SABINE OIL & GAS CORP
Form 10-K
March 24, 2016

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

FORM 10-K

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2015
or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number: 01-13515

SABINE OIL & GAS CORPORATION

(Exact name of registrant as specified in its charter)

New York	25-0484900

(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1415 Louisiana Street, Suite 1600
Houston, Texas 77002
(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code: (832) 242-9600

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

Title of class	Name of each exchange on which registered
Common Stock, Par Value $0.10 Per Share	OTC Pink Marketplace

Securities registered pursuant to Section 12 (g) of the Act: None

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Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15 (d) of the Act. Yes No

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

Large accelerated filer	Accelerated filer
Non-accelerated filer (Do not check if a smaller reporting company)	Smaller reporting company

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2015 was approximately $14 million, based upon the closing price of $0.07 per share as reported by the New York Stock Exchange on such date.

211,693,364 shares of our $0.10 par value common stock were outstanding on March 21, 2016.

DOCUMENTS INCORPORATED BY REFERENCE

None.

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EXPLANATORY NOTE

As discussed in "Items 1 and 2. Business and Properties" below, on December 16, 2014, Sabine Oil & Gas LLC, a Delaware limited liability company ("Sabine O&G"), and Forest Oil Corporation, a New York corporation, completed the combination of their respective businesses through a series of transactions ("the Combination") whereby certain indirect equity holders of Sabine O&G contributed the equity interests in Sabine O&G to Forest Oil Corporation. In exchange for this contribution, the equity holders of Sabine O&G received shares of Sabine Oil & Gas Corporation ("Sabine") common stock and Series A senior non-voting equity-equivalent preferred stock collectively representing approximately a 73.5% economic interest in Sabine and 40% of the total voting power in Sabine (the "Combination"). On December 19, 2014, Forest Oil Corporation changed its name to "Sabine Oil & Gas Corporation." Because Sabine O&G was considered the accounting acquirer in the Combination under US GAAP, Sabine O&G is also considered the accounting predecessor of Sabine Oil & Gas Corporation. Accordingly, the historical financial and operating data of Sabine Oil & Gas Corporation included in this Annual Report on Form 10-K which cover periods prior to the completion of the Combination, reflect the assets, liabilities and operations of Sabine O&G, the predecessor to Sabine Oil & Gas Corporation, and do not reflect the assets, liabilities and operations of Sabine Oil & Gas Corporation (which was then known as "Forest Oil Corporation") prior to the Combination. References in this Annual Report on Form 10-K to "Sabine," "the Company," "we," "us" and "our" refer (i) with respect to the period from and after December 16, 2014, to the group of entities within the consolidated group of Sabine Oil & Gas Corporation, and (ii) with respect to the period prior to December 16, 2014, to the group of entities within the consolidated group of Sabine O&G, the predecessor, unless, in each case, otherwise indicated or the context otherwise requires. References in this Annual Report on Form 10-K to "Forest" refer to Sabine Oil & Gas Corporation prior to the Combination, when it was known as "Forest Oil Corporation." For more information regarding Forest's historical operating data, please see the Company's prior Annual Reports on Form 10-K and Quarterly Reports on Form 10-Q.

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Certain Terms Used in this Annual Report on Form 10-K

Unless the context otherwise requires, references in this Annual Report on Form 10-K to the following terms have the meanings set forth below:

- "Bankruptcy Code" refers to title 11 of the United States Code.
- "Bankruptcy Court" refers to the United States Bankruptcy Court for the Southern District of New York.
- "Bar Dates" means the deadlines for filing certain proofs of claims in the Debtors' Chapter 11 cases, which deadline is December 22, 2015 for general claims and January 11, 2016 for governmental claims.
- "Combination" refers to the consummation of a series of transactions whereby certain indirect equity holders of Sabine O&G contributed the equity interests in Sabine O&G to Sabine Oil & Gas Corporation (which was then known as "Forest Oil Corporation"). In exchange for this contribution, the equity holders of Sabine O&G received shares of Sabine common stock and Series A senior non-voting equity-equivalent preferred stock ("Sabine Series A preferred stock") collectively representing approximately a 73.5% economic interest in Sabine and 40% of the total voting power in Sabine. The Combination was completed on December 16, 2014.
- "Chapter 11" refers to chapter 11 of the Bankruptcy Code which may also be referred to herein as "Chapter 11 Cases" or "Chapter 11 Proceedings".
- "Debtors" refers to the Company and certain of its subsidiaries, including Giant Gas Gathering LLC, Sabine Bear Paw Basin LLC, Sabine East Texas Basin LLC, Sabine Mid-Continent Gathering LLC, Sabine Mid-Continent LLC, Sabine Oil & Gas Finance Corp., Sabine South Texas Gathering LLC, Sabine South Texas LLC and Sabine Williston Basin LLC.
- "Forest" refers to Sabine Oil & Gas Corporation, a New York corporation, prior to the Combination, which was then known as "Forest Oil Corporation." Forest changed its name to "Sabine Oil & Gas Corporation" on December 19, 2014.
- "Sabine," "we," "us" or the "Company" refers (i) with respect to the period from and after December 16, 2014, the date of the Combination, to the group of entities within the consolidated group of Sabine Oil & Gas Corporation, a New York corporation and the entity which survived the Combination and (ii) with respect to the period prior to December 16, 2014, to the group of entities within the consolidated group of Sabine O&G.
- "Sabine Investor Holdings" refers to Sabine Investor Holdings LLC, a Delaware limited liability company, of which the common equity interests are owned by affiliates of First Reserve, certain members of the Company's management and board of directors.
- "Sabine O&G" refers to Sabine Oil & Gas LLC, a Delaware limited liability company and the accounting predecessor of Sabine.
- "Sabine O&G Properties" refer to the oil and natural gas properties historically owned by Sabine O&G prior to the Combination.
- "Sabine Oil & Gas Corporation" refers to Sabine Oil & Gas Corporation, a New York corporation.

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Glossary of Oil and Gas Terms

The terms defined in this section are used throughout this Annual Report on Form 10-K. Certain definitions, including the definitions of proved reserves, proved developed reserves, and proved undeveloped reserves, have been abbreviated from the applicable definitions contained in Rule 4-10 (a) of Regulation S-X under the Securities Exchange Act of 1934.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, of crude oil or liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate, or natural gas liquids.

Bbtu. One billion British Thermal Units.

Boe. Barrels of oil equivalent in which six Mcf of natural gas equals one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

Btu. A British Thermal Unit, or the amount of heat necessary to raise the temperature of one pound of water one degree Fahrenheit.

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface temperature and pressure.

Developed acreage. Acreage that is held by producing wells or wells capable of production.

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole; dry well. A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well. Also referred to as a non-productive well.

Equivalent volumes. Equivalent volumes are computed with oil and natural gas liquid quantities converted to Mcf on an energy equivalent ratio of one barrel to six Mcf.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well.

Farmout. An assignment of an interest in a drilling location and related acreage conditional upon the drilling of a well on that location or the undertaking of other work obligations.

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Full cost pool. The full cost pool consists of all costs associated with property acquisition, exploration, and development activities for a company using the full cost method of accounting. Additionally, any internal costs that can be directly identified with acquisition, exploration, and development activities are included. Any costs related to production, general and administrative expense, or similar activities are not included.

Gas. Natural Gas.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

HH or Henry Hub. Henry Hub is the major exchange for pricing natural gas futures on the NYMEX.

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Hydraulic fracturing. A process used to stimulate production of hydrocarbons. The process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production.

Lease operating expenses. The expenses of lifting oil or gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs, and other expenses incidental to production, but not including lease acquisition or drilling or completion expenses.

Liquids. Oil, condensate, and natural gas liquids.

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

MMBbl. One million barrels of crude oil or other liquid hydrocarbons.

MBoe. Thousand barrels of crude oil equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate, or natural gas liquids.

MMBoe. One million barrels of oil equivalent.

Mcf. Thousand cubic feet of natural gas.

Mcfe. Thousand cubic feet equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate, or natural gas liquids.

MMbtu. One million British Thermal Units. One British thermal unit is the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

MMcf. Million cubic feet of natural gas.

MMcfe. Million cubic feet equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate, or natural gas liquids.

MMcfe/d. One million cubic feet of gas equivalent per day.

NGL or natural gas liquids. Liquid hydrocarbons found in natural gas which may be extracted as separate components, including ethane, propane, butanes, and natural gasoline.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells expressed in whole numbers and fractions of whole numbers.

Net revenue interest. An owner's share of petroleum after satisfaction of all royalty and other non-cost bearing interests.

NYMEX. New York Mercantile Exchange.

Oil. Crude oil, condensate and natural gas liquids.

Operator. The individual or company responsible for the exploration and/or exploitation and/or production of an oil or gas well or lease.

Productive wells. Producing wells and wells that are mechanically capable of production.

Proved developed reserves. Estimated proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves. Quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under

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existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Existing economic conditions include prices and costs which economic productability from a reservoir is to be determined. The price shall be the average price during the twelve-month period prior to the end of the reporting period, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped reserves or PUDs. Estimated proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Royalty. An interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner’s royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Spot market price. The price for a one-time open market transaction for immediate delivery of a specific quantity of product at a specific location where the commodity is purchased “on the spot” at current market rates.

Tcfe. One trillion cubic feet of gas equivalent.

Standardized measure or present value of estimated future net revenues. An estimate of the present value of the estimated future net revenues from proved oil and gas reserves at a date indicated after deducting estimated production and property taxes, future capital costs, operating expenses, and estimated future income taxes. The estimated future net revenues are discounted at an annual rate of 10%, in accordance with the SEC’s requirements, to determine their “present value.” The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties. Estimates of future net revenues are made using oil and natural gas prices and operating costs at the estimation date in accordance with the SEC’s regulations and are held constant for the life of the reserves.

Undeveloped acreage. Acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

Working interest. An operating interest which gives the owner the right to drill, produce, and conduct operating activities on the property, and to receive a share of production.

Workover. A series of operations on a producing well to restore or increase production.

WTI or West Texas Intermediate. A grade of crude oil used as a benchmark in oil pricing.

3-D Seismic. Advanced technology method of detecting accumulations of hydrocarbons identified through a three-dimensional picture of the subsurface created by the collection and measurement of the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K and the documents referred to in this Annual Report on Form 10-K contain "forward-looking statements" within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933 (as amended, the "Securities Act") and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Forward-looking statements are statements that are not statements of historical fact, including statements about beliefs, opinions and expectations. Forward-looking statements are based on, and include statements about, our plans, prospects, expected future financial condition, results of operations, cash flows, dividends and dividend plans, objectives, beliefs, financing plans, business strategies, budgets, goals, future events, future revenues or performance, financing needs, outcomes of litigation, projected costs, operating metrics, capital expenditures, competitive positions, acquisitions, investment opportunities, integration, cost savings, synergies, growth opportunities, dispositions, plans and objectives of management for future operations and any other information that is not historical information. These statements, which may include statements regarding the period following completion of the reincorporation merger and the related transactions, include, without limitation, words such as "may," "will," "could," "should," "would," "expect," "plan," "project," "forecast," " "anticipate," "believe," "estimate," "predict," "suggest," "view," "potential," "pursue," "target," "continue" and similar express variations as well as the negative of these terms. These statements involve risks, uncertainties, assumptions and other factors that are difficult to predict and that could cause actual results to differ materially from those expressed in them or indicated by them.

These risks and uncertainties are not exhaustive. Other sections of this Annual Report on Form 10-K describe additional factors that could adversely affect our business and financial performance. Moreover, we operate in a very competitive and rapidly changing environment. New risks and uncertainties emerge from time to time, and it is not possible to predict all risks and uncertainties, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

Although we believe the expectations reflected in the forward-looking statements are reasonable, we cannot guarantee future results, level of activity, performance or achievements. Moreover, neither we nor any other person assumes responsibility for the accuracy or completeness of any of these forward-looking statements. You should not rely upon forward-looking statements as predictions of future events. We are under no duty to update any of these forward-looking statements after the date of this Annual Report on Form 10-K to conform our prior statements to actual results or revised expectations and we do not intend to do so.

These forward-looking statements appear in a number of places and include statements with respect to, among other things:

- risks and uncertainties associated with the Chapter 11 process, including our inability to develop, confirm and consummate a plan under Chapter 11 of the Bankruptcy Code or an alternative restructuring transaction, including a sale of all or substantially all of our assets, which may be necessary to continue as a going concern;
- inability to maintain our relationship with suppliers, customers, employees and other third parties as a result of our Chapter 11 filing;
- failure to satisfy our short- or long-term liquidity needs, including our inability to generate sufficient cash flow from operations or to obtain adequate financing to fund our capital expenditures and meet working capital needs and our ability to continue as a going concern;
- estimates of our oil and natural gas reserves;
- our future financial condition, results of operations, revenues, cash flows, and expenses;
- our future levels of indebtedness, liquidity, and compliance with debt covenants;
- our ability to access the capital markets and the terms on which capital may be available to us;

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- our ability to fund our operations and capital expenditures;
- our future business strategy and other plans and objectives for future operations;
- our ability to integrate the historical Forest and Sabine O&G businesses and achieve synergies related to the Combination;
- our business' competitive position;
- our outlook on oil and natural gas prices;
- the amount, nature, and timing of our future capital expenditures, including future development costs;
- our potential future asset dispositions and other transactions, the timing of closing of such transactions and the use of proceeds, if any, from such transactions;
- the risks associated with potential acquisitions or alliances by us;
- the recruitment and retention of our officers and employees;
- our expected levels of compensation;
- the likelihood of success of and impact of litigation on us;
- our assessment of our counterparty risk and the ability of our counterparties to perform their future obligations; and
- the impact of federal, state, and local political, regulatory, and environmental developments in the United States where we conduct business operations.

We expressly qualify in its entirety each forward-looking statement attributable to us or any person acting on our behalf by the cautionary statements contained or referred to in this section. Except to the extent required by applicable law or regulation, we do not undertake any obligation to update forward-looking statements to reflect events or circumstances after the date of this Annual Report on Form 10-K or to reflect the occurrence of unanticipated events.

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PART I

You should read this entire report carefully, including the risks described under Part I, Item 1A. Risk Factors and our consolidated financial statements and the notes to those consolidated financial statements included elsewhere in this Annual Report on Form 10-K. For the reasons discussed in the Explanatory Note to this Annual Report on Form 10-K, references in this Annual Report on Form 10-K to "Sabine," "the Company," "we," "us" and "our" refer (i) with respect to the period from and after December 16, 2014, to the group of entities within the consolidated group of Sabine Oil & Gas Corporation, and (ii) with respect to the period prior to December 16, 2014, to the group of entities within the consolidated group of Sabine O&G, the accounting predecessor, unless, in each case, otherwise indicated or the context otherwise requires. References in this Annual Report on Form 10-K to "Forest" refer to Sabine Oil & Gas Corporation prior to the Combination, when it was known as "Forest Oil Corporation."

Items 1 and 2.Business and Properties

General

We are an independent oil and natural gas company engaged in the acquisition, development, exploitation and exploration of oil and natural gas properties onshore in the United States.

On December 16, 2014, pursuant to a series of transaction agreements, certain indirect equity holders of Sabine O&G (such indirect equity holders are referred to as the "Legacy Sabine Investors") contributed the equity interests in Sabine O&G to us (we were then known as "Forest Oil Corporation"). In exchange for this contribution, the Legacy Sabine Investors received shares of our common stock and our Series A preferred stock collectively representing approximately a 73.5% economic interest in us and 40% of the total voting power in us. Holders of our common stock immediately prior to the closing of the Combination continued to hold their common stock following the closing, which immediately following the closing represented approximately a 26.5% economic interest in us and 60% of the total voting power in us.

On December 19, 2014, we filed a certificate of amendment with the New York Secretary of State to change our name from "Forest Oil Corporation" to "Sabine Oil & Gas Corporation." Our principal executive offices and corporate headquarters are located at 1415 Louisiana Street, Suite 1600, Houston, Texas 77002. Our telephone number at that address is (832) 242-9600.

Chapter 11 Filings

On July 15, 2015, we and certain of our subsidiaries, including Giant Gas Gathering LLC, Sabine Bear Paw Basin LLC, Sabine East Texas Basin LLC, Sabine Mid-Continent Gathering LLC, Sabine Mid-Continent LLC, Sabine Oil & Gas Finance Corp., Sabine South Texas Gathering LLC, Sabine South Texas LLC and Sabine Williston Basin LLC (collectively, the "Filing Subsidiaries" and, together with us, the "Debtors"), filed voluntary petitions (the "Bankruptcy Petitions") for reorganization under the Bankruptcy Code in the United States Bankruptcy Court for the Southern District of New York (the "Bankruptcy Court"). The Debtors Chapter 11 cases (the "Chapter 11 Cases") are being jointly administered under the case styled In re Sabine Oil & Gas Corporation, et al, Case No. 15-11835. The Debtors will continue to operate their businesses as "debtors-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court.

By certain "first day" motions filed in the Chapter 11 Cases, we obtained Bankruptcy Court approval to, among other things and subject to the terms of the orders entered by the Bankruptcy Court, pay certain employee wages, health benefits and certain other employee obligations, pay certain lienholders and forward funds to third parties, including royalty holders and other partners.

For the duration of our Chapter 11 proceedings, our operations and ability to develop and execute our business plan are subject to the risks and uncertainties associated with the Chapter 11 process. For example, negative events associated with our Chapter 11 proceedings could adversely affect our relationships with our suppliers, service providers, customers, and other third parties and our ability to retain employees, which in turn could adversely affect our operations and financial condition. For a description of these and other risks, please see “Part I, Item 1A. Risk Factors.” As a result of these risks and uncertainties, the number of our outstanding shares and shareholders, assets, liabilities, officers and/or

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directors could be significantly different following the outcome of the Chapter 11 proceedings, and the description of our operations, properties and capital plans included in this Annual Report may not accurately reflect our operations, properties and capital plans following the Chapter 11 process.

In particular, subject to certain exceptions, under the Bankruptcy Code, the Debtors may assume, assign, or reject certain executory contracts and unexpired leases subject to the approval of the Bankruptcy Court and certain other conditions. The rejection of an executory contract or unexpired lease is generally treated as a pre-petition breach of such executory contract or unexpired lease and, subject to certain exceptions, relieves the Debtors of performing their future obligations under such executory contract or unexpired lease but entitles the contract counterparty or lessor to a pre-petition general unsecured claim for damages caused by such deemed breach. Counterparties to such rejected contracts or leases may assert claims against the applicable debtor's estate for such damages. The assumption of an executory contract or unexpired lease generally requires the Debtors to cure existing monetary defaults under such executory contract or unexpired lease and provide adequate assurance of future performance. Accordingly, any description of an executory contract or unexpired lease with the Debtors in this Annual Report, including where applicable a quantification of our obligations under any such executory contract or unexpired lease with the Debtors, is qualified by any overriding rejection rights we have under the Bankruptcy Code. Further, nothing herein is or shall be deemed an admission with respect to any claim amounts or calculations arising from the rejection of any executory contract or unexpired lease and the Debtors expressly preserve all of their rights with respect thereto.

Our filing of the Bankruptcy Petitions described above constitutes an event of default that accelerated our obligations under the New Revolving Credit Facility, the Term Loan Facility, the 2017 Notes and the Legacy Forest Notes. We have classified all debt as "Liabilities Subject to Compromise" in the Consolidated Balance Sheet at December 31, 2015. This debt includes unsecured and under secured obligations which are reported at the amounts expected to be allowed as claims by the Bankruptcy Court, even if they may be settled for lesser amounts. If we cannot continue as a going concern, adjustments to the carrying values and classification of our assets and liabilities and the reported income and expenses could be required and could be material. For additional description of the defaults present under our debt obligations, please see Note 8 within "Part II, Item 8. Financial Statements and Supplementary Data".

We are making adequate protection payments to the lenders under the New Revolving Credit Facility in an amount equal to the non-default rate of interest, fees and costs due and payable on a monthly basis under the New Revolving Credit Facility, in accordance with the cash collateral order filed with the Bankruptcy Court. Additionally, cash generated by the Company deemed to be proceeds of the oil and gas properties that represent prepetition collateral is deposited into a segregated account, which is reflected as Cash in the Consolidated Balance Sheet as of December 31, 2015, and is used solely to pay for the operations of the prepetition collateral properties.

On October 21, 2015 the Debtors filed a motion to set a bar date to assist with the claims reconciliation process. On January 26, 2016, the Debtors filed with the Bankruptcy Court a joint plan of reorganization (the "Plan of Reorganization") for the resolution of the outstanding claims against and interests in the Debtors and a disclosure statement (the "Disclosure Statement") related thereto. The Plan of Reorganization, if implemented as proposed by the Debtors, would significantly reduce our outstanding long-term debt and annual interest payments. The Disclosure Statement has not yet been approved by the Bankruptcy Court. Although the Debtors currently have the exclusive right to file a plan and solicit the appropriate votes thereon, such rights expire on February 10, 2016 and April 11, 2016, respectively. Accordingly, the Debtors have filed a motion to further extend their exclusive right to file and solicit acceptance of the Plan of Reorganization, or any other plan, through June 9, 2016 and August 9, 2016, respectively. A hearing on that motion will be held before the US Bankruptcy Court on April 7, 2016 and April 11, 2016. There can be no assurances regarding our ability to successfully develop, confirm or consummate the Plan of Reorganization, an alternative plan or reorganization or another alternative restructuring transactions, including a sale of all or substantially all of our assets, which satisfies the conditions of the Bankruptcy Code and is authorized by the Bankruptcy Court.

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Our Properties

Overview

Our properties are primarily focused in three core geographic areas:

- East Texas, targeting the Cotton Valley Sand and Haynesville Shale formations;
- South Texas, targeting the Eagle Ford Shale formation; and
- North Texas, targeting the Granite Wash formation.

As of December 31, 2015, we held interests in approximately 272,100 gross (217,000 net) acres in East Texas, 82,900 gross (53,400 net) acres in South Texas and 33,900 gross (25,300 net) acres in North Texas. As of December 31, 2015, we were the operator on 90%, 99% and 99% of our net acreage positions in East Texas, South Texas and North Texas, respectively.

The hydrocarbon content of our drilling inventory ranges from predominantly oil to entirely natural gas, providing significant optionality for our capital allocation to maximize returns in a wide variety of commodity price environments. In the near term, our capital program is expected to be focused primarily in the Cotton Valley Sand and Haynesville formations, where we have a history of development activities with consistent and reliable economic results. Our acreage in the Haynesville Shale in East Texas and our acreage in the Eagleville area in South Texas are primarily held by production.

The 2015 drilling and completion capital program associated with our properties was focused on projects that exhibited the most attractive economics based on commodity prices at that time. Full year 2015 capital expenditures were approximately $197 million, including approximately $203 million on drilling and completion activities, offset by approximately $6 million on acquisitions and other activities. Drilling and completion expenditures included approximately $144 million for the development of proved undeveloped reserves and approximately $59 million for the development of unproved reserves. Our 2016 capital expenditures are forecasted to total approximately $18 million.

Our Acquisition History

During 2013 through 2015, we successfully completed four significant transactions, including the Combination, under which we combined the respective businesses of Sabine O&G and Forest. Additionally, we purchased additional working interests in properties. In prior periods, the Company has executed farm out agreements which established our positions in the Eagle Ford Shale in South Texas and in the Granite Wash area in North Texas, and expanded our positions in the Cotton Valley Sand and Haynesville Shale areas in East Texas.

Operating Regions Associated with Our Properties

East Texas

The East Texas portion of our properties is characterized by several productive horizons, such as the Cotton Valley Sand, Haynesville Shale, Haynesville Lime, Pettet, Bossier Shale, Travis Peak and other formations. Currently, our primary operational focus in this area is directed at the Cotton Valley Sand and Haynesville Shale formations. We believe the Cotton Valley Sand formation is a well-understood play given its history of extensive vertical development, making it a predictable and repeatable development opportunity. Geologically, the Cotton Valley Sand formation is a thick, consolidated sand formation at depths ranging from approximately 7,800 feet to 10,800 feet, and has had over 400 horizontal wells drilled in the play in our properties' core operating area.

Our other primary target in East Texas, the Haynesville Shale, lies approximately 1,500 feet below the Cotton Valley Sand formation. The Haynesville Shale is a Jurassic age reservoir, which is as much as 300 feet thick, is composed of organic-rich black shale and is found under much of the East Texas acreage position associated with our properties at depths ranging from approximately 11,000 feet to 12,000 feet. We believe this Haynesville Shale position

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represents a large gas resource, which is strategically positioned geographically to benefit from a growing demand for domestic natural gas.

Our East Texas properties are primarily located in Harrison, Panola and Rusk Counties in Texas and Red River Parish in Northern Louisiana with estimated proved reserves of 623 Bcfe as of December 31, 2015, of which 78% is natural gas and 74% is developed. As of December 31, 2015 our properties were producing from 1,462 wells in East Texas, and we operated 1,251, or 86%, of those wells. Average net daily production in East Texas from our properties for the three months ended December 31, 2015 was 194 MMcfe/d.

Primary operations are in the following areas for which a significant portion of our Cotton Valley Sand and Haynesville Shale acreage overlaps geographically, representing two distinct targets and development opportunities:

- Cotton Valley Sand—As of December 31, 2015, approximately 151,000 gross (101,300 net) acres of this East Texas position was prospective for the liquids-rich Cotton Valley Sand formation, 96% of which was held by production. As of December 31, 2015, our properties produced from 110 horizontal and 972 vertical wells in the Cotton Valley Sand, and we operated 947, or 88%, of those wells.
- Haynesville Shale—As of December 31, 2015, approximately 98,900 gross (71,800 net) acres of our East Texas position was prospective for the Haynesville Shale, 84% of which was held by production. Approximately 8,000 gross (7,900 net) of this acreage is located in Red River Parish, Louisiana. As of December 31, 2015, we produced from 132 wells in the Haynesville Shale, and we operated 110, or 83%, of those wells.

South Texas

The South Texas assets associated with our properties are primarily prospective for the Eagle Ford Shale formation. The first horizontal wells in the Eagle Ford Shale were drilled in 2008, and the play has become one of the largest unconventional oil producing plays in North America. The formation is characterized as having low geologic risks and repeatable drilling opportunities. Geologically, the Eagle Ford Shale is a thick, organic-rich, carbonaceous shale reservoir found at depths ranging from 4,000 feet to 13,000 feet, and in much of the deeper portions of the play is over-pressurized, enhancing well performance.

In South Texas, as of December 31, 2015, our properties represented interests in approximately 82,900 gross (53,400 net) acres in DeWitt, Lavaca and Gonzales Counties prospective for the Eagle Ford Shale, approximately 69% of which was held by production. This area had estimated proved reserves of 62 Bcfe as of December 31, 2015, of which 64% was oil or NGLs and 100% was developed. As of December 31, 2015, our properties were producing from 186 wells in South Texas, and we operated 183, or 98%, of those wells. Average net daily production associated with our properties in South Texas for the three months ended December 31, 2015 was 36 MMcfe/d.

Primary operations are in the following areas:

- Sugarkane Area—As of December 31, 2015, the Sugarkane area included approximately 2,800 gross (2,500 net) acres, 99% of which was held by production. As of December 31, 2015, our properties were producing from 20 horizontal wells, 19 of which we operated.
- Shiner Area—As of December 31, 2015, the Shiner area included approximately 32,400 gross (27,500 net) acres, 40% of which was held by production. As of December 31, 2015, our properties were producing from 48 horizontal wells, 47 of which we operated.
- Eagleville Area—As of December 31, 2015, the Eagleville area included approximately 47,700 gross (23,300 net) acres, 99% of which was held by production. As of December 31, 2015, our properties were producing from 115 horizontal wells, all 115 of which we operated.

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North Texas

The North Texas properties are located in the Anadarko Basin with the Granite Wash as the target horizon. The Granite Wash is a series of stacked, silty-sandy deposits found at depths of 8,500 feet to 11,000 feet that were laid down throughout the Pennsylvanian era and into early Permian time, and is over 3,000 feet thick.

In North Texas, as of December 31, 2015, we held rights to develop approximately 33,900 gross (25,300 net) acres primarily in Roberts County in Texas, approximately 23% of which was held by production. The North Texas acreage as of December 31, 2015 includes approximately 18,850 net acres that are subject to a continuous drilling clause which requires us to drill one gross well every 180 days to hold the entire approximately 18,850 net acre position.

This area has estimated proved reserves of 17 Bcfe as of December 31, 2015, of which 59% was oil or NGLs and 84% was developed. As of December 31, 2015, our properties were producing from 44 wells in North Texas, and we operated 40, or 91% of those wells. Average net daily production in North Texas for the three months ended December 31, 2015 was 20 MMcfe/d.

Other

As of December 31, 2015, our position outside of our three core geographic areas included approximately 23,900 gross (11,200 net) acres primarily in North Dakota, Mississippi and Wyoming.

Estimated Proved Reserves

The information with respect to our estimated proved reserves as of December 31, 2015 and December 31, 2014 presented below has been prepared by our independent petroleum engineering firm, Ryder Scott Company, L.P. (“Ryder Scott”), in accordance with rules and regulations of the Securities and Exchange Commission (“SEC”) applicable to companies involved in oil and natural gas producing activities in effect at the applicable time. The reports of Ryder Scott are dated February 5, 2016 and January 20, 2015. The reports of Ryder Scott are filed as Exhibits 99.1 and 99.2 to this Annual Report on Form 10-K. These proved reserve estimates as of December 31, 2015 and December 31, 2014 were prepared using the unweighted average of the historical first-day-of-the-month prices for the prior twelve months. It should not be assumed that the present value of future net revenues from our proved reserves is the current market value of our estimated reserves. Actual future prices and costs may differ materially from those used in the present value estimates.

The following table sets forth information regarding our estimated proved reserves, by region, for the periods indicated. The information in the table does not give any effect to or reflect commodity hedges. Although the SEC’s rules also permit the presentation of estimated “probable” or “possible” reserves, we have limited our presentation to estimated proved reserves.

	At December 31,	
	2015 (1)	2014 (2)
	Proved reserves (Bcfe)	Proved reserves (Bcfe)
Operating area		
East Texas (3)	623	1,198
South Texas	62	106
North Texas	17	43

Other (4)	0	10
Total	702	1,357

(1) Data for December 31, 2015 is based on the unweighted average of the first-day-of-the-month (a) West Texas Intermediate posted prices for the prior twelve months of $50.28 per Bbl for oil and (b) Henry Hub spot market prices for the prior twelve months of $2.58 per MMbtu for natural gas.

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(2) Data for December 31, 2014 is based on the unweighted average of the first-day-of-the-month (a) West Texas Intermediate posted prices for the prior twelve months of $94.99 per Bbl for oil and (b) Henry Hub spot market prices for the prior twelve months of $4.35 per MMbtu for natural gas.
(3) Includes Northern Louisiana.
(4) Includes Wyoming, North Dakota and the Permian Basin.

The following table sets forth additional information regarding our estimated proved reserves at the dates indicated.

	At December 31,	
	2015 (1)	2014 (2)
Estimated proved reserves:		
Oil (MMBbl)	9.2	20.1
NGLs (MMBbl)	22.0	41.1
Natural gas (Bcf)	514.3	989.8
Total estimated proved reserves (Bcfe)	701.8	1,357.1
Proved developed producing reserves:		
Oil (MMBbl)	7.7	13.2
NGLs (MMBbl)	16.0	23.0
Natural gas (Bcf)	391.4	498.1
Total proved developed producing reserves (Bcfe)	533.5	715.4
Proved developed non-producing:		
Oil (MMBbl)	0.1	0.5
NGLs (MMBbl)	0.2	0.8
Natural gas (Bcf)	4.8	22.3
Total proved developed non-producing reserves (Bcfe)	6.4	30.0
Total proved undeveloped:		
Oil (MMBbl)	1.5	6.5
NGLs (MMBbl)	5.8	17.2
Natural gas (Bcf)	118.0	469.4
Total proved undeveloped reserves (Bcfe)	161.9	611.7
Percent developed	76.9 %	54.9 %

(1) Data for December 31, 2015 is based on the unweighted average of the first-day-of-the-month (a) West Texas Intermediate posted prices for the prior twelve months of $50.28 per Bbl for oil and (b) Henry Hub spot market prices for the prior twelve months of $2.58 per MMbtu for natural gas.
(2) Data for December 31, 2014 is based on the unweighted average of the first-day-of-the-month (a) West Texas Intermediate posted prices for the prior twelve months of $94.99 per Bbl for oil and (b) Henry Hub spot market prices for the prior twelve months of $4.35 per MMbtu for natural gas.

Controls and Qualifications of Technical Persons

In accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and guidelines established by the SEC, Ryder Scott, independent reserve engineers, estimated 100% of our proved reserve information as of December 31, 2014 and December 31, 2015. The technical persons responsible for preparing the reserves estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

We maintain an internal staff of petroleum engineers and geoscience professionals who worked closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets. Our internal technical team members met with our independent reserve engineers

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periodically during the period covered by the reserve report to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to the independent reserve engineers for our properties such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs.

The preparation of proved reserve estimates was completed in accordance with our procedures, which are intended to ensure reliability of reserve estimations, include the following:

- review and verification of historical production data, which data is based on actual production as reported by us;
- preparation of reserve estimates by our Vice President—Corporate Engineering or under his direct supervision;
- review by our Vice President—Corporate Engineering of all of our reported proved reserves at the close of each quarter, including the review of all significant reserve changes and all new proved undeveloped reserves additions;
- direct reporting responsibilities by our Vice President—Corporate Engineering to our Chief Operating Officer; and
- verification of property ownership by our land department.

Tim Pownell, Vice President—Corporate Engineering, is the technical person primarily responsible for overseeing the preparation of our reserve estimates. Mr. Pownell is a graduate of Texas A&M University with a Bachelor of Science degree in Chemical Engineering, and obtained his MBA from the UCLA Anderson School of Management. Mr. Pownell has 25 years of energy experience and our petrotechnical staff has an average of more than 19 years of industry experience per person.

The reserves estimates shown herein have been independently estimated by Ryder Scott, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. Ryder Scott was founded in 1937 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-1580. Within Ryder Scott, the technical person primarily responsible for overseeing the estimates set forth in the Ryder Scott evaluation letters incorporated herein is Mr. Joseph E. Blankenship. Mr. Blankenship has been practicing consulting petroleum engineering at Ryder Scott since 1982. Mr. Blankenship is a Licensed Professional Engineer in the State of Texas (No. 62093) and has over 30 years of experience in petroleum engineering and in the estimation and evaluation of reserves. Mr. Blankenship graduated from the University of Alabama in 1977 with a Bachelor of Science Degree in Mechanical Engineering. Mr. Blankenship is a member of the Society of Petroleum Engineers (“SPE”) and a member of the Society of Petroleum Evaluation Engineers (“SPEE”). Mr. Blankenship exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE. Mr. Blankenship is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Technology Used to Establish Proved Reserves

Under the SEC rules, proved reserves are those quantities of oil and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs, and under existing economic conditions, operating methods and government regulations. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

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To establish reasonable certainty with respect to our estimated proved reserves, our independent reserve engineers, Ryder Scott, employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, open hole logs, core analyses, geologic maps, available downhole and production data and seismic data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves, material balance calculations or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using pore volume calculations and performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. These wells were considered to be analogous based on production performance from the same formation and completion using similar techniques.

Proved Undeveloped Reserves (PUDs)

Year Ended December 31, 2015

As of December 31, 2015, our proved undeveloped reserves totaled 1.5 MMBbls of oil, 5.8 MMBbls of NGLs and 118.0 Bcf of natural gas, for a total of 161.9 Bcfe. There were a total of 21 PUDs booked with 18, 2 and 1 wells booked in the Cotton Valley Sand, Granite Wash and Haynesville Shale, respectively.

Changes in PUDs that occurred during 2015 were primarily due to:

- negative revisions of 341,156 MMcfe primarily due to reduced rig activity due to low prices;
- the conversion of approximately 142,287 MMcfe attributable to PUDs into proved developed reserves net of revisions, a 23% conversion rate of 2014 PUD volumes; and
- additions of approximately 33,640 MMcfe in PUDs due to a combination of adjustments in PUD working interest, performance revisions and optimized well lengths.

Costs incurred relating to the development of PUDs were approximately $144 million during the twelve months ended December 31, 2015.

As of December 31, 2015, 1% of our total proved reserves were classified as proved developed non-producing.

Productive Wells

Productive wells consist of producing wells and wells mechanically capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of productive wells in which we have working interests, and net wells are the sum of our fractional working interests owned in gross wells. The following table sets forth the number of productive wells in which we owned a working interest at December 31, 2015.

	Oil		Gas	
	Gross Wells	Net Wells	Gross Wells	Net Wells
East Texas	70	65	1,392	1,168
South Texas	124	80	62	48
North Texas	41	26	3	1
Total	235	171	1,457	1,217

Drilling Activities

The table below sets forth the results of our drilling activities for the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce a

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reasonable rate of return. Dry wells are those that prove to be incapable of producing hydrocarbons in sufficient quantities to justify completion.

	For the Year Ended December 31,					
	2015		2014 (1)		2013 (2)	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive (3)	0.0	0.0	0.0	0.0	2.0	1.3
Dry	1.0	0.8	0.0	0.0	—	—
Total Exploratory	1.0	0.8	0.0	0.0	2.0	1.3
Development Wells:						
Productive (3)	35.0	30.1	65.0	49.1	43.0	30.8
Dry	1.0	1.0	0.0	0.0	1.0	0.4
Total Development	36.0	31.1	65.0	49.1	44.0	31.2
Total Wells:						
Productive (3)	35.0	30.1	65.0	49.1	45.0	32.1
Dry	2.0	2.0	0.0	0.0	1.0	0.4
Total	37.0	32.1	65.0	49.1	46.0	32.5

(1) Drilling activities for the year ended December 31, 2014 include the results of Forest for the period beginning December 16, 2014 and ending December 31, 2014. For the period from January 1, 2014 through December 15, 2014, Forest drilled a total of 18 gross (16.3 net) productive wells.
(2) The drilling activities for the year ended December 31, 2013 relate only to those associated with the Sabine O&G Properties.
(3) Although a well may be classified as productive upon completion, future changes in oil and natural gas prices, operating costs and production may result in the well becoming uneconomical, particularly exploratory wells where there is no production history.

Developed and Undeveloped Acreage

Our properties include interests in developed and undeveloped oil and natural gas acreage in the regions set forth in the table below. Also set forth in the table below, is the percentage of acreage held by production (“HBP”). These interests generally take the form of working interests in oil and natural gas leases or licenses that have varying terms. The following table presents a summary of our acreage interests as of December 31, 2015:

	Developed acreage		Undeveloped acreage		Total acreage		HBP	
	Gross	Net	Gross	Net	Gross	Net	%	
East Texas	219,469	183,828	52,585	33,182	272,054	217,010	85	%
South Texas	65,130	36,715	17,815	16,715	82,945	53,430	69	%
North Texas	9,433	5,925	24,508	19,402	33,941	25,327	23	%
Total Acreage	294,032	226,468	94,908	69,299	388,940	295,767	77	%

Our inventory of undeveloped oil and natural gas leaseholds is comprised of three to five year term leases and leases that are held by production beyond their primary term. In most cases, the terms of the undeveloped leases can be extended by paying delay rentals or by producing oil and natural gas reserves that are discovered under those leases, however undeveloped acreage could expire subject to development requirements.

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Undeveloped Acreage Expirations

The following table sets forth the number of total net undeveloped acres as of December 31, 2015 that will expire in 2016, 2017 and 2018 unless production is established within the spacing units covering the acreage prior to the expiration dates or unless such leasehold rights are extended or renewed.

	2016	2017	2018	Total
East Texas	7,812	5,386	1,350	14,548
South Texas	11,246	4,709	189	16,144
North Texas	2,162	199	31	2,392
Total	21,220	10,294	1,570	33,084

Production, Revenues and Price History

Oil and natural gas are commodities. The prices we receive for the oil, natural gas and NGLs we produce are largely a function of market supply and demand. We are not committed to provide any material fixed or determinable quantities of oil or natural gas under any existing contracts or agreements. Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or natural gas can result in substantial price volatility. Historically, commodity prices have been volatile and we expect that volatility to continue in the future. Oil and natural gas prices declined significantly in the last half of 2014 with continued weakness in 2015. A further decline or sustained depression in oil or natural gas prices could have a material adverse effect on our business, results of operations, financial condition, access to capital and ability to meet our financial commitments and other obligations. For additional information on commodity price volatility and related risks, see “Part I, Item 1A. Risk Factors.” For a description of our working capital policy, see “Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Working Capital.” See “Part II, Item 8. Financial Statements and Supplementary Data” for information regarding our profits, losses and total assets relating to our production, revenues and price history.

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The following table sets forth information regarding oil and natural gas production, revenues and realized prices and production costs for the years ended December 31, 2015, 2014 and 2013. For additional information on price calculations, see information set forth in “Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

	For the Years Ended December 31,		
	2015	2014 (1)	2013 (2)
Oil, NGLs and natural gas sales by product (in thousands):			
Oil	$ 120,996	$ 181,313	$ 132,513
NGL	41,610	62,420	59,772
Natural gas	172,378	218,630	161,938
Total	$ 334,984	$ 462,363	$ 354,223
Production data:			
Oil (MBbl)	2,786.40	2,169.52	1,403.62
NGL (MBbl))	3,168.98	2,120.56	1,842.47
Natural gas (Bcf)	66.22	49.22	44.29
Combined (Bcfe) (3)	101.95	74.96	63.77
Average prices before effects of economic hedges (4):			
Oil (per Bbl)	$ 43.42	$ 83.57	$ 94.41
NGL (per Bbl)	$ 13.13	$ 29.44	$ 32.44
Natural gas (per Mcf)	$ 2.60	$ 4.44	$ 3.66
Combined (per Mcfe) (3)	$ 3.29	$ 6.17	$ 5.55
Average realized prices after effects of economic hedges (4):			
Oil (per Bbl)	$ 60.83	$ 81.79	$ 90.49
NGL (per Bbl)	$ 13.13	$ 29.44	$ 32.44
Natural gas (per Mcf)	$ 3.26	$ 4.30	$ 4.82
Combined (per Mcfe) (3)	$ 4.19	$ 6.02	$ 6.28
Average costs (per Mcfe) (3):			
Lease operating expenses	$ 0.87	$ 0.68	$ 0.70
Marketing, gathering, transportation and other	$ 0.33	$ 0.32	$ 0.28
Production and ad valorem taxes	$ 0.17	$ 0.24	$ 0.28
General and administrative expenses	$ 0.42	$ 0.41	$ 0.43
Depletion, depreciation and amortization	$ 1.79	$ 2.53	$ 2.15

(1) Production data for the year ended December 31, 2014 include the results of Forest for the period beginning December 16, 2014 and ending December 31, 2014.
(2) Production data for the year ended December 31, 2013 relate only to those associated with the Sabine O&G Properties.
(3) Oil and NGL production was converted at 6 Mcf per Bbl to calculate combined production and per Mcfe amounts.
(4) Average prices shown in the table reflect prices both before and after the effects of our realized commodity derivative transactions. Our calculation of such effects includes realized gains or losses on cash settlements for commodity derivative transactions.

Competitive Conditions in the Business

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater financial and other resources than we do. Many of these companies explore for, produce and market oil and natural gas, as well as carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, obtaining sufficient rig availability, obtaining purchasers and transporters of the oil and natural gas we produce and hiring and retaining key employees. Our larger competitors may be able to pay more for productive oil and natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit and may be able to expend greater resources to attract and maintain industry personnel. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Also, our level of indebtedness may adversely affect our ability to raise additional capital to fund operations and limit our ability to fund future capital expenditures and working capital, to engage in future acquisitions or development activities, or to otherwise realize the value of our assets and opportunities fully because of the need to dedicate a substantial portion of our cash flow from operations to payments of interest and principal on our debt or to comply with any restrictive terms of our debt. This could limit our flexibility in planning for, or reacting to, changes in our business or industry in which we operate, placing us at a competitive disadvantage compared to our competitors who are less highly leveraged and who therefore may be able to take advantage of opportunities that our leverage prevents us from exploring.

There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the governments of the United States and the jurisdictions in which we operate. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position.

Marketing and Significant Customers

We market the majority of the natural gas residue, crude oil, and natural gas liquids from properties we operate for both our account and the account of the other working interest owners in these properties.

In East Texas, we have approximately 85% of our NGL's under three to five year gathering and processing contracts to a variety of midstream companies. The remainder of our NGL's are being sold under gathering and processing contracts which are past their primary term with a 30 day evergreen. We sell approximately 45% of our residue under NAESB contracts on a year to year term ending October 31, 2016 at competitive market prices. The remainder of the residue is sold in conjunction with the NGL sale to the midstream companies processing our NGL's. In East Texas, our oil is sold to one purchaser under a short-term contract which is month-to-month.

In South Texas, we sell our Sugarkane NGL's under two five-year gathering and processing contracts. Our N. Shiner NGL's are sold under a five year gas services agreement. Our S. Shiner NGL's are sold under two separate five year gathering and processing agreements. We sell all our STX residue under NAESB contracts on a year-to-year term ending October 31, 2016. In South Texas, our oil is sold to two separate purchasers under short-term contracts which are month-to-month.

In North Texas, we sell our natural gas residue and NGLs production under a long-term contract to one midstream company, through an acreage dedication. Our oil is sold under a three year contract which allows us to offtake to a dedicated lease automatic custody transfer unit.

During the year ended December 31, 2015, purchases by three companies exceeded 10% of our total oil, NGLs and natural gas sales. Purchases by Enbridge Pipeline (East Texas) LP, NGL Crude Logistics LLC, and Laclede Energy accounted for approximately 28%, 14% and 10%. of our oil, NGLs and natural gas sales, respectively. During the year ended December 31, 2014, purchases by four companies exceeded 10% of our total oil, NGLs and natural gas sales. Purchases by Enbridge Pipelines, NGL Crude Logistics LLC, Laclede Energy and Eastex Crude Company accounted for approximately 13%, 12%, 12% and 10% of our oil, NGLs and natural gas sales, respectively. During the year ended December 31, 2013, purchases by three companies exceeded 10% of our total oil, NGLs and natural gas sales. Purchases by Eastex Crude Company, Enbridge Pipeline (East Texas) LP and CP Energy LLC accounted for approximately 19%, 16% and 11% of our oil, NGLs and natural gas sales, respectively. We believe that the loss of any of the purchasers above would not result in a material adverse effect on our ability to competitively market future oil and natural gas production.

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Seasonality of Business

Weather conditions affect the demand for, and prices of, oil and natural gas and can also delay drilling activities, disrupting our overall business plans. Demand for natural gas is typically higher in the fourth and first quarters resulting in higher natural gas prices. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission (“FERC”), and the courts. We cannot predict when or whether any such proposals may become effective.

We believe that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, results of operations or cash flows. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur, or past non-compliance with environmental laws or regulations may be discovered.

Regulation of Production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation of Transportation of Oil

Sales of crude oil, condensate and NGLs are not currently regulated and are made at negotiated prices. Nevertheless, Congress could enact price controls in the future.

Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil by common carrier pipelines is also subject to rate and access regulation. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil pipelines that allows a pipeline to increase its rates annually up to a prescribed ceiling, without making a cost of service filing. Every five years, FERC reviews the appropriateness of the index level in relation to changes in industry costs. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is generally governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily FERC. FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The open access policies implemented by FERC since the mid-1980s serve to enhance the competitive structure of the interstate natural gas pipeline industry and create a regulatory framework that puts natural gas sellers into direct contractual relations with natural gas buyers by, among other things, ensuring that the sale of natural gas is unbundled from the sale of transportation and storage services. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future.

Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act (the "NGA") and by regulations and orders promulgated under the NGA by FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

We cannot accurately predict how FERC's actions will impact competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are regularly pending before FERC and the courts, as the natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that any of the measures established by FERC will continue in effect or that they will not be materially altered, potentially on short notice. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the Commodity Futures Trading Commission (the "CFTC") and the Federal Trade Commission. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities.

Gathering services, which occur upstream of FERC jurisdictional transmission services, are regulated by the states onshore and in state waters. Although FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, FERC's determinations as to the classification of facilities is done on a case by case basis. State regulation of natural gas gathering facilities generally includes various

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safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of Pipeline Safety

Natural gas and crude oil pipelines are subject to regulation by the Pipeline and Hazardous Materials Safety Administration (“PHMSA”) of the U.S. Department of Transportation under the Natural Gas Pipeline Safety Act of 1968, as amended (“NGPSA”), with respect to natural gas, and the Hazardous Liquids Pipeline Safety Act of 1979, as amended (“HLPSA”), with respect to crude oil, NGLs and condensates. Both the NGPSA and the HLPSA were amended by the Pipeline Safety Improvement Act of 2002 (“PSI Act”) and the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (“PIPES Act”). The NGPSA and HLPSA, as amended, govern the design, installation, testing, construction, operation, replacement and management of natural gas, crude oil, NGL and condensate pipeline facilities. Pursuant to these acts, PHMSA has promulgated regulations governing, among other things, pipeline wall thickness, design pressures, maximum operating pressures, pipeline patrols and leak surveys, minimum depth requirements, and emergency procedures, as well as other matters intended to ensure adequate protection for the public and to prevent accidents and failures. Additionally, PHMSA has promulgated regulations requiring pipeline operators to develop and implement integrity management programs for certain gas and hazardous liquid pipelines that, in the event of a pipeline leak or rupture, could affect “high consequence areas,” which are areas where a release could have the most significant adverse consequences, including high-population areas, certain drinking water sources and unusually sensitive ecological areas. At present, our operations are not subject to PHMSA’s integrity management regulations. We believe that our pipeline operations are in substantial compliance with applicable NGPSA and HLPSA requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, future compliance with the NGPSA and HLPSA could result in increased costs.

We, or the entities in which we own an interest, inspect our pipelines regularly in compliance with state and federal maintenance requirements. Nonetheless, the adoption of new or amended regulations by PHMSA or the states that result in more stringent or costly pipeline integrity management or safety standards could have a significant adverse effect on us and similarly situated operators. For instance, in August 2011, PHMSA published an advance notice of proposed rulemaking and sought public comment on a number of proposed changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, revising the definitions of “high consequence areas” and “gathering lines” and strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed. Most recently, in an August 2014 report to Congress from the U.S. Government Accountability Office (“GAO”), the GAO acknowledged PHMSA’s continued assessment of the safety risks posed by gathering lines and recommended that PHMSA move forward with rulemaking to address larger-diameter, higher-pressure gathering lines, including subjecting such pipelines to emergency response planning requirements that currently do not apply. Our gathering line assets only include small diameter, low-pressure pipelines. Based on current regulatory initiatives and statements made by

PHMSA, we do not expect our gathering assets to become regulated as a result of any future rulemakings related to gathering lines. However, we cannot guarantee that PHMSA will not attempt to extend its jurisdiction over our assets at some point in the future.

Environmental Regulation

Our operations are subject to stringent federal, state and local laws and regulations regulating the discharge and disposal of materials into the environment or otherwise relating to health and safety or the protection of the environment

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and natural resources. These laws and regulations may, among other things: (i) require the acquisition of permits to conduct drilling and other regulated activities; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities; (iii) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (iv) require remedial measures to clean up or mitigate pollution from former and ongoing operations, such as requirements to close waste pits and plug abandoned wells, or at off-site waste disposal locations; (v) impose specific safety and health criteria addressing worker protection; and (vi) impose substantial liabilities for pollution resulting from drilling and production operations. Numerous governmental agencies, such as the U.S. Environmental Protection Agency ("EPA") and analogous state agencies (and, in some cases, private individuals), enforce these laws and regulations, which often require difficult and costly compliance measures. Failure to comply with these laws and regulations may result in the assessment of substantial administrative, civil and criminal penalties, the issuance of injunctions limiting or prohibiting our activities, or the imposition of remedial obligations. In addition, some laws and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, rendering a person liable for environmental damages and cleanup costs without regard to negligence or fault on the part of that person. Adherence to these regulatory requirements increases our cost of doing business and consequently affects our profitability.

New programs and changes in existing regulatory programs are anticipated, some of which include regulations related to the management of natural occurring radioactive materials, oil and natural gas exploration and production, waste management, and underground injection of waste material and the regulation of hydraulic fracturing. Environmental laws and regulations have been subject to frequent changes over the years, and the trend has been the imposition of more stringent requirements. While we believe that we are in substantial compliance with current applicable environmental laws and regulations, changes in existing or new laws or regulations could have a material adverse effect on our financial condition and results of operations. From time to time, we may be involved in lawsuits related to alleged pollution or environmental damage. In addition, we cannot assure you that we will not incur significant costs as a result of releases or spills in the course of our operations. For example, following the closing of the Combination, we inherited potential liability for several legacy lawsuits filed against Forest. Adverse judgments against us related to these matters could have a material impact on our business. Please see "Part I, Item 3. Legal Proceedings" for more information.

The following is a summary of select existing and proposed environmental and occupational health and safety laws, as amended from time to time, to which our business operations are or may be subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous Substances and Wastes

The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes and their implementing regulations, regulate the generation, storage, treatment, transportation, disposal and cleanup of certain hazardous and non-hazardous solid wastes. Under the auspices of the EPA, most states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of oil or natural gas, including naturally occurring radioactive material, if properly handled, are exempt from regulation as hazardous waste under Subtitle C of RCRA. These wastes, instead, are regulated under RCRA's less stringent nonhazardous solid waste provisions, state laws or other laws. However, it is possible that certain oil and natural gas exploration, development and production wastes now classified by regulatory agencies as nonhazardous solid wastes could be classified as hazardous wastes in the future. For example, in August 2015, nonprofit environmental groups filed a notice of intent to sue the EPA regarding its failure to review the exemption. A loss of the RCRA hazardous waste exclusion for drilling fluids, produced waters and related wastes could result in an increase in our costs to manage and dispose of generated wastes, which could have a material adverse effect on our results of operations and financial position. In addition, in the course of our operations, we generate ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may become regulated as hazardous wastes if such wastes have hazardous characteristics.

The Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”), also known as the Superfund law and comparable state laws impose liability, without regard to fault or legality of conduct, on classes of persons considered to be responsible for the release of certain “hazardous substances” into the environment. These

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persons can include the current and past owner or operator of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible parties the costs they incur. In addition, neighboring landowners and other third-parties may file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Although petroleum, including crude oil or any fraction thereof, is not a CERCLA "hazardous substance," we generate materials in the course of our operations that may be regulated as CERCLA hazardous substances and thus may be subject to joint and several liability for the costs to clean up sites at which these hazardous substances have been released into the environment.

We currently own, lease, operate and/or have acquired, and have in the past owned, leased operated, numerous properties that have been used for oil and natural gas exploration and production activities for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for recycling or disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or petroleum hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or pit closure operations to prevent future contamination.

Water Discharges and Releases

Our operations are also subject to the Clean Water Act (the "CWA") and analogous state laws. The CWA and similar state laws regulate discharges of wastewater, oil, and other pollutants to regulated water bodies, such as lakes, rivers, wetlands, and streams. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the analogous state agency. In addition, spill prevention, control and countermeasure plan requirements imposed under the CWA require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. The CWA and analogous state laws also require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities, and also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. We believe that we will be able to obtain, or be included under, these permits, where necessary, and would be able to make whatever minor modifications to existing facilities and operations are necessary to comply with CWA requirements and that such modifications would not have a material effect on us. Failure to obtain or comply with permits or other CWA could result in administrative, civil and criminal penalties, orders to cease such discharges, and costs to remediate and pay natural resources damages.

The Oil Pollution Act of 1990 ("OPA"), which amended the CWA, imposes ongoing requirements on owners and operators of facilities that handle certain quantities of oil, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental clean-up and restoration costs that could be incurred in connection with an oil spill. In addition, OPA establishes strict liability for owners and operators of facilities that are the site of a release of oil into regulated waters. If a release into regulated waters occurs, we could be liable for clean-up costs, natural resources damages and public and private damages.

Hydraulic Fracturing

Hydraulic fracturing is an essential and common practice in the oil and natural gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the well bore. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with many of the wells for which we are the operator. While hydraulic fracturing is generally exempt from regulation the Safe Drinking Water Act’s (“SDWA”) Underground Injection Control (“UIC”) and has historically been regulated by state oil and natural gas commissions, the EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities. For example, the EPA published revised permitting guidance in February 2014 addressing the performance of such activities using diesel fuels. Also, in May 2014, the EPA published an advance notice of proposed rulemaking under the Toxic Substances Control Act seeking stakeholder input on development of a requirement regarding disclosure of information on chemical substances and mixtures used in hydraulic fracturing. The public comment period on the EPA's advance notice ended in September 2014, and a final notice of proposed rulemaking is expected in 2016. In addition, in April 2015, the EPA proposed regulations under the Clean Water Act to regulate wastewater discharges from hydraulic fracturing to publicly-owned treatment works (the final rule is expected to be issued in 2016). In addition to rulemakings, increased scrutiny of the oil and natural gas industry may occur as a result of the EPA's FY2014-2016 National Enforcement Initiative, "Ensuring Energy Extraction Activities Comply with Environmental Laws," through which the EPA will address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment; starting October 1, 2016, this initiative will continue for three more fiscal years.

In March 2015, the federal Bureau of Land Management published a final rule governing hydraulic fracturing on federal and Indian lands that replaces a prior draft of proposed rulemaking issued by the agency in May 2012. The rule requires public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. However, a federal judge has granted a preliminary injunction preventing enforcement of the rules.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater in 2011 and issued a draft assessment for public comment and peer review in June 2015; the assessment is expected to be finalized in 2016. The draft assessment concluded that hydraulic fracturing has not led to widespread, systemic impacts on drinking water resources, but it does have the potential to impact drinking water resources; however, this conclusion has recently been criticized by the EPA's Science Advisory Board. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal SDWA or other regulatory mechanisms.

In addition, the U.S. Congress has from time to time considered the adoption of legislation to provide for federal regulation of the hydraulic fracturing or to require disclosure of the chemicals used in the hydraulic fracturing process. Furthermore, some states, including Texas, have adopted or are considering adopting legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities, or that ban hydraulic fracturing altogether. Some local governments have also adopted ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Any additional federal, state or local restrictions on hydraulic fracturing that may be imposed in areas where we conduct business could result in substantial incremental operating, capital and compliance costs as well as delay our ability to develop oil and natural gas reserves.

Underground Injection Wells

Our oil and natural gas exploration and production operations generate produced water, drilling muds, and other waste streams, some of which may be disposed via injection in underground wells situated in non-producing subsurface formations. The disposal of oil and natural gas wastes into underground injection wells are subject to the SDWA's UIC program and analogous state programs. EPA directly administers the UIC program in some states and in others it delegates administration to the state. Permits must be obtained before drilling salt water disposal wells, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking saltwater to groundwater. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SDWA and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury. In response to recent seismic events near underground injection wells used for the disposal

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of oil and gas-related wastewaters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity. For example, in 2015, a U.S. Geological Survey report identified eight states, including Texas, with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. In response to these concerns, regulators in some states have shut down or imposed moratoria on the use of such injection wells and are considering additional requirements related to seismic safety. For example, the Texas Railroad Commission ("RRC") on October 28, 2014, adopted new oil and gas permit rules for wells used to dispose of saltwater and other fluids resulting from the production of oil and natural gas in order to address these seismic activity concerns within the state. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells, and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. If new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in our operations, our costs to operate may significantly increase and our ability to continue production may be delayed or limited, which could have a material adverse effect on our results of operations and financial position.

Air Emissions

The federal Clean Air Act (the "CAA") and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed and continues to develop stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations. Our operations are in certain circumstances and locations subject to permitting requirements and restrictions under these statutes for emissions of air pollutants.

Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in January 2013, the EPA published revised regulations under the CAA to control emissions of hazardous air pollutants from existing stationary reciprocal internal combustion engines. The revised rule requires management practices for all covered engines and requires the installation of oxidation catalysts or non-selective catalytic reduction equipment on larger equipment at sites that are not deemed "remote" under the rule. We believe our operations are in substantial compliance with the requirements of this rule.

In addition, in 2012, the EPA issued final rules under the CAA that subject oil and natural gas production, processing, transmission, and storage operations to regulation under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants programs. These rules restrict volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non wildcat and non delineation gas wells; and all "other" fractured and refractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare. "Other" wells, however, must use reduced emission completions, also known as "green completions," with or without combustion devices. The capture of flowback emissions is required only after the facility's processing system can be brought to pressure. These regulations also establish specific requirements regarding emissions from production related wet seal and reciprocating compressors, pneumatic controllers, and storage vessels. The EPA received numerous requests for reconsideration of these rules, and court challenges to the rules were also filed. The EPA has issued, and will likely continue to issue, revised rules responsive to some of these requests. For example, on December 19, 2014, the EPA finalized amendments and clarifications to the NSPS rules, including, for example, updates and clarifications to requirements related to well completion activities, storage tanks, and leak detection. To date, our costs to comply with the NSPS have not been material. In September 2015, the EPA proposed updates to the NSPS rules that would impose volatile organic compound emissions limits on certain oil and natural gas operations that were previously unregulated, including hydraulically fractured oil wells, as well as methane emissions limits for certain new or modified oil and natural gas emissions sources (the rules are expected to be finalized in June 2016). In addition, the EPA published a final regulation on October 1, 2015 that reduces the National Ambient Air Quality Standard for ozone to between 65 to 70 parts per billion ("ppb") for both the 8 hour primary and secondary standards protective of public health and public welfare. These regulations, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities, or utilize specific

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equipment or technologies to control emissions. Compliance with these requirements could increase our costs of development and production, which costs could be significant.

Climate Change

The EPA has determined that emissions of greenhouses gases ("GHGs") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted various regulations regarding GHGs under existing provisions of the CAA. For example, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain oil and natural gas production facilities on an annual basis, which includes certain of our operations. Further, in 2015, the EPA finalized a rule that requires reporting of GHG emissions from gathering and boosting systems, oil well completions and workovers using hydraulic fracturing, and blowdowns of natural gas transmission pipelines. The expansion of the EPA's GHG reporting program could result in increased compliance costs.

The EPA also recently proposed new regulations that set methane emission standards for new and modified oil and natural gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and natural gas sector by up to 45% from 2012 levels by 2025; the regulations are expected to be finalized in 2016. To aid in these efforts, in January 2016, the federal Bureau of Land Management proposed rules to reduce methane emissions from venting, flaring and leaking on public lands. In addition, the Clean Power Plan, which was announced in August 2015, seeks to reduce carbon dioxide emissions by 32 percent from 2005 levels by 2030; however, on February 9, 2016, the U.S. Supreme Court stayed the implementation of the plan while it is being challenged in court. Furthermore, the U.S. is a party to the Paris Agreement adopted in December 2015 to reduce global greenhouse emissions.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that require reporting of GHGs or otherwise limit emissions of GHGs from our equipment and operations could require us to incur costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with our operations, and such requirements also could adversely affect demand for the oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Threatened and Endangered Species

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, as well as migratory birds. We may conduct operations in areas where certain species that are listed as threatened or endangered are known to exist and where other species that potentially could be listed as threatened or endangered may exist. The U.S. Fish and Wildlife Service ("FWS") may designate critical habitat and suitable habitat areas that it believes are necessary for the survival of threatened or endangered species. On February 11, 2016, the U.S. Fish and Wildlife Service published a final policy which alters how it identifies critical habitat for endangered and threatened species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or development. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the FWS is required to make a determination on listing of more than 250 species as endangered or threatened under the Endangered Species Act ("ESA") by no later than completion of the agency's 2017 fiscal year. For example, in March 2014, FWS listed the lesser prairie chicken as a threatened species under the ESA. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising

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from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves.

OSHA

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended ("OSHA") and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right-to-Know Act and comparable state statutes and any implementing regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens. In December 2015, the U.S. Departments of Justice and Labor announced a plan to more frequently and effectively prosecute worker health and safety violations, including enhanced penalties. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Related Permits and Authorizations

Many environmental laws require us to obtain permits or other authorizations from state and/or federal agencies before initiating certain drilling, construction, production, operation, or other oil and natural gas activities, and to maintain these permits and compliance with their requirements for ongoing operations. These permits are generally subject to protest, appeal, or litigation, which can in certain cases delay or halt projects and cease production or operation of wells, pipelines, and other operations.

Related Insurance

We maintain an insurance program designed to provide coverage for our property and casualty exposures. Our risk management program provides coverage types, limits, and deductibles commensurate with companies of comparable size and with similar risk profiles. As is common in the oil and natural gas industry, we do not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a material adverse effect on our financial position and results of operations. There can be no assurance that the insurance coverage that we maintain will be sufficient to cover every claim made against us in the future. As hydraulic fracturing is a key component of our operational strategy, we maintain Claims Made Pollution Liability Insurance, which provides coverage for long-term gradual seepage pollution events. A loss in connection with our oil and natural gas operations could have a material adverse effect on our financial position and results of operations to the extent that the insurance coverage provided under our policies is inadequate to cover any such loss.

Employees

As of December 31, 2015, we had 146 full-time employees. We hire independent contractors on an as needed basis. We have no collective bargaining agreements with our employees. We believe that our employee relationships are satisfactory. In connection with our bankruptcy filing and liquidity constraints, we have performed layoffs throughout 2015 and into the first quarter of 2016. We continue to monitor the best allocation of our capital to promote enterprise value, including any cost-reducing cuts to our general and administrative expenses.

Geographical Data

We operate in one industry segment, oil and gas exploration and production, and have one reportable geographical business segment, the United States.

Available Information

We are required to file any annual, quarterly and current reports, proxy statements and certain other information with the SEC. You may read and copy any documents filed by us with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1 800 SEC 0330. Our filings with the SEC are also available to the public from commercial document retrieval services and at the SEC's website at http://www.sec.gov.

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We also make available on our website (www.sabineoil.com) all of the documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Our Code of Business Conduct and Ethics, Corporate Governance Guidelines, Financial Code of Ethics and Regulation FD Policy are also available on our website and in print free of charge to any stockholder who requests them. Requests should be sent by mail to 1415 Louisiana, Suite 1600, Houston, Texas 77002, attention Secretary. Information contained on our website is not incorporated by reference into this Annual Report on Form 10 K.

Legal Proceedings

We are party to lawsuits arising in the ordinary course of our business. We cannot predict the outcome of any such lawsuits with certainty, but our management team does not expect the outcome of pending or threatened legal matters to have a material adverse impact on our financial condition. Please see "Part I, Item 3. Legal Proceedings" for more information.

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Item 1A. Risk Factors

The following are certain risk factors that affect our business, financial condition, results of operations and cash flows. Many of these risks are beyond our control. These risk factors should be considered in connection with evaluating the forward-looking statements contained in this Annual Report on Form 10-K. The risks and uncertainties described below are not the only ones that we face. If any of the events described below were to actually occur, our business, financial condition, results of operations and cash flows could be adversely affected and our results could differ materially from expected and historical results, any of which may also adversely affect the holders of our stock.

We have filed voluntary petitions for relief under the Bankruptcy Code and are subject to the risks and uncertainties associated with bankruptcy cases.

We have filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code. For the duration of the Chapter 11 Cases, our business and operations will be subject to various risks, including but not limited to the following:

- Our ability to develop, file and complete a Chapter 11 plan of reorganization, particularly during the exclusivity period (i.e. in general, the period in which we have the exclusive right to file a Chapter 11 plan of reorganization);
- Our ability to obtain Bankruptcy Court, creditor and regulatory approval of a Chapter 11 plan of reorganization in a timely manner;
- Our ability to obtain Bankruptcy Court approval with respect to motions in the Chapter 11 Cases and the outcomes of Bankruptcy Court rulings and of the Chapter 11 Cases in general;
- Risks associated with third party motions in the Chapter 11 Cases, which may interfere with our business operations or our ability to propose and/or complete a Chapter 11 plan of reorganization;
- Increased costs related to the Chapter 11 Cases and related litigation;
- A loss of, or a disruption in the materials or services received from, suppliers, contractors or service providers with whom we have commercial relationships;
- Potential increased difficulty in retaining and motivating our key employees through the process of reorganization, and potential increased difficulty in attracting new employees;
- Significant time and effort required to be spent by our senior management in dealing with the bankruptcy and restructuring activities rather than focusing exclusively on business operations;

We are also subject to risks and uncertainties with respect to the actions and decisions of creditors and other third parties who have interests in our Chapter 11 Cases that may be inconsistent with our plans. These risks and uncertainties could affect our business and operations in various ways and may significantly increase the duration of the Chapter 11 Cases. Because of the risks and uncertainties associated with Chapter 11 Cases, we cannot predict or quantify the ultimate impact that events occurring during the Chapter 11 Cases may have on our business, cash flows, liquidity, financial condition and results of operations, nor can we predict the ultimate impact that events occurring during the Chapter 11 Cases may have on our corporate or capital structure.

We believe it is highly likely that the shares of our existing common stock will be cancelled in our Chapter 11 proceedings.

We have a significant amount of indebtedness that is senior to our existing common stock in our capital structure. As a result, we believe that it is highly likely that the shares of our existing common stock will be cancelled in our Chapter 11 proceedings and will be entitled to a limited recovery, if any. Any trading in shares of our common stock during the pendency of the Chapter 11 proceedings is highly speculative and poses substantial risks to purchasers of shares of our common stock.

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Operating under Bankruptcy Court protection for a long period of time may harm our business.

Our future results are dependent upon the successful confirmation and implementation of a plan of reorganization. A long period of operations under Bankruptcy Court protection could have a material adverse effect on our business, financial condition, results of operations and liquidity. So long as the proceedings related to the Chapter 11 proceedings continue, our senior management will be required to spend a significant amount of time and effort dealing with the reorganization instead of focusing exclusively on our business operations. A prolonged period of operating under Bankruptcy Court protection also may make it more difficult to retain management and other key personnel necessary to the success and growth of our business. In addition, the longer the proceedings related to the Chapter 11 proceedings continue, the more likely it is that our customers and suppliers will lose confidence in our ability to reorganize our businesses successfully and seek to establish alternative commercial relationships.

Furthermore, so long as the Chapter 11 proceedings continue, we will be required to incur substantial costs for professional fees and other expenses associated with the administration of the Chapter 11 proceeding. The Chapter 11 cases may also require us to seek debtor-in-possession financing to fund operations. If we are unable to obtain such financing on favorable terms or at all, our chances of successfully reorganizing our business may be seriously jeopardized, the likelihood that we instead will be required to liquidate our assets may be enhanced, and, as a result, any securities in the debtor could become further devalued or become worthless.

Furthermore, we cannot predict the ultimate amount of all settlement terms for the liabilities that will be subject to a plan of reorganization. Even once a plan of reorganization is approved and implemented, our operating results may be adversely affected by the possible reluctance of prospective lenders and other counterparties to do business with a company that recently emerged from Chapter 11 proceedings.

We may not be able to obtain confirmation of a Chapter 11 plan of reorganization.

On January 26, 2016, the Debtors filed with the Bankruptcy Court a joint plan of Reorganization (the "Plan of Reorganization") for the resolution of the outstanding claims against and interests in the Debtors and a disclosure statement (the "Disclosure Statement") related thereto. The Plan of Reorganization, if implemented as proposed by the Debtors, would significantly reduce our outstanding long-term debt and annual interest payments. To emerge successfully from Bankruptcy Court protection as a viable entity, we must meet certain statutory requirements with respect to adequacy of disclosure with respect to the Plan of Reorganization, solicit and obtain the requisite acceptances of such Plan of Reorganization and fulfill other statutory conditions for confirmation of such Plan of Reorganization, most of which have not occurred to date. The confirmation process is subject to numerous, unanticipated potential delays, including a delay in the Bankruptcy Court's commencement of the confirmation hearing regarding our Plan of Reorganization.

We may not receive the requisite acceptances of constituencies in these Chapter 11 proceedings to confirm or consummate the Plan of Reorganization, an alternative plan of reorganization or another alternative restructuring transaction, including a sale of all or substantially all of our assets, which satisfies the condition of the Bankruptcy Code and is authorized by the Bankruptcy Court. Even if the requisite acceptances of our Plan of Reorganization are received, the Bankruptcy Court may not confirm the Plan of Reorganization. The precise requirements and evidentiary showing for confirming a plan, notwithstanding its rejection by one or more impaired classes of claims or equity interests, depends upon a number of factors including, without limitation, the status and seniority of the claims or equity interests in the rejecting class (e.g., secured claims or unsecured claims, subordinated or senior claims, preferred or common stock).

If a Chapter 11 plan of reorganization is not confirmed by the Bankruptcy Court, it is unclear whether we would be able to reorganize our business and what, if anything, holders of claims against us would ultimately receive with respect to their claims.

Even if a Chapter 11 plan of reorganization is consummated, we will continue to face risks.

Even if a Chapter 11 plan of reorganization is consummated, we will continue to face a number of risks, including certain risks that are beyond our control, such as further deterioration or other changes in economic conditions, changes in our industry, potential revaluing of our assets due to Chapter 11 proceedings, changes in consumer demand for, and acceptance of, our oil and gas and increasing expenses. Some of these concerns and effects typically become more acute when a case under the Bankruptcy Code continues for a protracted period without indication of how or when the case may be completed. As a result of these risks and others, there is no guaranty that the Plan of Reorganization or any other plan of reorganization will achieve our stated goals.

In addition, at the outset of the Chapter 11 proceedings, the Bankruptcy Code gives the debtor the exclusive right to file and solicit acceptance of the Plan of Reorganization and prohibits creditors, equity security holders and others from filing or soliciting a plan for a certain period of time. To date, we have retained the exclusive right to propose the Plan of Reorganization, and, on December 16, 2015, the Bankruptcy Court granted a request to extend our exclusive rights to file and solicit acceptance of the Plan of Reorganization through February 10, 2016, and April 11, 2016, respectively. The Debtors have filed a motion to further extend their exclusive rights to file and solicit acceptance of the Plan of Reorganization through June 9, 2016 and August 9, 2016, respectively. If the Bankruptcy Court terminates that right, however, or the exclusivity period expires, there could be a material adverse effect on our ability to achieve confirmation of the Plan of Reorganization in order to achieve our stated goals.

Furthermore, even if our debts are reduced or discharged through the Plan of Reorganization, we may need to raise additional funds through public or private debt or equity financing or other various means to fund our business after the completion of the Chapter 11 process. Adequate funds may not be available when needed or may not be available on favorable terms.

We have substantial liquidity needs and may be required to seek additional financing. If we are unable to obtain financing on satisfactory terms or maintain adequate liquidity, our ability to replace our proved reserves or to maintain current production levels and generate revenue will be limited.

Our principal sources of liquidity historically have been equity contributions, borrowings under the New Revolving Credit Facility, net cash provided by operating activities, net proceeds from the issuance of the 2017 Notes and proceeds from the Term Loan Facility. Our capital program will require additional financing above the level of cash generated by our operations to fund growth. If our cash flow from operations remains depressed or decreases as a result of lower commodity prices or otherwise, our ability to expend the capital necessary to replace our proved reserves, maintain our leasehold acreage or maintain current production may be limited, resulting in decreased production and proved reserves over time. In addition, drilling activity may be directed by our partners in certain areas and we may have to forfeit acreage if we do not have sufficient capital resources to fund our portion of expenses.

We face uncertainty regarding the adequacy of our liquidity and capital resources and have extremely limited, if any, access to additional financing. In addition to the cash requirements necessary to fund ongoing operations, we have incurred significant professional fees and other costs in connection with preparation for and consummation of the Chapter 11 proceedings. We cannot assure you that cash on hand and cash flow from operations will be sufficient to continue to fund our operations and allow us to satisfy our obligations related to the Chapter 11 Cases until we are able to emerge from Chapter 11. We face additional uncertainty regarding the ability to emerge successfully from Chapter 11 and to obtain adequate liquidity to finance our capital program subsequent to emergence from Chapter 11.

Our liquidity, including our ability to meet our ongoing operational obligations, is dependent upon, among other things: (i) our ability to comply with the terms and conditions of the final cash collateral order entered by the Bankruptcy Court on September 16, 2015 in connection with the Chapter 11 proceedings, (ii) our ability to maintain adequate cash on hand, (iii) our ability to generate cash flow from operations, (iv) our ability to develop, confirm and consummate a Chapter 11 plan or other alternative restructuring transaction, and (v) the cost, duration and outcome of the Chapter 11 proceedings. Our ability to maintain adequate liquidity depends in part upon industry conditions and general economic, financial, competitive, regulatory and other factors beyond our control. In the event that cash on hand and cash flow from operations is not sufficient to meet our liquidity needs, we may be required to seek additional financing. We can provide no assurance that additional financing would be available or, if available, offered to us on acceptable terms. Our access to additional financing is, and for the foreseeable future will likely continue to be, extremely limited if it is available at all. Our long-term liquidity requirements and the adequacy of our capital resources are difficult to predict at this time.

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As a result of the Chapter 11 Cases, our historical financial information may be volatile and not be indicative of our future financial performance.

During the Chapter 11 proceedings, we expect our financial results to continue to be volatile as asset impairments, asset dispositions, restructuring activities and expenses, contract terminations and rejections, and claims assessments and may significantly impact our consolidated financial statements. As a result, our historical financial performance may not be indicative of our financial performance after the date of the bankruptcy filing.

Our capital structure will likely be significantly altered under any Chapter 11 plan confirmed by the Bankruptcy Court. Under fresh-start accounting rules that may apply to us upon the effective date of a Chapter 11 plan, our assets and liabilities would be adjusted to fair value, which could have a significant impact on our financial statements. Accordingly, if fresh-start accounting rules apply, our financial condition and results of operations following our emergence from Chapter 11 would not be comparable to the financial condition and results of operations reflected in our historical financial statements. In connection with the Chapter 11 Cases and the development of a Chapter 11 plan, it is also possible that additional restructuring and related charges may be identified and recorded in future periods. Such charges could be material to our consolidated financial position, liquidity and results of operations.

We may be subject to claims that will not be discharged in the Chapter 11 proceedings, which could have a material adverse effect on our financial condition and results of operations.

The Bankruptcy Court provides that the confirmation of a plan of reorganization discharges a debtor from substantially all debts arising prior to confirmation. With few exceptions, all claims that arose prior to July 15, 2015 or before confirmation of the plan of reorganization (i) would be subject to compromise and/or treatment under the plan of reorganization and/or (ii) would be discharged in accordance with the Bankruptcy Code and the terms of the plan of reorganization. Any claims not ultimately discharged through a plan of reorganization could be asserted against the reorganized entities and may have an adverse effect on our financial condition and results of operations on a post-reorganization basis.

Transfers of our equity, or issuances of equity in connection with our Chapter 11 proceedings, may impair our ability to utilize our federal income tax net operating loss carryforwards in future years.

Under federal income tax law, a corporation is generally permitted to deduct from taxable income net operating losses carried forward from prior years. We have net operating loss carryforwards of approximately $1.0 billion as of December 31, 2015. Our ability to utilize our net operating loss carryforwards to offset future taxable income and to reduce federal income tax liability is subject to certain requirements and restrictions. If we experience an “ownership change,” as defined in section 382 of the Internal Revenue Code, then our ability to use our net operating loss carryforwards may be substantially limited, which could have a negative impact on our financial position and results of operations. Generally, there is an “ownership change” if one or more shareholders owning 5% or more of a corporation’s common stock have aggregate increases in their ownership of such stock of more than 50 percentage points over the prior three-year period. Following the implementation of a plan of reorganization, it is possible that an “ownership change” may be deemed to occur. Under section 382 of the Internal Revenue Code, absent an application exception, if a corporation undergoes an “ownership change,” the amount of its net operating losses that may be utilized to offset future taxable income generally is subject to an annual limitation.

We may experience increased levels of employee attrition as a result of the Chapter 11 Cases.

As a result of the Chapter 11 Cases, we may experience increased levels of employee attrition, and our employees likely will face considerable distraction and uncertainty. A loss of key personnel or material erosion of employee morale could adversely affect our business and results of operations. Our ability to engage, motivate and retain key employees or take other measures intended to motivate and incent key employees to remain with us through the pendency of the Chapter 11 Cases is limited by restrictions on implementation of incentive programs under the Bankruptcy Code. The loss of services of members of our senior management team could impair our ability to execute our strategy and implement operational initiatives, which would be likely to have a material adverse effect on our financial condition, liquidity and results of operations.

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Oil, natural gas and NGLs prices are volatile. The recent decline in oil, natural gas and NGLs prices has adversely affected our financial position, financial results, cash flow, access to capital and ability to grow.

Our future financial condition, revenues, results of operations and rate of growth depend primarily upon the prices we receive for our oil and natural gas production, and the carrying value of our oil and natural gas properties is dependent upon prevailing prices for oil, natural gas and NGLs. Oil, natural gas and NGLs prices historically have been volatile, and are likely to continue to be volatile in the future, especially given current economic and geopolitical conditions. The New York Mercantile Exchange ("NYMEX") natural gas prices during 2015 ranged from a high of $3.32 to a low of $1.63 per MMbtu and the NYMEX oil prices during 2015 ranged from a high of $61.36 to a low of $34.55 per Bbl. Thus far in 2016, commodity prices have continued to be significantly depressed and volatile, with NYMEX natural gas prices ranging from a high of $2.54 to a low of $1.49 per MMbtu and the NYMEX oil prices ranging from a high of $38.51 to a low of $26.19 per Bbl through March 21, 2016. This low commodity price environment and price volatility also affects the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital.

The speed and severity of the decline in oil and gas prices during 2015 and the continued lower prices in the first quarter of 2016 has adversely affected our results of operations and our estimates of our proved oil and natural gas reserves. Continued periods of depressed commodity prices or further price decreases could have a material adverse effect on our operations and limit our ability to fund capital expenditures. Without the ability to fund capital expenditures, we would be unable to replace reserves and production. Sustained low commodity prices will further adversely affect our revenues, net income, cash flows, proved reserves and our ability to fund capital expenditures.

Prices for oil, natural gas and NGLs may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the regional, domestic and foreign supply of oil and natural gas;
- uncertainty in capital and commodities markets;
- the price of foreign imports;
- the ability and willingness of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- overall domestic and global economic conditions;
- political and economic conditions in oil and natural gas producing countries, including the Middle East, Africa, South America and Russia including the imposition of trade sanctions;
- the level of consumer product demand;
- weather conditions;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxes;
- proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of competitors' supplies of oil and natural gas and alternative fuels;
- variations between product prices at sales points and applicable index prices; and
- the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East.

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We have significant exposure to fluctuations in commodity prices since none of our estimated future production is covered by commodity derivatives and we may not be able to enter into commodity derivatives covering our estimated future production on favorable terms or at all.

In the past, we have entered into financial commodity derivative contracts to mitigate the potential negative impact on cash flow caused by changes in oil and natural gas prices. However, as a result of certain events of default under our derivative contracts, all our derivative contracts have been terminated. Subsequent to the termination of these derivative contracts, we have not entered into additional derivative contracts. During the Chapter 11 proceedings, our ability to enter into new commodity derivatives covering additional estimated future production will be dependent upon either entering into unsecured hedges or obtaining Bankruptcy Court approval to enter into secured hedges. As a result, we may not be able to enter into additional commodity derivatives covering our production in future periods on favorable terms or at all. If we cannot or choose not to enter into commodity derivatives in the future, we could be more affected by changes in commodity prices than our competitors who engage in hedging arrangements. Our inability to hedge the risk of low commodity prices in the future, on favorable terms or at all, could have a material adverse impact on our business, financial condition and results of operations.

If we are able to enter into any commodity derivatives, they may limit the benefit we would receive from increases in commodity prices. These arrangements would also expose us to risk of financial losses in some circumstances, including the following:

- our production could be materially less than expected; or
- the counterparties to the contracts could fail to perform their contractual obligations.

If our actual production and sales for any period are less than the production covered by any commodity derivatives (including reduced production due to operational delays) or if we are unable to perform our exploration and development activities as planned, we might be required to satisfy a portion of our obligations under those commodity derivatives without the benefit of the cash flow from the sale of that production, which may materially impact our liquidity. Additionally, if market prices for our production exceed collar ceilings or swap prices, we would be required to make monthly cash payments, which could materially adversely affect our liquidity.

The trustee for our 2019 Notes has asserted certain claims against us related to the Combination.

On February 26, 2015, we were served with a complaint (the “Complaint”) concerning the indenture that governs our 2019 Notes that generally alleges that certain events of default had occurred with respect to the 2019 Notes due to the Combination. Specifically, the Complaint alleges that the Combination constituted a change of control under the indenture which requires us to offer to purchase the 2019 Notes at 101% of the outstanding principal, plus accrued and outstanding interest of the notes. We also received a notice of default and acceleration from the Trustee with respect to the 2019 Notes containing similar allegations. We believe these allegations against us are without merit and intend to vigorously defend against such claims and pursue any and all defenses available. We are separately evaluating potential claims that we may assert against the trustee for the 2019 Notes for any and all losses we may suffer as a result of the complaint or notice. We can provide no guarantee that any such claims, if brought by us, will be successful or, if successful, that the responsible parties will have the financial resources to address any such claims. Furthermore, additional claims, lawsuits, or proceedings may be filed or commenced arising out of the indentures to which we are a party and with respect to the Combination.

As a result of the pending bankruptcy proceedings, this matter is currently stayed.

Our common stock is no longer listed on a national securities exchange and is quoted only in over-the-counter markets, which carries substantial risks and could continue to negatively impact our stock price, volatility and liquidity.

Upon the closing of the Combination, the New York Stock Exchange (the “NYSE”) suspended trading in our common stock and commenced delisting proceedings due to our failure to meet the initial listing standards under Rule 102.01 of the NYSE Listed Company Manual. On December 17, 2014, our common stock began trading over the counter on the OTCQB Marketplace (the “OTCQB”) under the ticker symbol “FSTO” and later under the ticker symbol

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"SOGCQ." Additionally, as a result of the filing of the Bankruptcy Petitions, the Company's common stock can no longer be traded on the OTCQB Marketplace and is now trading on the OTC Pink Marketplace. We continue to file periodic reports with the SEC in accordance with the requirements of Section 12 (g) of the Exchange Act.

Our delisting from the NYSE and commencement of trading on the OTC Pink Marketplace has resulted and may continue to result in a reduction in some or all of the following, each of which could have a material adverse effect on our stockholders:

- the liquidity of our common stock;
- the market price of shares of our common stock;
- our ability to obtain financing for the continuation of our operations;
- the number of institutional and other investors that will consider investing in shares of our common stock;
- the number of market makers in shares of our common stock;
- the availability of information concerning the trading prices and volume of shares of our common stock; and
- the number of broker-dealers willing to execute trades in shares of our common stock.

Estimates of reserves and future net cash flows are not precise. The actual quantities of our reserves and future net cash flows may prove to be lower than estimated.

Numerous uncertainties exist in estimating quantities of reserves and future net cash flows therefrom. Our estimates of reserves and related future net cash flows are based on various assumptions, which may ultimately prove to be inaccurate. Petroleum engineering is a subjective process of estimating accumulations of oil or natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including the following:

- historical production from the area compared with production from other producing areas;
- the quality, quantity and interpretation of available relevant data;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future commodity prices; and
- assumptions concerning future operating costs, severance, ad valorem and excise taxes, development costs, and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items, or other items not identified below, may differ materially from those assumed in estimating reserves:

- the quantities of oil and natural gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future commodity prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material.

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The prices used in calculating our estimated proved reserves and the estimated discounted future net cash flows from proved reserves are, in accordance with SEC requirements, calculated by determining the unweighted arithmetic average of the first-day-of-the-month commodity prices for the preceding twelve months. December 31, 2015, average prices used to calculate our estimated proved reserves and estimated discounted future net cash flows from proved reserves were $50.28 per Bbl for crude oil and $2.58 per MMbtu for natural gas. Commodity prices declined significantly throughout 2015 and if such prices do not increase significantly, it could have a negative impact on our future calculations of estimated proved reserves and the estimated discounted future net cash flows from proved reserves will be significantly lower than as of December 31, 2015. This could result in our having to remove non-economic reserves from our proved reserves in future periods.

Holding all other factors constant, if SEC pricing as of March 2016 of $46.26 per Bbl for crude oil and $2.39 per Mcf for natural gas is used in our year-end reserve estimates, our estimated discounted future net cash flows from proved reserves at December 31, 2015 would decrease by approximately $69 million, or 14%.

Actual future net cash flows also will be affected by other factors, including:

- the amount and timing of actual production;
- levels of future capital spending;
- increases or decreases in the supply of or demand for oil and natural gas; and
- changes in governmental regulations or taxation.

Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. In addition, the ten percent discount factor mandated by the rules and regulations of the SEC to be used in calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. Therefore, the estimates of discounted future net cash flows included in this Annual Report on Form 10-K should not be construed as accurate estimates of the current market value of our proved reserves.

Drilling for and producing oil and natural gas are risky activities with many uncertainties that could adversely affect our business, financial condition and results of operations.

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for oil and natural gas can be unprofitable, not only from dry holes, but from productive wells that do not produce sufficient revenues to return a profit. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on our evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical or less economic than forecasted. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory and contractual requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or other services or in obtaining water for hydraulic fracturing activities;
- equipment failures or accidents;
- adverse weather conditions;
- reductions in oil, natural gas and NGL prices;
- surface access restrictions;

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- loss of title or other title related issues;
- pipe or cement failures or casing collapses;
- compliance with environmental and other government requirements;
- environmental hazards, such as natural gas leaks, groundwater contamination resulting from improper well casing and cementing, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface or subsurface environment;
- fires, blowouts, surface craterings and explosions;
- uncontrollable flows of oils, natural gas, formation water, or well fluids;
- oil, natural gas or NGLs gathering, transportation and processing availability restrictions or limitations; and
- limitations in the market for oil and natural gas.

The occurrence of certain of these events could also affect third parties, including persons living near our operations, our employees and employees of our contractors, leading to injuries or death or property damage. As a result, we face the possibility of liabilities from these events that could adversely affect our business, financial condition and results of operations.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition and results of operations.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. The rate of decline will change if production from existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our future oil and natural gas reserves and production and, therefore, our cash flow and results of operations are highly dependent upon our success in efficiently developing and exploiting our current properties and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

Drilling locations that we have identified may not yield oil, natural gas or NGLs in commercially viable quantities.

Our drilling locations are in various stages of evaluation, ranging from a location which is ready to drill to a location that will require substantial additional interpretation. It is impossible to predict in advance of drilling and testing whether any particular location will yield oil, natural gas or NGLs in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil, natural gas or NGLs will be present or, if present, whether oil, natural gas or NGLs will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil, natural gas or NGLs exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from or abandonment of the well. If we drill additional wells that we identify as dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. In sum, the cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

Our identified drilling location inventories are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management has specifically identified drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These identified drilling locations represent a significant part of our business strategy. Our ability to drill and develop these locations depends on a number of factors, some of which are beyond our control,

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including the availability and cost of capital, weather conditions, including seasonal restrictions, regulatory approvals, oil, natural gas and NGLs prices, costs and drilling results. As a consequence, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. Therefore, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

As a result of the uncertainties described above, we may be unable to drill many of our potential resource play drilling locations. In addition, depending on the timing and concentration of the development of the non-proved locations, we would be required to generate or raise significant capital to develop all of our potential drilling locations should we elect to do so. Estimated reserves related to our properties as of December 31, 2015 assumed that capital costs of approximately $109.7 million would be required over a period of approximately five years in order to develop our proved undeveloped reserves. We may not be able to raise or generate the capital required to drill or develop these additional non-proved locations. Any drilling activities we are able to conduct on these potential locations may not be successful or allow us to add additional proved reserves to our overall proved reserves or may result in a downward revision of estimated proved reserves, which could have a material adverse effect on our future business and results of operations.

We have incurred losses from operations for various periods since our inception and may do so in the future.

Our development of and participation in an increasingly larger number of prospects has required and will continue to require substantial capital expenditures. The uncertainty and factors described throughout this “Risk Factors” section may impede our ability to economically find, develop, exploit and acquire oil and natural gas reserves. As a result, we may not be able to sustain profitability or positive cash flows from operating activities in the future.

We cannot be certain that the insurance coverage we maintain will be adequate to cover all losses that may be sustained in connection with our oil and natural gas producing activities.

We maintain an insurance program designed to provide coverage for our property and casualty exposures. Our risk management program provides coverage types, limits and deductibles commensurate with companies of comparable size and with similar risk profiles.

As is common in the oil and natural gas industry, we do not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a material adverse effect on our financial position and results of operations. There can be no assurance that the insurance coverage that we maintain will be sufficient to cover every claim made against us in the future. As hydraulic fracturing is a key component of our operational strategy, we maintain claims made pollution liability insurance, which provides coverage for long-term gradual seepage pollution events. A loss in connection with our oil and natural gas operations could have a material adverse effect on our financial position and results of operations to the extent that the insurance coverage provided under our policies is inadequate to cover any such loss.

Lower oil, natural gas, and natural gas liquids prices and other factors have resulted, and in the future may result, in ceiling test write-downs.

We use the full cost method of accounting to report our oil and natural gas activities. Under this method, we capitalize the cost to acquire, explore for, and develop oil and natural gas properties. Under full cost accounting rules, the net capitalized costs of proved oil and natural gas properties may not exceed a ceiling limit, which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%. If net capitalized costs of proved oil and natural gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings.

This is called a ceiling test writedown. Under the accounting rules, we are required to perform a ceiling test each quarter. A ceiling test write-down does not impact cash flows from operating activities, but it does reduce our shareholders’ equity.

The risk that we will be required to write-down the carrying value of our oil and natural gas properties increases when oil, natural gas, and natural gas liquids prices are low. In addition, write-downs may occur if we experience downward adjustments to our estimated proved reserves, or if estimated future development or operating costs increase.

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For example, during 2013, 2014 and 2015 we incurred a ceiling test write-down of zero, $247.7 million and $1.6 billion, respectively.

Additional write-downs may be required in subsequent periods if, among other things, the unweighted arithmetic average of the first-day-of-the-month oil, natural gas, and natural gas liquids prices used in the calculation of the present value of future net revenue from estimated production of estimated proved reserves decline compared to prices used as of December 31, 2015, estimated proved reserve volumes are revised downward, or costs incurred in exploration, development, or acquisition activities exceed the discounted future net cash flows from the additional reserves, if any. For example, the unweighted average of the historical first day of the month pricing for the previous twelve months of oil and natural gas as of December 31, 2015, were $50.28 per Bbl and $2.58 per MMbtu, respectively, compared to $46.26 per Bbl and $2.39 per MMbtu for oil and natural gas, respectively, as of March 2016. Holding all other factors constant, if commodity prices used in our year-end reserve estimates were decreased to these prices as of March 2016, our estimated discounted future cash flows from proved reserves at December 31, 2015 would decrease by approximately $69 million, or 14%.

There are inherent limitations in all internal control over financial reporting systems, and misstatements due to error or fraud may occur and not be detected.

While we have taken actions designed to address compliance with the requirements of the Sarbanes-Oxley Act of 2002, as amended, and the rules and regulations thereunder, there are inherent limitations in our ability to comply with these requirements. Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our internal control over financial reporting and disclosure controls and procedures will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, in our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Further, controls can be circumvented by individual acts of some persons, by collusion of two or more persons, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, a control may be inadequate because of changes in conditions or the degree of compliance with the policies or procedures may deteriorate. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Poor general economic, business or industry conditions, including commodity prices, may adversely affect our ability to refinance our debt, results of operations, liquidity and financial condition.

Oil, natural gas and NGL prices historically and recently have been volatile, and are likely to continue to be volatile in the future, and as such economic uncertainty for the oil and gas industry exists.

Concerns about global economic conditions have had a significant adverse impact on global financial markets and commodity prices and the volatility of oil and gas prices have had a significant effect on the oil and gas industry. If the economic recovery in the United States or abroad slows or is not sustained, demand for petroleum products could diminish or stagnate, which could affect the price at which we can sell our production and affect our vendors', suppliers' and customers' ability to continue operations. Similarly, if the price of oil and gas does not increase, it may affect our production plans and profitability and affect our vendors', suppliers' and customers' ability to continue operations.

Further, our ability to access the capital markets or borrow money may be restricted or more expensive at a time when we would like, or need, to raise capital, which could have an adverse impact on our flexibility to react to changing economic and business conditions and on our ability to fund operations and capital expenditures in the future or refinance our debt as it becomes current and matures. Economic circumstances, including commodity prices, could have an impact on our lenders or customers, causing them to fail to meet their obligations to us, and on the liquidity of our operating partners, resulting in delays in operations or their failure to make required payments. Also, market conditions could have an impact on commodities derivatives transactions if our counterparties are unable to perform their

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obligations or seek bankruptcy protection. The ultimate outcome and impact of current economic conditions cannot be predicted and may have a material adverse effect on our future results of operations, liquidity and financial condition.

The recent decreases in oil and gas prices have adversely affected our revenues, net income, cash flow and proved reserves. Continued price decreases could have a material adverse effect on our operations and limit our ability to fund capital expenditures. Without the ability to fund capital expenditures, we would be unable to replace reserves and production. Sustained decreases in oil and gas prices will further adversely affect our revenues, net income, cash flows, proved reserves and our ability to fund capital expenditures.

The results of our horizontal drilling activities are subject to drilling and completion technique risks, and actual drilling results may not meet our expectations for reserves or production. As a result, we may incur material impairment of the carrying value of our unevaluated properties, and the value of our undeveloped acreage could decline if drilling results are unsuccessful.

During the year ended December 31, 2015, we completed 37 gross (31.9 net) wells. Risks that we face while horizontally drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our horizontal wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage. Ultimately, the success of these horizontal drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our horizontal drilling results are less than anticipated, the return on our investment in these areas may not be as attractive as we anticipate. The carrying value of our unevaluated properties could become impaired, which would increase our depletion rate per Mcfe if there were no corresponding additions to recoverable reserves, and the value of our undeveloped acreage could decline in the future.

Our business depends on transportation by truck for our oil and condensate production, and our natural gas production depends on transportation facilities that are owned by third parties.

We transport a significant portion of our oil and condensate production by truck, which is more expensive and less efficient than transportation via pipeline, and can be less reliable than transportation via pipeline in circumstances when availability of trucks is constrained. Our natural gas production depends in part on the availability, proximity and capacity of pipeline systems and processing facilities owned by third parties. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas. The disruption of third-party facilities due to maintenance or weather could negatively affect our ability to market and deliver our products. We have no control over when or if such facilities are restored or what prices will be charged in such situations. A total shut-in of production could materially affect us due to a lack of cash flows, and if a substantial portion of the production is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flows.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local landowners for use in our operations. Over the past several years, areas where we operate have experienced severe drought conditions, and it is possible that such conditions could persist in the future. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce our reserves, which could have an adverse effect on our financial condition, results of operations and cash flows.

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We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Companies that explore for and develop, produce and sell oil and natural gas in the United States are subject to extensive federal, state and local laws and regulations, including complex tax, environmental, occupational, health and safety laws and the corresponding regulations, and are required to obtain various permits and approvals from federal, state and local agencies. If these permits are not issued or unfavorable restrictions or conditions are imposed on our drilling activities, we may not be able to conduct our operations as planned. We may be required to make large expenditures to comply with such governmental regulations. Matters subject to regulation may include:

- water use, discharge and disposal permits for drilling operations;
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