PFIZER INC
Form 4
April 17, 2007

FORM 4

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

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

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

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

OMB APPROVAL

OMB Number:	3235-0287
Expires:	January 31, 2005
Estimated average burden hours per response...	0.5

(Print or Type Responses)

1. Name and Address of Reporting Person *
KINDLER JEFFREY B

(Last) (First) (Middle)

PFIZER INC. ATT: CORPORATE SECRETARY, 235 EAST 42ND STREET

(Street)

NEW YORK, NY 10017

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
PFIZER INC [PFE]

3. Date of Earliest Transaction (Month/Day/Year)
04/13/2007

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

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

__X__ Director _____ 10% Owner
__X__ Officer (give title below) _____ Other (specify below)
Chairman & CEO

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

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

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			

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

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SEC 1474 (9-02)

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

1. Title of Derivative	2. Conversion	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if	4. Transaction	5. Number of	6. Date Exercisable and Expiration Date	7. Title and Amount of Underlying Securities	8. Price of Derivativ

Security (Instr. 3)	or Exercise Price of Derivative Security		any (Month/Day/Year)	Code (Instr. 8)		Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		(Month/Day/Year)		(Instr. 3 and 4)		Security (Instr. 5)
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares	
Phantom Stock Units SSP	(1)	04/13/2007		A		103		(2)	(2)	Common Stock	103	$ 26.6

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
KINDLER JEFFREY B PFIZER INC. ATT: CORPORATE SECRETARY 235 EAST 42ND STREET NEW YORK, NY 10017	X		Chairman & CEO	

Signatures

By: Lawrence A. Fox, by power of atty.	04/17/2007
**Signature of Reporting Person	Date

Explanation of Responses:

- * If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).
- ** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).
- **(1)** Each unit represents one phantom share of common stock.
- **(2)** These units, which were acquired pursuant to the Pfizer Inc. Nonfunded Deferred Compensation and Supplemental Savings Plan, are settled in cash following the reporting person's separation from service and, subject to certain conditions, may be transferred by the reporting person into an alternative investment account at any time.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
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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.
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 three months ended March 31, 2016 were approximately $1.9 million.

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Due to the unobservable nature of the inputs, the fair value of the Company's investment in Grizzly was estimated using assumptions that represent Level 3 inputs. The Company estimated the fair value of the investment as of March 31, 2016 to be approximately $39.1 million. See Note 3 for further discussion of the Company's investment in Grizzly.

Due to the unobservable nature of the inputs, the fair value of the Company's initial investment in Strike Force was estimated using assumptions that represent Level 3 inputs. The Company's estimated fair value of the investment as of the February 1, 2016 contribution date was $22.5 million. See Note 3 for further discussion of the Company's contribution to Strike Force.

13. 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 Construction 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 March 31, 2016, the carrying value of the outstanding debt represented by the Notes was approximately $944.7 million, including the remaining unamortized discount of approximately $2.4 million related to the October Notes, the remaining unamortized premium of approximately $0.3 million related to the December Notes and $14.0 million related to the August Notes. Also, included in the carrying value of the Notes is unamortized debt issuance cost of approximately $4.8 million related to the October Notes, approximately $1.1 million related to the December Notes, approximately $4.7 million related to the August Notes and approximately $6.6 million related to the 2023 Notes. Based on the quoted market price, the fair value of the Notes was determined to be approximately $924.3 million at March 31, 2016.

14. 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, December Notes, and the August Notes are collectively referred to as the "2020 Notes". The 2020 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 2020 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 2020 Notes, the Company and the subsidiary guarantors entered into registration rights agreements with the initial purchasers, pursuant to which the Company and the subsidiary guarantors agreed to file a registration statement with respect to an offer to exchange the 2020 Notes for a new issue of substantially identical debt securities registered under the Securities Act. The exchange offer for the October Notes and December Notes was completed in October 2013 and 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 2023 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 2023 Notes for a new issue of substantially identical debt securities registered under the Securities Act. The exchange offer for the 2023 Notes was completed on October 13, 2015.

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

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CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	March 31, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$453,743	$634	$ —	$—	$454,377
Accounts receivable - oil and gas	78,419	2,324	—	(2,242)	78,501
Accounts receivable - related parties	17	—	—	—	17
Accounts receivable - intercompany	341,062	661	—	(341,723)	—
Prepaid expenses and other current assets	2,755	—	—	—	2,755
Short-term derivative instruments	152,211	—	—	—	152,211
Total current assets	1,028,207	3,619	—	(343,965)	687,861
Property and equipment:					
Oil and natural gas properties, full-cost accounting	5,174,684	332,615	—	(729)	5,506,570
Other property and equipment	40,533	43	—	—	40,576
Accumulated depletion, depreciation, amortization and impairment	(3,112,737)	(30)	—	—	(3,112,767)
Property and equipment, net	2,102,480	332,628	—	(729)	2,434,379
Other assets:					
Equity investments	234,063	22,500	39,054	(51,016)	244,601
Long-term derivative instruments	42,455	—	—	—	42,455
Deferred tax asset	76,327	—	—	—	76,327
Other assets	17,038	(2)	—	—	17,036
Total other assets	369,883	22,498	39,054	(51,016)	380,419
Total assets	$3,500,570	$358,745	$ 39,054	$(395,710)	$3,502,659
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	$233,745	$4,801	$ —	$(2,712)	$235,834
Accounts payable - intercompany	—	341,128	125	(341,253)	—
Asset retirement obligation - current	75	—	—	—	75
Short-term derivative instruments	5,715	—	—	—	5,715
Deferred tax liability	51,908	—	—	—	51,908
Total current liabilities	291,443	345,929	125	(343,965)	293,532
Long-term derivative instrument	10,127	—	—	—	10,127
Asset retirement obligation - long-term	28,471	—	—	—	28,471
Long-term debt	949,740	—	—	—	949,740
Total liabilities	1,279,781	345,929	125	(343,965)	1,281,870
Stockholders' equity:					
Common stock	1,252	—	—	—	1,252
Paid-in capital	3,239,294	22,822	243,374	(266,196)	3,239,294
Accumulated other comprehensive (loss) income	(46,119)	—	(44,903)	44,903	(46,119)
Retained (deficit) earnings	(973,638)	(10,006)	(159,542)	169,548	(973,638)
Total stockholders' equity	2,220,789	12,816	38,929	(51,745)	2,220,789
Total liabilities and stockholders' equity	$3,500,570	$358,745	$ 39,054	$(395,710)	$3,502,659

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CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	December 31, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$112,494	$479	$ 1	$—	$112,974
Accounts receivable - oil and gas	72,241	54	—	(423)	71,872
Accounts receivable - related parties	16	—	—	—	16
Accounts receivable - intercompany	326,475	60	—	(326,535)	—
Prepaid expenses and other current assets	3,905	—	—	—	3,905
Short-term derivative instruments	142,794	—	—	—	142,794
Total current assets	657,925	593	1	(326,958)	331,561
Property and equipment:					
Oil and natural gas properties, full-cost accounting,	5,108,258	316,813	—	(729)	5,424,342
Other property and equipment	33,128	43	—	—	33,171
Accumulated depletion, depreciation, amortization and impairment	(2,829,081)	(29)	—	—	(2,829,110)
Property and equipment, net	2,312,305	316,827	—	(729)	2,628,403
Other assets:					
Equity investments	231,892	—	50,644	(40,143)	242,393
Long-term derivative instruments	51,088	—	—	—	51,088
Deferred tax assets	74,925	—	—	—	74,925
Other assets	6,364	—	—	—	6,364
Total other assets	364,269	—	50,644	(40,143)	374,770
Total assets	$3,334,499	$317,420	$ 50,645	$(367,830)	$3,334,734
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	$264,893	$527	$ —	$(292)	$265,128
Accounts payable - intercompany	—	326,541	124	(326,665)	—
Asset retirement obligation - current	75	—	—	—	75
Short-term derivative instruments	437	—	—	—	437
Deferred tax liability	50,697	—	—	—	50,697
Current maturities of long-term debt	179	—	—	—	179
Total current liabilities	316,281	327,068	124	(326,957)	316,516
Long-term derivative instrument	6,935	—	—	—	6,935
Asset retirement obligation - long-term	26,362	—	—	—	26,362
Long-term debt, net of current maturities	946,084	—	—	—	946,084
Total liabilities	1,295,662	327,068	124	(326,957)	1,295,897
Stockholders' equity:					
Common stock	1,082	—	—	—	1,082
Paid-in capital	2,824,303	322	241,553	(241,875)	2,824,303
Accumulated other comprehensive (loss) income	(55,177)	—	(55,177)	55,177	(55,177)

Retained (deficit) earnings	(731,371)	(9,970)	(135,855)	145,825	(731,371)
Total stockholders' equity	2,038,837	(9,648)	50,521	(40,873)	2,038,837
Total liabilities and stockholders' equity	$3,334,499	$317,420	$ 50,645	$(367,830)	$3,334,734

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CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Three months ended March 31, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$156,751	$ 212	$ —	$ —	$ 156,963
Costs and expenses:					
Lease operating expenses	16,472	185	—	—	16,657
Production taxes	3,087	24	—	—	3,111
Midstream gathering and processing	37,623	29	—	—	37,652
Depreciation, depletion, and amortization	65,476	1	—	—	65,477
Impairment of oil and gas properties	218,991	—	—	—	218,991
General and administrative	10,612	6	2	—	10,620
Accretion expense	247	—	—	—	247
	352,508	245	2	—	352,755
LOSS FROM OPERATIONS	(195,757)	(33)	(2)	—	(195,792)
OTHER (INCOME) EXPENSE:					
Interest expense	16,022	1	—	—	16,023
Interest income	(94)	—	—	—	(94)
Loss (income) from equity method investments and investments in subsidiaries	30,773	—	23,685	(23,721)	30,737
	46,701	1	23,685	(23,721)	46,666
(LOSS) INCOME BEFORE INCOME TAXES	(242,458)	(34)	(23,687)	23,721	(242,458)
INCOME TAX BENEFIT	(191)				(191)
NET (LOSS) INCOME	$(242,267)	$ (34)	$ (23,687)	$ 23,721	$ (242,267)

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CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Three months ended March 31, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ 175,832	$ 485	$ —	$ —	$ 176,317
Costs and expenses:					
Lease operating expenses	16,787	193	—	—	16,980
Production taxes	4,253	32	—	—	4,285
Midstream gathering and processing	25,374	7	—	—	25,381
Depreciation, depletion, and amortization	89,908	1	—	—	89,909
General and administrative	10,761	36	2	—	10,799
Accretion expense	190	—	—	—	190
	147,273	269	2	—	147,544
INCOME (LOSS) FROM OPERATIONS	28,559	216	(2)	—	28,773
OTHER (INCOME) EXPENSE:					
Interest expense	8,759	—	—	—	8,759
Interest income	(9)	—	—	—	(9)
(Income) loss from equity method investments and investments in subsidiaries	(20,189)	—	4,142	(3,928)	(19,975)
	(11,439)	—	4,142	(3,928)	(11,225)
INCOME (LOSS) BEFORE INCOME TAXES	39,998	216	(4,144)	3,928	39,998
INCOME TAX EXPENSE	14,479	—	—	—	14,479
NET INCOME (LOSS)	$ 25,519	$ 216	$ (4,144)	$ 3,928	$ 25,519

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	Three months ended March 31, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net (loss) income	$ (242,267)	$ (34)	$ (23,687)	$ 23,721	$ (242,267)
Foreign currency translation adjustment	9,058	—	10,273	(10,273)	9,058
Other comprehensive income (loss)	9,058	—	10,273	(10,273)	9,058
Comprehensive (loss) income	$ (233,209)	$ (34)	$ (13,414)	$ 13,448	$ (233,209)

	Three months ended March 31, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$ 25,519	$ 216	$ (4,144)	$ 3,928	$ 25,519
Foreign currency translation adjustment	(14,984)	—	(14,984)	14,984	(14,984)
Other comprehensive (loss) income	(14,984)	—	(14,984)	14,984	(14,984)
Comprehensive income (loss)	$ 10,535	$ 216	$ (19,128)	$ 18,912	$ 10,535

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Amounts in thousands)

	Three months ended March 31, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ 83,620	$ 155	$ (1)	$ —	$ 83,774
Net cash (used in) provided by investing activities	(157,529)	(22,500)	(1,821)	24,321	(157,529)
Net cash provided by (used in) financing activities	415,158	22,500	1,821	(24,321)	415,158
Net increase (decrease) in cash and cash equivalents	341,249	155	(1)	—	341,403
Cash and cash equivalents at beginning of period	112,494	479	1	—	112,974
Cash and cash equivalents at end of period	$ 453,743	$ 634	$ —	$ —	$ 454,377

	Three months ended March 31, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by operating activities	$ 95,879	$ 3,158	$ —	$ —	$ 99,037
Net cash (used in) provided by investing activities	(228,601)	(2,890)	(6,093)	6,093	(231,491)
Net cash provided by (used in) financing activities	64,854	—	6,093	(6,093)	64,854
Net (decrease) increase in cash and cash equivalents	(67,868)	268	—	—	(67,600)

Cash and cash equivalents at beginning of period	141,535	804	1			—		142,340
Cash and cash equivalents at end of period	$73,667	$ 1,072	$	1	$	—		$ 74,740

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15. RECENT ACCOUNTING PRONOUNCEMENTS

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("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 of this ASU 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 periods after December 15, 2016, with early adoption 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. 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis. This ASU provides additional guidance to reporting entities in evaluating whether certain legal entities, such as limited partnerships, limited liability corporation and securitization structure, should be consolidated. The ASU is considered to be an improvement on current accounting requirements as it reduces the number of existing consolidation models. The ASU is effective for annual and interim periods beginning in 2016 and is required to be adopted using a retrospective or modified retrospective approach, with early adoption permitted. The Company adopted this ASU on January 1, 2016. As a result, certain of the Company's equity investments were determined to be variable interest entites; however, the Company was not required to consolidate these investments.

In April 2015, the FASB issued ASU No. 2015-03, Simplifying the Presentation of Debt Issuance Costs. To simplify the 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. This guidance is effective for periods after December 15, 2015. The Company adopted this guidance effective December 31, 2015, and has reclassified $17.2 million and $17.9 million of debt issuance costs to offset long-term debt at March 31, 2016 and December 31, 2015, respectively, as shown in Note 6.

In September 2015, the FASB issued ASU No. 2015-16, Simplifying the Accounting for Measurement-Period Adjustments. The guidance eliminates the requirement to retrospectively adjust the financial statements for measurement-period adjustments that occur in periods after a business combination is consummated. Measurement period adjustments are calculated as if they were known at the acquisition date, but are recognized in the reporting period in which they are determined. Additional disclosures are required about the impact on current-period income statement line items of adjustments that would have been recognized in prior periods if the prior-period information had been revised. The guidance is effective for periods after December 15, 2015. The Company adopted this guidance in the first quarter of 2016 and there was no impact to its consolidated financial statements.

In November 2015, the FASB issued ASU No. 2015-17, Balance Sheet Classification of Deferred Taxes (Topic 705). Current guidance requires an entity to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified statement of financial position. Deferred tax liabilities and assets are classified as current or noncurrent based on the classification of the related asset or liability for financial reporting. Deferred tax liabilities and assets that are not related to an asset or liability for financial reporting are classified according to the expected reversal date of the temporary difference. To simplify the presentation of deferred income taxes, the amendments in this update require that deferred income tax liabilities and assets be classified as noncurrent in a classified statement of financial position. This guidance is effective for periods after December 15, 2016, with early adoption permitted. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, Leases. The guidance requires the lessee to recognize most leases on the balance sheet thereby resulting in the recognition of lease assets and liability for those leases currently classified as operating leases. The accounting for lessors is largely unchanged. The guidance is effective for periods after December 15,

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2018, with early adoption permitted. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements.

In March 2016, the FASB issued ASU No. 2016-05, Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships. The guidance was issued to clarify that change in the counterparty to a derivative instrument that had been designated as the hedging instrument under Topic 815, does not require dedesignation of that hedging relationship provided that all other hedge accounting criteria continue to be met. This guidance is effective for periods after December 15, 2017, with early adoption permitted. The Company is in the process of evaluating the impact on its consolidated financial statements. The Company does not believe that the adoption of this guidance will have a material impact on its consolidated financial statements because all current derivative instruments are not designated for hedge accounting.

In March 2016, the FASB issued ASU No. 2016-07, Equity Method and Joint Ventures. This guidance simplified current requirements by eliminating the need to retrospectively apply the equity method of accounting upon obtaining significant influence over an investment that it previously accounted for under the cost basis or at fair value. This guidance is effective for periods after December 15, 2016, with early adoption permitted. The Company is in the process of evaluating the impact on its consolidated financial statements. The Company does not believe that the adoption of this guidance will have a material impact on its consolidated financial statements because all current investments are accounted under the equity method investment.

In March 2016, the FSB issued ASU No. 2016-09, Improvements to Employee Share-Based Payment Accounting. This guidance was intended to simplify the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. This guidance is effective for periods after December 15, 2016, with early adoption permitted. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements.

16. SUBSEQUENT EVENTS

Derivatives

In April 2016, the Company entered into fixed price swaps for the period November 2017 through March 2018, for 50,000 MMBtu of natural gas per day at a weighted average price of $3.17 per MMBtu. The Company's fixed price swap contracts are tied to the commodity prices on NYMEX. The Company will receive the fixed price amount stated in the contract and pay to its counterparty the current market price as listed on NYMEX for natural gas.

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

The following discussion and analysis should be read in conjunction with the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section and audited consolidated financial statements and related notes 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 an interest in an entity that operates in Southeast Asia, including the Phu Horm gas field in Thailand. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

2016 Operational Highlights

- Production increased 65% to 62,993 net million cubic feet of natural gas equivalent, or MMcfe, for the three months ended March 31, 2016 from 38,198 MMcfe for the three months ended March 31, 2015. Our net daily production mix was comprised of approximately 85% of natural gas, 9% of natural gas liquids, or NGLs, and 6% of oil.
- During the three months ended March 31, 2016, we spud ten gross (7.1 net) wells, participated in an additional eight gross (0.49 net) wells that were drilled by other operators on our Utica Shale acreage and recompleted 17 gross and net wells. Of our ten new wells spud at March 31, 2016, seven were in various stages of completion and three were

being drilled. In addition, we turned-to-sales 15 gross (8.0 net) wells during the three months ended March 31, 2016.

- During the three months ended March 31, 2016, we reduced our unit midstream gathering and processing expense by 10% to $0.60 per Mcfe from $0.66 per Mcfe during the three months ended March 31, 2015.

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- In February 2016, we, through our wholly owned subsidiary Gulfport Midstream Holdings, LLC, or Midstream Holdings, entered into an agreement with Rice Midstream Holdings LLC, or Rice, a subsidiary of Rice Energy Inc., to develop natural gas gathering assets in eastern Belmont County and Monroe County, Ohio. We contributed certain gathering assets for a 25% interest in the newly formed entity called Strike Force Midstream LLC, or Strike Force. Rice acts as operator and owns the remaining 75% interest in Strike Force. See "— 2016 Updates Regarding Our Equity Investments - Other Investments" below for additional information regarding this investment.
- On March 9, 2016, we issued 16,905,000 shares of our common stock in an underwritten public offering (which included 2,205,000 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 this equity offering were approximately $411.9 million, after deducting underwriting discounts and commissions and estimated offering expenses. We intend to use the net proceeds from this offering primarily to fund a portion of our 2017 capital development plan and for general corporate purposes.

2016 Production and Drilling Activity

During the three months ended March 31, 2016, our total net production was 53,306,532 thousand cubic feet, or Mcf, of natural gas, 601,844 barrels of oil and 42,527,287 gallons of NGLs for a total of 62,993 MMcfe, as compared to 25,965,064 Mcf of natural gas, 765,575 barrels of oil and 53,478,118 gallons of NGLs, or 38,198 MMcfe, for the three months ended March 31, 2015. Our total net production averaged approximately 692.2 MMcfe per day during the three months ended March 31, 2016 as compared to 424.4 MMcfe per day during the same period in 2015. The 65% increase in production is largely the result of the continuing development of our Utica Shale acreage.

Utica Shale. As of April 29, 2016, we had acquired leasehold interests in approximately 239,000 gross (231,000 net) acres in the Utica Shale. From January 1, 2016 through April 29, 2016, we spud 15 gross (12 net) wells, of which 12 were in various stages of completion and three were still being drilled at April 29, 2016. In addition, eight gross (0.49 net) wells were drilled by other operators on our Utica Shale acreage during the three months ended March 31, 2016. As of April 29, 2016, we had three rigs under contract on our Utica Shale acreage. We currently intend to spud 29 to 32 gross (19 to 21 net) wells on our Utica Shale acreage in 2016.

Aggregate net production from our Utica Shale acreage during the three months ended March 31, 2016 was approximately 61,038 MMcfe, or 670.7 MMcfe per day, 87% of which was from natural gas and 13% of which was from oil and NGLs. During April 2016, our average daily net production from the Utica Shale was approximately 665.8 MMcfe, 89% of which was from natural gas and 11% of which was from oil and NGLs. The slight decrease in April 2016 production was a result of natural production declines and the timing of our wells turned-to-sales in 2016.

WCBB. From January 1, 2016 through April 29, 2016, we recompleted ten wells and spud no new wells.

Aggregate net production from the WCBB field during the three months ended March 31, 2016 was approximately 1,323 MMcfe, or an average of 14.5 MMcfe per day, 99% of which was from oil and 1% of which was from natural gas. During April 2016, our average net daily production at WCBB was approximately 15.2 MMcfe, 100% of which was from oil. The slight increase in April 2016 production was primarily a result of our 2016 recompletion activities.

East Hackberry Field. From January 1, 2016 through April 29, 2016, we recompleted ten wells and spud no new wells.

Aggregate net production from the East Hackberry field during the three months ended March 31, 2016 was approximately 498 MMcfe, or an average of 5.5 MMcfe per day, 96% of which was from oil and 4% of which was from natural gas. During April 2016, our average net daily production at East Hackberry was approximately 6.3 MMcfe, 95% of which was from oil and 5% of which was from natural gas. The increase in April 2016 production is primarily the result of our 2016 recompletion activities.

West Hackberry Field. From January 1, 2016 through April 29, 2016, we did not spud any wells in our West Hackberry field.

Explanation of Responses:

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Aggregate net production from the West Hackberry field was approximately 51 MMcfe, or an average of 555.4 Mcfe per day, 96% of which was from oil and 4% of which was from natural gas. During April 2016, our average net daily production at West Hackberry was approximately 464.4 Mcfe, 81% of which was from oil and 19% of which was from natural gas.

Niobrara Formation. As of March 31, 2016, we held leases for approximately 5,300 net acres in the Niobrara Formation in Northwestern Colorado. From January 1, 2016 through April 29, 2016, there were no wells spud on our Niobrara Formation acreage and aggregate net production was approximately 25 MMcfe, or an average of 269.8 Mcfe per day during the three months ended March 31, 2016, 100% of which was from oil. During April 2016, our average net daily production from our Niobrara Formation acreage was approximately 258.0 Mcfe, 100% of which was from oil. During 2016, we currently do not anticipate drilling any wells in the Niobrara Formation.

Bakken. As of March 31, 2016, we held approximately 778 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 March 31, 2016 was approximately 58 MMcfe, or an average of 639.1 Mcfe per day, of which 87% was from oil, 10% was from natural gas and 3% was from NGLs. During April 2016, our average daily net production from our Bakken Formation acreage was approximately 544.0 Mcfe, of which 81% was from oil and NGLs and 19% was from natural gas.

2016 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, 2016, 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. We reviewed our investment in Grizzly at March 31, 2016 for impairment, resulting in an aggregate other than temporary impairment write down of $23.1 million for the quarter ended March 31, 2016. If commodity prices continue to decline, further impairment of our investment in Grizzly may result in the future.

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.

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. 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, including drilling, completion and workover activities, rental tools, cementing, pressure pumping, gathering, compression, processing and marketing activities and mining, processing and sale of hydraulic fracturing grade sand. See Note 3 to our consolidated financial statements included elsewhere in this report for additional information regarding these other investments.

In February 2016, we, through our wholly owned subsidiary Midstream Holdings, entered into an agreement with Rice, a subsidiary of Rice Energy Inc., to develop natural gas gathering assets in eastern Belmont County and Monroe County, Ohio, which we refer to as the dedicated areas. We contributed certain gathering assets for a 25% interest in the newly formed entity called Strike Force. Rice will act as operator and owns the remaining 75% interest in Strike Force. Construction of the gathering assets, which is underway, is expected to provide gathering services for our operated wells and connectivity of existing dry gas gathering systems. Strike Force has completed the first phase of the projects: a lateral that connects two existing dry gas gathering systems on which we currently flow the majority of our dry gas volumes. The lateral has been commissioned and first flow commenced on February 1, 2016. In connection with the formation of Strike Force, we contributed certain assets, including an approximately 11 mile-long, 12-inch diameter gathering line.

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

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application of significant judgment by our management. We analyze our estimates including those related to oil and natural gas properties, revenue recognition, income taxes and commitments and contingencies, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our consolidated financial statements:

Oil and Natural Gas Properties. We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including non-productive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price for the prior twelve months, adjusted for any contract provisions or financial derivatives, if any, that hedge our oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required. Such capitalized costs, including the estimated future development costs and site remediation costs of proved undeveloped properties are depleted by an equivalent units-of-production method, converting gas to barrels at the ratio of six Mcf of gas to one barrel of oil. No gain or loss is recognized upon the disposal of oil and natural gas properties, unless such dispositions significantly alter the relationship between capitalized costs and proven oil and natural gas reserves. Oil and natural gas properties not subject to amortization consist of the cost of undeveloped leaseholds and totaled approximately $1.8 billion at both March 31, 2016 and December 31, 2015. 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 (as defined in the preceding paragraph). 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. As a result of the decline in commodity prices, we recognized a ceiling test impairment of $219.0 million for the three months ended March 31, 2016. If prices of oil, natural gas and natural gas liquids continue to decline, we may be required to further write down the value of our oil and natural gas properties, which could negatively affect our results of operations.

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

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

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

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Oil and Gas Reserve Quantities. Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Netherland, Sewell & Associates, Inc. and to a lesser extent our personnel have prepared reserve reports of our reserve estimates at December 31, 2015 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 basis 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 March 31, 2016, a valuation allowance of $365.4 million had been established for the net deferred tax asset, with the exception of certain state NOL's and alternative minimum tax, or AMT, credits that we expect to utilize 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.

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. For the period ended March 31, 2016, we recognized an impairment loss related to our investment in Grizzly of approximately $23.1 million.

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

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Derivative Instruments and Hedging Activities. We seek to reduce our exposure to unfavorable changes in oil, natural gas and natural gas liquids prices, which are subject to significant and often volatile fluctuation, by entering into over-the-counter fixed price swaps, basis swaps and various types of option 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 industry-standard models that considered various assumptions including current market and contractual prices for the underlying instruments, implied volatility, time value and nonperformance risk, as well as other relevant economic measures.

The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. While we have historically designated derivative instruments as accounting hedges, effective January 1, 2015, we discontinued hedge accounting prospectively. Our current commodity derivative instruments are not designated as hedges for accounting purposes. Accordingly, the changes in fair value are recognized in the consolidated statements of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities.

See Item 3. "Quantitative and Qualitative Disclosures About Market Risk" for a summary of our derivative instruments in place as of March 31, 2016.

RESULTS OF OPERATIONS

Comparison of the Three Months Ended March 31, 2016 and 2015

We reported a net loss of $242.3 million for the three months ended March 31, 2016 as compared to net income of $25.5 million for the three months ended March 31, 2015. This $267.8 million decrease in period-to-period net income was due primarily to an impairment charge of $219.0 million, a 46% decrease in realized Mcfe prices to $2.49 from $4.61, a $7.3 million increase in interest expense and a $12.3 million increase in midstream gathering and processing expenses, partially offset by a 65% increase in net production to 62,993 MMcfe from 38,198 MMcfe, a $24.4 million decrease in depreciation, depletion and amortization expense and a $14.7 million decrease in income tax expense for the three months ended March 31, 2016 as compared to the three months ended March 31, 2015.

Oil and Gas Revenues. For the three months ended March 31, 2016, we reported oil and natural gas revenues of $157.0 million as compared to oil and natural gas revenues of $176.1 million during the same period in 2015. This $19.1 million, or 11%, decrease in revenues was primarily attributable to a 46% decrease in realized Mcfe prices to $2.49 from $4.61 due to the continued decline in commodity prices and a shift in our production mix toward natural gas, partially offset by a 65% increase in net production to 62,993 MMcfe from 38,198 MMcfe for the three months ended March 31, 2016 as compared to the three months ended March 31, 2015.

The following table summarizes our oil and natural gas production and related pricing for the three months ended March 31, 2016, as compared to such data for the three months ended March 31, 2015:

	Three months ended March 31,	
	2016	2015
Oil production volumes (MBbls)	602	766
Gas production volumes (MMcf)	53,307	25,965
Natural gas liquids production volumes (MGal)	42,527	53,478
Gas equivalents (MMcfe)	62,993	38,198
Average oil price (per Bbl)	$28.45	$46.37
Average gas price (per Mcf)	$2.46	$4.57
Average natural gas liquids (per Gal)	$0.21	$0.41
Gas equivalents (per Mcfe)	$2.49	$4.61

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes decreased to $16.7 million for the three months ended March 31, 2016 from $17.0 million for the three months ended March 31, 2015.

This decrease was

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mainly the result of a decrease in expenses related to contract labor and location, road and equipment repairs, partially offset by increases in ad valorem taxes and water hauling.

Production Taxes. Production taxes decreased $1.2 million to $3.1 million for the three months ended March 31, 2016 from $4.3 million for the three months ended March 31, 2015. 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 $12.3 million to $37.7 million for the three months ended March 31, 2016 from $25.4 million for the same period in 2015. This increase was primarily attributable to midstream expenses related to our increased production volumes in the Utica Shale resulting from our 2015 drilling activities.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense decreased to $65.5 million for the three months ended March 31, 2016, and consisted of $64.8 million in depletion of oil and natural gas properties and $0.7 million in depreciation of other property and equipment, as compared to total DD&A expense of $89.9 million for the three months ended March 31, 2015. This decrease was due to a decrease in our full cost pool as a result of our 2015 and 2016 ceiling test impairments and an increase in our total proved reserves volume used to calculate our total DD&A expense, partially offset by an increase in our production.

General and Administrative Expenses. Net general and administrative expenses decreased to $10.6 million for the three months ended March 31, 2016 from $10.8 million for the three months ended March 31, 2015. This $0.2 million decrease was due to a decrease in franchise taxes, travel expense, corporate fees, and stock compensation expense, partially offset by increases in legal fees, accounting fees, computer expenses and bank fees.

Accretion Expense. Accretion expense remained relatively flat at $0.2 million for the three months ended March 31, 2016 and 2015.

Interest Expense. Interest expense increased to $16.0 million for the three months ended March 31, 2016 from $8.8 million for the three months ended March 31, 2015 due primarily to the issuance of $350.0 million of 6.625% Senior Notes due 2023 on April 21, 2015. This increase is partially offset by total weighted average debt outstanding under our revolving credit facility of $136.5 million for the three months ended March 31, 2015 as compared to no debt outstanding under such facility for the three months ended March 31, 2016. As of March 31, 2016, no borrowings were outstanding under this credit facility as compared to $165.0 million outstanding under such facility at March 31, 2015. Additionally, we capitalized approximately $1.6 million and $3.7 million in interest expense to undeveloped oil and natural gas properties during the three months ended March 31, 2016 and 2015, respectively. This decrease in capitalized interest in the 2016 period was the result of changes to our development plan for our oil and natural gas properties.

Income Taxes. As of March 31, 2016, we had a net operating loss carryforward of approximately $132.0 million, in addition to numerous temporary differences, which gave rise to a net deferred tax asset. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management's opinion, it is more likely than not that some portion will not be realized. At March 31, 2016, a valuation allowance of $365.4 million had been provided against the net deferred tax asset, with the exception of certain state net operating losses and AMT credits that we expect to be able to utilize with net operating loss carrybacks and tax planning in the amount of $24.4 million. We recognized an income tax benefit of $0.2 million for the three months ended March 31, 2016.

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 2015, we received net proceeds of approximately $343.6 million from the sale of our 6.625% Senior Notes due 2023 issued in April 2015. In addition, we received an aggregate of $981.5 million in net proceeds from the sale of shares of our common stock in underwritten public offerings completed in April and June 2015.

On March 9, 2016, we issued 16,905,000 shares of our common stock in an underwritten public offering (which included 2,205,000 shares sold pursuant to an option to purchase additional shares of our common stock granted by the us to, and exercised in full by, the underwriters). The net proceeds from this equity offering were approximately $411.9 million, after

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deducting underwriting discounts and commissions and estimated offering expenses. We intend to use the net proceeds from the offering primarily to fund a portion of our 2017 capital development plan and for general corporate purposes.

Net cash flow provided by operating activities was $83.8 million for the three months ended March 31, 2016 as compared to net cash flow provided by operating activities of $99.0 million for the same period in 2015. This decrease was primarily the result of a decrease in cash receipts from our oil and natural gas purchasers due to a 46% decrease in net realized Mcfe prices, partially offset by a 65% increase in our net Mcfe production. In addition, 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 three months ended March 31, 2016 was $157.5 million as compared to $231.5 million for the same period in 2015. During the three months ended March 31, 2016, we spent $151.3 million in additions to oil and natural gas properties, of which $47.1 million was spent on our 2016 drilling and completion programs, $67.3 million was spent on expenses attributable to the wells spud and completed during 2015, $2.8 million was spent on facility enhancements, $24.7 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, $1.8 million was invested in Grizzly during the three months ended March 31, 2016. We did not make any investments in our other equity investments during the three months ended March 31, 2016.

Net cash provided by financing activities for the three months ended March 31, 2016 was $415.2 million as compared to net cash provided by financing activities of $64.9 million for the same period in 2015. The 2016 amount provided by financing activities is primarily attributable to the net proceeds of approximately $411.9 million from our 2016 equity offering.

Credit Facility. We have entered into a senior secured revolving credit facility, as amended, with The Bank of Nova Scotia, as the lead arranger and administrative agent and certain lenders from time to time party thereto. The credit agreement provides for a maximum facility amount of $1.5 billion and matures on June 6, 2018. On February 19, 2016, we further amended our credit facility to, among other things, (a) increase the basket for unsecured debt issuances to $1.35 billion from $1.2 billion (of which $950 million was then outstanding), (b) reaffirm our borrowing base of $700.0 million, and (c) increase the percentage of projected oil and gas production that may be hedged by us during 2016. As of March 31, 2016, we had no balance outstanding under our revolving credit facility and total funds available for borrowing, after giving effect to an aggregate of $227.8 million of outstanding letters of credit, were $472.2 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 facility 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 4.00 to 1.00; and (2) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. We were in compliance with these financial covenants at March 31, 2016.
Senior Notes. In October 2012, December 2012 and August 2014, we issued an aggregate of $600.0 million in principal amount of our senior notes due 2020 which we refer to as the 2020 Notes. Interest on the 2020 Notes accrues at a rate of 7.75% per annum on the outstanding principal amount payable semi-annually on May 1 and November 1 of each year. The 2020 Notes mature on November 1, 2020.
In April 2015, we issued an aggregate of $350.0 million in principal amount of our senior notes due 2023. Interest on these senior notes, which we refer to as the 2023 Notes, accrues at a rate of 6.625% per annum on the outstanding principal amount thereof on May 1 and November 1 of each year. The 2023 Notes mature on May 1, 2023. The 2020 Notes and the 2023 Notes are our senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness, including the 2020 Notes, and senior in right of payment to any of our future subordinated indebtedness.
All of our existing restricted subsidiaries that guarantee our secured revolving credit facility or certain other debt (other than Grizzly Holdings, Inc.) guarantee the 2020 Notes and the 2023 Notes. 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 2020 Notes and the 2023 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 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 2020 Notes and the 2023 Notes.
The senior note indentures relating to the 2020 Notes and the 2023 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. For additional information regarding the 2020 Notes and the 2023 Notes, see Note 6 and Note 14 to our consolidated financial statements included elsewhere in this report.
Construction Loan. In June 2015, we entered into a construction loan agreement, or the construction loan, with InterBank for the construction of our new corporate headquarters in Oklahoma City. The construction loan allows for maximum principal borrowings of $24.5 million and requires us to fund 30% of the estimated cost of the construction before any funds can be drawn, which occurred in January 2016. Interest accrues daily on the outstanding principal balance at a fixed rate of 4.5% per annum and is payable on the last day of the month 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 March 31, 2016, $5.0 million of borrowings were outstanding under the construction loan.
Capital Expenditures. Our recent capital commitments have been primarily for the execution of our drilling programs, for acquisitions primarily in the Utica Shale, 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, 2015, 55.0% 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, 2016 through April 29, 2016, we spud 15 gross (12 net) wells in the Utica Shale. We currently expect our 2016 capital expenditures to be $219.0 million to $247.0 million to drill 29 to 32 gross (19 to 21 net) horizontal wells and commence sales from 44 to 48 gross (28 to 30 net) wells on our Utica Shale acreage. As of April 29, 2106, we had three operated horizontal rigs drilling in the play. We also anticipate an additional 17 to 19 gross (two to three net) horizontal wells will be drilled, and sales commenced from 30 to 34 gross (eight to nine net) horizontal wells, on our Utica Shale acreage by other operators for estimated 2016 expenditures to us of $90.0 million to $100.0 million. In addition, we currently expect to spend $60.0 million to $65.0 million in 2016 for acreage expenses, primarily lease extensions, in the Utica Shale.

From January 1, 2016 through April 29, 2016, we recompleted ten existing wells and spud no new wells at our WCBB field. In our Hackberry fields, from January 1, 2016 through April 29, 2016, we recompleted ten existing wells and spud no new wells. We currently expect our 2016 capital expenditures to be $26.0 million to $28.0 million for maintenance capital expenditures and recompletions in Southern Louisiana.

From January 1, 2016 through April 29, 2016, no new wells were spud on our Niobrara Formation acreage. We do not currently anticipate any capital expenditures in the Niobrara Formation in 2016.

As of March 31, 2016, our net investment in Grizzly was approximately $39.1 million. During the three months ended March 31, 2016, we paid cash calls of $1.8 million to Grizzly. Effective October 5, 2012, Grizzly entered into a $125.0 million revolving credit facility, under which $57.2 million was outstanding at March 31, 2016. Grizzly has agreed to pay the outstanding balance by the maturity date of June 2016, of which our proportionate share is approximately $14.3 million. We do not currently anticipate any additional material capital expenditures in 2016 related to Grizzly's activities.

In connection with the formation of Strike Force, we contributed certain assets valued at $22.5 million, including an approximately 11 mile-long, 12-inch diameter gathering line. We currently anticipate that we will also make $30.0 million to $35.0 million in cash contributions to our investment in Strike Force in 2016.

We had no capital expenditures during the three months ended March 31, 2016 related to our interests in Thailand. We do not currently anticipate any capital expenditures in Thailand in 2016.

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 "-2016 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 three months ended March 31, 2016, we did not make any investments in these entities, and we do not currently anticipate any capital expenditures related to these entities in 2016.

During 2015 and the first quarter of 2016, we continued to focus on operational efficiencies in an effort to reduce our overall well costs and deliver better results in a more economical manner, particularly in light of the continued downturn in commodity prices. To do so, we have leveraged the lower commodity price environment to gain access to higher-quality equipment and superior services for reduced costs, which has contributed to increased productivity. To further benefit from these efficiencies and cost savings, we elected to accelerate our completion activities in late 2015 in advance of the winter months when operations are less efficient and more costly due to the cold weather. Our total capital expenditures for 2016 are currently estimated to be in the range of $335.0 million to $375.0 million for drilling and completion expenditures, of which $74.5 million was spent during the first quarter of 2016. In addition, we currently expect to spend $60.0 million to $65.0 million in 2016 for acreage expenses, primarily lease extensions, in the Utica Shale, of which $19.7 million was spent during the first quarter of 2016, and $30.0 million to $35.0 million to fund our investment in Strike Force. Approximately 94% of our 2016 estimated capital expenditures are currently expected to be spent in the Utica Shale. The estimated 2016 range of capital expenditures for drilling and completion is down from the $851.8 million spent in 2015, primarily due to the low commodity price environment and a desire to maintain a favorable liquidity position. As a result of the decline in commodity prices, our 2016 development plan contemplates running an average of 2.5 rigs on our operated Utica Shale acreage, as compared to an average of 3.7 rigs in 2015. Strong results from our existing production base and efficiencies realized in our completion activities resulted in our achieving 2015 production above expectations. Taking into consideration our strong production results, realized efficiencies and the weakness in natural gas commodity pricing, we made the decision to idle completion crews and suspend our hydraulic fracturing activities during the first quarter of 2016 and entered into an agreement with one of our service providers that adjusted the amount of service fees that would otherwise be payable during this period. We resumed these activities on April 1, 2016. As a result of these suspended activities, we anticipate that our daily average production during the second quarter of 2016 will be flat or slightly below our production in the first quarter of 2016 due to normal production declines from existing wells and the timing of our wells turned-to-sales in 2016. We expect that the effects of our renewed completion activities will begin to be recognized at the end of the second quarter of 2016 and later in the year.

We continually monitor market conditions and are prepared to adjust our drilling program if commodity prices dictate. Currently, we believe that our cash flow from operations, cash on hand and borrowings under our loan agreements will be sufficient to meet our normal recurring operating needs and capital requirements for the next twelve months. In the event commodity prices decline further, our capital or other costs increase, our equity investments require additional contributions

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and/or we pursue additional equity method investments or acquisitions, 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. Further, 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. If the low commodity price environment continues or worsens, our revenues, cash flows, results of operations, liquidity and reserves may be materially and adversely affected.

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. During the past six years, the posted price for West Texas intermediate light sweet crude oil, which we refer to as West Texas Intermediate or WTI, has ranged from a low of $26.05 per barrel, or Bbl, in February 2016 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 $1.61 per MMBtu in March 2016 to a high of $7.51 per MMBtu in January 2010. On April 29, 2016, the WTI posted price for crude oil was $45.92 per Bbl and the Henry Hub spot market price of natural gas was $2.18 per MMBtu. If the prices of oil and natural gas continue at current levels or decline further, our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves may be materially and adversely affected. In addition, lower oil and natural gas prices may reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development activities are curtailed, full cost accounting rules may require us to further write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties. Reductions in our reserves could also negatively impact the borrowing base under our revolving credit facility, which could further limit our liquidity and ability to conduct additional exploration and development activities.

See Item 3. Quantitative and Qualitative Disclosures about Market Risk for information regarding our open fixed price swaps at March 31, 2016.

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. As of March 31, 2016, the plugging and abandonment trust totaled approximately $3.1 million. At March 31, 2016, 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, 2015.

Off-balance Sheet Arrangements

We had no off-balance sheet arrangements as of March 31, 2016.

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update, or 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

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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). 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 periods after December 15, 2016, with early adoption 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. 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis. This ASU provides additional guidance to reporting entities in evaluating whether certain legal entities, such as limited partnerships, limited liability corporation and securitization structure, should be consolidated. The ASU is considered to be an improvement on current accounting requirements as it reduces the number of existing consolidation models. The ASU is for periods after December 15, 2015 and is required to be adopted using a retrospective or modified retrospective approach, with early adoption permitted. We adopted this ASU on January 1, 2016. As a result, certain of our equity investments were determined to be variable interest entites; however, we were not required to consolidate these investments.

In April 2015, the FASB issued ASU No. 2015-03, Simplifying the Presentation of Debt Issuance Costs. To simplify the 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. This guidance is effective for periods after December 15, 2015. We adopted this guidance effective December 31, 2015, and have reclassified $17.2 million and $17.9 million of debt issuance costs to offset long-term debt at March 31, 2016 and December 31, 2015, respectively, as shown in Note 6 to our consolidated financial statements included elsewhere in this quarterly report.

In September 2015, the FASB issued ASU No. 2015-16, Simplifying the Accounting for Measurement-Period Adjustments. The guidance eliminates the requirement to retrospectively adjust the financial statements for measurement-period adjustments that occur in periods after a business combination is consummated. Measurement period adjustments are calculated as if they were known at the acquisition date, but are recognized in the reporting period in which they are determined. Additional disclosures are required about the impact on current-period income statement line items of adjustments that would have been recognized in prior periods if the prior-period information had been revised. The guidance is effective for periods after December 15, 2015. We adopted this guidance in the first quarter of 2016 and there was no material impact to our consolidated financial statements.
In November 2015, the FASB issued ASU No. 2015-17, Balance Sheet Classification of Deferred Taxes (Topic 705). Current guidance requires an entity to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified statement of financial position. Deferred tax liabilities and assets are classified as current or noncurrent based on the classification of the related asset or liability for financial reporting. Deferred tax liabilities and assets that are not related to an asset or liability for financial reporting are classified according to the expected reversal date of the temporary difference. To simplify the presentation of deferred income taxes, the amendments in this update require that deferred income tax liabilities and assets be classified as noncurrent in a classified statement of financial position. This guidance is effective for periods after December 15, 2016, with early adoption permitted. We are in the process of evaluating the impact of this guidance on our consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, Leases. The guidance requires the lessee to recognize most leases on the balance sheet thereby resulting in the recognition of lease assets and liability for those leases currently classified as operating leases. The accounting for lessors is largely unchanged. The guidance is effective for periods after December 15, 2018, with early adoption permitted. We are in the process of evaluating the impact of this guidance on our consolidated financial statements.

In March 2016, the FASB issued ASU No. 2016-05, Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships. The guidance was issued to clarify that change in the counterparty to a derivative instrument that had been designated as the hedging instrument under Topic 815, does not require dedesignation of that hedging relationship provided that all other hedge accounting criteria continue to be met. This guidance is effective for periods after December 15, 2017, with early adoption permitted. We are in the process of evaluating the impact on our consolidated financial statements. We do not believe that the adoption of this guidance will have a material impact on our consolidated financial statements because all current derivative instruments are not designated for hedge accounting.

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In March 2016, the FASB issued ASU No. 2016-07, Equity Method and Joint Ventures. This guidance simplified current requirements by eliminating the need to retrospectively apply the equity method of accounting upon obtaining significant influence over an investment that it previously accounted for under the cost basis or at fair value. This guidance is effective for periods after December 15, 2016, with early adoption permitted. We are in the process of evaluating the impact on our consolidated financial statements. We do not believe that the adoption of this guidance will have a material impact on our consolidated financial statements because all current investments are accounted under the equity method investment.

In March 2016, the FSB issued ASU No. 2016-09, Improvements to Employee Share-Based Payment Accounting. This guidance was intended to simplify the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. This guidance is effective for periods after December 15, 2016, with early adoption permitted. We are in the process of evaluating the impact of this guidance on our consolidated financial statements.

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. During the past six years, the posted price for WTI, has ranged from a low of $26.05 per barrel, or Bbl, in February 2016 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 $1.61 per MMBtu in March 2016 to a high of $7.51 per MMBtu in January 2010. On April 29, 2016, the WTI posted price for crude oil was $45.92 per Bbl and the Henry Hub spot market price of natural gas was $2.18 per MMBtu. If the prices of oil and natural gas continue at current levels or decline further, our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves may be materially and adversely affected. In addition, lower oil and natural gas prices may reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development activities are curtailed, full cost accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties. Reductions in our reserves could also negatively impact the borrowing base under our revolving credit facility, which could further limit our liquidity and ability to conduct additional exploration and development activities.

To mitigate the effects of commodity price fluctuations on our oil and natural gas production, we had the following open fixed price swap positions at March 31, 2016:

	Location	Daily Volume (Bbls/day)	Weighted Average Price
April 2016 - June 2016	ARGUS LLS	1,500	$ 63.03
April 2016 - June 2016	NYMEX WTI	1,000	$ 61.40

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	Location	Daily Volume (MMBtu/day)	Weighted Average Price
April 2016	NYMEX Henry Hub	570,000	$ 3.23
May 2016 - June 2016	NYMEX Henry Hub	510,000	$ 3.10
July 2016	NYMEX Henry Hub	530,000	$ 3.09
August 2016 - September 2016	NYMEX Henry Hub	540,000	$ 3.07
October 2016	NYMEX Henry Hub	570,000	$ 3.05
November 2016 - December 2016	NYMEX Henry Hub	525,000	$ 3.18
January 2017 - March 2017	NYMEX Henry Hub	412,500	$ 3.13
April 2017 - June 2017	NYMEX Henry Hub	367,500	$ 3.15
July 2017 - December 2017	NYMEX Henry Hub	305,000	$ 2.99
January 2018 - December 2018	NYMEX Henry Hub	160,000	$ 3.01
January 2019 - March 2019	NYMEX Henry Hub	20,000	$ 3.37

	Location	Daily Volume (Bbls/day)	Weighted Average Price
April 2016 - December 2016	Mont Belvieu	1,500	$ 19.95

We sold call options and used the associated premiums to enhance the fixed price for a portion of the fixed price natural gas swaps listed above. Each short call option has an established ceiling price. When the referenced settlement price is above the price ceiling established by these short call options, we pay our counterparty an amount equal to the difference between the referenced settlement price and the price ceiling multiplied by the hedged contract volume.

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
January 2017 - March 2017	NYMEX Henry Hub	105,000	$ 3.27
April 2017 - December 2017	NYMEX Henry Hub	125,000	$ 3.21
January 2018 - March 2018	NYMEX Henry Hub	20,000	$ 2.91

For a portion of the combined natural gas derivative instruments containing fixed price swaps and sold call options, the counterparty has an option to extend the original terms an additional twelve months for the period January 2017 through December 2017. The option to extend the terms expires in December 2016. If executed, we would have additional fixed price swaps for 30,000 MMBtu per day at a weighted average price of $3.33 per MMBtu and additional short call options for 30,000 MMBtu per day at a weighted average ceiling price of $3.33 per MMBtu.
In addition, we have entered into natural gas basis swap positions, which settle on the pricing index to basis differential of MichCon or Tetco M2 to the NYMEX Henry Hub natural gas price. As of March 31, 2016, we had the following natural gas basis swap positions for MichCon and Tetco M2, respectively.

	Location	Daily Volume (MMBtu/day)	Hedged Differential
April 2016 - December 2016	MichCon	40,000	$ 0.02
November 2016 - March 2017	Tetco M2	50,000	$ (0.59)

In April 2016, we entered into fixed price swaps for the period November 2017 through March 2018, for 50,000 MMBtu of natural gas per day at a weighted average price of $3.17 per MMBtu. Our fixed price swap contracts are tied to the commodity prices on NYMEX. We will receive the fixed price amount stated in the contract and pay to our counterparty the current market price as listed on NYMEX for natural gas.
Under our 2016 contracts, we have hedged approximately 74% to 78% of our estimated 2016 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. At March 31, 2016, we had a net asset derivative position of $178.8 million as compared to a

Explanation of Responses:

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net asset derivative position of $134.2 million as of March 31, 2015, 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 $85.5 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by approximately $85.5 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 March 31, 2016, we had no variable interest rate borrowings outstanding; therefore, an increase in interest rates would not have impacted our interest expense. Our interest rate on borrowings under our revolving credit facility was 2.18% on April 20, 2015, the last day on which borrowings were outstanding under such facility. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our interest expense of approximately $3.0 million based on the $300.0 million outstanding in the aggregate under our revolving credit facility as of such date. As of March 31, 2016, 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 Accounting 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 Accounting Officer, as appropriate to allow timely decisions regarding required disclosures.

As of March 31, 2016, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and President and our Chief Accounting 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 Accounting Officer have concluded that, as of March 31, 2016, our disclosure controls and procedures are effective.

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

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PART II

ITEM 1. LEGAL PROCEEDINGS

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, 2015.

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 March 31, 2016, 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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10.1	Fifth Amendment to Amended and Restated Credit Agreement, dated as of September 18, 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 September 24, 2015).
10.2*	Six Amendment, dated February 19, 2016, to Amended and Restated Credit Agreement, dated as of September 18, 2015, among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto.
10.3#	Amendment to Sand Supply Agreement, dated as of November 3, 2015, by and between Muskie Proppant LLC and Gulfport Energy Corporation (incorporated by reference to Exhibit 10.2 to the Form 10-Q, File No. 000-19516, filed by the Company with the SEC on November 7, 2015).
10.4#	Amendment to Amended and Restated Master Services Agreement, dated as of February 18, 2016 to be effective as of January 1, 2016, by and between Gulfport Energy Corporation and Stingray Pressure Pumping LLC (incorporated by reference to Exhibit 10.19 to the Form 10-K, File No. 000-19514, filed by the Company with the SEC on February 19, 2016).
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.

\# Confidential treatment was granted by the SEC as to certain portions, which portions have been omitted and filed separately with the SEC.

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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: May 5, 2016

GULFPORT ENERGY CORPORATION

By: /s/ Keri Crowell
Keri Crowell
Chief Accounting Officer

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