GULFPORT ENERGY CORP
Form 10-Q
August 07, 2015
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

ý	QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
	For the quarterly period ended June 30, 2015 OR
¨	TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF SECURITIES EXCHANGE ACT OF 1934
	For the transition period from to

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)
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	The NASDAQ Stock Market LLC

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 preceding 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 (Section 232.405 of this chapter) during the preceding 12 months (or 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 definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):
Large Accelerated filer ý 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 August 3, 2015, 108,210,444 shares of the registrant’s common stock were outstanding.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2015	December 31, 2014
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$525,488	$142,340
Restricted cash	75,005	—
Accounts receivable—oil and gas	86,621	103,858
Accounts receivable—related parties	90	46
Prepaid expenses and other current assets	15,168	3,714
Short-term derivative instruments	77,350	78,391
Total current assets	779,722	328,349
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $1,797,025 and $1,465,538 excluded from amortization in 2015 and 2014, respectively	4,798,835	3,923,154
Other property and equipment	22,930	18,344
Accumulated depletion, depreciation, amortization and impairment	(1,211,308)	(1,050,879)
Property and equipment, net	3,610,457	2,890,619
Other assets:		
Equity investments	362,391	369,581
Derivative instruments	25,871	24,448
Other assets	25,418	19,396
Total other assets	413,680	413,425
Total assets	$4,803,859	$3,632,393
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$318,725	$371,410
Asset retirement obligation—current	75	75
Deferred tax liability	26,508	27,070
Short-term derivative instruments	937	—
Current maturities of long-term debt	1,738	168
Total current liabilities	347,983	398,723
Long-term derivative instrument	2,753	—
Asset retirement obligation—long-term	21,202	17,863
Deferred tax liability	201,022	203,195
Long-term debt, net of current maturities	963,593	716,316
Total liabilities	1,536,553	1,336,097
Commitments and contingencies (Note 9)		
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, 108,203,981 issued and outstanding at June 30, 2015 and 85,655,438 at December 31, 2014	1,081	856
Paid-in capital	2,816,930	1,828,602

Accumulated other comprehensive loss	(38,412)	(26,675)
Retained earnings	487,707	493,513
Total stockholders’ equity	3,267,306	2,296,296
Total liabilities and stockholders’ equity	$4,803,859	$3,632,393

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(In thousands, except share data)			
Revenues:				
Gas sales	$65,871	$35,522	$184,441	$53,871
Oil and condensate sales	34,465	68,078	69,965	141,455
Natural gas liquid sales	11,958	10,897	33,965	37,033
Other (expense) income	(24)	239	216	406
	112,270	114,736	288,587	232,765
Costs and expenses:				
Lease operating expenses	16,863	12,680	33,843	24,309
Production taxes	3,285	6,601	7,570	13,558
Midstream gathering and processing	32,904	10,780	58,285	18,549
Depreciation, depletion and amortization	71,155	55,994	161,064	112,871
General and administrative	9,515	10,382	20,314	19,893
Accretion expense	192	189	382	377
Gain on sale of assets	—	—	—	(11)
	133,914	96,626	281,458	189,546
(LOSS) INCOME FROM OPERATIONS	(21,644)	18,110	7,129	43,219
OTHER (INCOME) EXPENSE:				
Interest expense	12,023	2,402	20,782	6,287
Interest income	(248)	(36)	(257)	(142)
Litigation settlement	—	6,000	—	24,000
Loss (income) from equity method investments	15,120	(69,569)	(4,855)	(198,044)
	26,895	(61,203)	15,670	(167,899)
(LOSS) INCOME BEFORE INCOME TAXES	(48,539)	79,313	(8,541)	211,118
INCOME TAX (BENEFIT) EXPENSE	(17,214)	31,461	(2,735)	80,708
NET (LOSS) INCOME	$(31,325)	$47,852	$(5,806)	$130,410
NET (LOSS) INCOME PER COMMON SHARE:				
Basic	$(0.32)	$0.56	$(0.06)	$1.53
Diluted	$(0.32)	$0.56	$(0.06)	$1.52
Weighted average common shares outstanding—Basic	96,663,358	85,448,678	91,201,824	85,354,566
Weighted average common shares outstanding—Diluted	96,663,358	85,805,896	91,201,824	85,766,679

See accompanying notes to consolidated financial statements.

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

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(In thousands)			
Net (loss) income	$(31,325)	$47,852	$(5,806)	$130,410
Foreign currency translation adjustment	3,247	6,816	(11,737)	(462)
Other comprehensive income (loss)	3,247	6,816	(11,737)	(462)
Comprehensive (loss) income	$(28,078)	$54,668	$(17,543)	$129,948

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 Loss	Retained Earnings	Total Stockholders' Equity
	Shares	Amount				
	(In thousands, except share data)					
Balance at January 1, 2015	85,655,438	$856	$1,828,602	$ (26,675)	$493,513	$2,296,296
Net loss	—	—	—	—	(5,806)	(5,806)
Other Comprehensive Loss	—	—	—	(11,737)	—	(11,737)
Stock Compensation	—	—	6,735	—	—	6,735
Issuance of Common Stock in public offerings, net of related expenses	22,425,000	224	981,594			981,818
Issuance of Restricted Stock	123,543	1	(1)	—	—	—
Balance at June 30, 2015	108,203,981	$1,081	$2,816,930	$ (38,412)	$487,707	$3,267,306
Balance at January 1, 2014	85,177,532	$851	$1,813,058	$ (9,781)	$246,110	$2,050,238
Net income	—	—	—	—	130,410	130,410
Other Comprehensive Loss	—	—	—	(462)	—	(462)
Stock Compensation	—	—	7,665	—	—	7,665
Issuance of Restricted Stock	124,526	1	(1)	—	—	—
Issuance of Common Stock through exercise of options	192,908	2	646	—	—	648
Balance at June 30, 2014	85,494,966	$854	$1,821,368	$ (10,243)	$376,520	$2,188,499

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six months ended June 30, 2015	2014
	(In thousands)	
Cash flows from operating activities:		
Net (loss) income	$(5,806)	$130,410
Adjustments to reconcile net income to net cash provided by operating activities:		
Accretion of discount—Asset Retirement Obligation	382	377
Depletion, depreciation and amortization	161,064	112,871
Stock-based compensation expense	4,041	4,599
Loss (gain) from equity investments	2,171	(113,257)
Interest income - note receivable	—	(25)
Unrealized loss on derivative instruments	3,309	6,433
Deferred income tax (benefit) expense	(2,735)	55,550
Amortization of loan commitment fees	1,416	637
Amortization of note discount and premium	(1,065)	158
Changes in operating assets and liabilities:		
Decrease (increase) in accounts receivable	17,237	(48,631)
(Increase) decrease in accounts receivable—related party	(44)	2,490
Increase in prepaid expenses	(11,454)	(994)
(Decrease) increase in accounts payable and accrued liabilities	(28,522)	53,988
Settlement of asset retirement obligation	(1,120)	(3,097)
Net cash provided by operating activities	138,874	201,509
Cash flows from investing activities:		
Deductions to cash held in escrow	8	8
Additions to other property and equipment	(4,154)	(1,759)
Additions to oil and gas properties	(898,639)	(672,967)
Proceeds from sale of oil and gas properties	1,679	—
Proceeds from sale of investments	—	89,120
Funding of restricted cash	(75,005)	—
Contributions to equity method investments	(8,267)	(39,162)
Distributions from equity method investments	4,612	—
Net cash used in investing activities	(979,766)	(624,760)
Cash flows from financing activities:		
Principal payments on borrowings	(350,088)	(85)
Borrowings on line of credit	250,000	40,000
Proceeds from bond issuance	350,000	—
Debt issuance costs and loan commitment fees	(7,738)	(975)
Proceeds from issuance of common stock, net of offering costs and exercise of stock options	981,866	648
Net cash provided by financing activities	1,224,040	39,588
Net increase (decrease) in cash and cash equivalents	383,148	(383,663)
Cash and cash equivalents at beginning of period	142,340	458,956
Cash and cash equivalents at end of period	$525,488	$75,293
Supplemental disclosure of cash flow information:		
Interest payments	$24,176	$11,738

Income tax payments	$29,753	$16,700
Supplemental disclosure of non-cash transactions:		
Capitalized stock based compensation	$2,694	$3,066
Asset retirement obligation capitalized	$4,077	$3,613
Interest capitalized	$8,399	$6,245
Foreign currency translation loss on investment in Grizzly Oil Sands ULC	$(11,737)	$(462)

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 six month periods ended June 30, 2015 are not necessarily indicative of the results expected for the full year.

1. ACQUISITIONS

In February 2014, the Company entered into a definitive agreement with Rhino Exploration LLC ("Rhino") to acquire additional oil and natural gas properties consisting of approximately 8,000 net acres in the Utica Shale, as well as Rhino's interest in all of the producing wells on this acreage (the "Rhino Acquisition"). The Company purchased approximately $182.0 million ($179.5 million net of purchase price adjustments) of these assets in 2014.

The Rhino Acquisition qualified as a business combination for accounting purposes and, as such, the Company estimated the fair value of the acquired properties as of the March 20, 2014 acquisition date. The fair value of the assets and liabilities acquired was estimated using assumptions that represent Level 3 inputs. See Note 10 - "Fair Value Measurements" for additional discussion of the measurement inputs.

The Company estimated that the consideration paid in the Rhino Acquisition for these properties approximated the fair value that would be paid by a typical market participant. As a result, no goodwill or bargain purchase gain was recognized in conjunction with the purchase.

The following table summarizes the consideration paid in the Rhino Acquisition to acquire the properties and the fair value amount of the assets acquired as of March 20, 2014.

	(In thousands)
Consideration paid	
Cash, net of purchase price adjustments	$179,527
Fair value of identifiable assets acquired	
Oil and natural gas properties	
Proved	$31,961
Unproved	6,263
Unevaluated	141,303
Fair value of net identifiable assets acquired	$179,527

In April 2015, the Company entered into an agreement to acquire Paloma Partners III, LLC ("Paloma") for a total purchase price of approximately $301.3 million, subject to closing adjustments. Paloma holds approximately 24,000 net nonproducing acres in the Utica Shale of Ohio. This transaction is expected to close during the third quarter of 2015, subject to the satisfaction of certain closing conditions. In accordance with the agreement, the Company deposited $75.0 million into an escrow account. At the closing of the transaction the deposit shall be credited toward the purchase price. This deposit is shown as restricted cash on the accompanying consolidated balance sheets at June 30, 2015.

On June 9, 2015, the Company completed the acquisition of 6,198 gross and net acres located in Belmont and Jefferson Counties, Ohio from American Energy-Utica, LLC ("AEU") for a purchase price of approximately $68.2 million, subject to adjustment. On June 12, 2015, the Company completed the acquisition of 38,965 gross (27,228 net) acres located in Monroe

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County, Ohio, 14.6 MMcf per day of average net production (estimated for April 2015), 18 gross (11.3 net) drilled but uncompleted wells, an 11 mile gas gathering system and a four well pad location from AEU for a total purchase price of approximately $319.0 million (the "Monroe Acquisition"). On June 29, 2015, the Company acquired an additional 4,950 gross (1,900 net) acres in Monroe County for an additional $18.2 million from AEU. The total purchase price of these transactions, collectively referred to as the ("AEU Acquisition"), was approximately $405.4 million ($405.0 million net of purchase price adjustments).

The AEU Acquisition qualified as a business combination for accounting purposes and, as such, the Company estimated the fair value of the acquired properties as of the June 12, 2015 acquisition date. The fair value of the assets and liabilities acquired was estimated using assumptions that represent Level 3 inputs. See Note 11 - "Fair Value Measurements" for additional discussion of the measurement inputs.

The Company estimated that the consideration paid in the AEU Acquisition for these properties approximated the fair value that would be paid by a typical market participant. As a result, no goodwill or bargain purchase gain was recognized in conjunction with the purchase.

The following table summarizes the consideration paid in the AEU Acquisition to acquire the properties and the fair value amount of the assets acquired as of June 12, 2015. Both the consideration paid and the fair value assigned to the assets is preliminary and subject to adjustment upon final closing.

	(In thousands)
Consideration paid	
Cash, net of purchase price adjustments	$405,029
Fair value of identifiable assets acquired	
Oil and natural gas properties	
Proved	$70,804
Unevaluated	334,225
Fair value of net identifiable assets acquired	$405,029

2. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of June 30, 2015 and December 31, 2014 are as follows:

	June 30, 2015	December 31, 2014
	(In thousands)	
Oil and natural gas properties	$4,798,835	$3,923,154
Office furniture and fixtures	11,430	10,752
Building	7,833	5,398
Land	3,667	2,194
Total property and equipment	4,821,765	3,941,498
Accumulated depletion, depreciation, amortization and impairment	(1,211,308)	(1,050,879)
Property and equipment, net	$3,610,457	$2,890,619

Included in oil and natural gas properties at June 30, 2015 is the cumulative capitalization of $86.2 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 $6.3 million and $13.5 million for the three and six months ended June 30, 2015, respectively, and $6.9 million and $13.2 million for the three and six months ended June 30, 2014, respectively.

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The following table summarizes the Company’s non-producing properties excluded from amortization by area at June 30, 2015:

	June 30, 2015
	(In thousands)
Colorado	$5,083
Bakken	96
Southern Louisiana	263
Ohio	1,791,538
Other	45
	$1,797,025

At December 31, 2014, approximately $1.5 billion 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.

The Company performs a ceiling test each quarter. If prices of oil, natural gas and natural gas liquids continue to decline and are not adequately offset by reserve additions from the Company's drilling activities, the Company may be required to write down the value of its oil and gas properties, which could negatively affect its results of operations. No ceiling test impairment was required for the quarter ended June 30, 2015.

A reconciliation of the Company's asset retirement obligation for the six months ended June 30, 2015 and 2014 is as follows:

	June 30, 2015	June 30, 2014
	(In thousands)	
Asset retirement obligation, beginning of period	$17,938	$15,083
Liabilities incurred	4,077	3,613
Liabilities settled	(1,120)	(3,097)
Accretion expense	382	377
Asset retirement obligation as of end of period	21,277	15,976
Less current portion	75	795
Asset retirement obligation, long-term	$21,202	$15,181

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.

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. Following the Contribution, the Company

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has accounted for its interest in Diamondback as an equity investment. In November 2014, the Company sold all of the remaining shares of Diamondback common stock that it received in the Contribution and, as of June 30, 2015, Gulfport did not own any shares of Diamondback's common stock. See Note 3, "Equity Investments - Diamondback Energy, Inc."

3. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of June 30, 2015 and December 31, 2014:

		Carrying Value		(Income) loss from equity method investments			
	Approximate Ownership %	June 30, 2015	December 31, 2014	Three months ended June 30, 2015	2014	Six months ended June 30, 2015	2014
		(In thousands)					
Investment in Tatex Thailand II, LLC	23.5 %	$—	$ —	$—	$—	$—	$—
Investment in Tatex Thailand III, LLC	17.9 %	—	—	189	121	189	170
Investment in Grizzly Oil Sands ULC	24.9999 %	164,113	180,218	8,494	2,228	12,636	4,229
Investment in Bison Drilling and Field Services LLC	— %	—	—	—	(329)	—	1,604
Investment in Muskie Proppant LLC	— %	—	—	—	(101)	—	433
Investment in Timber Wolf Terminals LLC	50.0 %	1,000	1,013	7	—	13	—
Investment in Windsor Midstream LLC	22.5 %	27,766	13,505	881	(35)	(17,906)	(203)
Investment in Stingray Pressure Pumping LLC	— %	—	—	—	1,630	—	2,143
Investment in Stingray Cementing LLC	50.0 %	2,002	2,647	105	106	172	201
Investment in Blackhawk Midstream LLC	48.5 %	—	—	—	—	(7,217)	(84,787)
Investment in Stingray Logistics LLC	— %	—	—	—	(238)	—	(157)
Investment in Diamondback Energy, Inc.	— %	—	—	—	(72,945)	—	(121,712)
Investment in Stingray Energy Services LLC	50.0 %	5,905	5,718	311	(6)	321	35
Investment in Sturgeon Acquisitions LLC	25.0 %	22,599	22,507	(491)	—	(1,059)	—
Investment in Mammoth Energy Partners LP	30.5 %	139,006	143,973	5,624	—	7,996	—
		$362,391	$ 369,581	$15,120	$(69,569)	$(4,855)	$(198,044)

The tables below summarize financial information for the Company's equity investments as of June 30, 2015 and December 31, 2014.

Summarized balance sheet information:

	June 30, 2015	December 31, 2014
	(In thousands)	
Current assets	$170,637	$181,060
Noncurrent assets	$1,414,991	$1,306,891
Current liabilities	$96,004	$114,506
Noncurrent liabilities	$208,319	$230,062

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Summarized results of operations:

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(In thousands)			
Gross revenue	$130,134	$220,013	$263,690	$378,294
Net (loss) income	$(45,246)	$26,099	$45,422	$207,604

Tatex Thailand II, LLC

The Company has an indirect ownership interest in Tatex Thailand II, LLC (“Tatex”). 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.

Tatex Thailand III, LLC

The Company has an ownership interest in Tatex Thailand III, LLC ("Tatex III"). Tatex III previously owned a concession covering approximately 245,000 acres in Southeast Asia. As of December 31, 2014, the Company reviewed its investment in Tatex III and made the decision to allow the concession to expire in 2015. As such, the Company fully impaired the asset as of December 31, 2014. The concession expired in January 2015. Gulfport recorded $0.2 million of expense relating to its investment in Tatex III during the six months ended June 30, 2015.

Grizzly Oil Sands ULC

The Company, through its wholly owned subsidiary Grizzly Holdings Inc. ("Grizzly Holdings"), owns an interest in Grizzly Oil Sands ULC ("Grizzly"), a Canadian unlimited liability company. The remaining interest in Grizzly is owned by Grizzly Oil Sands Inc. ("Oil Sands"). As of June 30, 2015, Grizzly had approximately 830,000 acres under lease in the Athabasca and Peace River oil sands regions of Alberta, Canada. Initiation of steam injection at its first project, Algar Lake Phase 1, commenced in January 2014 and first bitumen production was achieved during the second quarter of 2014. In April 2015, Grizzly determined to cease bitumen production at its Algar Lake facility due to the level of commodity prices. Grizzly intends to monitor market conditions as it assesses future plans for the facility. The Company reviewed its investment in Grizzly at June 30, 2015 and determined no impairment was needed. If commodity prices continue to decline, an impairment of the investment in Grizzly may result in the future. During the six months ended June 30, 2015, Gulfport paid $8.3 million in cash calls. Grizzly’s functional currency is the Canadian dollar. The Company's investment in Grizzly was increased by $3.2 million as a result of a foreign currency translation gain and decreased by $11.7 million as a result of a foreign currency translation loss for the three and six months ended June 30, 2015, respectively. The Company's investment in Grizzly was increased by $6.8 million as a result of a foreign currency translation gain and decreased by $0.5 million as a result of a foreign currency translation loss for the three and six months ended June 30, 2014, respectively.

Bison Drilling and Field Services LLC

During 2011, the Company invested in Bison Drilling and Field Services LLC (“Bison”). Bison owns and operates drilling rigs. The Company contributed its investment in Bison to Mammoth Energy Partners LP ("Mammoth") during the fourth quarter of 2014. See below under "-Mammoth Energy Partners LP" for a discussion of the contribution.

Muskie Proppant LLC

During 2011, the Company invested in Muskie Proppant LLC (“Muskie”). Muskie processes and sells sand for use in hydraulic fracturing by the oil and natural gas industry and holds certain rights in a lease covering land in Wisconsin for mining oil and natural gas fracture grade sand. The (income) loss from equity method investments presented in the table above reflects any intercompany profit eliminations. The Company contributed its investment in Muskie to Mammoth during the fourth quarter of 2014. See below under "-Mammoth Energy Partners LP" for a discussion of the contribution.

Timber Wolf Terminals LLC

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During 2012, the Company invested in Timber Wolf Terminals LLC (“Timber Wolf”). Timber Wolf will operate a crude/condensate terminal and a sand transloading facility in Ohio. During the six months ended June 30, 2015, Gulfport did not pay any cash calls related to Timber Wolf.

Windsor Midstream LLC

During 2012, the Company purchased an ownership interest in Windsor Midstream LLC (“Midstream”). Midstream owned a 28.4% interest in Coronado Midstream LLC ("Coronado"), a gas processing plant in West Texas. In March 2015, Coronado was sold to Enlink Midstream Partners, LP ("EnLink") for proceeds of approximately $600.0 million, consisting of cash and units representing a limited partnership interest in Enlink. Midstream recorded an $81.6 million gain on the sale of its investment in Coronado. As a result of the sale, Gulfport received $3.6 million in distributions from Midstream during the six months ended June 30, 2015.

Stingray Pressure Pumping LLC

During 2012, the Company invested in Stingray Pressure Pumping LLC ("Stingray Pressure"). Stingray Pressure provides well completion services. The (income) loss from equity method investments presented in the table above reflects any intercompany profit eliminations. The Company contributed its investment in Stingray Pressure to Mammoth during the fourth quarter of 2014. See below under "-Mammoth Energy Partners LP" for a discussion of the contribution.

Stingray Cementing LLC

During 2012, the Company invested in Stingray Cementing LLC ("Stingray Cementing"). Stingray Cementing provides well cementing services. During the six months ended June 30, 2015, the Company did not pay any cash calls related to Stingray Cementing. The (income) loss from equity method investments presented in the table above reflects any intercompany profit eliminations.

Blackhawk Midstream LLC

During 2012, the Company invested in Blackhawk Midstream LLC ("Blackhawk"). Blackhawk coordinates gathering, compression, processing and marketing activities for the Company in connection with the development of its Utica Shale acreage. On January 28, 2014, Blackhawk closed on the sale of its equity interests in Ohio Gathering Company, LLC and Ohio Condensate Company, LLC for a purchase price of $190.0 million, of which $14.3 million was placed in escrow. Gulfport received $84.8 million in net proceeds from this transaction in the first quarter of 2014, which is included in income from equity method investments in the consolidated statements of operations. During the first quarter of 2015, the Company received net proceeds of approximately $7.2 million from the release of escrow from the Blackhawk sale, which is included in loss (income) from equity method investments in the consolidated statements of operations.

Stingray Logistics LLC

During 2012, the Company invested in Stingray Logistics LLC ("Stingray Logistics"). Stingray Logistics provides well services. The Company contributed its investment in Stingray Logistics to Mammoth during the fourth quarter of 2014. See below under "-Mammoth Energy Partners LP" for a discussion of the contribution.

Diamondback Energy, Inc.

As noted above in Note 2, on October 11, 2012, following the closing of the Diamondback IPO, the Company owned 7,914,036 shares of Diamondback's outstanding common stock for an initial investment in Diamondback valued at $138.5 million. In 2013, the Company sold an aggregate of 4,534,536 shares of its Diamondback common stock and received aggregate net proceeds of approximately $192.7 million. In June and September of 2014, the Company sold 1,000,000 and 1,437,500 shares of its Diamondback common stock, respectively, and received aggregate net proceeds of approximately $197.6 million. On November 12, 2014, the Company sold its remaining 942,000 shares of Diamondback common stock for net proceeds of approximately $60.8 million. As of June 30, 2015 and December 31, 2014, the Company did not own any shares of Diamondback common stock.

The Company accounted for its interest in Diamondback as an equity method investment and had elected the fair value option of accounting for this investment. While the Company's ownership interest in Diamondback was below 20% prior to the Company's sale of its remaining Diamondback common stock in November 2014, the Company had appointed a member of

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Diamondback's Board. The individual appointed by the Company continues to serve on Diamondback's Board and the Company had influence through this board seat. The Company recognized an aggregate gain of approximately $72.9 million and $121.7 million on its investment in Diamondback for the three and six months ended June 30, 2014, respectively, which is included in loss (income) from equity method investments in the consolidated statements of operations.

Stingray Energy Services LLC

During 2013, the Company invested in Stingray Energy Services LLC ("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. During the six months ended June 30, 2015, the Company did not pay any cash calls to Stingray Energy. The (income) loss from equity method investments presented in the table above reflects any intercompany profit eliminations.

Sturgeon Acquisitions LLC

During 2014, the Company invested $20.7 million and received an ownership interest of 25% in Sturgeon Acquisitions LLC ("Sturgeon"). Sturgeon owns and operates sand mines that produce hydraulic fracturing grade sand. During the six months ended June 30, 2015, Gulfport received $1.0 million in distributions from Sturgeon.

Mammoth Energy Partners LP

In the fourth quarter of 2014, the Company contributed its investments in Stingray Pressure, Stingray Logistics, Bison and Muskie to Mammoth for a 30.5% interest in this newly formed limited partnership. Mammoth has filed a registration statement on Form S-1 with the SEC in connection with its proposed initial public offering. Mammoth intends to pursue this offering in 2015 or 2016 subject to market conditions.

The Company accounted for the contribution as a sale of financial assets under ASC 860. The Company estimated the fair market value of its investment in Mammoth as of the contribution date using an average of the market approach and the income approach, based on an independently prepared valuation of the contributed assets. The fair market value was reduced by a discount factor for lack of marketability due to the Company's minority interest, resulting in a fair value of $143.5 million for the Company's 30.5% interest. The fair value of the assets and liabilities acquired was estimated using assumptions that represent Level 3 inputs. See "Note 11 - Fair Value Measurements" for additional discussion of the measurement inputs.

4. OTHER ASSETS

Prepaid expenses and other current assets consist of the following at June 30, 2015: prepaid taxes of $12.1 million, prepaid insurance of $1.7 million and prepaid other expense of $1.4 million.

Other assets consist of the following as of June 30, 2015 and December 31, 2014:

	June 30, 2015	December 31, 2014
	(In thousands)	
Plugging and abandonment escrow account on the WCBB properties (Note 9)	$3,089	$3,097
Certificates of Deposit securing letter of credit	275	275
Prepaid drilling costs	269	483
Loan commitment fees	21,640	15,390
Deposits	34	34
Other	111	117
	$25,418	$19,396

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5. LONG-TERM DEBT

Long-term debt consisted of the following items as of June 30, 2015 and December 31, 2014:

	June 30, 2015	December 31, 2014
	(In thousands)	
Revolving credit agreement (1)	$—	$100,000
Building loans (2)	1,738	1,826
7.75% senior unsecured notes due 2020 (3)	600,000	600,000
6.625% senior unsecured notes due 2023 (4)	350,000	—
Unamortized original issue (discount) premium, net (5)	13,593	14,658
Construction loan (6)	—	—
Less: current maturities of long term debt	(1,738)	(168)
Debt reflected as long term	$963,593	$716,316

The Company capitalized approximately $4.7 million and $8.4 million in interest expense to oil and natural gas properties during the three and six months ended June 30, 2015, respectively. The Company capitalized approximately $3.9 million and $6.2 million in interest expense to oil and natural gas properties during the three and six months ended June 30, 2014, respectively.

(1) On December 27, 2013, the Company entered into an Amended and Restated Credit Agreement with The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and other lenders (The "Amended and Restated Credit Agreement") that provides for a maximum facility amount of $1.5 billion. The Amended and Restated Credit Agreement matures on June 6, 2018. The Company's wholly-owned subsidiaries have guaranteed the obligations of the Company under the Amended and Restated Credit Agreement.

On April 23, 2014, the Company entered into a first amendment to the Amended and Restated Credit Agreement. The first amendment increased the letter of credit sublimit from $20.0 million to $70.0 million and provided for an increase in the borrowing base availability from $150.0 million to $275.0 million. The first amendment also made certain changes to the lenders and their respective lending commitments thereunder.

On November 26, 2014, the Company entered into a second amendment to the Amended and Restated Credit Agreement. The second amendment changed the definition of EBITDAX to exclude proceeds from the disposition of equity method investments and changed the ratio of funded debt to EBITDAX to be the ratio of net funded debt to EBITDAX. Net funded debt is funded debt less the amount of cash and short-term investments the Company has at the end of the relevant fiscal quarter. The second amendment increases the ratio from 2.00 to 1.00 to 3.50 to 1.00 for the period December 31, 2014 through June 30, 2015 and then decreases the ratio to 3.25 to 1.00 for the periods thereafter. Further, the second amendment increased the letter of credit sublimit from $70.0 million to $125.0 million and provided for an increase in the borrowing base availability from $275.0 million to $450.0 million.

On April 10, 2015, the Company entered into a third amendment to the Amended and Restated Credit Agreement. The third amendment increased the borrowing base from $450.0 million to $575.0 million and increased the Company's basket for unsecured debt issuances to $1.2 billion. The third amendment also made certain changes to the lenders and their respective lending commitments thereunder.

On May 29, 2015, the Company entered into a fourth amendment to the Amended and Restated Credit Agreement. The fourth amendment increased the letter of credit sublimit from $125.0 million to $150.0 million. Additionally, the Company received consent from its lenders to incur certain new secured indebtedness, limited to $30.0 million, to finance the construction of its new Oklahoma City headquarters. The lenders also agreed to waive certain provisions of the Amended and Restated Credit Agreement that may prohibit the construction loan. As of June 30, 2015, the Company did not have any outstanding borrowings under the Amended and Restated Credit Agreement. At June 30, 2015, the total availability for future borrowings under the Amended and Restated Credit Agreement, after giving effect to an aggregate of $92.7 million of letters of credit, was $482.3 million.

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Advances under the Amended and Restated Credit Agreement may be in the form of either base rate loans or eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 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 pages LIBOR01 or LIBOR02 of the Reuters screen that displays such rate for deposits in U.S. dollars, or, if such rate is not available, the rate as administered by ICE Benchmark Administration (or any other person that takes over administration of such rate) per annum equal to the offered rate on such other page or service that displays on average London interbank offered rate as determined by ICE Benchmark Administration (or any other person that takes over administration of such 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 Amended and Restated 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 Amended and Restated Credit Agreement. The Amended and Restated Credit Agreement also contains certain affirmative covenants, including, but not limited to the following financial covenants:
(i) the ratio of net funded debt to EBITDAX (net income, excluding (i) any non-cash revenue or expense associated with swap contracts resulting from ASC 815 and (ii) any cash or noncash revenue or expense attributable to minority investments plus without duplication and, in the case of expenses, 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) exploration costs deducted in determining net income under successful efforts accounting, (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 (provided that expenses related to any unsuccessful disposition will be limited to $3.0 million in the aggregate) for a twelve-month period may not be greater than 3.50 to 1.00; for the period December 31, 2014 through June 30, 2015 and 3.25 to 1.00 for the twelve-month period ending September 30, 2015 and periods thereafter; 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 June 30, 2015.
(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.

(3) On October 17, 2012, the Company issued $250.0 million in aggregate principal amount of senior unsecured notes due 2020 (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 (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 senior unsecured notes due 2020 (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 Offering"). The December Notes were issued as additional securities under the senior note indenture. 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 the 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. The October Notes and the December Notes were exchanged for substantially identical notes in the same aggregate principal amount that were registered under the Securities Act in October 2013 (the "Exchange Notes").

On August 18, 2014, the Company issued an additional $300.0 million in aggregate principal amount of senior unsecured notes due 2020 (the "August 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 August Notes Offering"). The August Notes were issued as additional securities under the senior note indenture. The Company used a portion of the net proceeds from the August Notes Offering to repay all amounts outstanding at such time under its revolving credit facility. The Company intends to use the remaining net proceeds of the August Notes Offering for general corporate purposes, including funding a portion of its 2014 and 2015 capital development plans. The October Notes Offering, December Notes Offering and the August Notes Offering are collectively referred to as the "Notes Offerings" and the Exchange Notes, and the August Notes are collectively referred to as the "Old Notes".

In connection with the issuance of the August Notes, the Company and the subsidiary guarantors entered into a registration rights agreement with the initial purchasers on August 18, 2014, pursuant to which the Company and the subsidiary guarantors have agreed to file a registration statement with respect to an offer to exchange the August Notes for a new issue of substantially identical debt securities registered under the Securities Act. The registration statement relating to the exchange offer for the August Notes was filed on November 6, 2014, as amended on February 3, 2015, and declared effective by the SEC on February 4, 2015. The exchange offer for the August Notes was completed in March 2015.

Under the senior note indenture relating to the Old Notes, interest on the Old 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 Old 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 Old Notes; provided, however, that the Old 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 Old 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 Old 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 Old Notes with the net proceeds of certain equity offerings, provided that at least 65% of the aggregate principal amount of the Old Notes initially issued remains outstanding immediately after such redemption.

(4) On April 21, 2015, the Company issued $350.0 million in aggregate principal amount of 6.625% Senior Notes due 2023 (the "April Notes" and, together with the "Old Notes," the "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 "April Notes Offering"). The Company received net proceeds of approximately $343.6 million after initial purchaser discounts and commissions and estimated offering expenses.

The April notes were issued under an indenture, dated as of April 21, 2015, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee. Pursuant to the indenture relating to the April Notes, interest on the April Notes will accrue at a rate of 6.625% per annum on the outstanding principal amount thereof from April 21, 2015, payable semi-annually on May 1 and November 1 of each year, commencing on November 1, 2015. The April Notes are not guaranteed by Grizzly Holdings, Inc. and will not be guaranteed by any of the Company's future unrestricted subsidiaries.

In connection with the April Notes Offering, the Company and its subsidiary guarantors entered into a registration rights agreement, dated as of April 21, 2015, pursuant to which the Company agreed to file a registration statement with respect to an

offer to exchange the April Notes for a new issue of substantially identical debt securities registered under the Securities Act. The Company may be required to file a shelf registration statement to cover resales of the April Notes under certain circumstances. If the Company fails to satisfy certain obligations under the registration rights agreement, it agreed to pay additional interest to the holders of the April Notes as specified in the registration rights agreement.
(5) 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 August Notes were issued at a price of 106.000% resulting in a gross premium of $18.0 million and an effective rate of 6.561%. The April Notes were issued at par. The premium and discount are being amortized using the effective interest method.
(6) On June 4, 2015, the Company entered into a construction loan agreement (the "Construction Loan") with InterBank for the construction of a new corporate headquarters in Oklahoma City. The Construction Loan allows for a maximum principal amount of $24.5 million to be drawn. Interest accrues daily on the outstanding principal balance at a fixed rate of 4.50% per annum and is payable on the last day of the month beginning June 30, 2015 through May 31, 2017. Monthly interest and principal payments are due beginning June 30, 2017, with the final payment due June 4, 2025. As of June 30, 2015, the Company had not drawn on this loan.

6. COMMON STOCK AND CHANGES IN CAPITALIZATION

Equity Offering

On April 21, 2015, the Company issued 10,925,000 shares of its common stock in an underwritten public offering (which included 1,425,000 shares sold pursuant to an option to purchase additional shares of the Company's common stock granted by the Company to, and exercised in full by, the underwriters). The net proceeds from this equity offering (including the net proceeds from the sale of the shares of common stock to the underwriters pursuant to their option to purchase additional shares) were approximately $501.9 million after underwriting discounts and commissions and estimated offering expenses. The Company used a portion of these net proceeds, together with a portion of the net proceeds from its concurrent senior notes offering (see Note 5, "Long Term Debt"), to repay all amounts outstanding at that time under its revolving credit facility and intends to use the remaining net proceeds from these offerings to fund the pending acquisition of Paloma and for general corporate purposes, including the funding of a portion of its 2015 capital development plans.
On June 12, 2015, the Company issued 11,500,000 shares of its common stock in an underwritten public offering (which included 1,500,000 shares sold pursuant to an option to purchase additional shares of the Company's common stock granted by the Company to, and exercised in full by, the underwriters). The net proceeds from this equity offering (including the net proceeds from the sale of the shares of common stock to the underwriters pursuant to their option to purchase additional shares) were approximately $479.8 million after underwriting discounts and commissions and estimated offering expenses. The Company used a portion of the net proceeds to fund the Monroe Acquisition (see Note 1) and intends to use the remaining funds for general corporate purposes, including the funding of a portion of its 2015 capital development plans.

7. STOCK-BASED COMPENSATION

During the three and six months ended June 30, 2015, the Company’s stock-based compensation cost was $3.2 million and $6.7 million, respectively, of which the Company capitalized $1.3 million and $2.7 million, respectively, relating to its exploration and development efforts. During the three and six months ended June 30, 2014, the Company's stock-based compensation cost was $3.4 million and $7.7 million, respectively, of which the Company capitalized $1.3 million and $3.1 million, respectively, relating to its exploration and development efforts.
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 2013 Restated Stock Incentive Plan (which amended and restated 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 six months ended June 30, 2015 and 2014.

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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 six months ended June 30, 2015 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, 2014	5,000	$9.07	0.69	$163
Granted	—	—		
Exercised	—	—		—
Forfeited/expired	—	—		
Options outstanding at June 30, 2015	5,000	$9.07	0.19	$156
Options exercisable at June 30, 2015	5,000	$9.07	0.19	$156

The following table summarizes information about the stock options outstanding at June 30, 2015:

Exercise Price	Number Outstanding	Weighted Average Remaining Life (in years)	Number Exercisable
$9.07	5,000	0.19	5,000
	5,000		5,000

The following table summarizes restricted stock activity for the six months ended June 30, 2015:

	Number of Unvested Restricted Shares	Weighted Average Grant Date Fair Value
Unvested shares as of December 31, 2014	387,245	$55.87
Granted	100,226	44.04
Vested	(123,543)	51.02
Forfeited	(4,000)	57.91
Unvested shares as of June 30, 2015	359,928	$54.22

Unrecognized compensation expense as of June 30, 2015 related to outstanding stock options and restricted shares was $15.4 million. The expense is expected to be recognized over a weighted average period of 1.52 years.

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8. EARNINGS PER SHARE

Reconciliations of the components of basic and diluted net income per common share are presented in the tables below:

	Three months ended June 30,					
	2015			2014		
	Income	Shares	Per Share	Income	Shares	Per Share
	(In thousands, except share data)					
Basic:						
Net (loss) income	$(31,325)	96,663,358	$(0.32)	$47,852	85,448,678	$0.56
Effect of dilutive securities:						
Stock options and awards	—	—		—	357,218	
Diluted:						
Net (loss) income	$(31,325)	96,663,358	$(0.32)	$47,852	85,805,896	$0.56

	Six months ended June 30,					
	2015			2014		
	Income	Shares	Per Share	Income	Shares	Per Share
	(In thousands, except share data)					
Basic:						
Net (loss) income	$(5,806)	91,201,824	$(0.06)	$130,410	85,354,566	$1.53
Effect of dilutive securities:						
Stock options and awards	—	—		—	412,113	
Diluted:						
Net (loss) income	$(5,806)	91,201,824	$(0.06)	$130,410	85,766,679	$1.52

There were 378,550 shares and 382,494 shares of common stock that were considered anti-dilutive for the three and six months ended June 30, 2015, respectively. There were no potential shares of common stock that were considered anti-dilutive for the three and six months ended June 30, 2014.

9.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 the Company's 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 June 30, 2015, the plugging and abandonment trust totaled approximately $3.1 million. At June 30, 2015, the Company had plugged 463 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 an employment agreement with Messrs. James Palm, Mike Liddell and Michael G. Moore, each with an initial three-year term expiring 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 provided for minimum salary and bonus levels, subject to review and potential increase by the Compensation Committee and/or the Board of Directors, as well as participation in the Company's incentive plans and other employee benefits.

Effective February 15, 2014, Gulfport's former Chief Executive Officer, James D. Palm, retired and his employment agreement with the company terminated. The Company entered into a separation agreement with Mr. Palm, under which agreement certain benefits are provided to, and obligations imposed on, Mr. Palm. As of June 30, 2015, the minimum commitment under Mr. Palm's separation agreement was approximately $0.4 million.

Mr. Liddell resigned as the Company's Chairman effective June 2013 at which date his employment agreement with Gulfport terminated. At that same time, the Company entered into a consulting agreement with Mr. Liddell. Mr. Liddell terminated his consulting agreement with the Company effective January 1, 2015.

On April 22, 2014, the Board of Directors appointed Michael G. Moore as Chief Executive Officer of the Company. The Company and Mr. Moore entered into an amended and restated employment agreement. The agreement has a three-year term commencing effective April 22, 2014. This agreement provides, among other things, for a minimum salary level, subject to review and potential increase by the Compensation Committee and/or the Board of Directors, as well as participation in the Company's incentive plans and other employee benefits.

On March 13, 2015, the Company entered into an employment agreement with Ross Kirtley, the Company's Chief Operating Officer. The agreement has a two-year term commencing effective April 22, 2014. This agreement provides, among other things, for a minimum salary level, subject to review and potential increase by the Compensation Committee and/or the Board of Directors, as well as participation in the Company's incentive plans and other employee benefits.

On March 13, 2015, the Company entered into an employment agreement with Aaron Gaydosik, the Company's Chief Financial Officer. The agreement has a three-year term commencing effective August 11, 2014. This agreement provides, among other things, for a minimum salary level, subject to review and potential increase by the Compensation Committee and/or the Board of Directors, as well as participation in the Company's incentive plans and other employee benefits.

Effective as of April 29, 2015, the Company amended and restated its existing employment agreement with Mr. Moore. The employment agreement, as amended and restated as of April 29, 2015, reflects the decision of the compensation committee of the Company’s board of directors to increase Mr. Moore’s annual base salary to $460,000 for 2015 and the determination by the compensation committee to continue to increase Mr. Moore’s annual base salary during 2016 and 2017 so as to achieve alignment between the 25th and 50th percentile of the Company’s peer group disclosed in the Company’s annual proxy statement. The amended and restated employment agreement also eliminated Mr. Moore’s right to receive a fixed annual grant of 40,000 shares of restricted stock. Instead, consistent with the recommendation of the Company’s compensation consultant and approved by the compensation committee, the amended and restated employment agreement provided that Mr. Moore is entitled to receive an award of restricted stock equal to 500% of his annual base salary on the same vesting schedule as previously provided in his employment agreement with respect to his equity awards.

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The aggregate minimum commitment for future salary at June 30, 2015 under the above listed employment agreements was approximately $1.8 million.

Operating Leases

The Company leases office facilities under non-cancellable operating leases exceeding one year. Future minimum lease commitments under these leases at June 30, 2015 were as follows:

	(In thousands)
Remaining 2015	$332
2016	617
2017	513
2018	20
2019	—
Total	$1,482

Other Commitments

Effective October 1, 2014, the Company entered into a Sand Supply Agreement with Muskie that expires on September 30, 2018. Pursuant to this agreement, the Company has agreed to purchase annual and monthly amounts of proppant sand subject to exceptions specified in the agreement at a fixed price per ton, subject to certain adjustments, plus agreed costs and expenses. Failure by either Muskie or the Company to deliver or accept the minimum monthly amount results in damages calculated per ton based on the difference between the monthly obligation amount and the amount actually delivered or accepted, as applicable. The Company did not incur any expenses related to non-utilization fees during the three and six months ended June 30, 2015.

Effective October 1, 2014, the Company entered into an Amended and Restated Master Services Agreement for pressure pumping services with Stingray Pressure that expires on September 30, 2018. Pursuant to this agreement, Stingray Pressure has agreed to provide hydraulic fracturing, stimulation and related completion and rework services to the Company and the Company has agreed to pay Stingray Pressure a monthly service fee plus the associated costs of the services provided.

Future minimum commitments under these agreements at June 30, 2015 are as follows:

	(In thousands)
Remaining 2015	$26,220
2016	52,440
2017	52,440
2018	39,330
Total	$170,430

Litigation

Due to the nature of the Company's business, it is, from time to time, involved in routine litigation or subject to disputes or claims related to its business activities, including workers' compensation claims and employment related disputes. In the opinion of the Company's management, none of the pending litigation, disputes or claims against the Company, if decided adversely, will have a material adverse effect on its financial condition, cash flows or results of operations.

10. 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, swaptions and basis swaps. These contracts allow

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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 records all derivative contracts at fair value. 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 2014 and 2015, the Company entered into fixed price swap contracts for 2014 through 2019 with five financial institutions. The Company's fixed price swap and swaption contracts are tied to the commodity prices on Argus 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 Argus for Louisiana Light Sweet Crude for oil, the NYMEX West Texas Intermediate for oil and on the NYMEX Henry Hub for natural gas. At June 30, 2015, the Company had the following fixed price swaps and swaptions in place:

	Daily Volume (Bbls/day)	Weighted Average Price
July 2015 - June 2016	2,500	$62.38
	Daily Volume (MMBtu/day)	Weighted Average Price
July 2015 - August 2015	256,875	$3.87
September 2015	286,875	$3.82
October 2015	322,500	$3.79
November 2015 - December 2015	282,500	$3.91
January 2016 - March 2016	312,500	$3.73
April 2016	302,500	$3.72
May 2016 - December 2016	232,500	$3.63
January 2017 - June 2017	182,500	$3.59
July 2017 - December 2017	120,000	$3.40
January 2018 - December 2018	70,000	$3.35
January 2019 - March 2019	20,000	$3.37

In addition, the Company has entered into natural gas basis swap positions, which settle on the pricing index to basis differential of MichCon to the NYMEX Henry Hub natural gas price. As of June 30, 2015, the Company's natural gas basis swap positions were as follows:

	Daily Volume (MMBtu/day)	Hedged Differential
July 2015 - December 2016	40,000	$0.02

At June 30, 2015 the fair value of derivative assets and liabilities related to the fixed price swaps, swaptions and basis swaps was as follows:

	(In thousands)
Short-term derivative instruments - asset	$77,350
Long-term derivative instruments - asset	$25,871
Short-term derivative instruments - liability	$937
Long-term derivative instruments - liability	$2,753

All fixed price swaps, swaptions and basis swaps have been executed in connection with the Company's oil and natural gas price hedging program. For fixed price swaps, swaptions and basis 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 those contracts which are not designated as cash flow hedges changes in the fair value are classified as revenues on the Company's consolidated statements of operations.

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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. The Company had no cash flow hedges in place for the three and six months ended June 30, 2015 and 2014, as all fixed price swaps, swaptions and basis swaps had either been deemed ineffective at their inception or had been accounted for using the mark-to-market accounting method.

At June 30, 2015, no amounts related to fixed price swaps, swaptions or basis swaps remain in accumulated other comprehensive income (loss).

The Company recognized a loss of $34.6 million and $3.3 million due to the change in fair value of derivative instruments for the three and six months ended June 30, 2015, respectively, which is included in oil and condensate and gas sales in the consolidated statements of operations. The Company recognized a gain of $2.2 million and a loss of $6.4 million due to the change in fair value of derivative instruments for the three and six months ended June 30, 2014, respectively, which is included in oil and condensate and gas sales in the consolidated statements of operations.

11. FAIR VALUE MEASUREMENTS

The Company records certain financial and non-financial assets and liabilities on the balance sheet at fair value in accordance with FASB ASC 820, "Fair Value Measurement and Disclosures" ("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 June 30, 2015:

	June 30, 2015		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets:			
Derivative Instruments	$103,221	$—	$—
Liabilities:			
Derivative Instruments	$3,690	$—	$—

The estimated fair value of the Company’s fixed price swap, swaption and basis swap contracts were based upon forward commodity prices based on quoted market prices, adjusted for differentials. See Note 10 for further discussion of the Company's hedging activities.

The estimated fair values of proved oil and gas properties assumed in business combinations are based on a discounted cash flow model and market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates, and risk-adjusted discount rates. The estimated fair values of unevaluated oil and gas properties was based on geological studies, historical well performance, location and applicable mineral lease terms. Based on the unobservable nature of certain of the inputs the estimated fair value of the oil and gas properties assumed is deemed to use Level 3 inputs. See Note 1 for further discussion of the Company's acquisitions.

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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 2 for further discussion of the Company’s asset retirement obligations. Asset retirement obligations incurred during the six months ended June 30, 2015 were approximately $4.1 million.

Due to the unobservable nature of the inputs, the fair value of the Company's initial investment in Mammoth was estimated using assumptions that represent Level 3 inputs. The Company estimated the fair value of the investment as of the November 24, 2014 contribution date. See Note 3 for further discussion of the Company's contribution to Mammoth. The estimated fair value of the Company's investment in Mammoth was $143.5 million at December 31, 2014.

12. 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 June 30, 2015, the carrying value of the outstanding debt represented by the Notes was $963.6 million, including the remaining unamortized discount of approximately $2.7 million related to the October Notes and the remaining unamortized premium of approximately $0.4 million related to the December Notes and $15.9 million related to the August Notes. Based on the quoted market price, the fair value of the Notes was determined to be approximately $989.8 million at June 30, 2015.

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, and for the Company's swaptions, market implied volatilities of the underlying commodity are also evaluated. Forward market prices for oil and natural gas are dependent upon supply and demand factors in such forward market and are subject to significant volatility.

13. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

On October 17, 2012, December 21, 2012, and August 18, 2014, the Company issued an aggregate of $600.0 million principal amount of its 7.75% Senior Notes. The October Notes and the December Notes were exchanged for substantially identical notes in the same aggregate principal amount that were registered under the Securities Act. The Exchange Notes and the August Notes are collectively referred to as the "Old Notes". The Old 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 Old 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.

In connection with the issuance of the August Notes, the Company and the subsidiary guarantors entered into a registration rights agreement with the initial purchasers on August 18, 2014, pursuant to which the Company and the subsidiary guarantors have agreed to file a registration statement with respect to an offer to exchange the August Notes for a new issue of substantially identical debt securities registered under the Securities Act. The registration statement relating to the exchange offer for the August Notes was filed on November 6, 2014, as amended on February 3, 2015, and declared effective by the SEC on February 4, 2015. The exchange offer for the August Notes was completed in March 2015.

On April 21, 2015, the Company issued $350.0 million in aggregate principal amount of 6.625% Senior Notes due 2023 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. In connection with the April Notes Offering, the Company and its subsidiary guarantors entered into a registration rights agreement, dated as of April 21, 2015, pursuant to which the Company agreed to file a registration statement with respect to an offer to exchange the April Notes for a new issue of substantially identical debt securities registered under the Securities Act. The Company may be required to file a shelf registration statement to cover resales of the April Notes under certain circumstances.
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

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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)

	June 30, 2015 Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$524,240	$1,247	$ 1	$—	$525,488
Restricted cash	75,005	—	—	—	75,005
Accounts receivable - oil and gas	86,558	63	—	—	86,621
Accounts receivable - related parties	90	—	—	—	90
Accounts receivable - intercompany	48,401	55	—	(48,456)	—
Prepaid expenses and other current assets	15,168	—	—	—	15,168
Short-term derivative instruments	77,350	—	—	—	77,350
Total current assets	826,812	1,365	1	(48,456)	779,722
Property and equipment:					
Oil and natural gas properties, full-cost accounting	4,760,793	38,771	—	(729)	4,798,835
Other property and equipment	22,887	43	—	—	22,930
Accumulated depletion, depreciation, amortization and impairment	(1,211,281)	(27)	—	—	(1,211,308)
Property and equipment, net	3,572,399	38,787	—	(729)	3,610,457
Other assets:					
Equity investments and investments in subsidiaries	353,243	—	164,112	(154,964)	362,391
Derivative instruments	25,871	—	—	—	25,871
Other assets	25,418	—	—	—	25,418
Total other assets	404,532	—	164,112	(154,964)	413,680
Total assets	$4,803,743	$40,152	$ 164,113	$(204,149)	$4,803,859
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	$318,609	$116	$ —	$—	$318,725
Accounts payable - intercompany	—	48,326	130	(48,456)	—
Asset retirement obligation - current	75	—	—	—	75
Short-term derivative instruments	937	—	—	—	937
Deferred tax liability - current	26,508	—	—	—	26,508
Current maturities of long-term debt	1,738	—	—	—	1,738
Total current liabilities	347,867	48,442	130	(48,456)	347,983
Long-term derivative instrument	2,753	—	—	—	2,753
Asset retirement obligation - long-term	21,202	—	—	—	21,202
Deferred tax liability	201,022	—	—	—	201,022
Long-term debt, net of current maturities	963,593	—	—	—	963,593
Total liabilities	1,536,437	48,442	130	(48,456)	1,536,553
Stockholders' equity:					
Common stock	1,081	—	—	—	1,081
Paid-in capital	2,816,930	322	235,347	(235,669)	2,816,930

Accumulated other comprehensive income (loss)	(38,412)	—	(38,412)	38,412	(38,412)
Retained earnings (accumulated deficit)	487,707	(8,612)	(32,952)	41,564	487,707
Total stockholders' equity	3,267,306	(8,290)	163,983	(155,693)	3,267,306
Total liabilities and stockholders' equity	$4,803,743	$40,152	$ 164,113	$(204,149)	$4,803,859

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CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	December 31, 2014				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$141,535	$804	$ 1	$—	$142,340
Accounts receivable - oil and gas	103,762	96	—	—	103,858
Accounts receivable - related parties	46	—	—	—	46
Accounts receivable - intercompany	45,222	27	—	(45,249)	—
Prepaid expenses and other current assets	3,714	—	—	—	3,714
Short-term derivative instruments	78,391	—	—	—	78,391
Total current assets	372,670	927	1	(45,249)	328,349
Property and equipment:					
Oil and natural gas properties, full-cost accounting,	3,887,874	35,990	—	(710)	3,923,154
Other property and equipment	18,301	43	—	—	18,344
Accumulated depletion, depreciation, amortization and impairment	(1,050,855)	(24)	—	—	(1,050,879)
Property and equipment, net	2,855,320	36,009	—	(710)	2,890,619
Other assets:					
Equity investments and investments in subsidiaries	360,238	—	180,217	(170,874)	369,581
Derivative instruments	24,448	—	—	—	24,448
Other assets	19,396	—	—	—	19,396
Total other assets	404,082	—	180,217	(170,874)	413,425
Total assets	$3,632,072	$36,936	$ 180,218	$(216,833)	$3,632,393
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	$371,089	$321	$ —	$—	$371,410
Accounts payable - intercompany	—	45,143	106	(45,249)	—
Asset retirement obligation - current	75	—	—	—	75
Deferred tax liability	27,070	—	—	—	27,070
Current maturities of long-term debt	168	—	—	—	168
Total current liabilities	398,402	45,464	106	(45,249)	398,723
Asset retirement obligation - long-term	17,863	—	—	—	17,863
Deferred tax liability	203,195	—	—	—	203,195
Long-term debt, net of current maturities	716,316	—	—	—	716,316
Total liabilities	1,335,776	45,464	106	(45,249)	1,336,097
Stockholders' equity:					
Common stock	856	—	—	—	856
Paid-in capital	1,828,602	322	227,079	(227,401)	1,828,602
	(26,675)	—	(26,675)	26,675	(26,675)

Accumulated other comprehensive income (loss)					
Retained earnings (accumulated deficit)	493,513	(8,850)	(20,292)	29,142	493,513
Total stockholders' equity	2,296,296	(8,528)	180,112	(171,584)	2,296,296
Total liabilities and stockholders' equity	$3,632,072	$36,936	$ 180,218	$(216,833)	$3,632,393

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CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Three months ended June 30, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$112,027	$243	$—	$—	$112,270
Costs and expenses:					
Lease operating expenses	16,685	178	—	—	16,863
Production taxes	3,260	25	—	—	3,285
Midstream gathering and processing	32,892	12	—	—	32,904
Depreciation, depletion, and amortization	71,154	1	—	—	71,155
General and administrative	9,488	5	22	—	9,515
Accretion expense	192	—	—	—	192
	133,671	221	22	—	133,914
(LOSS) INCOME FROM OPERATIONS	(21,644)	22	(22)	—	(21,644)
OTHER (INCOME) EXPENSE:					
Interest expense	12,023	—	—	—	12,023
Interest income	(248)	—	—	—	(248)
Loss (income) from equity method investments and investments in subsidiaries	15,120	—	8,494	(8,494)	15,120
	26,895	—	8,494	(8,494)	26,895
(LOSS) INCOME BEFORE INCOME TAXES	(48,539)	22	(8,516)	8,494	(48,539)
INCOME TAX BENEFIT	(17,214)	—	—	—	(17,214)
NET (LOSS) INCOME	$(31,325)	$22	$ (8,516)	$8,494	$(31,325)

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CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Three months ended June 30, 2014				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$114,014	$722	$—	$—	$114,736
Costs and expenses:					
Lease operating expenses	12,457	223	—	—	12,680
Production taxes	6,529	72	—	—	6,601
Midstream gathering and processing	10,758	22	—	—	10,780
Depreciation, depletion, and amortization	55,993	1	—	—	55,994
General and administrative	10,346	35	1	—	10,382
Accretion expense	189	—	—	—	189
	96,272	353	1	—	96,626
INCOME (LOSS) FROM OPERATIONS	17,742	369	(1)	—	18,110
OTHER (INCOME) EXPENSE:					
Interest expense	2,402	—	—	—	2,402
Interest income	(36)	—	—	—	(36)
Litigation settlement	6,000	—	—	—	6,000
(Income) loss from equity method investments and investments in subsidiaries	(69,937)	—	2,228	(1,860)	(69,569)
	(61,571)	—	2,228	(1,860)	(61,203)
INCOME (LOSS) BEFORE INCOME TAXES	79,313	369	(2,229)	1,860	79,313
INCOME TAX EXPENSE	31,461	—	—	—	31,461
NET INCOME (LOSS)	$47,852	$369	$ (2,229)	$1,860	$47,852

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CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Six months ended June 30, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$287,859	$728	$ —	$—	$288,587
Costs and expenses:					
Lease operating expenses	33,472	371	—	—	33,843
Production taxes	7,513	57	—	—	7,570
Midstream gathering and processing	58,266	19	—	—	58,285
Depreciation, depletion, and amortization	161,062	2	—	—	161,064
General and administrative	20,249	41	24	—	20,314
Accretion expense	382	—	—	—	382
	280,944	490	24	—	281,458
INCOME (LOSS) FROM OPERATIONS	6,915	238	(24)	—	7,129
OTHER (INCOME) EXPENSE:					
Interest expense	20,782	—	—	—	20,782
Interest income	(257)	—	—	—	(257)
(Income) loss from equity method investments and investments in subsidiaries	(5,069)	—	12,636	(12,422)	(4,855)
	15,456	—	12,636	(12,422)	15,670
(LOSS) INCOME BEFORE INCOME TAXES	(8,541)	238	(12,660)	12,422	(8,541)
INCOME TAX BENEFIT	(2,735)	—	—	—	(2,735)
NET (LOSS) INCOME	$(5,806)	$238	$ (12,660)	$12,422	$(5,806)

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CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Six months ended June 30, 2014				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$231,864	$901	$ —	$—	$232,765
Costs and expenses:					
Lease operating expenses	23,838	471	—	—	24,309
Production taxes	13,466	92	—	—	13,558
Midstream gathering and processing	18,515	34	—	—	18,549
Depreciation, depletion, and amortization	112,870	1	—	—	112,871
General and administrative	19,834	62	(3)	—	19,893
Accretion expense	377	—	—	—	377
Gain on sale of assets	(11)	—	—	—	(11)
	188,889	660	(3)	—	189,546
INCOME FROM OPERATIONS	42,975	241	3	—	43,219
OTHER (INCOME) EXPENSE:					
Interest expense	6,287	—	—	—	6,287
Interest income	(142)	—	—	—	(142)
Litigation settlement	24,000	—	—	—	24,000
(Income) loss from equity method investments and investments in subsidiaries	(198,288)	—	4,229	(3,985)	(198,044)
	(168,143)	—	4,229	(3,985)	(167,899)
INCOME (LOSS) BEFORE INCOME TAXES	211,118	241	(4,226)	3,985	211,118
INCOME TAX EXPENSE	80,708	—	—	—	80,708
NET INCOME (LOSS)	$130,410	$241	$ (4,226)	$3,985	$130,410

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

	Three months ended June 30, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net (loss) income	$(31,325)	$22	$(8,516)	$8,494	$(31,325)
Foreign currency translation adjustment	3,247	—	3,247	(3,247)	3,247
Other comprehensive income (loss)	3,247	—	3,247	(3,247)	3,247
Comprehensive (loss) income	$(28,078)	$22	$(5,269)	$5,247	$(28,078)

	Three months ended June 30, 2014				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$47,852	$369	$(2,229)	$1,860	$47,852
Foreign currency translation adjustment	6,816	—	6,816	(6,816)	6,816
Other comprehensive income (loss)	6,816	—	6,816	(6,816)	6,816
Comprehensive income (loss)	$54,668	$369	$4,587	$(4,956)	$54,668

	Six months ended June 30, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net (loss) income	$(5,806)	$238	$(12,660)	$12,422	$(5,806)
Foreign currency translation adjustment	(11,737)	—	(11,737)	11,737	(11,737)
Other comprehensive (loss) income	(11,737)	—	(11,737)	11,737	(11,737)
Comprehensive (loss) income	$(17,543)	$238	$(24,397)	$24,159	$(17,543)

	Six months ended June 30, 2014				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$130,410	$241	$(4,226)	$3,985	$130,410
Foreign currency translation adjustment	(462)	—	(462)	462	(462)
Other comprehensive (loss) income	(462)	—	(462)	462	(462)
Comprehensive income (loss)	$129,948	$241	$(4,688)	$4,447	$129,948

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CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Amounts in thousands)

	Six months ended June 30, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$135,485	$3,389	$(1)	$1	$138,874
Net cash (used in) provided by investing activities	(976,820)	(2,946)	(8,267)	8,267	(979,766)
Net cash provided by (used in) financing activities	1,224,040	—	8,268	(8,268)	1,224,040
Net increase in cash and cash equivalents	382,705	443	—	—	383,148
Cash and cash equivalents at beginning of period	141,535	804	1	—	142,340
Cash and cash equivalents at end of period	$524,240	$1,247	$1	$—	$525,488

	Six months ended June 30, 2014				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$203,057	$(1,546)	$(2)	$—	$201,509
Net cash provided by (used in) investing activities	(621,155)	(3,608)	(16,569)	16,572	(624,760)
Net cash provided by (used in) financing activities	39,588	—	16,572	(16,572)	39,588
Net increase (decrease) in cash and cash equivalents	(378,510)	(5,154)	1	—	(383,663)
Cash and cash equivalents at beginning of period	451,431	7,525	—	—	458,956
Cash and cash equivalents at end of period	$72,921	$2,371	$1	$—	$75,293

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14. RECENT ACCOUNTING PRONOUNCEMENTS

In April 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2014-08: Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360) - Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. ASU 2014-08 changes the threshold for a disposal to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other material disposal transactions that do not meet the revised definition of a discontinued operation. Under the updated standard, a disposal of a component or group of components of an entity is required to be reported as discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity’s operations and financial results when the component or group of components of the entity (1) has been disposed of by a sale, (2) has been disposed of other than by sale or (3) is classified as held for sale. The ASU is effective for annual and interim periods beginning after December 15, 2014, however, early adoption is permitted. The Company early adopted this ASU on a prospective basis beginning with the second quarter of 2014. The adoption did not have a material impact on the Company’s consolidated financial statements.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers, which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance. The core principle of the new standard is for the recognition of revenue to depict the transfer of goods or services to customers in amounts that reflect the payment to which the company expects to be entitled in exchange for those goods or services. The new standard will also result in enhanced revenue disclosures, provide guidance for transactions that were not previously addressed comprehensively and improve guidance for multiple-element arrangements. The ASU is effective for annual periods beginning after December 15, 2016, and interim periods within those years, using either a full or a modified retrospective application approach. In July 2015, the FASB decided to defer the effective date by one year (until 2018). The Company is in the process of evaluating the impact on its consolidated financial statements.

In August 2014, the FASB issued ASU No. 2014-15, "Presentation of Financial Statements - Going Concern (Subtopic 205-40)." The new guidance addresses management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and in certain circumstances to provide related footnote disclosures. The standard is effective for the annual period ending after December 15, 2016 and for annual and interim periods thereafter. Early adoption is permitted. The Company does not believe that the adoption of this guidance will have a material impact on its consolidated financial statements.

In April 2015, the FASB issued ASU No. 2015-03, "Simplifying the Presentation of Debt Issuance Costs (ASU 2015-03)." To simplify presentation of debt issuance costs, ASU 2015-03 requires that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts. ASU 2015-03 is effective for public entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. The Company is in the process of assessing the effects of adoption of this new guidance.

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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 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; our ability to identify, complete and integrate acquisitions of properties and businesses; changes in laws or regulations; adverse weather conditions and natural disasters such as hurricanes and other factors, including those listed in the “Risk Factors” section of our most recent Annual Report on Form 10-K, Quarterly Reports on Form 10-Q or any other filings we make with the SEC, 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, and interests in entities that operate in Southeast Asia, including the Phu Horm gas field in Thailand. Until November 2014, we held 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. At June 30, 2015, we did not own any shares of Diamondback. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

2015 Operational Highlights

- Net production increased 196% to 43,128 net million cubic feet of natural gas equivalent, or MMcfe, for the three months ended June 30, 2015 from 14,592 MMcfe for the three months ended June 30, 2014.
- During the three months ended June 30, 2015, we spud nine gross (6.7 net) wells, participated in an additional three gross (1.1 net) wells that were drilled by other operators on our Utica Shale acreage and recompleted 13 gross and net wells. Of our nine new wells spud at June 30, 2015, six were in various stages of completion and three were being drilled. In addition, we turned-to-sales 19 gross (14.5 net) wells during the three months ended June 30, 2015.
- On April 15, 2015, we entered into an agreement to acquire Paloma Partners III, LLC, or Paloma, for a total purchase price of approximately $301.3 million, subject to closing adjustments. Paloma holds approximately 24,000 net

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nonproducing acres in the Utica Shale of Ohio. This transaction is expected to close during the third quarter of 2015, subject to the satisfaction of certain closing conditions.

- On April 21, 2015, we issued 10,925,000 shares of our common stock in an underwritten public offering (which included 1,425,000 shares sold pursuant to an option to purchase additional shares of our common stock granted to and exercised by the underwriters in full). The net proceeds from the equity offering (including the net proceeds from the sale of the shares of common stock to the underwriters under their option to purchase additional shares) were approximately $501.9 million. We used a portion of these net proceeds, together with a portion of the net proceeds from our concurrent senior notes offering described below, to repay all borrowings outstanding at that time under our senior secured revolving credit facility and intend to use the remaining net proceeds from these offerings to fund the pending acquisition of Paloma and for general corporate purposes, including the funding of a portion of our 2015 capital development plans.
- On April 21 2015, we issued $350.0 million in aggregate principal amount of our 6.625% senior unsecured notes due 2023, resulting in net proceeds to us of $343.6 million.
- On June 12, 2015, we issued 11,500,000 shares of our common stock in an underwritten public offering (which included 1,500,000 shares sold pursuant to an option to purchase additional shares of our common stock granted to and exercised by the underwriters in full). The net proceeds from the equity offering (including the net proceeds from the sale of the shares of common stock to the underwriters under their option to purchase additional shares) were approximately $479.8 million. We used a portion of these net proceeds to fund the acquisition of certain acreage and other assets in the Utica Shale in Ohio from American Energy - Utica, LLC, or AEU, described below and intend to use the remaining funds for general corporate purposes, including the funding of a portion of our 2015 capital development plans.
- As of June 8, 2015, we completed the acquisition of 6,198 gross and net acres located in Belmont and Jefferson Counties, Ohio from AEU for a purchase price of approximately $68.2 million, subject to adjustment, in a transaction we refer to as the Belmont/Jefferson acquisition. This acreage is located near or adjacent to the acreage included in our pending acquisition of Paloma. This newly acquired Belmont and Jefferson County acreage is undeveloped.
- On June 12, 2015, we completed the acquisition of 38,965 gross (27,228 net) acres located in Monroe County, Ohio, which we refer to as the Monroe County Acreage, 14.6 MMcf per day of average net production (estimated for April 2015), 18 gross (11.3 net) drilled but uncompleted wells, an 11 mile gas gathering system and a four well pad location from AEU for a total purchase price of approximately $319.0 million, which we refer to as the Monroe Acquisition. We used a portion of the net proceeds from our June 2015 equity offering described above to fund the Monroe Acquisition. The Monroe County Acreage has a net revenue interest of approximately 84% and is approximately 85% held by production by a ten well per year drilling commitment. On June 29, 2015, we acquired an additional 4,950 gross (1,900 net) acres in Monroe County for an additional approximately $18.2 million from AEU, which we refer to as the Additional Monroe County Acreage Acquisition.
- We continue to see improvement in our service costs and expect that our operational efficiencies, combined with our service costs reductions, will lower our overall well costs by approximately 15% during 2015 as compared to peak 2014 pricing.

2015 Production and Drilling Activity

During the three months ended June 30, 2015, our total net production was 727,082 barrels of oil, 33,119,727 thousand cubic feet, or Mcf, of natural gas, and 39,521,093 gallons of natural gas liquids, or NGLs, for a total of 43,128 MMcfe, as compared to 709,484 barrels of oil, 8,972,137 Mcf of natural gas and 9,538,843 gallons of NGLs, or 14,592 MMcfe, for the three months ended June 30, 2014. Our total net production averaged approximately 473.9 MMcfe per day during the three months ended June 30, 2015 as compared to 160.3 MMcfe per day during the same period in 2014. The 196% increase in production is largely the result of the development of our Utica Shale acreage.

Utica Shale. As of August 1, 2015, we had acquired leasehold interests in approximately 224,000 gross (219,000 net) acres in the Utica Shale, excluding the acreage associated with our pending acquisition of Paloma. From January 1, 2015 through August 1, 2015, we spud 25 gross (19.4 net) wells, of which 21 were in various stages of completion and four were still being drilled at August 1, 2015. In addition, nine gross (3.0 net) wells were drilled by other operators on our Utica Shale acreage during the six months ended June 30, 2015.

As of August 1, 2015, we had four rigs under contract on our Utica Shale acreage. We currently intend to spud 50 to 56 gross (32 to 36 net) wells on our Utica Shale acreage in 2015.

Aggregate net production from our Utica Shale acreage during the three months ended June 30, 2015 was approximately 41,638 MMcfe, or 457.6 MMcfe per day, 80% of which was from natural gas and 20% of which was from oil and NGLs.

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During July 2015, our average daily net production from the Utica Shale was approximately 551.0 MMcfe, 84% of which was from natural gas and 16% of which was from oil and NGLs. The increase in July 2015 production was a result of our drilling activity on our Utica Shale acreage.

WCBB. From January 1, 2015 through August 1, 2015, we recompleted 19 wells and spud no new wells.

Aggregate net production from the WCBB field during the three months ended June 30, 2015 was approximately 1,004 MMcfe, or an average of 11.0 MMcfe per day, 100% of which was from oil. During July 2015, our average net daily production at WCBB was approximately 15.6 MMcfe, 100% of which was from oil. The increase in July 2015 production was a result of our 2015 recompletion activity in our WCBB field.

East Hackberry Field. From January 1, 2015 through August 1, 2015, we recompleted 30 wells and spud no new wells.

Aggregate net production from the East Hackberry field during the three months ended June 30, 2015 was approximately 379 MMcfe, or an average of 4.2 MMcfe per day, 96% of which was from oil and 4% of which was from natural gas. During July 2015, our average net daily production at East Hackberry was approximately 6.4 MMcfe, 95% of which was from oil and 5% of which was from natural gas. The increase in July 2015 production is primarily the result of our 2015 recompletion activity.

West Hackberry Field. From January 1, 2015 through August 1, 2015, we did not spud any wells in our West Hackberry field.

Aggregate net production from the West Hackberry field was approximately 31 MMcfe, or an average of 345.3 Mcfe per day, 100% of which was from oil. During July 2015, our average net daily production at West Hackberry was approximately 188.9 Mcfe, 100% of which was from oil.

Niobrara Formation. Effective as of April 1, 2010, we acquired leasehold interests in the Niobrara Formation in Northwestern Colorado and, as of June 30, 2015, we held leases for approximately 5,700 net acres. From January 1, 2015 through August 1, 2015, there were no wells spud on our Niobrara Formation acreage. Aggregate net production from our Niobrara Formation acreage during the three months ended June 30, 2015 was approximately 28 MMcfe, or an average of 313.0 Mcfe per day, 100% of which was from oil. During July 2015, our average net daily production from our Niobrara Formation acreage was approximately 322.6 Mcfe, 100% of which was from oil. During 2015, we currently do not anticipate drilling any wells in the Niobrara Formation.

Bakken. As of June 30, 2015, we held approximately 864 net acres in the Bakken Formation of Western North Dakota and Eastern Montana with interests in 18 wells and overriding royalty interests in certain existing and future wells. Aggregate net production from this acreage during the three months ended June 30, 2015 was approximately 45 MMcfe, or an average of 497.3 Mcfe per day, of which 85% was from oil, 12% was from natural gas and 3% was from NGLs. During July 2015, our average daily net production from our Bakken Formation acreage was approximately 411.0 Mcfe, of which 85% was from oil and 15% was from natural gas.

2015 Updates Regarding Our Equity Investments

Grizzly Oil Sands. We, through our wholly-owned subsidiary Grizzly Holdings Inc., own a 24.9% interest in Grizzly. As of March 31, 2015, Grizzly had approximately 830,000 net acres under lease in the Athabasca, Peace River and Cold Lake oil sands regions of Alberta, Canada. Grizzly has three oil sands projects in various stages of development. Grizzly commenced commercial production from its Algar Lake Phase 1 steam-assisted gravity drainage, or SAGD, oil sand project during the second quarter of 2014 and has received regulatory approval for up to 11,300 barrels per day of bitumen production. Grizzly produced approximately 900 barrels of bitumen per day at its Algar Lake SAGD project during the first quarter of 2015. In April 2015, Grizzly determined to cease bitumen production at its Algar Lake facility due to the level of commodity prices. Grizzly intends to monitor market conditions as it assesses future plans for the facility. Although we determined that no impairment of our investment in Grizzly was needed at June 30, 2015, an impairment of such investment may result in the future if commodity prices continue to decline. In the first quarter of 2012, Grizzly acquired the May River property comprising approximately 47,000 acres. An initial 12,000 barrel per day development application was filed with the regulatory authorities in the fourth quarter of 2013, covering the eastern portion of the May River lease. The development application continues to move through the regulatory process and is expected to be approved by mid-2015. In the first quarter of 2014, a 2-D seismic program covering approximately 83 kilometers was completed to more fully define the resource over the remaining lease beyond the development application area. At the Thickwood thermal project, a development application for a 12,000 barrel per

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day oil sands project was filed in the fourth quarter of 2012. Since then, the Alberta Energy Regulator, or AER, announced it is implementing a policy for future regulatory requirements for reservoir containment in shallow SAGD areas, which impacts the Thickwood application. Additional work to advance the Thickwood application will be required and is expected to be addressed once the May River development approval is received. Grizzly has also developed delineation drilling, seismic and regulatory work plans at its Cadotte, Peace River property. Grizzly has pursued a rail marketing strategy to ensure consistent and flexible access to premium markets for its production, including its Windell truck to rail terminal located near Conklin, Alberta, which commenced transloading blended bitumen production from Algar Lake on to rail cars for delivery to the US Gulf Coast markets in the second quarter of 2014.

Thailand. We own a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex II. Tatex II, a privately held entity, holds an 8.5% interest in 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. Our investment is accounted for on the equity method. Tatex II accounts for its investment in APICO using the cost method. 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.

We own a 17.9% ownership interest in Tatex Thailand III, LLC, or Tatex III. Tatex III previously owned a concession covering approximately 245,000 acres in Southeast Asia. In 2009, Tatex III completed a 3-D seismic survey on this concession. Between 2010 and 2013, three wells were drilled on this concession. Each of the wells lacked sufficient permeability to produce in commercial quantities. Tatex III allowed the concession to expire in January 2015.

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 2013, we participated in the formation of Stingray Energy Services LLC, or Stingray Energy, with an initial ownership interest of 50%. 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 2012, we participated in the formation of Stingray Pressure Pumping LLC, or Stingray Pressure, Stingray Cementing LLC, or Stingray Cementing, and Stingray Logistics LLC, or Stingray Logistics, with an initial ownership interest in each entity of 50%. These entities provide well completion and other well services. In 2012, we also participated in the formation of Blackhawk Midstream LLC, or Blackhawk, and Timber Wolf Terminals LLC, or Timber Wolf, with an initial ownership interest of 50% in each entity. Blackhawk coordinates gathering, compression, processing and marketing activities in connection with the development of our Utica Shale acreage and Timber Wolf will operate a crude/condensate terminal and a sand transloading facility in Ohio. Also in 2012, we acquired a 22.5% equity interest in Windsor Midstream LLC, or Midstream, which owned a 28.4% equity interest in Coronado Midstream LLC, or Coronado, an entity that owns gas processing facilities in West Texas. Midstream sold its interest in Coronado in March 2015. In 2011 and 2012, we acquired an aggregate 40% equity interest in Bison Drilling and Field Services LLC, or Bison, which owns and operates drilling rigs and related equipment. Also in 2011, we acquired a 25% interest in Muskie Proppant LLC, or Muskie, which is engaged in the processing and sale of hydraulic fracturing grade sand. We are currently evaluating strategic alternatives with respect to some of these oil field service entities. In 2014, we acquired a 25% equity interest in Sturgeon Acquisitions LLC, or Sturgeon. Sturgeon owns and operates sand mines that produce hydraulic fracturing grade sand. In the fourth quarter of 2014, we contributed our investments in Stingray Pressure, Stingray Logistics, Bison and Muskie to Mammoth Energy Partners LP, or Mammoth, in exchange for a 30.5% limited partner interest in this newly formed limited partnership. Mammoth has filed a registration statement on Form S-1 with the SEC in connection with a contemplated initial public offering which it intends to pursue in 2015 or 2016 subject to market conditions. See Note 3 to our consolidated financial statements included elsewhere in this report for additional information regarding these other investments.

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

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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 approximately $1.8 billion at June 30, 2015 and approximately $1.5 billion at December 31, 2014. 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 natural gas liquids continue to decline and are not adequately offset by reserve additions from our drilling activities, 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 June 30, 2015.

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

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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. Ryder Scott Company, L.P., Netherland, Sewell & Associates, Inc. and to a lesser extent our personnel have prepared reserve reports of our reserve estimates at December 31, 2014 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 June 30, 2015, a valuation allowance of $3.1 million had been provided for state net operating loss and federal foreign 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 had 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 from equity method investments in the consolidated statements of operations. As of June 30, 2015, the Company did not own any shares of Diamondback's common stock.

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 June 30, 2015.

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During the year ended December 31, 2014, we recognized an impairment of $12.1 million related to our investment in Tatex Thailand III, LLC.

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. There were no hedges designated as cash flow hedges during the three months ended June 30, 2015.

RESULTS OF OPERATIONS

Comparison of the Three Months Ended June 30, 2015 and 2014

We reported a net loss of $31.3 million for the three months ended June 30, 2015 as compared to net income of $47.9 million for the three months ended June 30, 2014. This 165% decrease in period-to-period net income was due primarily to a 67% decrease in realized Mcfe prices to $2.60 from $7.85, a $4.2 million increase in lease operating expenses, a $9.6 million increase in interest expense and a $22.1 million increase in midstream gathering and processing expenses, partially offset by a 196% increase in net production to 43,128 MMcfe from 14,592 MMcfe and a $48.7 million decrease in income tax expense for the three months ended June 30, 2015 as compared to the three months ended June 30, 2014. In addition, our net income for the three months ended June 30, 2014 included a $72.9 million gain from our former equity method investment in Diamondback.

Oil and Gas Revenues. For the three months ended June 30, 2015, we reported oil and natural gas revenues of $112.3 million as compared to oil and natural gas revenues of $114.5 million during the same period in 2014. This $2.2 million, or 2%, decrease in revenues was primarily attributable to a 67% decrease in realized Mcfe prices to $2.60 from $7.85 due to a shift in our production mix toward natural gas and NGLs and the decline in commodity prices, partially offset by a 196% increase in net production to 43,128 MMcfe from 14,592 MMcfe for the three months ended June 30, 2015 as compared to the three months ended June 30, 2014.

The following table summarizes our oil and natural gas production and related pricing for the three months ended June 30, 2015, as compared to such data for the three months ended June 30, 2014:

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	Three months ended June 30,	
	2015	2014
Oil production volumes (MBbls)	727	709
Gas production volumes (MMcf)	33,120	8,972
Natural gas liquids production volumes (MGal)	39,521	9,539
Gas equivalents (MMcfe)	43,128	14,592
Average oil price (per Bbl)	$47.40	$95.95
Average gas price (per Mcf)	$1.99	$3.96
Average natural gas liquids (per Gal)	$0.30	$1.14
Gas equivalents (per Mcfe)	$2.60	$7.85

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to $16.9 million for the three months ended June 30, 2015 from $12.7 million for the three months ended June 30, 2014. This increase was mainly the result of an increase in expenses related to contract labor, contract pumpers and field supervision, ad valorem taxes, location repairs, field telemetry and repairs and maintenance due to our increased production in the Utica Shale.

Production Taxes. Production taxes decreased $3.3 million to $3.3 million for the three months ended June 30, 2015 from $6.6 million for the three months ended June 30, 2014. This decrease was related to changes in our product mix and production location as well as a decrease in realized prices.

Midstream Gathering and Processing Expenses. Midstream gathering and processing expenses increased by $22.1 million to $32.9 million for the three months ended June 30, 2015 from $10.8 million for the same period in 2014. This increase was primarily attributable to midstream expenses related to our increased production volumes in the Utica Shale resulting from our 2013 and 2014 drilling activities.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $71.2 million for the three months ended June 30, 2015, and consisted of $70.6 million in depletion of oil and natural gas properties and $0.6 million in depreciation of other property and equipment, as compared to total DD&A expense of $56.0 million for the three months ended June 30, 2014. 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 decreased to $9.5 million for the three months ended June 30, 2015 from $10.4 million for the three months ended June 30, 2014. This $0.9 million decrease was due to a decrease in franchise taxes, corporate fees and consulting expense, partially offset by an increase in salaries and benefits resulting from an increased number of employees, increases in legal fees, travel expense and bank fees.

Accretion Expense. Accretion expense remained relatively flat at $0.2 million for the three months ended June 30, 2015 and 2014.

Interest Expense. Interest expense increased to $12.0 million for the three months ended June 30, 2015 from $2.4 million for the three months ended June 30, 2014 due primarily to the issuance of $300.0 million in additional 7.75% Senior Notes due 2020, the issuance of $350.0 million of 6.625% Senior Notes due 2023 and increased borrowings under our revolving credit facility. On August 18, 2014, we issued $300.0 million aggregate principal amount of our 7.75% Senior Notes due 2020 and on April 21, 2015, we issued $350.0 million aggregate principal amount of our 6.625% senior unsecured notes due 2023. Total weighted debt outstanding under our revolving credit facility was $51.9 million for the three months ended June 30, 2015 as compared to $14.5 million outstanding under such facility for the same period in 2014. As of June 30, 2015, no borrowings were outstanding under this credit facility as compared to borrowings of $40.0 million outstanding as of June 30, 2014. Additionally, we capitalized approximately $4.7 million and $3.9 million in interest expense to undeveloped oil and natural gas properties during the three months ended June 30, 2015 and June 30, 2014, respectively. This increase in capitalized interest in the 2015 period was the result of an increase in our undeveloped oil and natural gas properties.

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Income Taxes. As of June 30, 2015, we had a federal net operating loss carry forward from the year ended December 31, 2014 of approximately $3.1 million, in addition to numerous temporary differences, which gave rise to a net deferred tax liability. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management's opinion, it is more likely than not that some portion will not be realized. At June 30, 2015, a valuation allowance of $3.1 million had been provided for certain state net operating losses and federal foreign tax credit deferred tax assets based on the uncertainty these assets may be realized. We recognized an income tax benefit of $17.2 million for the three months ended June 30, 2015.

Comparison of the Six Months Ended June 30, 2015 and 2014

We reported a net loss of $5.8 million for the six months ended June 30, 2015 as compared to net income of $130.4 million for the six months ended June 30, 2014. This 104% decrease in period-to-period net income was due primarily to a 55% decrease in realized Mcfe prices to $3.55 from $7.95, a $9.5 million increase in lease operating expenses, a $39.8 million increase in midstream processing and marketing expenses and a $14.5 million increase in interest expense, partially offset by a 178% increase in net production to 81,326 MMcfe from 29,219 MMcfe for the six months ended June 30, 2015 as compared to the six months ended June 30, 2014. The six months ended June 30, 2014 also included $84.8 million of income recognized from our equity method investment in Blackhawk and $121.7 million of income recognized from our former equity method investment in Diamondback.

Oil and Gas Revenues. For the six months ended June 30, 2015, we reported oil and natural gas revenues of $288.4 million as compared to oil and natural gas revenues of $232.4 million during the same period in 2014. This $56.0 million, or 24%, increase in revenues was primarily attributable to a 178% increase in net production to 81,326 MMcfe from 29,219 MMcfe, partially offset by a 55% decrease in realized Mcfe prices to $3.55 from $7.95 due to a shift in our production mix toward natural gas and NGLs and the decline in commodity prices.

The following table summarizes our oil and natural gas production and related pricing for the six months ended June 30, 2015, as compared to such data for the six months ended June 30, 2014:

	Six months ended June 30,	
	2015	2014
Oil production volumes (MBbls)	1,493	1,436
Gas production volumes (MMcf)	59,085	16,634
Natural gas liquids production volumes (MGal)	92,999	27,774
Gas equivalents (MMcfe)	81,326	29,219
Average oil price (per Bbl)	$46.87	$98.49
Average gas price (per Mcf)	$3.12	$3.24
Average natural gas liquids (per Gal)	$0.37	$1.33
Gas equivalents (per Mcfe)	$3.55	$7.95

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to $33.8 million for the six months ended June 30, 2015 from $24.3 million for the six months ended June 30, 2014. This increase was mainly the result of an increase in expenses related to contract pumpers, contract labor and field supervision, insurance, environmental services, location repairs, rentals, repair and maintenance, ad valorem taxes and salt water disposal due to our increased production in the Utica Shale.

Production Taxes. Production taxes decreased $6.0 million to $7.6 million for the six months ended June 30, 2015 from $13.6 million for the same period in 2014. This decrease was primarily related to changes in our product mix and production location as well as a decrease in realized prices.

Midstream Processing and Marketing Expenses. Midstream processing and marketing expenses increased by $39.8 million to $58.3 million for the six months ended June 30, 2015 from $18.5 million for the same period in 2014. This increase was

primarily attributable to midstream expenses related to our increased production volumes in the Utica Shale resulting from our 2013 and 2014 drilling activities.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $161.1 million for the six months ended June 30, 2015, and consisted of $159.9 million in depletion of oil and natural gas properties and $1.2 million in depreciation of other property and equipment, as compared to total DD&A expense of $112.9 million for the six months ended June 30, 2014. 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 $20.3 million for the six months ended June 30, 2015 from $19.9 million for the six months ended June 30, 2014. This $0.4 million increase was due to an increase in salaries and benefits resulting from an increased number of employees, increases in legal expense, travel expense and bank fees, partially offset by a decrease in stock compensation expense, corporate fees, consulting expense and franchise taxes and an increase in general and administrative costs related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense remained relatively flat at $0.4 million for the six months ended June 30, 2015 and 2014.

Interest Expense. Interest expense increased to $20.8 million for the six months ended June 30, 2015 from $6.3 million for the six months ended June 30, 2014 due primarily to the issuance of $300.0 million in additional 7.75% Senior Notes due 2020, issuance of $350.0 million of 6.625% Senior Notes due 2023 and increased borrowings under our revolving credit facility. On August 18, 2014, we issued $300.0 million aggregate principal amount of our 7.75% Senior Notes due 2020 and on April 21, 2015, we issued $350.0 million aggregate principal amount of our 6.625% senior unsecured notes due 2023. Total weighted debt outstanding under our revolving credit facility was $94.0 million for the six months ended June 30, 2015 as compared to $7.3 million for the same period in 2014. As of June 30, 2015, we had no debt outstanding under our revolving credit facility as compared to $40.0 million as of June 30, 2014. Additionally, we capitalized approximately $8.4 million and $6.2 million in interest expense to undeveloped oil and natural gas properties during the six months ended June 30, 2015 and June 30, 2014, respectively. This increase in capitalized interest during the 2015 period was the result of an increase in our undeveloped oil and natural gas properties.

Income Taxes. As of June 30, 2015, we had a federal net operating loss carry forward from the year ended December 31, 2014 of approximately $3.1 million, in addition to numerous temporary differences, which gave rise to a net deferred tax liability. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management's opinion, it is more likely than not that some portion will not be realized. At June 30, 2015, a valuation allowance of $3.1 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. We recognized an income tax benefit of $2.7 million for the six months ended June 30, 2015.

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 credit facility 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 2014, we received net proceeds of $312.0 million from the sale of our 7.75% Senior Notes due 2020, aggregate net proceeds of $258.4 million from the sale of shares of our Diamondback common stock in 2014 and also received net proceeds of $84.8 million from the sale of Blackhawk's equity interest in Ohio Gathering Company, LLC and Ohio Condensate Company, LLC.

On April 21, 2015, we issued 10,925,000 shares of our common stock in an underwritten public offering (which included the 1,425,000 shares of our common stock sold pursuant to the option to purchase additional shares of our common stock granted by us to, and exercised in full by, the underwriters). The aggregate net proceeds from this equity offering were approximately $501.9 million (after deducting underwriting discounts and commissions and estimated offering expenses). We intend to use a portion of the net proceeds from this equity offering to fund our pending acquisition of Paloma, with the remaining net proceeds to be used for general corporate purposes, including the funding of a portion of our 2015 capital development plans.

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On April 21, 2015, we also completed an offering of $350.0 million in aggregate principal amount of our new 6.625% senior notes due 2023 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. This offering is discussed in more detail below.

On June 12, 2015, we issued 11,500,000 shares of our common stock in an underwritten public offering (which included 1,500,000 shares sold pursuant to an option to purchase additional shares of our common stock granted to and exercised by the underwriters in full). The net proceeds from the equity offering (including the net proceeds from the sale of the shares of common stock to the underwriters under their option to purchase additional shares) were approximately $479.8 million. We used a portion of these net proceeds to fund the acquisition of certain acreage and other assets in the Utica Shale in Ohio from AEU and intend to use the remaining funds for general corporate purposes, including the funding of a portion of our 2015 capital development plans.

Net cash flow provided by operating activities was $138.9 million for the six months ended June 30, 2015 as compared to net cash flow provided by operating activities of $201.5 million for the same period in 2014. This decrease was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to a 178% increase in our net Mcfe production partially offset by a 55% decrease in net realized Mcfe prices, partially offset by an increase in our operating expenses. In addition, in January 2014, we recognized proceeds of $84.8 million from the sale of Blackhawk's equity interest in Ohio Gathering Company, LLC and Ohio Condensate Company, LLC and, in the first quarter of 2015, we received net proceeds of $7.2 million from the release of escrow from the Blackhawk sale.

Net cash used in investing activities for the six months ended June 30, 2015 was $979.8 million as compared to $624.8 million for the same period in 2014. During the six months ended June 30, 2015, we spent $898.6 million in additions to oil and natural gas properties, of which $72.3 million was spent on our 2015 drilling and recompletion programs, $344.4 million was spent on expenses attributable to the wells spud and recompleted during 2014, $404.8 million was spent on the acquisition from AEU, $6.6 million was spent on compressors and other facility enhancements, $3.0 million was spent on plugging costs, $37.0 million was spent on lease related costs, primarily the acquisition of leases in the Utica Shale with the remainder attributable mainly to capitalized general and administrative expenses. In addition, $8.3 million was invested in Grizzly during the six months ended June 30, 2015. We did not make any investments in our other equity investments during the six months ended June 30, 2015.

Net cash provided by financing activities for the six months ended June 30, 2015 was $1.2 billion as compared to net cash provided by financing activities of $39.6 million for the same period in 2014. The 2015 amount provided by financing activities is primarily attributable to the net proceeds of $343.6 million from the issuance of our 6.625% senior notes due 2023 and net proceeds of $981.9 million from our 2015 equity offerings, partially offset by net payments under our revolving credit facility.

Credit Facility. On December 27, 2013, we entered into an amended and restated credit agreement with The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and the other lenders, which we refer to as the amended and restated credit agreement. The amended and restated credit agreement provides for a maximum facility amount of $1.5 billion and matures on June 6, 2018.

On April 23, 2014, we entered into a first amendment to the amended and restated credit agreement. The first amendment increased the letter of credit sublimit from $20.0 million to $70.0 million and provided for an increase in the borrowing base availability from $150.0 million to $275.0 million. The first amendment also made certain changes to the lenders and their respective lending commitments thereunder.

On November 26, 2014, we entered into a second amendment to the amended and restated credit agreement. The second amendment changed the definition of EBITDAX to exclude proceeds from the disposition of equity method investments and changed the ratio of funded debt to EBITDAX to be the ratio of net funded debt to EBITDAX. Net funded debt is funded debt less the amount of cash and short-term investments at the end of the relevant fiscal quarter. The second amendment requires the ratio of net funded debt to EBITDAX to be less than 3.50 to 1.00 for the period December 31, 2014 through June 30, 2015 and then less than 3.25 to 1.00 for the periods thereafter. Further, the second amendment increased the letter of credit sublimit from $70.0 million to $125.0 million and provided for an increase in the borrowing base availability from $275.0 million to $450.0 million.

As of April 10, 2015, we entered into a third amendment to the amended and restated credit agreement. The third amendment increased the borrowing base from $450.0 million to $575.0 million and increased our basket for unsecured debt issuances to $1.2 billion. The third amendment also made certain changes to the lenders and their respective lending commitments thereunder.

On May 29, 2015, we entered into a fourth amendment to the amended and restated credit agreement. The fourth amendment increased the letter of credit sublimit from $125.0 million to $150.0 million. Additionally, we received consent from our lenders to incur certain new secured indebtedness, limited to $30.0 million, to finance the construction of our new Oklahoma City headquarters. The lenders also agreed to waive certain provisions of the amended and restated credit agreement that may prohibit the construction loan.

As of June 30, 2015, we had no balance outstanding under our revolving credit facility and total funds available for borrowing, after giving effect to an aggregate of $92.7 million of letters of credit, was $482.3 million. This facility is secured by substantially all of our assets. Our wholly-owned subsidiaries guarantee our obligations under our revolving credit facility.

Advances under our revolving credit agreement may be in the form of either base rate loans or eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 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 pages LIBOR01 or LIBOR02 of the Reuters screen that displays such rate for deposits in U.S. dollars, or, if such rate is not available, the rate as administered by ICE Benchmark Administration (or any other person that takes over administration of such rate) per annum equal to the offered rate on such other page or other service that displays an average London interbank offered rate as administered by ICE Benchmark Administration (or any other person that takes over the administration of such 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.

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 net funded debt to EBITDAX (net income, excluding (i) any non-cash revenue or expense associated with swap contracts resulting from ASC 815 and (ii) any cash or non-cash revenue or expense attributable to minority investment plus without duplication and, in the case of expenses, 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) exploration costs deducted in determining net income under successful efforts accounting, (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 (provided that expenses related to any unsuccessful dispositions will be limited to $3.0 million in the aggregate) for a twelve-month period may not be greater than 3.50 to 1.00 for the period December 31, 2014 through June 30, 2015 and 3.25 to 1.00 for the twelve-month period ending September 30, 2015 and periods thereafter; 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 June 30, 2015.

Senior Notes. In October 2012, December 2012 and August 2014, we issued an aggregate of $600.0 million in principal amount of our 7.75% senior notes due 2020 under an indenture among us, our subsidiary guarantors and Wells Fargo Bank, National Association, as the trustee. These senior notes are treated as a single class of debt securities under the senior note indenture and are referred to collectively as the Old Notes. Interest on the Old 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 Old 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. We may redeem some or all of the Old 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 Old 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.

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In April 2015, we issued $350.0 million in aggregate principal amount of our 6.625% senior unsecured notes due 2023, which we refer to as the April Notes and, together with the Old Notes, the 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, or the April Notes Offering. We used a portion of the net proceeds from the April Notes Offering, together with the net proceeds from our concurrent equity offering, to repay all amounts outstanding at such time under our revolving credit facility and intend to use the remaining net proceeds from these offerings to fund our pending acquisition of Paloma, and for general corporate purposes, including the funding of a portion of our 2015 capital development plans.

The April Notes were issued under a new indenture, dated as of April 21, 2015, among us, our subsidiary guarantors and Wells Fargo Bank, N.A., as trustee. Interest on the April Notes accrues at a rate of 6.625% per annum on the outstanding principal amount thereof from April 21, 2015, payable semi-annually on May 1 and November 1 of each year, commencing on November 1, 2015. The April Notes will mature on May 1, 2023. The April Notes are our senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness, including the Old Notes, and senior in right of payment to any of our future subordinated indebtedness. We may redeem some or all of the April Notes at any time on or after May 1, 2018, at the redemption prices listed in the indenture relating to the April Notes. Prior to May 1, 2018, we may redeem all or a portion of the April Notes at a price equal to 100% of the principal amount of the April Notes plus a “make-whole” premium and accrued and unpaid interest to the redemption date. In addition, any time prior to May 1, 2018, we may redeem the April Notes in an aggregate principal amount not to exceed 35% of the aggregate principal amount of the April Notes issued prior to such date at a redemption price of 106.625%, plus accrued and unpaid interest to the redemption date, with an amount equal to the net cash proceeds from certain equity offerings.

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 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 amended and restated credit agreement) 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.

If we experience a change of control (as defined in the senior note indentures relating to the Old Notes and the April Notes), 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 our senior note indentures, 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 indentures relating to the Old Notes and the April Notes contain 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. Under the indenture relating to the April Notes, certain of these covenants are subject to termination upon the occurrence of certain events, including in the event the April Notes are ranked as "investment grade".

In connection with the April Notes Offering, we and our subsidiary guarantors entered into a registration rights agreement with the representatives of the initial purchasers, dated as of April 21, 2015, pursuant to which we agreed to file a registration statement with respect to an offer to exchange the April Notes for a new issue of substantially

identical debt securities registered under the Securities Act. Under the registration rights agreement, we also agreed to use our commercially reasonable efforts to have the registration statement declared effective by the SEC on or prior to the 330th day after the issue date of the April Notes and to keep the exchange offer open for not less than 30 days (or longer if required by applicable law). We may be required to file a shelf registration statement to cover resales of the April Notes under certain circumstances. If we fail to satisfy these obligations under the registration rights agreement, we agreed to pay additional interest to the holders of the April Notes as specified in the registration rights agreement.
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 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, 2014, 51.4% 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.

From January 1, 2015 through August 1, 2015, we spud 25 gross (19.4 net) wells in the Utica Shale. We currently expect our 2015 capital expenditures to be $416.0 million to $446.0 million to spud 50 to 56 gross (32 to 36 net) wells on our Utica Shale acreage. In addition, we currently expect to spend $85.0 million to $95.0 million in 2015 to acquire additional acreage in the Utica Shale.

From January 1, 2015 through August 1, 2015, we recompleted 19 existing wells and spud no new wells at our WCBB field. In our Hackberry fields, from January 1, 2015 through August 1, 2015, we recompleted 30 existing wells and spud no new wells. We currently expect our 2015 capital expenditures to be $20.0 million to $25.0 million for maintenance capital expenditures and recompletions in Southern Louisiana.

From January 1, 2015 through August 1, 2015, no new wells were spud on our Niobrara Formation acreage. We do not currently anticipate any capital expenditures in the Niobrara Formation in 2015.

As of June 30, 2015, our net investment in Grizzly was approximately $164.1 million. We do not currently anticipate any material capital expenditures in 2015 related to Grizzly's activities.

We had no capital expenditures during the six months ended June 30, 2015 related to our interests in Thailand. We do not currently anticipate any additional capital expenditures in Thailand in 2015.

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. See "-2015 Updates Regarding Our Equity Investments-Other Investments" and Note 3 to our consolidated financial statements included elsewhere in this report for additional information regarding these other investments. In the year ended December 31, 2014, we invested approximately $43.6 million in these entities. In the six months ended June 30, 2015, we did not make any additional investments in these entities, and we do not currently anticipate any capital expenditures related to these entities in 2015.

Our total capital expenditures for 2015 are currently estimated to be in the range of $561.0 million to $611.0 million. In addition, we currently expect to spend $85.0 million to $95.0 million in 2015 to acquire additional Utica Shale acreage. Our total capital expenditures spent during the six months ended June 30, 2015 were approximately $482.6 million, including leasehold acquisitions but excluding our AEU and Paloma acquisitions. Approximately 96% of our 2015 estimated capital expenditures are currently expected to be spent in the Utica Shale. This range is down from the $872.9 million spent in 2014, excluding Utica leasehold acquisitions and the Rhino acquisition, primarily due to current commodity prices and a desire to maintain a strong liquidity position. During 2015, we have continued to focus on operational efficiencies in an effort to reduce our overall well costs. Further, due in large part to the significant decline in commodity prices, we have been able to negotiate reductions in service costs with our vendors. We continue to see improvement in our service costs and expect that our operational efficiencies, combined with our service costs reductions, will lower our overall well costs by approximately 15% during 2015 as compared to peak 2014 pricing. We intend to continue to monitor pricing and cost developments and make adjustments to our future capital expenditure programs as warranted.

We believe that our cash flow from operations, cash on hand (including proceeds from our recent debt and equity offerings) and borrowings under our loan facilities 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 program or pursue additional acquisitions, or Grizzly's oil sands projects require additional investments, 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 six years, the West Texas Intermediate posted price for crude oil has ranged from a low of $34.03 per barrel in February 2009 to a high of $113.39 per barrel in April 2011. The Henry Hub spot market price of natural gas has ranged from a low of $1.82 per million British thermal units, or MMBtu, in April 2012 to a high of $7.51 per MMBtu in January 2010. On July 31, 2015, the West Texas Intermediate posted price for crude oil was $47.12 per barrel and the Henry Hub spot market price of natural gas was $2.72 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 entered into certain fixed price swaps and basis swaps. See Item 3. Quantitative and Qualitative Disclosures about Market Risk for information regarding our open fixed price swaps, swaptions and basis swaps at June 30, 2015.

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 our abandonment obligations to Chevron have been fulfilled. Beginning in 2009, we could access the trust for use in plugging and abandonment charges associated with the property, but have not yet done so. As of June 30, 2015, the plugging and abandonment trust totaled approximately $3.1 million. At June 30, 2015, we have plugged 463 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, 2014.

Off-balance Sheet Arrangements

We had no off-balance sheet arrangements as of June 30, 2015.

New Accounting Pronouncements

In April 2014, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update, or ASU, No. 2014-08: Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360) - Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. ASU 2014-08 changes the threshold for a disposal to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other material disposal transactions that do not meet the revised definition of a discontinued operation. Under the updated standard, a disposal of a component or group of components of an entity is required to be reported as discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results when the component or group of components of the entity (1) has been disposed of by a sale, (2) has been disposed of other than by sale or (3) is classified as held for sale. The ASU is effective for annual and interim periods beginning after December 15, 2014, however, early adoption is permitted. We early adopted this ASU on a prospective basis beginning with the second quarter of 2014. The adoption did not have a material impact on our consolidated financial statements.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers, which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance. The core principle of the new standard is for the recognition of revenue to depict the transfer of goods or services to customers in amounts that reflect the payment to which the company expects to be entitled in exchange for those goods or services. The new standard will also result in enhanced revenue disclosures, provide guidance for transactions that were not previously addressed comprehensively and improve guidance for multiple-element arrangements. The ASU is effective for annual periods beginning after December 15, 2016, and interim periods within those years, using either a full or a modified retrospective application approach. In July 2015,

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the FASB decided to defer the effective date by one year (until 2018). We are in the process of evaluating the impact on our consolidated financial statements.

In August 2014, the FASB issued ASU No. 2014-15, "Presentation of Financial Statements - Going Concern (Subtopic 205-40)." The new guidance addresses management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and in certain circumstances to provide related footnote disclosures. The standard is effective for the annual period ending after December 15, 2016 and for annual and interim periods thereafter. Early adoption is permitted. We do not believe that the adoption of this guidance will have a material impact on our consolidated financial statements.

In April 2015, the FASB issued ASU No. 2015-03, "Simplifying the Presentation of Debt Issuance Costs (ASU 2015-03)." To simplify presentation of debt issuance costs, ASU 2015-03 requires that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts. ASU 2015-03 is effective for public entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. We are in the process of assessing the effects of adoption of this new guidance.

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 six years, the West Texas Intermediate posted price for crude oil has ranged from a low of $34.03 per barrel, or Bbl, in February 2009 to a high of $113.39 per Bbl in April 2011. The Henry Hub spot market price of natural gas has ranged from a low of $1.82 per MMBtu in April 2012 to a high of $7.51 per MMBtu in January 2010. On July 31, 2015, the West Texas Intermediate posted price for crude oil was $47.12 per barrel and the Henry Hub spot market price of natural gas was $2.72 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 had the following open fixed price swaps, swaptions and basis swaps at June 30, 2015:

	Daily Volume (Bbls/day)	Weighted Average Price
Fixed Price Swaps:		
July 2015 - June 2016	2,500	$62.38

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	Daily Volume (MMBtu/day)	Weighted Average Price
Fixed Price Swaps and Swaptions:		
July 2015 - August 2015	256,875	$3.87
September 2015	286,875	$3.82
October 2015	322,500	$3.79
November 2015 - December 2015	282,500	$3.91
January 2016 - March 2016	312,500	$3.73
April 2016	302,500	$3.72
May 2016 - December 2016	232,500	$3.63
January 2017 - June 2017	182,500	$3.59
July 2017 - December 2017	120,000	$3.40
January 2018 - December 2018	70,000	$3.35
January 2019 - March 2019	20,000	$3.37
	Daily Volume (MMBtu/day)	Hedged Differential
Basis Swaps:		
July 2015 - December 2016	40,000	$0.02

Under our 2015 contracts, we have hedged approximately 53% to 55% of our estimated 2015 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 recorded at fair value pursuant to FASB ASC 815 and related pronouncements. At June 30, 2015, we had a net asset derivative position of $99.5 million as compared to a net liability derivative position of $29.2 million as of June 30, 2014, 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 $78.0 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by approximately $78.0 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 amended and restated credit agreement 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 June 30, 2015, we had no variable interest rate borrowings outstanding; therefore, an increase in interest rates would not have impacted our interest expense. As of June 30, 2015, 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 President and our 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 President and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

As of June 30, 2015, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and President and our 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 President and our Chief Financial Officer have concluded that, as of June 30, 2015, our disclosure controls and procedures are effective.

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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

Due to the nature of our business, we are, from time to time, involved in routine litigation or subject to disputes or claims related to our business activities, including workers' compensation claims and employment related disputes. In the opinion of our management, none of the pending litigation, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

ITEM 1A. RISK FACTORS

See risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2014.

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

(a) None.

(b) Not Applicable.

(c) We do not have a share repurchase program, and during the three months ended June 30, 2015, 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

None.

ITEM 6. EXHIBITS

Exhibit Number	Description
2.1	Contribution Agreement, dated May 7, 2012, by and between the Company and Diamondback Energy, Inc. (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on May 8, 2012).
2.2	Purchase and Sale Agreement, dated December 17, 2012, 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 December 18, 2012).
2.3	Amendment, dated December 19, 2012, to the Purchase and Sale Agreement, dated December 17, 2012, 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 December 20, 2012).
2.4	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	Certificate of Amendment No. 2 to 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 July 23, 2013).
3.4	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).
3.5	First Amendment to the 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 23, 2013).
3.6	Second Amendment to the Amended and Restated Bylaws (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company on May 2, 2014).
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	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).
4.3	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).
4.4	Second Supplemental Indenture, dated as of August 18, 2014, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on August 19, 2014).
4.5	Indenture, dated as of April 21, 2015, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (including the form of the Company’s 6.625% Senior Notes due 2023) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 21, 2015).

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4.6	Registration Rights Agreement, dated as of April 21, 2015, among the Company, the subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC and Scotia Capital (USA) Inc., as representatives 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 April 21, 2015).
10.1	Third Amendment to Amended and Restated Credit Agreement, dated as of April 10, 2015, among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 15, 2015).
10.2*	Fourth Amendment to Amended and Restated Credit Agreement, dated as of May 29, 2015, among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, and the lenders party thereto.
10.3+	Amended and Restated Employment Agreement, dated as of April 29, 2015, by and between the Company and Michael G. Moore (incorporated by reference to Exhibit 10.3 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on May 7, 2015.
10.4	Investor Rights Agreement, dated as of October 11, 2012, between Gulfport Energy Corporation and Diamondback Energy, Inc. (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 17, 2012).
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.

* Filed herewith.

\+ Management contract, compensatory plan or arrangement.

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SIGNATURES

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

Date: August 7, 2015

GULFPORT ENERGY CORPORATION

By:	/s/ Aaron Gaydosik
	Aaron Gaydosik
	Chief Financial Officer