—	875
Total current assets	193,908	5,375	1	(18,419)	180,865
Property and equipment:					
Oil and natural gas properties, full-cost accounting	2,247,150	6,455	—	—	2,253,605
Other property and equipment	10,135	29	—	—	10,164
Accumulated depletion, depreciation, amortization and impairment	(747,677)	(21)	—	—	(747,698)
Property and equipment, net	1,509,608	6,463	—	—	1,516,071
Other assets:					
Equity investments and investments in subsidiaries	493,860	—	189,942	(183,123)	500,679
Derivative instruments	127	—	—	—	127
Other assets	12,827	—	—	—	12,827
Total other assets	506,814	—	189,942	(183,123)	513,633
Total assets	$2,210,330	$11,838	$ 189,943	$(201,542)	$2,210,569
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	$179,118	$239	$ —	$—	$179,357
Accounts payable - intercompany	—	18,309	110	(18,419)	—
Asset retirement obligation - current	780	—	—	—	780
Short-term derivative instruments	4,808	—	—	—	4,808
Current maturities of long-term debt	156	—	—	—	156
Total current liabilities	184,862	18,548	110	(18,419)	185,101
Long-term derivative instrument	962	—	—	—	962
Asset retirement obligation - long-term	13,988	—	—	—	13,988
Deferred tax liability	93,957	—	—	—	93,957
Long-term debt, net of current maturities	298,992	—	—	—	298,992
Total liabilities	592,761	18,548	110	(18,419)	593,000
Stockholders' equity:					
Common stock	775	—	—	—	775
Paid-in capital	1,399,803	322	199,437	(199,759)	1,399,803

Accumulated other comprehensive income (loss)	(4,841)	—	(3,344)	3,344	(4,841)
Retained earnings (accumulated deficit)	221,832	(7,032)	(6,260)	13,292	221,832
Total stockholders' equity	1,617,569	(6,710)	189,833	(183,123)	1,617,569
Total liabilities and stockholders' equity	$2,210,330	$11,838	$ 189,943	$(201,542)	$2,210,569

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CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	December 31, 2012				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$165,293	$1,795	$—	$—	$167,088
Accounts receivable - oil and gas	25,070	545	—	—	25,615
Accounts receivable - related parties	33,806	1,042	—	—	34,848
Accounts receivable - intercompany	15,368			(15,368)	—
Prepaid expenses and other current assets	1,506	—	—	—	1,506
Short-term derivative instruments	664	—	—	—	664
Total current assets	241,707	3,382	—	(15,368)	229,721
Property and equipment:					
Oil and natural gas properties, full-cost accounting,	1,606,172	4,918	—	—	1,611,090
Other property and equipment	8,642	20	—	—	8,662
Accumulated depletion, depreciation, amortization and impairment	(665,864)	(20)	—	—	(665,884)
Property and equipment, net	948,950	4,918	—	—	953,868
Other assets:					
Equity investments and investments in subsidiaries	374,209	—	172,766	(165,491)	381,484
Other assets	13,295	—	—	—	13,295
Total other assets	387,504	—	172,766	(165,491)	394,779
Total assets	$1,578,161	$8,300	$ 172,766	$(180,859)	$1,578,368
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	$110,037	$207	$—	$—	$110,244
Accounts payable - intercompany	—	15,259	109	(15,368)	—
Asset retirement obligation - current	60	—	—	—	60
Short-term derivative instruments	10,442	—	—	—	10,442
Current maturities of long-term debt	150	—	—	—	150
Total current liabilities	120,689	15,466	109	(15,368)	120,896
Asset retirement obligation - long-term	13,215	—	—	—	13,215
Deferred tax liability	18,607	—	—	—	18,607
Long-term debt, net of current maturities	298,888	—	—	—	298,888
Other non-current liabilities	354	—	—	—	354
Total liabilities	451,753	15,466	109	(15,368)	451,960
Stockholders' equity:					
Common stock	674	—	—	—	674
Paid-in capital	1,036,245	322	174,348	(174,670)	1,036,245
	(3,429)	—	2,442	(2,442)	(3,429)

Accumulated other comprehensive income (loss)					
Retained earnings (accumulated deficit)	92,918	(7,488)	(4,133)	11,621	92,918
Total stockholders' equity	1,126,408	(7,166)	172,657	(165,491)	1,126,408
Total liabilities and stockholders' equity	$1,578,161	$8,300	$172,766	$(180,859)	$1,578,368

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CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Three Months Ended September 30, 2013				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$68,855	$397	$—	$—	$69,252
Costs and expenses:					
Lease operating expenses	7,137	160	—	—	7,297
Production taxes	7,050	21	—	—	7,071
Midstream transportation, processing and marketing	3,616	6	—	—	3,622
Depreciation, depletion, and amortization	30,691	—	—	—	30,691
General and administrative	5,229	31	(1)	—	5,259
Accretion expense	180	—	—	—	180
Gain on sale of assets	(5)	—	—	—	(5)
	53,898	218	(1)	—	54,115
INCOME (LOSS) FROM OPERATIONS	14,957	179	1	—	15,137
OTHER (INCOME) EXPENSE:					
Interest expense	2,602	—	—	—	2,602
Interest income	(70)	—	—	—	(70)
(Income) loss from equity method investments and investments in subsidiaries	(51,502)	—	863	(683)	(51,322)
	(48,970)	—	863	(683)	(48,790)
INCOME (LOSS) BEFORE INCOME TAXES	63,927	179	(862)	683	63,927
INCOME TAX EXPENSE	23,400	—	—	—	23,400
NET INCOME (LOSS)	$40,527	$179	$ (862)	$683	$40,527

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CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Three Months Ended September 30, 2012				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$60,283	$254	$ —	$—	$60,537
Costs and expenses:					
Lease operating expenses	6,467	171	—	—	6,638
Production taxes	6,971	3	—	—	6,974
Midstream transportation, processing and marketing	93	3	—	—	96
Depreciation, depletion, and amortization	25,377	—	—	—	25,377
General and administrative	3,052	46	—	—	3,098
Accretion expense	176	—	—	—	176
	42,136	223	—	—	42,359
INCOME FROM OPERATIONS	18,147	31	—	—	18,178
OTHER (INCOME) EXPENSE:					
Interest expense	1,003	—	—	—	1,003
Interest income	(6)	—	—	—	(6)
(Income) loss from equity method investments and investments in subsidiaries	1,134	—	280	(249)	1,165
	2,131	—	280	(249)	2,162
INCOME (LOSS) BEFORE INCOME TAXES	16,016	31	(280)	249	16,016
INCOME TAX EXPENSE	15,514	—	—	—	15,514
NET INCOME (LOSS)	$502	$31	$ (280)	$249	$502

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CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Nine Months Ended September 30, 2013				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$193,550	$1,136	$—	$—	$194,686
Costs and expenses:					
Lease operating expenses	17,849	498	—	—	18,347
Production taxes	20,317	64	—	—	20,381
Midstream transportation, processing and marketing	5,926	14	—	—	5,940
Depreciation, depletion, and amortization	81,813	1	—	—	81,814
General and administrative	14,466	103	2	—	14,571
Accretion expense	529	—	—	—	529
Loss on sale of assets	567	—	—	—	567
	141,467	680	2	—	142,149
INCOME (LOSS) FROM OPERATIONS	52,083	456	(2)	—	52,537
OTHER (INCOME) EXPENSE:					
Interest expense	9,365	—	—	—	9,365
Interest income	(211)	—	—	—	(211)
(Income) loss from equity method investments and investments in subsidiaries	(163,094)	—	2,125	(1,671)	(162,640)
	(153,940)	—	2,125	(1,671)	(153,486)
INCOME (LOSS) BEFORE INCOME TAXES	206,023	456	(2,127)	1,671	206,023
INCOME TAX EXPENSE	77,109	—	—	—	77,109
NET INCOME (LOSS)	$128,914	$456	$(2,127)	$1,671	$128,914

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CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Nine Months Ended September 30, 2012				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$191,386	$937	$ —	$—	$192,323
Costs and expenses:					
Lease operating expenses	17,685	516	—	—	18,201
Production taxes	22,178	50	—	—	22,228
Midstream transportation, processing and marketing	176	7	—	—	183
Depreciation, depletion, and amortization	70,424	—	—	—	70,424
General and administrative	9,256	88	26	—	9,370
Accretion expense	529	—	—	—	529
	120,248	661	26	—	120,935
INCOME (LOSS) FROM OPERATIONS	71,138	276	(26)	—	71,388
OTHER (INCOME) EXPENSE:					
Interest expense	1,630	—	—	—	1,630
Interest income	(37)	—	—	—	(37)
(Income) loss from equity method investments and investments in subsidiaries	1,543	—	864	(614)	1,793
	3,136	—	864	(614)	3,386
INCOME (LOSS) BEFORE INCOME TAXES	68,002	276	(890)	614	68,002
INCOME TAX EXPENSE	15,514	—	—	—	15,514
NET INCOME (LOSS)	$52,488	$276	$ (890)	$614	$52,488

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CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Amounts in thousands)

	Three Months Ended September 30, 2013				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$40,527	$179	$ (862)	$683	$40,527
Foreign currency translation adjustment	3,894	—	3,894	(3,894)	3,894
Change in fair value of derivative instruments, net of taxes	630	—	—	—	630
Reclassification of settled contracts, net of taxes	1,617	—	—	—	1,617
Other comprehensive income (loss)	6,141	—	3,894	(3,894)	6,141
Comprehensive income (loss)	$46,668	$179	$ 3,032	$(3,211)	$46,668

	Three Months Ended September 30, 2012				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$502	$31	$ (280)	$249	$502
Foreign currency translation adjustment	5,320	—	5,320	(5,320)	5,320
Change in fair value of derivative instruments, net of taxes	(19,251)	—	—	—	(19,251)
Reclassification of settled contracts, net of taxes	185	—	—	—	185
Other comprehensive income (loss)	(13,746)	—	5,320	(5,320)	(13,746)
Comprehensive income	$(13,244)	$31	$ 5,040	$(5,071)	$(13,244)

	Nine Months Ended September 30, 2013				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$128,914	$456	$ (2,127)	$1,671	$128,914
Foreign currency translation adjustment	(5,786)	—	(5,786)	5,786	(5,786)
Change in fair value of derivative instruments, net of taxes	(444)	—	—	—	(444)
Reclassification of settled contracts, net of taxes	4,818	—	—	—	4,818
Other comprehensive income (loss)	(1,412)	—	(5,786)	5,786	(1,412)
Comprehensive income	$127,502	$456	$ (7,913)	$7,457	$127,502

	Nine Months Ended September 30, 2012				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$52,488	$276	$ (890)	$614	$52,488
Foreign currency translation adjustment	3,394	—	3,394	(3,394)	3,394
Change in fair value of derivative instruments, net of taxes	(11,678)	—	—	—	(11,678)

Reclassification of settled contracts, net of taxes	646	—	—	—	646
Other comprehensive income (loss)	(7,638)	—	3,394	(3,394)	(7,638)
Comprehensive income	$44,850	$276	$ 2,504	$(2,780)	$44,850

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CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Amounts in thousands)

	Nine Months Ended September 30, 2013				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$139,818	$1,213	$(1)	$—	$141,030
Net cash provided by (used in) investing activities	(569,291)	(1,539)	(25,087)	25,089	(570,828)
Net cash provided by (used in) financing activities	358,176	—	25,089	(25,089)	358,176
Net increase (decrease) in cash and cash equivalents	(71,297)	(326)	1	—	(71,622)
Cash and cash equivalents at beginning of period	165,293	1,795	—	—	167,088
Cash and cash equivalents at end of period	$93,996	$1,469	$1	$—	$95,466

	Nine Months Ended September 30, 2012				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by operating activities	$164,659	$1,218	$(1)	$—	$165,876
Net cash provided by (used in) investing activities	(386,506)	(1,387)	(93,436)	93,436	(387,893)
Net cash provided by (used in) financing activities	140,400	—	93,436	(93,436)	140,400
Net increase (decrease) in cash and cash equivalents	(81,447)	(169)	(1)	—	(81,617)
Cash and cash equivalents at beginning of period	93,124	772	1	—	93,897
Cash and cash equivalents at end of period	$11,677	$603	$—	$—	$12,280

16. SUBSEQUENT EVENTS

In October 2013, the Company entered into fixed price swaps for 30,000 MMBtu of natural gas per day at a weighted average price of $4.11 per MMBtu for the period from January 2014 through December 2014. For the period from January 2015 through April 2016, the Company entered into fixed price swaps for 40,000 MMBtu of natural gas per day at a weighted average price of $4.15 per MMBtu. The Company's fixed price swap contracts are tied to the commodity prices on NYMEX. The Company will receive the fixed price amount stated in the contract and pay to its counterparty the current market price as listed on NYMEX for natural gas.

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

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

Disclosure Regarding Forward-Looking Statements

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

Overview

We are an independent oil and natural gas exploration and production company focused on the exploration, exploitation, acquisition and production of crude oil, natural gas liquids and natural gas in the United States. Our corporate strategy is to internally identify prospects, acquire lands encompassing those prospects and evaluate those prospects using subsurface geology and geophysical data and exploratory drilling. Using this strategy, we have developed an oil and natural gas portfolio of proved reserves, as well as development and exploratory drilling opportunities on high potential conventional and unconventional oil and natural gas prospects. Our principal properties are located in the Utica Shale in Eastern Ohio and along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields. In addition, we have producing properties in the Niobrara Formation of Northwestern Colorado and the Bakken Formation. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, or Grizzly, an equity interest in Diamondback Energy, Inc., or Diamondback, a NASDAQ Global Select Market listed company to which we contributed our Permian Basin oil and natural gas interests in October 2012 immediately prior to Diamondback's initial public offering, or the Diamondback IPO, and interests in entities that operate in Southeast Asia, including the Phu Horm gas field in Thailand. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

Third Quarter 2013 Operational Highlights

- Oil and natural gas revenues increased 14% to $68.8 million for the three months ended September 30, 2013 from $60.5 million for the three months ended September 30, 2012.

- Net income increased $40.0 million to $40.5 million for the three months ended September 30, 2013 from $0.5 million for the three months ended September 30, 2012 , primarily due to $52.9 million of income recognized from our equity method investment in Diamondback during the three months ended September 30, 2013, partially offset by income tax expense of $23.4 million.

- Production increased 82% to 1,193,808 barrels of oil equivalent, or BOE, for the three months ended September 30, 2013 from 655,437 BOE for the three months ended September 30, 2012, due primarily to the increased production results from our drilling activity on our Utica Shale acreage, partially offset by the October 2012 contribution of our oil and natural gas properties in the Permian Basin to Diamondback in connection with the Diamondback IPO.

- During the three months ended September 30, 2013, we, and in some cases other operators, spud 24 gross (20.1 net) wells and recompleted 41 gross and net wells. Of these 24 gross new wells at September 30, 2013, six had been completed as producing wells, nine were waiting on completion, one was waiting on a horizontal rig and eight were being drilled.

- As of November 1, 2013, we had acquired leasehold interests in approximately 157,000 gross (147,000 net) acres in the Utica Shale. We spud our first well on our Utica Shale acreage in February 2012 and as of November 1, 2013, had spud 58 additional wells, including 14 gross wells in the third quarter of 2013.

2013 Production and Drilling Activity

During the three months ended September 30, 2013, our total net production was 590,187 barrels of oil, 2,981,632 thousand cubic feet, or Mcf, of natural gas, and 4,480,667 gallons of natural gas liquids, or NGLs, for a total of 1,193,808 BOE as compared to 579,288 barrels of oil, 314,674 Mcf of natural gas and 995,549 gallons of NGLs, or 655,437 BOE, for the three months ended September 30, 2012. Our total net production averaged approximately 12,976 BOE per day during the three months ended September 30, 2013 as compared to 7,124 BOE per day during the same period in 2012. The 82% increase in production is largely the result of the development of our Utica Shale acreage. In addition, during October 2012, we contributed our Permian Basin oil and natural gas properties to Diamondback in connection with the Diamondback IPO. As a result, during the three months ended September 30, 2013 we had no production from these Permian Basin properties compared to 110,846 BOE of production attributable to these assets during the same period in 2012. This decrease was offset by production related to the 2013 drilling and recompletion activities in our fields.

WCBB. During the third quarter of 2013, we drilled seven wells, completing five as producers with two waiting on completion at the end of the quarter. From January 1, 2013 through October 31, 2013, we recompleted 74 existing wells on our WCBB acreage. We also spud 17 wells, of which 16 were completed as producers and, at October 31, 2013, one was waiting on completion. We currently intend to recomplete a total of approximately 80 existing wells and drill a total of 22 to 24 wells during 2013.

Aggregate net production from the WCBB field during the three months ended September 30, 2013 was 351,171 BOE, or 3,817 BOE per day, 100% of which was from oil. During October 2013, our average daily net production at WCBB was approximately 4,304 BOE, 96% of which was from oil and 4% of which was from natural gas. The increase in October 2013 production was the result of our 2013 drilling and recompletion program.

East Hackberry Field. During the third quarter of 2013, we drilled three wells, completing one was as productive and, at the end of the quarter, one well was waiting on completion and one was still being drilled. From January 1, 2013 through October 31, 2013, we recompleted 54 existing wells in our East Hackberry field. We also spud 13 wells, of which ten were completed as producers, one was non-productive and, at October 31, 2013, one was waiting on completion and one was being drilled. We currently intend to drill 14 wells and recomplete 60 wells in our East Hackberry field in 2013.

Aggregate net production from the East Hackberry field during the three months ended September 30, 2013 was approximately 148,920 BOE, or 1,619 BOE per day, 85% of which was from oil and 15% of which was from natural gas. During October 2013, our average daily net production at East Hackberry was approximately 2,086 BOE, 92% of which was from oil and 8% of which was from natural gas. The increase in October 2013 production was the result of our 2013 drilling and recompletion activities.

West Hackberry Field. From January 1, 2013 through October 31, 2013, we recompleted two existing wells in our West Hackberry field. We also spud two wells, of which at October 31, 2013, one was being drilled and one was waiting on completion. Aggregate net production from the West Hackberry field during the three months ended September 30, 2013 was approximately 18,600 BOE, or 202 BOE per day, 99% of which was from oil and 1% of which was from natural gas. During October 2013, our average daily net production at West Hackberry was approximately 39 BOE, 100% of which was from oil.

Utica Shale (Eastern Ohio). As of November 1, 2013, we had acquired leasehold interests in approximately 157,000 gross (147,000 net) acres in the Utica Shale in Eastern Ohio. We spud our first well, the Wagner 1-28H, on our Utica Shale acreage in February 2012 and, as of October 31, 2013, had spud 59 wells, 31 of which had been completed and were producing as of that date. During the third quarter of 2013, we spud 14 gross (10.1 net wells) of which seven were waiting on completion and seven were still being drilled at the end of the quarter. In addition, 48 gross (2.6 net) wells were drilled by another operator on our Utica Shale acreage during 2012 and the first nine months of 2013. Gulfport's Irons 1-4H well was recently placed on production. The Irons 1-4H produced at an average 24-hour sales rate of 30.3 MMcf of natural gas per day.

At November 1, 2013, we had seven horizontal rigs under contract on our Utica Shale acreage. We currently intend to drill 55 to 60 gross (49 to 54 net) wells on our Utica Shale acreage in 2013.

Aggregate net production from our Utica Shale acreage during the three months ended September 30, 2013 was approximately 622,333 BOE, or 7,199 BOE per day, 29% of which was from oil and NGLs and 71% of which was from natural gas. During October 2013, our average daily net production from the Utica Shale was approximately 8,982 BOE, 34% of which was from oil and NGLs and 66% of which was from natural gas. The increased average daily net production was due to production results from our drilling activity on our Utica Shale acreage.

Niobrara Formation. Effective as of April 1, 2010, we acquired our initial leasehold interests in the Niobrara Formation in Northwestern Colorado and held leases for approximately 8,386 acres as of September 30, 2013. From January 1, 2013 through October 31, 2013, no new wells were spud on our Niobrara Formation acreage. Aggregate net production from our Niobrara Formation acreage during the three months ended September 30, 2013 was approximately 4,262 BOE, or 46 BOE per day, 100% of which was from oil. During October 2013, average daily net production from our Niobrara Formation acreage was approximately 55 BOE. There are no new activities currently scheduled for 2013 for our Niobrara Formation acreage.

Bakken. In the Bakken Formation of Western North Dakota and Eastern Montana, we held approximately 864 net acres, interests in eleven wells and overriding royalty interests in certain existing and future wells as of September 30, 2013. Aggregate net production from the Bakken Formation during the three months ended September 30, 2013 was approximately 8,251 BOE, or 90 BOE per day, 92% of which was from oil and NGLs and 8% of which was from natural gas. During October 2013, our average daily net production from the Bakken Formation was approximately 77 BOE. There are no new activities currently scheduled for 2013 for our Bakken acreage.

2013 Updates Regarding Our Equity Investments

Permian Basin. As of September 30, 2013, we owned approximately 12.1% of the outstanding common stock of Diamondback, a NASDAQ Global Select Market listed company to which we contributed our Permian Basin oil and gas interests in October 2012 immediately prior to the Diamondback IPO. See Notes 3 and 4 to our consolidated financial statements included elsewhere in this report for additional information regarding our investment in Diamondback.

Grizzly Oil Sands. We, through our wholly-owned subsidiary Grizzly Holdings Inc., own a 24.9% interest in Grizzly. The remaining interest in Grizzly is owned by Grizzly Oil Sands Inc., an entity owned by certain investment funds managed by Wexford Capital L.P., or Wexford. As of September 30, 2013, Grizzly had approximately 800,000 acres under lease in the Athabasca and Peace River oil sands regions of Alberta, Canada. Our total net investment in Grizzly was approximately $189.9 million as of September 30, 2013. As of that date, Grizzly had drilled an aggregate of 263 core holes and six water supply test wells on eleven separate lease blocks and conducted a number of seismic programs. In March 2010, Grizzly filed an application for the development of an 11,300 barrel per day steam-assisted gravity drainage, or SAGD, oil sand project at Algar Lake. During 2012, an 11 kilometer road was constructed to the project site, water and natural gas supply pipelines were installed, central plant modules were assembled, transported to the project site and lifted into place, ten production well pairs were drilled and completed and well pad modules and flow lines back to the central plant were installed. Grizzly expects to begin injecting steam into the Algar Lake reservoir before the end of 2013, with first oil production anticipated by the end of first quarter of 2014. In the first quarter of 2012, Grizzly acquired the May River property comprising approximately 47,000 acres. In the 2012/2013 drilling program, Grizzly completed a 29 well core hole drilling program at May River and plans to file an initial 12,000 barrel per day development application with the ERCB by the end of 2013. At the Thickwood thermal project, Grizzly's 2012 activities included the completion of a 22 well core hole drilling program and the acquisition of 31 kilometers of seismic data. A development application for a 12,000 barrel per day oil sands project at Thickwood was filed in the fourth quarter of 2012. Grizzly anticipates approval of this development application by the end of 2014. Grizzly has also entered into a memorandum of understanding that outlines the rate structure for a ten year agreement with Canadian National Railway Company, or CN, to transport its bitumen to the U.S. Gulf Coast via CN's rail network. Grizzly expects that this arrangement will provide consistent access to Brent-based pricing from Grizzly's Algar Lake project. Grizzly is also pursuing the design, permitting and construction of rail terminals in Northern Alberta and on the Lower Mississippi River, where it plans to develop scalable capacity to accommodate unit trains to ship and receive up to 40,000 barrels per day. Grizzly anticipates beginning to transport its bitumen starting in the first quarter of 2014.

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Thailand. During 2005, we purchased a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex II, at a cost of $2.4 million. The remaining interests in Tatex II are owned by entities controlled by Wexford. Tatex II, a privately held entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering approximately 243,000 acres which includes the Phu Horm Field. During the nine months ended September 30, 2013 we received $0.6 million in distributions from Tatex II. Our investment is accounted for using the equity method. Tatex II accounts for its investment in APICO using the cost method. In December 2006, first gas sales were achieved at the Phu Horm field located in northeast Thailand. Phu Horm's initial gross production was approximately 60 million cubic feet per day. During the three months ended September 30, 2013, net gas production was approximately 62 MMcf per day and condensate production was 282 barrels per day. Hess Corporation, or Hess, operates the field with a 35% interest. Other interest owners include APICO (35% interest), PTT Exploration and Production Public Company Limited (20% interest) and ExxonMobil (10% interest). Our gross working interest (through Tatex II as a member of APICO) in the Phu Horm field is 0.7%. Since our ownership in the Phu Horm field is indirect and Tatex II's investment in APICO is accounted for by the cost method, these reserves are not included in our year-end reserve information.

During the first quarter of 2008, we purchased a 5% ownership interest in Tatex Thailand III, LLC, or Tatex III, at a cost of $0.9 million. In December 2009, we purchased an additional approximately 12.9% ownership interest at a cost of approximately $3.4 million bringing our total ownership interest to approximately 17.9%. Approximately 68.7% of the remaining interests in Tatex III are owned by entities controlled by Wexford. Tatex III owns a concession covering approximately 490,000 acres in Southeast Asia. In 2009, Tatex III completed a 3-D seismic survey on this concession. During the nine months ended September 30, 2013, we paid cash calls to Tatex III of approximately $2.4 million. Our total investment in Tatex III was $10.9 million at September 30, 2013. The first well was drilled on our concession in 2010 and was temporarily abandoned pending further scientific evaluation. Drilling of the second well concluded in March 2011. The second well was drilled to a depth of 15,026 feet and logged approximately 5,000 feet of apparent possible gas saturated column. The well experienced gas shows and carried a flare measuring up to 25 feet throughout drilling below the intermediate casing point of 9,695 feet. During testing, the well produced at rates as high as 16 MMcf per day of gas for short intervals, but would subsequently fall to a sustained rate of two MMcf per day of gas. Pressure buildup information confirmed that this wellbore lacked the permeability to deliver commercial quantities of gas. Despite an apparently well-developed porosity system suggesting potential for a large amount of gas in place, testing of the well did not exhibit that there was sufficient permeability to produce in commercial quantities. Tatex III intends to continue testing some of the structures identified through its 3-D seismic survey and has begun the application process for two more drilling locations. In October 2013, Tatex III spud the TEW-K well, located to the south of the TEW-E well.

Other Investments. In an effort to facilitate the development of our Utica Shale and other domestic acreage, we have invested in entities that can provide services that are required to support our operations. In the first quarter of 2013, we participated in the formation of Stingray Energy Services LLC, or Stingray Energy, with an initial ownership interest of 50%, and paid $2.2 million for our initial investment in Stingray Energy. Stingray Energy provides rental tools for land-based oil and natural gas drilling, completion and workover activities as well as the transfer of fresh water to wellsites. In the second quarter of 2012, we participated in the formation of each of Stingray Pressure Pumping LLC, or Stingray Pressure, and Stingray Cementing LLC, or Stingray Cementing, with an initial ownership interest in each entity of 50%. Stingray Pressure and Stingray Cementing provide well completion services. We also participated in the formation of Blackhawk Midstream LLC, or Blackhawk, with an initial ownership interest of 50%. Blackhawk coordinates gathering, compression, processing and marketing activities in connection with the development of our Utica Shale acreage. In the fourth quarter of 2012, we also participated in the formation of Stingray Logistics LLC, or Stingray Logistics, with an initial ownership interest of 50%. Stingray Logistics provides well services. In March

2012, we participated in the formation of Timber Wolf Terminals LLC, or Timber Wolf, with an initial ownership interest of 50% and made a $1.0 million capital contribution. Also in March 2012, we acquired a 22.5% equity interest in Windsor Midstream LLC, or Midstream, for $7.0 million. Midstream owns a 28.4% equity interest in a gas processing plant in West Texas. In 2011, we acquired a 25% equity interest in Bison Drilling and Field Services LLC, or Bison, which owns and operates drilling rigs and related equipment. In April 2012, we purchased an additional 15% equity interest in Bison for approximately $6.2 million, bringing our total ownership interest in Bison to 40%. Also in 2011, we acquired a 25% interest in Muskie Proppant LLC, or Muskie (formerly known as Muskie Holdings LLC), which is engaged in the mining of hydraulic fracturing grade sand. In 2012, we invested approximately $42.8 million in these entities. In the nine months ended September 30, 2013, we invested approximately $7.5 million in these entities. See Note 4 to our consolidated financial statements included elsewhere in this report for additional information regarding these other investments.

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Critical Accounting Policies and Estimates

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

Oil and Natural Gas Properties. We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including non-productive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price for the prior twelve months, adjusted for any contract provisions or financial derivatives, if any, that hedge our oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required. Such capitalized costs, including the estimated future development costs and site remediation costs of proved undeveloped properties are depleted by an equivalent units-of-production method, converting gas to barrels at the ratio of six Mcf of gas to one barrel of oil. No gain or loss is recognized upon the disposal of oil and natural gas properties, unless such dispositions significantly alter the relationship between capitalized costs and proven oil and natural gas reserves. Oil and natural gas properties not subject to amortization consist of the cost of undeveloped leaseholds and totaled $952.7 million at September 30, 2013 and $626.3 million at December 31, 2012. These costs are reviewed quarterly by management for impairment, with the impairment provision included in the cost of oil and natural gas properties subject to amortization. Factors considered by management in its impairment assessment include our drilling results and those of other operators, the terms of oil and natural gas leases not held by production and available funds for exploration and development.

Ceiling Test. Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price for the prior twelve months of the applicable year beginning with 2009, adjusted for any contract provisions or financial derivatives, if any, that hedge our oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required. Ceiling test impairment can give us a significant loss for a particular period; however, future depletion expense would be reduced. A decline in oil and gas prices may result in an impairment of oil and gas properties. For instance, as a result of the drop in commodity prices on December 31, 2008 and subsequent reduction in our proved reserves, we recognized a ceiling test impairment of $272.7 million for the year ended December 31, 2008. If prices of oil, natural gas and NGLs decline, we may be required to further write down the value of our oil and gas properties, which could negatively affect our results of operations. No ceiling test impairment was required for the quarter ended September 30, 2013.

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

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

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

Oil and Gas Reserve Quantities. Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Netherland, Sewell & Associates, Inc., Ryder Scott Company, L.P. and to a lesser extent our personnel have prepared reserve reports of our reserve estimates at December 31, 2012 on a well-by-well basis for our properties.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Our reserve estimates and the projected cash flows derived from these reserve estimates have been prepared in accordance with the guidelines of the Securities and Exchange Commission, or SEC. 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. Therefore, 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 September 30, 2013, a valuation allowance of $4.6 million had been provided for state net operating loss and federal tax credit deferred tax assets based on the uncertainty these assets may be realized.

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.

Investments-Equity Method. Investments in entities greater than 20% and less than 50% and/or investments in which we have significant influence are accounted for under the equity method. Under the equity method, our share of investees' earnings or loss is recognized in the statement of operations. In accordance with FASB ASC 825, “Financial Instruments,” we have elected the fair value option of accounting for our equity method investment in Diamondback's stock. At the end of each reporting period, the quoted closing market price of Diamondback's stock is multiplied by the total shares owned by us and the resulting gain or loss is recognized in (income) loss from equity method investments in the consolidated statements of operations.

We review our investments to determine if a loss in value which is other than a temporary decline has occurred. If such loss has occurred, we recognize an impairment provision. There was no impairment of equity method investments at September 30, 2013 and December 31, 2012.

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

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

RESULTS OF OPERATIONS

Comparison of the Three Months Ended September 30, 2013 and 2012

We reported net income of $40.5 million for the three months ended September 30, 2013 as compared to $0.5 million for the three months ended September 30, 2012. This $40.0 million increase in period-to-period net income was due primarily to $52.9 million of income recognized from our equity method investment in Diamondback and an 82% increase in net production to 1,193,808 BOE from 655,437 BOE, partially offset by a 38% decrease in realized BOE prices to $57.65 from $92.24, a $0.7 million increase in lease operating expenses, a $3.5 million increase in midstream transportation, processing and marketing expenses, a $2.2 million increase in general and administrative expenses and a $7.9 million increase in income tax expense for the quarter ended September 30, 2013 as compared to the quarter ended September 30, 2012.

Oil and Gas Revenues. For the three months ended September 30, 2013, we reported oil and natural gas revenues of $68.8 million as compared to oil and natural gas revenues of $60.5 million during the same period in 2012. This $8.4 million, or 14%, increase in revenues was primarily attributable to an 82% increase in net production to 1,193,808 BOE from 655,437 BOE due primarily to increased drilling in our Utica acreage, which was partially offset by the contribution of our oil and natural gas properties in the Permian Basin to Diamondback in connection with the Diamondback IPO and a 38% decrease in realized BOE prices to $57.65 from $92.24 due to a change in our production mix for the three months ended September 30, 2013 as compared to the three months ended September 30, 2012.

The following table summarizes our oil and natural gas production and related pricing for the three months ended September 30, 2013, as compared to such data for the three months ended September 30, 2012:

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	Three Months Ended September 30,	
	2013	2012
Oil production volumes (MBbls)	590	579
Gas production volumes (MMcf)	2,982	315
Liquid production volumes (MGal)	4,481	996
Oil equivalents (Mboe)	1,194	655
Average oil price (per Bbl)	$89.75	$101.17
Average gas price (per Mcf)	$3.61	$3.09
Average liquids price (per gallon)	$1.14	$0.88
Oil equivalents (per Boe)	$57.65	$92.24

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased by $0.7 million to $7.3 million for the three months ended September 30, 2013 from $6.6 million for the same period in 2012. This increase was mainly due to an increase in compressor repair and maintenance expense, contract pumper expense, property taxes, insurance and salt water hauling and disposal, which was partially offset by the contribution of our Permian Basin oil and natural gas properties to Diamondback during October 2012. During the three months ended September 30, 2012, our LOE included $2.4 million related to our Permian Basin properties. As a result of the contribution of our Permian Basin assets during October 2012, there was no LOE associated with those assets for the same period in 2013.

Production Taxes. Production taxes increased $0.1 million to $7.1 million for the three months ended September 30, 2013 from $7.0 million for the same period in 2012. This increase was primarily related to an 82% increase in production resulting in a 14% increase in oil and gas revenues.

Midstream Transportation, Processing and Marketing Expenses. Midstream transportation, processing and marketing expenses increased by $3.5 million to $3.6 million for the three months ended September 30, 2013 from $0.1 million for the same period in 2012. This increase is primarily the result of midstream expenses related to our production volumes in the Utica Shale resulting from our 2012 and 2013 drilling activities.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $30.7 million for the three months ended September 30, 2013, and consisted of $30.5 million in depletion on oil and natural gas properties and $0.2 million in depreciation of other property and equipment, as compared to total DD&A expense of $25.4 million for the three months ended September 30, 2012. This increase was due to an increase in our full cost pool as a result of our capital activities as well as an increase in our production, partially offset by an increase in our total proved reserves volume used to calculate our total DD&A expense.

General and Administrative Expenses. Net general and administrative expenses increased to $5.3 million for the three months ended September 30, 2013 from $3.1 million for the same period in 2012. This $2.2 million increase was due primarily to an increase in accounting, consulting and legal fees, franchise taxes, as well as increases in salaries, stock compensation and benefits resulting from an increase in the number of employees primarily attributable to our activities in the Utica Shale and a reduction to administrative reimbursements, partially offset by an increase in general and administrative costs related to exploration and development activity capitalized to the full cost pool.

Interest Expense. Interest expense increased to $2.6 million for the three months ended September 30, 2013 from $1.0 million for the same period in 2012 due largely to the issuance of our 7.75% Senior Notes due 2020. As of September 30, 2013, we had no debt outstanding under our revolving credit facility as compared to $141.0 million of total debt outstanding under our revolving credit facility as of September 30, 2012 . On October 17, 2012, we issued

$250.0 million aggregate principal amount of our 7.75% Senior Notes due 2020, a portion of the proceeds from which was used to repay all outstanding borrowings under our revolving credit facility. On December 21, 2012, we issued an additional $50.0 million aggregate principal amount of our 7.75% Senior Notes due 2020. Additionally, we capitalized approximately $3.5 million in interest expense to undeveloped oil and natural gas properties during the three months ended September 30, 2013 as a result of increased interest costs incurred on our 7.75% Senior Notes. We did not capitalize any interest costs for the three months ended September 30, 2012.

Income Taxes. As of September 30, 2013, we had numerous temporary differences, which gave rise to deferred tax assets and deferred tax liabilities. Periodically, management performs a forecast of our taxable income to determine whether it

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is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management's opinion, it is more likely than not that some portion will not be realized. At September 30, 2013, a valuation allowance of $4.6 million had been provided for state net operating losses and certain tax credits based upon the latest taxable income forecast. We recognized $23.4 million of income tax expense for the three months ended September 30, 2013 based upon the latest taxable income forecast.

Comparison of the Nine Months Ended September 30, 2013 and 2012

We reported net income of $128.9 million for the nine months ended September 30, 2013 as compared to $52.5 million for the nine months ended September 30, 2012. This $76.4 million increase in period-to-period net income was due primarily to $165.4 million of income recognized on our equity method investment in Diamondback (which includes the sale of 2,234,536 shares of our Diamondback common stock) and a 32% increase in net production to 2,584,651 BOE from 1,964,119 BOE, partially offset by a 23% decrease in realized BOE prices to $75.02 from $97.82, a $5.8 million increase in midstream transportation, processing and marketing expenses, a $61.6 million increase in income tax expense and a $5.2 million increase in general and administrative expenses for the nine months ended September 30, 2013 as compared to the nine months ended September 30, 2012.

Oil and Gas Revenues. For the nine months ended September 30, 2013, we reported oil and natural gas revenues of $193.9 million as compared to oil and natural gas revenues of $192.1 million during the same period in 2012. This $1.8 million, or 1%, increase in revenues was primarily attributable to a 32% increase in net production to 2,584,651 BOE from 1,964,119 BOE, partially offset by a 23% decrease in realized BOE prices to $75.02 from $97.82 as a result of a change in our production mix for the nine months ended September 30, 2013 as compared to the nine months ended September 30, 2012.
The following table summarizes our oil and natural gas production and related pricing for the nine months ended September 30, 2013, as compared to such data for the nine months ended September 30, 2012:

	Nine Months Ended September 30,	
	2013	2012
Oil production volumes (MBbls)	1,642	1,783
Gas production volumes (MMcf)	4,716	741
Liquid production volumes (MGal)	6,565	2,424
Oil equivalents (Mboe)	2,585	1,964
Average oil price (per Bbl)	$101.72	$105.25
Average gas price (per Mcf)	$4.03	$2.87
Average liquids price (per gallon)	$1.19	$0.98
Oil equivalents (per Boe)	$75.02	$97.82

Lease Operating Expenses. LOE, not including production taxes increased $0.1 million to $18.3 million for the nine months ended September 30, 2013 from $18.2 million for the same period in 2012. This increase was mainly the result of an increase in expenses for compressor repair and maintenance, contract pumper, salt water hauling and disposal, property taxes and insurance, which was partially offset by the contribution of our Permian Basin oil and natural gas properties to Diamondback during October 2012. During the nine months ended September 30, 2012, our LOE included $6.4 million related to our Permian Basin properties. As a result of the contribution of our Permian Basin assets during October 2012, there was no LOE associated with those assets for the same period in 2013.

Production Taxes. Production taxes decreased $1.8 million to $20.4 million for the nine months ended September 30, 2013 from $22.2 million for the same period in 2012. This decrease was primarily related to a 32% increase in production offset by a 23% decrease in the average realized BOE price received, resulting in a 1% increase in oil and gas revenues.

Midstream Transportation, Processing and Marketing Expenses. Midstream transportation, processing and marketing expenses increased by $5.8 million to $5.9 million for the nine months ended September 30, 2013 from $0.2 million for the same period in 2012. This increase is primarily the result of midstream expenses related to our production volumes in the Utica Shale resulting from our 2012 and 2013 drilling activities.

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Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $81.8 million for the nine months ended September 30, 2013, and consisted of $81.3 million in depletion on oil and natural gas properties and $0.5 million in depreciation of other property and equipment, as compared to total DD&A expense of $70.4 million for the nine months ended September 30, 2012. This increase was due to an increase in our full cost pool as a result of our capital activities and an increase in our production, partially offset by an increase in our total proved reserves volume used to calculate our total DD&A expense.

General and Administrative Expenses. Net general and administrative expenses increased to $14.6 million for the nine months ended September 30, 2013 from $9.4 million for the same period in 2012. This $5.2 million increase was due primarily to an increase in accounting, legal, consulting and corporate fees, franchise taxes, as well as increases in salaries, stock compensation and benefits resulting from an increase in the number of employees primarily attributable to our activities in the Utica Shale and a reduction in administrative reimbursements, partially offset by an increase in general and administrative costs related to exploration and development activity capitalized to the full cost pool.

Interest Expense. Interest expense increased to $9.4 million for the nine months ended September 30, 2013 from $1.6 million for the same period in 2012 due largely to the issuance of our 7.75% Senior Notes due 2020. As of September 30, 2013, we had no debt outstanding under our revolving credit facility as compared to $141.0 million of total debt outstanding under our revolving credit facility as of September 30, 2012. On October 17, 2012, we issued $250.0 million aggregate principal amount of our 7.75% Senior Notes due 2020, a portion of the proceeds from which was used to repay all outstanding borrowings under our revolving credit facility. On December 21, 2012, we issued an additional $50.0 million aggregate principal amount of our 7.75% Senior Notes due 2020. Additionally, we capitalized approximately $9.0 million in interest expense to undeveloped oil and natural gas properties during the nine months ended September 30, 2013 as a result of increased interest costs incurred on our 7.75% Senior Notes. We did not capitalize any interest costs for the nine months ended September 30, 2012.

Income Taxes. As of September 30, 2013, we had numerous temporary differences, which gave rise to deferred tax assets and deferred tax liabilities. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management’s opinion, it is more likely than not that some portion will not be realized. At September 30, 2013, a valuation allowance of $4.6 million had been provided for state net operating losses and certain tax credits based upon the latest taxable income forecast. We recognized $77.1 million of income tax expense for the nine months ended September 30, 2013 based upon the latest taxable income forecast.

Liquidity and Capital Resources

Overview. Historically, our primary sources of funds have been cash flow from our producing oil and natural gas properties, borrowings under our bank and other credit facilities and the issuances of equity and debt securities. Our ability to access any of these sources of funds can be significantly impacted by decreases in oil and natural gas prices or oil and natural gas production. During 2012, we received aggregate net proceeds (before offering expenses) of approximately $427.9 million from the sale of shares of our common stock and approximately $290.3 million from the sale of our 7.75% Senior Notes due 2020. In January 2013, we received $32.8 million of net proceeds from the underwriters' exercise of their option to purchase the remaining shares of common stock subject to the over-allotment option granted in connection with our December 2012 equity offering. We did not sell any of our equity securities during the nine months ended September 30, 2012.

On February 15, 2013, we closed an unwritten public offering of 8,912,500 shares of our common stock (including 1,162,500 shares purchased by the underwriters pursuant to an option to purchase additional shares) at a public offering price of $38.00 per share. We received aggregate net proceeds (before offering expenses) of approximately $325.8 million from this offering. We used a portion of the net proceeds from this offering to fund our acquisition of approximately 22,000 net acres in the Utica Shale. We intend to use the remaining net proceeds for general corporate purposes, including the funding of a portion of our 2013 capital development plan.

On June 24, 2013, we sold 1,951,781 shares of our Diamondback common stock in an underwritten public offering in which certain entities controlled by Wexford Capital LP also participated as selling stockholders and, on July 5, 2013, the underwriters purchased an additional 282,755 shares of Diamondback common stock from us pursuant to an option to purchase additional shares from the selling stockholders granted to the underwriters. The shares were sold to the public at $34.75 per share. We received an aggregate of $74.5 million in net proceeds from the sale of our shares of Diamondback common stock in this offering. We used a portion of these proceeds to fund the acquisition of additional acreage in the Utica Shale and intend to use the balance of these proceeds for general corporate purposes, including the funding of a portion of our 2013 capital development plan.

Net cash flow provided by operating activities was $141.0 million for the nine months ended September 30, 2013 as compared to net cash flow provided by operating activities of $165.9 million for the same period in 2012. This decrease was primarily the result of a decrease in cash receipts from our oil and natural gas purchasers due to a 23% decrease in net realized BOE prices, partially offset by a 32% increase in our net BOE production.

Net cash used in investing activities for the nine months ended September 30, 2013 was $570.8 million as compared to $387.9 million for the same period in 2012. During the nine months ended September 30, 2013, we spent $608.3 million in additions to oil and natural gas properties, of which $189.4 million was spent on our 2013 drilling and recompletion programs, $92.0 million was spent on expenses attributable to the wells drilled and recompleted during 2012, $5.1 million was spent on compressors and other facility enhancements, $1.2 million was spent on plugging costs, $299.3 million was spent on lease related costs, primarily the acquisition of leases in the Utica Shale, and $3.5 million was spent on tubulars, with the remainder attributable mainly to capitalized general and administrative expenses. In addition, $25.1 million was invested in Grizzly and $9.8 million was invested in our other equity investments during the nine months ended September 30, 2013. During the nine months ended September 30, 2013, we used cash from operations and proceeds from our 2012 and 2013 equity and debt offerings for our investing activities.

Net cash provided by financing activities for the nine months ended September 30, 2013 was $358.2 million as compared to net cash provided by financing activities of $140.4 million for the same period in 2012. The 2013 amount provided by financing activities is primarily attributable to the net proceeds of $325.8 million from our February 2013 equity offering. The 2012 amount provided by financing activities is primarily attributable to net borrowings under our secured revolving credit facility.

Credit Facility. On September 30, 2010, we entered into a senior secured revolving credit facility with The Bank of Nova Scotia, as administrative agent and letter of credit issuer and lead arranger, and Amegy Bank National Association, or Amegy Bank. The revolving credit facility initially matured on September 30, 2013, had a maximum commitment amount of $100.0 million and had a borrowing base availability of $50.0 million, which was increased to $65.0 million effective December 24, 2010. On May 3, 2011, we entered into a first amendment to the revolving credit facility with The Bank of Nova Scotia, Amegy Bank, KeyBank National Association, or KeyBank, and Société Générale. Under the terms of the first amendment, KeyBank and Société Générale were added as additional lenders, the maximum amount of the revolving credit facility was increased to $350.0 million, the borrowing base was increased to $90.0 million, certain fees and rates payable by us under the credit facility were decreased, and the maturity date was extended until May 3, 2015. On October 31, 2011, we entered into additional amendments to our revolving credit facility pursuant to which, among other things, the borrowing base under the facility was increased to $125.0 million. On December 14, 2011, we repaid all outstanding borrowings under the credit facility with a portion of the net proceeds of our equity offering completed on December 5, 2011 pending the application of such proceeds to fund certain Utica Shale lease acquisitions and for general corporate purposes. On May 2, 2012, we entered into an amendment to the revolving credit facility under which, among other things, the borrowing base was increased to $155.0 million. In addition, Credit Suisse, Deutsche Bank Trust Company Americas and IBERIABANK were added as additional lenders and Société Générale left the bank group.

On October 9, 2012, we entered into an amendment to our revolving credit facility that modified certain covenants to permit our October offering of 7.75% Senior Notes due 2020. The offering closed on October 17, 2012 and we repaid all indebtedness outstanding under our revolving credit facility on that date with a portion of the proceeds from the offering. Effective as of October 17, 2012, we amended our revolving credit facility to lower the applicable rates (i) from a range of 1.00% to 1.75% to a range of 0.75% to 1.50% for the base rate loans and (ii) from a range of 2.00% to 2.75% to a range of 1.75% to 2.50% for the eurodollar rate loans and letters of credit. This amendment also lowered the commitment fees for Level 1 and Level 2 usage levels, in each case, from 0.50% per annum to 0.375% per annum. Also, effective as of October 17, 2012, in connection with the completion of our October offering and the contribution of our Permian Basin properties to Diamondback, our borrowing base under the credit facility was reduced to $45.0

million until the next borrowing base redetermination. Effective as of December 18, 2012, we entered into another amendment to our revolving credit facility that modified certain covenants to permit our December offering of 7.75% Senior Notes due 2020 and reduce the borrowing base under our revolving credit facility to $40.0 million until the next borrowing base redetermination.

Advances under our revolving credit facility, as amended, may be in the form of either base rate loans or eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from .75% to 1.50%, plus (2) the highest of: (a) the federal funds rate plus 0.5%, (b) the rate of interest in effect for such day as publicly announced from time to time by

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agent as its “prime rate,” and (c) the eurodollar rate for an interest period of one month plus 1.00%. The interest rate for eurodollar loans is equal to (1) the applicable rate, which ranges from 1.75% to 2.50%, plus (2) the London interbank offered rate that appears on Reuters Screen LIBOR01 Page for deposits in U.S. dollars, or, if such rate is not available, the offered rate on such other page or service that displays the average British Bankers Association Interest Settlement Rate for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the “London Interbank Offered Rate” for deposits in U.S. dollars. We have had no outstanding borrowings under our revolving credit facility since October 17, 2012, on which date the outstanding borrowings, prior to repayment, bore interest at the eurodollar rate (2.97%) per annum.

In connection with the spring borrowing base redetermination of our revolving credit facility, completed as of June 6, 2013, we entered into an amendment to our revolving credit facility pursuant to which, among other things, our borrowing base under this facility was increased from $40.0 million to $50.0 million, an improved pricing grid was provided for and the maturity date of the facility was extended to June 2018. See also Note 6 to our financial statements included elsewhere in this report.

In connection with the fall borrowing base redetermination of our revolving credit facility, our lead lender has proposed to increase our borrowing base from $50.0 million to $150.0 million, subject to the approval of the additional banks within the syndicate.

As of September 30, 2013, there were no borrowings outstanding under our revolving credit facility. This facility is secured by substantially all of our assets. Our wholly-owned subsidiaries guarantee our obligations under our revolving credit facility.

Our revolving credit facility contains customary negative covenants including, but not limited to, restrictions on our and our subsidiaries' ability to: incur indebtedness; grant liens; pay dividends and make other restricted payments; make investments; make fundamental changes; enter into swap contracts and forward sales contracts; dispose of assets; change the nature of their business; and enter into transactions with their affiliates. The negative covenants are subject to certain exceptions as specified in our revolving credit facility. Our revolving credit facility also contains certain affirmative covenants, including, but not limited to the following financial covenants: (1) the ratio of funded debt to EBITDAX (net income, excluding any non-cash revenue or expense associated with swap contracts resulting from ASC 815, plus without duplication and to the extent deducted from revenues in determining net income, the sum of (a) the aggregate amount of consolidated interest expense for such period, (b) the aggregate amount of income, franchise, capital or similar tax expense (other than ad valorem taxes) for such period, (c) all amounts attributable to depletion, depreciation, amortization and asset or goodwill impairment or writedown for such period, (d) all other non-cash charges, (e) non-cash losses from minority investments, (f) actual cash distributions received from minority investments, (g) to the extent actually reimbursed by insurance, expenses with respect to liability on casualty events or business interruption, and (h) all reasonable transaction expenses related to dispositions and acquisitions of assets, investments and debt and equity offerings, and less non-cash income attributable to equity income from minority investments) for a twelve-month period may not be greater than 2.00 to 1.00; and (2) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. We were in compliance with these financial covenants at September 30, 2013.

Senior Notes. On October 17, 2012, we issued $250.0 million in aggregate principal amount of our 7.75% Senior Notes due 2020, or the October Notes, to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act under an indenture among us, our subsidiary guarantors and Wells Fargo Bank, National Association, as the trustee.

On December 21, 2012, we issued an additional $50.0 million in aggregate principal amount of our 7.75% Senior Notes due 2020, or the December Notes, to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act. The December Notes were issued as additional securities under the existing senior note indenture. The December Notes and the October Notes are treated as a single class of debt securities under the senior note indenture and are referred to collectively herein as the "Notes". We used a portion of the net proceeds from the October Notes Offering to repay all amounts outstanding at such time under our revolving credit facility. We used the remaining net proceeds of the October Notes

Offering and the net proceeds of the December Notes Offering for general corporate purposes, which includes funding a portion of our 2013 capital development plan.

Under the senior note indenture, interest on the Notes accrues at a rate of 7.75% per annum on the outstanding principal amount from October 17, 2012, payable semi-annually on May 1 and November 1 of each year, commencing on May 1, 2013. The Notes are senior unsecured obligations and rank equally in the right of payment with all of our other senior indebtedness and senior in right of payment to any of our future subordinated indebtedness. All of our existing and future restricted subsidiaries that guarantee our secured revolving credit facility or certain other debt guarantee the Notes, provided, however, that the Notes are not guaranteed by Grizzly Holdings, Inc. and will not be guaranteed by any of our future unrestricted

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subsidiaries. The guarantees rank equally in the right of payment with all of the senior indebtedness of the subsidiary guarantors and senior in the right of payment to any future subordinated indebtedness of the subsidiary guarantors. The Notes and the guarantees are effectively subordinated to all of our and the subsidiary guarantors' secured indebtedness (including all borrowings and other obligations under our revolving credit facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated to all indebtedness and other liabilities of any of our subsidiaries that do not guarantee the Notes.

We may redeem some or all of the Notes at any time on or after November 1, 2016, at the redemption prices listed in the senior note indenture. Prior to November 1, 2016, we may redeem the Notes at a price equal to 100% of the principal amount plus a “make-whole” premium. In addition, prior to November 1, 2015, we may redeem up to 35% of the aggregate principal amount of the Notes with the net proceeds of certain equity offerings, provided that at least 65% of the aggregate principal amount of the Notes initially issued remains outstanding immediately after such redemption.

If we experience a change of control (as defined in the senior note indenture), we will be required to make an offer to repurchase the Notes at a price equal to 101% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase. If we sell certain assets and fail to use the proceeds in a manner specified in the senior note indenture, we will be required to use the remaining proceeds to make an offer to repurchase the Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase.

The senior note indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit our ability and the ability of our restricted subsidiaries to incur or guarantee additional indebtedness, make certain investments, declare or pay dividends or make distributions on capital stock, prepay subordinated indebtedness, sell assets including capital stock of restricted subsidiaries, agree to payment restrictions affecting our restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of our assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and gas business and designate certain of our subsidiaries as unrestricted subsidiaries.

Building Loans. In June 2004, we purchased the office building we occupy in Oklahoma City, Oklahoma, for $3.7 million. We entered into a new building loan in March 2011 to refinance the $2.4 million outstanding at that time. The new agreement matures in February 2016 and bears interest at a fixed rate of 5.82% per annum. The new building loan requires monthly interest and principal payments of approximately $22,000 and is collateralized by the Oklahoma City office building and associated land. As of September 30, 2013, approximately $2.0 million was outstanding on this loan.

Capital Expenditures. Our recent capital commitments have been primarily for the execution of our drilling programs, for acquisitions (primarily in the Utica Shale), to fund Grizzly's delineation drilling program and initial preparation of the Algar Lake facility and for investments in entities that may provide services to facilitate the development of our acreage. Our strategy is to continue to (1) increase cash flow generated from our operations by undertaking new drilling, workover, sidetrack and recompletion projects to exploit our existing properties, subject to economic and industry conditions, (2) pursue acquisition and disposition opportunities and (3) pursue business integration opportunities.

Of our net reserves at December 31, 2012, 40.2% 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.

At December 31, 2012, our booked inventory of prospects included approximately 36 drilling locations at WCBB. The drilling schedule used in our December 31, 2012 reserve report anticipates that all of those wells will be drilled by the end of 2015. From January 1, 2013 through October 31, 2013, we recompleted 74 existing wells and spud 17 new wells at our WCBB field. We currently intend to recomplete 80 wells and drill 22 to 24 new wells during 2013 at our WCBB field. Our aggregate drilling and recompletion expenditures for our WCBB field during 2013 are estimated to be approximately $42.0 million to $45.0 million. We currently expect our 2014 capital expenditures to be $42.0

million to $45.0 million to drill 22 to 24 wells at our WCBB field.

In our Hackberry fields, from January 1, 2013 through October 31, 2013, we recompleted 56 existing wells and spud 15 new wells. We currently intend to drill 16 wells and recomplete 60 wells in our Hackberry fields in 2013. Total capital expenditures for our Hackberry fields during 2013 are estimated to be approximately $44.0 million to $46.0 million. We currently expect our 2014 capital expenditures to be $24.0 million to $26.0 million to drill 10 to 12 wells at our Hackberry fields.

From January 1, 2013 through October 31, 2013, we spud 45 gross wells in the Utica Shale. We currently intend to drill 55 to 60 gross (49 to 54 net) wells on our Utica Shale acreage in 2013. Total capital expenditures in the Utica Shale during 2013 are estimated to be approximately $494.0 million to $504.0 million, excluding leasehold acquisitions. We currently expect our 2014 capital expenditures to be $594.0 million to $634.0 million to drill 85 to 95 gross (64 to 71 net) wells on our Utica Shale acreage. In addition, we currently expect to spend $225.0 million to $275.0 million in 2014 to acquire additional acreage in the Utica Shale.

In the Niobrara Formation in Northwestern Colorado, in 2011, we completed a 60 square mile 3-D seismic survey and have received a processed version of the seismic data. From January 1, 2013 through October 31, 2013, no new wells were spud on our Niobrara Formation acreage. We do not currently anticipate any capital expenditures in the Niobrara Formation in 2013 or 2014.

During the third quarter of 2006, we purchased a 24.9% interest in Grizzly. As of September 30, 2013, our net investment in Grizzly was approximately $189.9 million. Our capital requirements in 2013 for Grizzly are estimated to be approximately $25.0 million to $30.0 million, primarily for the expenses associated with the construction of the Algar Lake facility and drilling activity during the 2012-2013 winter drilling season. In February 2012, Grizzly purchased approximately 47,000 acres of oil sands leases in the Athabasca oil sands area for $225.0 million CAD. We funded our portion of the purchase price with borrowings under our revolving credit facility. Effective October 5, 2012, Grizzly entered into a $125.0 million revolving credit facility, of which $75.0 million is initially available for borrowing to fund additional infrastructure relating to the Algar Lake facility and other future development projects. As of that same date, we entered into an agreement with Grizzly in which we committed to make monthly payments to fund the construction and development of the Algar Lake facility. Our remaining aggregate commitment including our proportionate share of any unfunded cost overruns at September 30, 2013 was approximately $6.1 million. Our capital requirements in 2014 are currently estimated to be approximately $15.0 million to $20.0 million.

We had capital expenditures of approximately $2.4 million during the nine months ended September 30, 2013 related to our interests in Thailand. Total 2013 capital expenditures for Thailand are estimated to be $2.0 million to $2.5 million to drill one gross well.

In an effort to facilitate the development of our Utica Shale and other domestic acreage, we have invested in entities that can provide services that are required to support our operations. In 2012, we invested approximately $42.8 million in these entities. In the nine months ended September 30, 2013, we invested approximately $7.5 million in these entities, and we expect to invest a total of approximately $8.0 million to $10.0 million in these entities in 2013.

Our total capital expenditures for 2013 are currently estimated to be in the range of $615.0 million to $638.0 million, excluding the acquisition costs associated with our February 2013 Utica Shale acquisition and with any additional Utica Shale acreage or other potential acquisitions. Our total capital expenditures for the nine months ended September 30, 2013 were approximately $240.8 million, excluding our Utica shale acreage acquisition. Approximately 85% of our 2013 estimated capital expenditures are currently expected to be spent in the Utica Shale. This range is up from the $277.6 million spent on 2012 activities primarily due to the significant increase in our acreage position in the Utica Shale and our contemplated Utica development plans. Unlike 2012, our anticipated 2013 expenditures do not include development costs in the Permian Basin as a result of the contribution of our Permian Basin properties to Diamondback. We intend to continue to monitor pricing and cost developments and make adjustments to our future capital expenditure programs as warranted.

We currently estimate our exploration and production capital expenditures for 2014 to be in the range of $675.0 million to $725.0 million and an additional $225.0 million to $275.0 million for acreage acquisitions in the Utica Shale. We believe that our cash on hand, cash flow from operations, proceeds from the sale of our securities, the sale of shares of our Diamondback common stock and borrowings under our revolving credit facility will be sufficient to meet our normal recurring operating needs and capital requirements for the next twelve months. In the event we elect to further expand or accelerate our drilling programs, pursue additional acquisitions, exercise our Blackhawk option or accelerate our Canadian oil sands project, we may be required to obtain additional funds which we would seek to do through traditional borrowings, offerings of debt or equity securities or other means, including the sale of assets. We regularly evaluate new acquisition opportunities. Needed capital may not be available to us on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to delay or curtail implementation of our business plan or not be able to complete acquisitions that may be favorable to us.

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Commodity Price Risk

The volatility of the energy markets makes it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, during the past five years, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.28 per barrel in December 2008 to a high of $145.31 per barrel in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $1.83 per million British thermal units, or MMBtu, in September 2009 to a high of $13.31 per MMBtu in July 2008. On November 1, 2013, the West Texas Intermediate posted price for crude oil was $95.14 per barrel and the Henry Hub spot market price of natural gas was $3.53 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 on our oil and natural gas production, we have the following open fixed price swaps at September 30, 2013:

	Volume (barrels per day)	Weighted Average Price ($ per Bbl)
Fixed Price Swaps:		
October 2013 - December 2013	5,000	$99.86
January 2014 - March 2014	4,000	$104.75
April 2014 - December 2014	2,000	$101.50

	Volume (MMBtu per day)	Weighted Average Price ($ per MMBtu)
Fixed Price Swaps:		
October 2013 - December 2013	10,000	$4.00
January 2014 - December 2014	20,000	$3.98
January 2015 - March 2016	15,000	$3.97
April 2016	5,000	$3.90

In October 2013, we entered into derivative contracts for 30,000 MMBtu of natural gas per day at a weighted average price of $4.11 per MMBtu for the period from January 2014 through December 2014. For the period from January 2015 through April 2016 we entered into derivative contracts for 40,000 MMBtu of natural gas per day at a weighted average price of $4.15 per MMBtu. Our derivative contracts are tied to the commodity prices on NYMEX. We will receive the fixed price amount stated in the contract and pay to our counterparty the current market price for natural gas as listed on NYMEX.

Under our 2013 fixed price swap contracts, we have hedged approximately 46% of our expected 2013 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements.

Commitments

In connection with our acquisition in 1997 of the remaining 50% interest in the WCBB properties, we assumed the seller's (Chevron) obligation to contribute approximately $18,000 per month through March 2004, to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11,

1997. Chevron retained a security interest in production from these properties until abandonment obligations to Chevron have been fulfilled. Beginning in 2009, we can access the trust for use in plugging and abandonment charges associated with the property. As of September 30, 2013, the plugging and abandonment trust totaled approximately $3.1 million. At September 30, 2013, we have plugged 354

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wells at WCBB since we began our plugging program in 1997, which management believes fulfills our current minimum plugging obligation.

Contractual and Commercial Obligations

We have various contractual obligations in the normal course of our operations and financing activities. There have been no material changes to our contractual obligations from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2012.

Off-balance Sheet Arrangements

We had no off-balance sheet arrangements as of September 30, 2013.

New Accounting Pronouncements

In February 2013, the FASB issued Accounting Standards Update ("ASU") No. 2013-02, "Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income," which requires additional information about amounts reclassified out of accumulated other comprehensive income by component. This ASU requires the presentation, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under GAAP to be reclassified in their entirety to net income, a cross-reference to other disclosures required under GAAP that provide additional detail about those amounts. The requirements of this ASU are effective prospectively for reporting periods beginning after December 15, 2012 with early adoption permitted. We have adopted the provisions of this ASU for reporting periods in 2013. Adoption of this ASU had no impact on our financial position or results of operations.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, during the past five years, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.28 per barrel, or Bbl, in December 2008 to a high of $145.31 per Bbl in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $1.83 per MMBtu in September 2009 to a high of $13.31 per MMBtu in July 2008. On November 1, 2013, the West Texas Intermediate posted price for crude oil was $95.14 per barrel and the Henry Hub spot market price of natural gas was $3.53 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.

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In October 2013, we entered into derivative contracts for 30,000 MMBtu of natural gas per day at a weighted average price of $4.11 per MMBtu for the period from January 2014 through December 2014. For the period from January 2015 through April 2016 we entered into derivative contracts for 40,000 MMBtu of natural gas per day at a weighted average price of $4.15 per MMBtu. Our derivative contracts are tied to the commodity prices on NYMEX. We will receive the fixed price amount stated in the contract and pay to our counterparty the current market price for natural gas as listed on NYMEX.

Under our 2013 contracts, we have hedged approximately 46% of our estimated 2013 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements. At September 30, 2013, we had a net liability derivative position of $4.0 million as compared to a net liability derivative position of $9.5 million as of September 30, 2012, related to our fixed price swaps. Utilizing actual derivative contractual volumes, a 10% increase in underlying commodity prices would have reduced the fair value of these instruments by approximately $20.4 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by approximately $20.4 million. However, any realized derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

Our revolving credit facility is structured under floating rate terms, as advances under this facility may be in the form of either base rate loans or eurodollar loans. As such, our interest expense is sensitive to fluctuations in the prime rates in the U.S. or, if the eurodollar rates are elected, the eurodollar rates. As of October 17, 2012 (the latest date on which we had borrowings outstanding), amounts borrowed under our revolving credit facility bore interest at the eurodollar rate of 2.97%. As of September 30, 2013, we had no variable interest rate borrowings outstanding; therefore, an increase in interest rates would not have impacted our interest expense. As of September 30, 2013, we did not have any interest rate swaps to hedge our interest risks.

ITEM 4. CONTROLS AND PROCEDURES

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

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As of September 30, 2013, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Vice President and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and Vice President and Chief Financial Officer have concluded that, as of September 30, 2013, our disclosure controls and procedures are effective.

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

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PART II

ITEM 1. LEGAL PROCEEDINGS

The Louisiana Department of Revenue, or LDR, is disputing our severance tax payments to the State of Louisiana from the sale of oil under fixed price contracts during the years 2005 to 2007. The LDR maintains that we paid approximately $1.8 million less in severance taxes under fixed price terms than the severance taxes we would have had to pay had we paid severance taxes on the oil at the contracted market rates only. We have denied any liability to the LDR for underpayment of severance taxes and have maintained that we were entitled to enter into the fixed price contracts with unrelated third parties and pay severance taxes based upon the proceeds received under those contracts. We have maintained our right to contest any final assessment or suit for collection if brought by the State. On April 20, 2009, the LDR filed a lawsuit in the 15th Judicial District Court, Lafayette Parish, in Louisiana against our company seeking $2.3 million in severance taxes, plus interest and court costs. We filed a response denying any liability to the LDR for underpayment of severance taxes and are defending our company in the lawsuit. The LDR had taken no further action on this lawsuit since filing its petition other than propounding discovery requests to which we have responded. Since serving discovery requests on the LDR and receiving the LDR's responses in 2012, there has been no further activity on the case and no trial date has been set.

In December 2010, the LDR filed two identical lawsuits against us in different venues to recover allegedly underpaid severance taxes on crude oil for the period January 1, 2007 through December 31, 2010, together with a claim for attorney’s fees. The petitions do not make any specific claim for damages or unpaid taxes. As with the first lawsuit filed by the LDR in 2009, we deny all liability and will vigorously defend the lawsuit. The cases are in the early stages, and we have not yet filed a response to the recent lawsuits. The LDR filed motions to stay the lawsuits before we filed any responsive pleadings. Although there had been no activity on either of these lawsuits for years, the LDR recently moved to dismiss one of the identical lawsuits it filed in the 19th Judicial District Court in 2010, amended the petition it filed in the 15th Judicial District Court in 2010, and served discovery requests on us. The LDR asserts that we underpaid severance taxes by nearly $12 million from 2007 to 2010. The LDR also asserts that we owe an additional $4.4 million and may be subject to additional penalties. The LDR's claims are still in their infancy and there has been no formal discovery. We maintain that the LDR's claims are not well-grounded in fact or law and intend to aggressively defend the lawsuits.

Other Litigation

On July 30, 2010, six individuals and one limited liability company sued 15 oil and gas companies in Cameron Parish Louisiana for surface contamination in areas where the defendants operated in an action entitled Reeds et al. v. BP American Production Company et al.,38th Judicial District. No. 10-18714. The plaintiffs’ original petition for damages, which did not name us as a defendant, alleges that the plaintiffs’ property located in Cameron Parish, Louisiana within the Hackberry oil field is contaminated as a result of historic oil and gas exploration and production activities. The plaintiffs allege that the defendants conducted, directed and participated in various oil and gas exploration and production activities on their property which allegedly have contaminated or otherwise caused damage to the property, and have sued the defendants for alleged breaches of oil, gas and mineral leases, as well as for alleged negligence, trespass, failure to warn, strict liability, punitive damages, lease liability, contract liability, unjust enrichment, restoration damages, assessment and response costs and stigma damages. On December 7, 2010, we were served with a copy of the plaintiffs’ first supplemental and amending petition which added four additional plaintiffs and six additional defendants, including us, bringing the total number of defendants to 21. It also increased the total acreage at issue in this litigation from 240 acres to approximately 1,700 acres. In addition to the damages sought in the original petition, the plaintiffs now also seek: damages sufficient to cover the cost of conducting a comprehensive environmental assessment of all present and yet unidentified pollution and contamination of their property; the cost to restore the property to its pre-polluted original condition; damages for mental anguish and annoyance, discomfort and inconvenience caused by the nuisance created by defendants; land loss and subsidence damages and the cost of backfilling canals and other excavations; damages for loss of use of land and lost profits and income; attorney fees and expenses and damages for evaluation and remediation of any contamination that threatens groundwater. In addition to us, current defendants include ExxonMobil Oil Corporation, Mobil Exploration & Producing North America Inc., Chevron U.S.A. Inc., The Superior Oil Company, Union Oil Company of California, BP America Production Company, Tempest Oil Company, Inc., ConocoPhillips Company, Continental Oil Company, WM. T. Burton Industries, Inc., Freeport Sulphur Company, Eagle Petroleum Company, U.S. Oil of Louisiana, M&S Oil Company, and Empire Land Corporation, Inc. of Delaware. On January 21, 2011, we filed a pleading challenging the legal sufficiency of the petitions on several grounds and requesting that they either be dismissed or that plaintiffs be required to amend such petitions. In response to the pleadings filed by us and similar pleadings filed by other defendants, the plaintiffs filed a third amending petition with exhibits which expands the description of the property at issue, attaches numerous aerial photos and identifies the mineral leases at issue. In response, we and numerous defendants re-urged their pleadings challenging the legal sufficiency of the petitions. Some of the defendants' grounds for challenging the plaintiffs' petitions were heard by the court on May 25, 2011 and were denied. The court signed the written judgment on December 9, 2011. We noticed our intent to seek supervisory review on December 19, 2011 and the trial court fixed a return date of January 11, 2012 for the filing of the writ application. We filed our supervisory writ, which was denied by the Louisiana Third Circuit Court of Appeal and the Louisiana Supreme Court. We have been active in serving discovery requests and responding to discovery requests from the plaintiffs. The parties recently engaged in a non-binding mediation in July 2013 to discuss settlement and settlement discussions are on-going. At this time, the parties are continuing to conduct discovery and no expert reports have been issued. The trial date has been continued to July 2014.

In September 2013, we entered into a compliance agreement with the Ohio Division of Oil and Gas Resources Management, or the Division, concerning aspects of our operations at seven drilling sites in Ohio. See "Item 1A. Risk Factors" for a description of this matter, the compliance agreement and certain risks involved.

Due to the early stages of the LDR and Reed litigation, the outcome is uncertain and management cannot determine the amount of loss, if any, that may result. In each case, management has determined the possibility of loss is remote. However, litigation is inherently uncertain. Adverse decisions in one or more of the above matters could have a material adverse effect on our financial condition or results of operations and management cannot determine the amount of loss, if any, that may result.

We have been named as a defendant in various other lawsuits related to our business. In each such case, management has determined that the possibility of loss is remote. The resolution of these matters is not expected to have a material adverse effect on our financial condition or results of operations in future periods.

ITEM 1A. RISK FACTORS

Except for the risk factor set forth below, there have been no material changes to the Risk Factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2012.

We have entered into a compliance agreement with the Ohio Division of Oil and Gas Resources Management and, if we fail to comply with the conditions of the compliance agreement, all or part of our drilling and producing operations in the State of Ohio may be suspended.

In September 2013, we entered into a compliance agreement with the Ohio Division of Oil and Gas Resources Management, or the Division, concerning aspects of our operations at seven drilling sites in Ohio. We had previously notified the Division of brine contamination at these drilling sites. After receipt of this notification, the Division conducted an investigation and determined that certain contaminants were escaping from underneath the containment liners at these locations. In the compliance agreement, we agreed, among other things, to conduct our production operations in compliance with all requirements of applicable regulations, implement a remediation plan and make a payment of $250,000. We are continuing to work with the Division to fulfill our obligations under the compliance agreement and to enhance our materials handling protocols. If the Chief of the Division determines that we have failed to comply with the conditions set forth in the compliance agreement, the Chief may suspend all or part of our drilling and production operations in the State of Ohio for a period determined by the Chief, and we could incur additional penalties and costs.

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 nine months ended September 30, 2013, we did not purchase any shares of our common stock.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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ITEM 5. OTHER INFORMATION

(a) None.

(b) None.

ITEM 6. EXHIBITS

Exhibit Number	Description
2.1	Purchase and Sale Agreement, dated February 11, 2013, by and between Windsor Ohio, LLC, as seller, and Gulfport Energy Corporation, as purchaser (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 15, 2013).
3.1	Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
3.2	Certificate of Amendment No. 1 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.2 to Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 6, 2009).
3.3	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 12, 2006).
4.1	Form of Common Stock certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.2	Form of Warrant Agreement (incorporated by reference to Exhibit 10.4 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.3	Registration Rights Agreement, dated as of February 23, 2005, by and among the Company, Southpoint Fund LP, a Delaware limited partnership, Southpoint Qualified Fund LP, a Delaware limited partnership and Southpoint Offshore Operating Fund, LP, a Cayman Islands exempted limited partnership (incorporated by reference to Exhibit 10.7 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2005).
4.4	Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.3 of Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on November 11, 2005).
4.5	Amendment No. 1, dated February 14, 2006, to the Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.15 of

	Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2006).
4.6	Indenture, dated as of October 17, 2012, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (including the form of Gulfport Energy Corporation's 7.750% Senior Note Due November 1, 2020) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 23, 2012).
4.7	Registration Rights Agreement, dated as of October 17, 2012, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 23, 2012).
4.8	First Supplemental Indenture, dated December 21, 2012, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 26, 2012).
4.9	Registration Rights Agreement, dated as of December 21, 2012, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.3 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 26, 2012).

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10.1+	2013 Restated Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Form S-4, File No. 333-189992, filed by the Company with the SEC on July 17, 2013).
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.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

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

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SIGNATURES

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

Date: November 5, 2013

GULFPORT ENERGY CORPORATION

/s/ JAMES D. PALM
James D. Palm
Chief Executive Officer
/s/ MICHAEL G. MOORE
Michael G. Moore
President and Chief Financial Officer