Laredo Petroleum, Inc.
Form 10-K
February 16, 2017

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

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

For the fiscal year ended December 31, 2016
or

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

Commission file number: 001-35380
Laredo Petroleum, Inc.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	45-3007926 (I.R.S. Employer Identification No.)
15 W. Sixth Street, Suite 900 Tulsa, Oklahoma (Address of principal executive offices)	74119 (Zip code)

(918) 513-4570
(Registrant's telephone number, including area code)
Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange On Which Registered
Common Stock, $0.01 par value per share	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No o
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 o No ý
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, 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 ý No o
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. ý
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller

reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates was approximately $1.1 billion on June 30, 2016, based on $10.48 per share, the last reported sales price of the common stock on the New York Stock Exchange on such date.

Number of shares of registrant's common stock outstanding as of February 13, 2017: 241,920,942

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2017 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2016, are incorporated by reference into Part III of this report for the year ended December 31, 2016.

Laredo Petroleum, Inc.
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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following terms are used throughout this Annual Report on Form 10-K (this "Annual Report"):

"2D"—Method for collecting, processing and interpreting seismic data in two dimensions.

"3D"—Method for collecting, processing and interpreting seismic data in three dimensions.

"Allocation well"—A horizontal well drilled by an oil and gas producer under two or more leaseholds that are not pooled, under a permit issued by the Texas Railroad Commission.

"Basin"—A large natural depression on the earth's surface in which sediments, generally brought by water, accumulate.

"Bbl" or "barrel"—One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate, natural gas liquids or water.

"Bcf"—One billion cubic feet of natural gas.

"BOE"—One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil.

"BOE/D"—BOE per day.

"Btu"—British thermal unit, the quantity of heat required to raise the temperature of a one pound mass of water by one degree Fahrenheit.

"Completion"—The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"Developed acreage"—The number of acres that are allocated or assignable to productive wells or wells capable of production.

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

"Dry hole"—A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"Earth Model"—A proprietary integrated workflow process combining geoscience, production, operations and engineering data utilizing multivariate analytics.

"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 natural gas in another reservoir.

"Field"—An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"Formation"—A layer of rock which has distinct characteristics that differ from nearby rock.

"Fracturing" or "Frac"—The propagation of fractures in a rock layer by a pressurized fluid. This technique is used to release petroleum and natural gas for extraction.

"GAAP"—Generally accepted accounting principles in the United States.

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

"HBP"—Acreage that is held by production.

"Horizon"—A term used to denote a surface in or of rock, or a distinctive layer of rock that might be represented by a reflection in seismic data.

"Horizontal drilling"—A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

"Initial Production"—The measurement of production from an oil or gas well when first brought on stream. Often stated in terms of production during the first thirty days.

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"Liquids"—Describes oil, water, condensate and natural gas liquids.
"MBbl"—One thousand barrels of crude oil, condensate or natural gas liquids.
"MBOE"—One thousand BOE.
"MMBOE"—One million BOE.
"Mcf"—One thousand cubic feet of natural gas.
"MMBtu"—One million British thermal units.
"MMcf"—One million cubic feet of natural gas.
"Natural gas liquids" or "NGL"—Components of natural gas that are separated from the gas state in the form of liquids, which include propane, butanes and ethane, among others.
"Net acres"—The percentage of gross acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.
"NYMEX"—The New York Mercantile Exchange.
"Production corridor"—Infrastructure put in place over an extended area, usually several miles, containing multiple pipelines to facilitate the transfer of oil, natural gas and/or water. A specific production corridor may also contain water recycling facilities, artificial gas lift and fuel gas distribution lines.
"Productive well"—A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.
"Proved developed non-producing reserves" or "PDNP"—Developed non-producing reserves.
"Proved developed reserves" or "PDP"—Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
"Proved reserves"—The estimated quantities of oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.
"Proved undeveloped reserves" or "PUD"—Proved reserves that are expected to be recovered within five years from new wells on undrilled locations and for which a specific capital commitment has been made or from existing wells where a relatively major expenditure is required for recompletion.
"Recompletion"—The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.
"Reservoir"—A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.
"Resource play"—An expansive contiguous geographical area, potentially supporting numerous drilling locations, with prospective crude oil and/or natural gas reserves that has the potential to be developed uniformly with repeatable commercial success due to advancements in horizontal drilling and multi-stage fracturing technologies.
"Spacing"—The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.
"Standardized measure"—Discounted future net cash flows estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.
"Two stream"—Production or reserve volumes of oil and wet natural gas, where the natural gas liquids have not been removed from the natural gas stream and the economic value of the natural gas liquids is included in the wellhead natural gas price.

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"Three stream"—Production or reserve volumes of oil, natural gas liquids and natural gas, where the natural gas liquids have been removed from the natural gas stream and the economic value of the natural gas liquids is separated from the wellhead natural gas price.
"Undeveloped acreage"—Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.
"Wellhead natural gas"—Natural gas produced at or near the well.
"Wolfberry"—A general industry term that applies to the vertical stratigraphic interval that can include the shallow Spraberry formation to the deeper Woodford formation throughout the Permian Basin.
"Working interest" or "WI"—The right granted to the lessee of a property to explore for and to produce and own crude oil, natural gas liquids, natural gas or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in or incorporated by reference into this Annual Report are forward-looking statements within the meaning of 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"). These forward-looking statements include statements, projections and estimates concerning our operations, performance, business strategy, oil and natural gas reserves, drilling program capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "will," "foresee," "plan," "goal," "should," "intend," "pursue," "target," "continue," "suggest" or the negative thereof or other variations thereof or other words that convey the uncertainty of future events or outcomes. Forward-looking statements are not guarantees of performance. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Among the factors that significantly impact our business and could impact our business in the future are:

- the volatility of, and substantial decline in, oil, natural gas liquids ("NGL") and natural gas prices, which remain at low levels;
- revisions to our reserve estimates as a result of changes in commodity prices and other uncertainties;
- impacts to our financial statements as a result of impairment write-downs;
- our ability to discover, estimate, develop and replace oil, NGL and natural gas reserves;
- changes in domestic and global production, supply and demand for oil, NGL and natural gas;
- the ongoing instability and uncertainty in the United States and international financial and consumer markets that could adversely affect the liquidity available to us and our customers and the demand for commodities, including oil, NGL and natural gas;
- capital requirements for our operations and projects;
- our ability to maintain the borrowing capacity under our Senior Secured Credit Facility (as defined below) or access other means of obtaining capital and liquidity, especially during periods of sustained low commodity prices;
- restrictions contained in our debt agreements, including our Senior Secured Credit Facility and the indentures governing our Senior Unsecured Notes (as defined below), as well as debt that could be incurred in the future;
- our ability to generate sufficient cash to service our indebtedness, fund our capital requirements and generate future profits;
- our ability to hedge and regulations that affect our ability to hedge;
- the potentially insufficient refining capacity in the United States Gulf Coast to refine all of the light sweet crude oil being produced in the United States, which could result in widening price discounts to world crude prices and potential shut-in of production due to lack of sufficient markets;
- regulations that prohibit or restrict our ability to apply hydraulic fracturing to our oil and natural gas wells and to access and dispose of water used in these operations;
- legislation or regulations that prohibit or restrict our ability to drill new allocation wells;
- our ability to execute our strategies;
- competition in the oil and natural gas industry;
- changes in the regulatory environment and changes in U.S. or international legal, political, administrative or economic conditions;
- drilling and operating risks, including risks related to hydraulic fracturing activities;
- risks related to the geographic concentration of our assets;
- the availability and costs of drilling and production equipment, labor and oil and natural gas processing and other services;
- the availability of sufficient pipeline and transportation facilities and gathering and processing capacity;

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- the ability to successfully identify and consummate strategic acquisitions at purchase prices that are accretive to our financial results and to successfully integrate acquired businesses, assets and properties;
- our ability to comply with federal, state and local regulatory requirements; and
- our ability to recruit and retain the qualified personnel necessary to operate our business.

These forward-looking statements involve a number of risks and uncertainties that could cause actual results to differ materially from those suggested by the forward-looking statements. Forward-looking statements should therefore be considered in light of various factors, including those set forth in this Annual Report under "Item 1A. Risk Factors," in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Annual Report. In light of such risks and uncertainties, we caution you not to place undue reliance on these forward-looking statements. These forward-looking statements speak only as of the date of this Annual Report, or if earlier, as of the date they were made. We do not intend to, and disclaim any obligation to, update or revise any forward-looking statements unless required by securities law.

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Part I

Laredo Petroleum, Inc. is a Delaware corporation formed in 2011 for the purpose of merging with Laredo Petroleum, LLC (a Delaware limited liability company formed in 2007) to consummate an initial public offering of common stock in December 2011 ("IPO"). Laredo Petroleum, Inc. was the survivor of such merger and currently has two wholly-owned subsidiaries, Laredo Midstream Services, LLC, a Delaware limited liability company ("LMS"), and Garden City Minerals, LLC, a Delaware limited liability company ("GCM").

Unless the context otherwise requires, references in this Annual Report to "Laredo," the "Company," "we," "our," "us," or similar terms refer to Laredo Petroleum, Inc. and its subsidiaries at the applicable time, including former subsidiaries and predecessor companies, as applicable.

Except where the context indicates otherwise, amounts, numbers, dollars and percentages presented in this Annual Report are rounded and therefore approximate.

Item 1. Business

Overview

Laredo is an independent energy company focused on the acquisition, exploration and development of oil and natural gas properties, and the transportation of oil and natural gas from such properties, primarily in the Permian Basin in West Texas. The oil and liquids-rich Permian Basin is characterized by multiple target horizons, extensive production histories, long-lived reserves, high drilling success rates and high initial production rates. We operate and analyze our results of operations through our two principal business segments:

- Exploration and production of oil and natural gas properties - conducted principally by Laredo Petroleum, Inc. through the exploration and development of our acreage in the Permian Basin. As of December 31, 2016, we had assembled 127,847 net acres in the Permian Basin and had total proved reserves, presented on a three-stream basis, of 167,100 MBOE.
- Midstream and marketing - conducted principally by our wholly-owned subsidiary, LMS. LMS buys, sells, gathers and transports oil, natural gas and water primarily for the account of Laredo. In addition, LMS owns a 49% interest in Medallion Gathering & Processing, LLC ("Medallion"), which, upon completion of current projects, will own and operate more than 650 miles of pipeline in the Permian Basin ("Medallion-Midland Basin"). This system gathered, transported and delivered an average of 129,087 BOE/D in the fourth quarter of 2016.

Financial information and other disclosures relating to our business segments are provided in the notes to our consolidated financial statements included elsewhere in this Annual Report (see Note 16 to our consolidated financial statements included elsewhere in this Annual Report).

2016 segment operation highlights

Exploration and production

- Produced a Company record 53,141 BOE/D in the fourth quarter of 2016, resulting in full-year 2016 production growth of 11% from full-year 2015;
- Grew proved developed reserves organically by 40% in 2016;
- Completed 45 horizontal development wells in 2016; and
- Reduced unit lease operating expenses to $3.56 per BOE in the fourth quarter of 2016, resulting in full-year 2016 reduction of 37% from full-year 2015.

Midstream and marketing

- Recognized $24 million of cash benefits from LMS field infrastructure investments through reduced capital and operating costs and increased revenue;
- Received $186 million of net cash settlements on commodity derivatives that matured during 2016, increasing the average sales price for oil by $20.34 per Bbl and for natural gas by $0.47 per thousand cubic feet compared to pre-hedged average sales prices; and
- Grew annual transported volumes on the Medallion-Midland Basin system, of which LMS is a 49% owner, by 159% in 2016 to 39.3 million Bbls of oil, with a fourth-quarter daily average rate of 129,087 BOE/D.

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Our core assets

Exploration and production

The Permian Basin is comprised of several distinct geological provinces, including the Midland Basin to the east, the Delaware Basin to the west and the Central Platform in the middle. Our primary development and production fairway is located on the east side of the Midland Basin, 35 miles east of Midland, Texas. Our acreage is largely contiguous in the neighboring Texas counties of Howard, Glasscock, Reagan, Sterling and Irion. We refer to this acreage block in this Annual Report as our "Permian-Garden City" area. As of December 31, 2016, we held 127,847 net acres in the Permian Basin, all of which were held in 268 sections in the Permian-Garden City area, with an average working interest of 95% in all Laredo-operated producing wells.

We believe our acreage in the Permian-Garden City area is a resource play for multiple producing formations that make up a significant portion of the entire stratigraphic section. We are currently focusing the majority of our development activities on four horizontal drilling targets (Upper, Middle and Lower Wolfcamp and Cline formations), although we have established the existence of additional producing formations, including the Spraberry and Canyon. From our inception in 2006 through December 31, 2016, we have drilled and completed (i.e., the particular well is flowing) 275 horizontal wells in these initial four identified targets and 967 vertical wells in the Wolfberry interval. Of these 275 wells, 127 were horizontal Upper Wolfcamp wells, 61 were horizontal Middle Wolfcamp wells, 30 were horizontal Lower Wolfcamp wells and 57 were horizontal Cline wells.

Beginning in mid-2012, we started focusing our horizontal activity on drilling longer laterals. Since that time our average lateral length has grown to 10,000 feet and longer in areas where our contiguous acreage position allows.

Following the sharp decline in oil, NGL and natural gas prices that began in the second half of 2014 and continued through 2015, we reduced our 2016 planned capital budget. As prices and related margins have somewhat stabilized, although still being at reduced levels from highs seen in 2013 and early 2014, we have approved a 2017 capital budget of $530 million, excluding acquisitions and investments in Medallion. Of this budget, $514 million is allocated to our exploration and production segment and $16 million is allocated to our midstream and marketing segment. Substantially all of the planned capital budget is anticipated to be invested in the Permian-Garden City area for both of our segments. Our strategy is to concentrate our drilling activities in multi-well packages around our previously established production corridors that have the infrastructure in place to provide us the flexibility to most efficiently and economically drill wells at an attractive rate of return. At the same time, we believe drilling wells in multi-well packages also enables us to minimize the impact of current drilling on future drilling plans by mitigating pressure depletion and frac impact. We will also continue to seek cost saving measures to more efficiently deploy our capital; however, as commodity prices have increased, service costs have also risen. We anticipate that this upward trend on service costs may continue. On December 31, 2016, we had a total of four operated drilling rigs drilling horizontal wells. Our current drilling schedule anticipates that we will utilize four horizontal rigs and no vertical rigs throughout 2017.

The timing of drilling our potential locations is influenced by several factors, including commodity prices, capital requirements and availability, the Texas Railroad Commission ("RRC") well-spacing requirements and the continuation of the positive results from our ongoing development drilling program.

We expect our Permian-Garden City acreage to continue to be the primary driver for the growth of our reserves, production and cash flow for the foreseeable future.

Since our inception, we have established and realized our reserves, production and cash flow primarily through our drilling program coupled with select strategic acquisitions. Our net proved reserves were estimated at 167,100 MBOE on a three-stream basis as of December 31, 2016, of which 84% are classified as proved developed reserves and 38% are attributed to oil reserves. For all periods prior to January 1, 2015, our reserves and production were reported in two streams: crude oil and liquids-rich natural gas. This means the economic value of the natural gas liquids in our natural gas was included in the wellhead natural gas price and total volumes on a BOE-basis were lower. Beginning on January 1, 2015, we started reporting our production volumes on a three-stream basis, which separately reports NGL from crude oil and natural gas. In this Annual Report, the information presented with respect to our estimated proved reserves has been prepared by Ryder Scott Company, L.P. ("Ryder Scott"), our independent reserve engineers, in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") applicable to the periods presented.

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The following table summarizes our total estimated net proved reserves presented on a three-stream basis, net acreage and producing wells as of December 31, 2016, and average daily production presented on a three-stream basis for the year ended December 31, 2016. Based on estimates in the report prepared by Ryder Scott, we operated wells that represent 99% of the economic value of our proved developed oil, NGL and natural gas reserves as of December 31, 2016.

	As of December 31, 2016 Estimated net proved reserves[(1)]				Producing wells		Year ended December 31, 2016
	MBOE	% of total reserves	% Oil	Net acreage	Gross	Net	average daily production (BOE/D)
Permian Basin	167,100	100 %	38 %	127,847	1,194	1,088	49,586
Other properties	—	— %	— %	15,193	—	—	—
Total	167,100	100 %	38 %	143,040	1,194	1,088	49,586

(1) See "—Our operations—Estimated proved reserves" for discussion of the prices utilized to estimate our reserves.

Our net average daily production for the year ended December 31, 2016 was 49,586 BOE/D, 47% of which was oil, 26% of which was NGL and 27% of which was natural gas.

As discussed previously in this Annual Report, during 2015 commodity prices for crude oil, NGL and natural gas experienced sharp declines, and this downward trend accelerated further into 2016, with crude oil prices reaching a twelve-year low in February 2016. In the second half of 2016 and into the first quarter of 2017, commodity prices increased and stabilized at relatively higher prices but at significantly lower levels than 2014. Prices continue to remain volatile. Our capital budget for 2017 is $530 million, representing a 42% increase from 2016 capital expenditures, excluding acquisitions.

Beginning in 2016, we purposely significantly reduced the portion of our reserves that have historically been categorized as "proved undeveloped" or "PUD." We adjusted our long-range five-year SEC PUD bookings methodology because we believe it enables us to develop our acreage in the most efficient manner possible and determine which potential locations will be most profitable. We believe that we can optimize the value for our shareholders by maintaining greater flexibility in choosing the specific drilling locations that will most efficiently develop our properties, particularly as technology changes and we continue to further understand our acreage.

As our activities to date have indicated, the majority of our acreage represents a resource play. In the near-term, our goal is to drill those locations that we anticipate have the potential to provide the greatest economic return and enhance shareholder value. We have determined that the most efficient way to accomplish this is to maintain the flexibility to choose those locations based upon our continuing insight as we drill and collect data across our acreage, regardless of SEC reserve-booking status. Reducing our future PUD commitments provides us the most flexibility to maximize our rate of return at prevailing conditions and minimize the requirement to drill wells previously assigned, under very different circumstances, as specific PUD locations. Accordingly, for 2017 we have further reduced our booked PUD locations to those we have reasonable certainty to believe that we will develop and have made a specific capital commitment to drill within one year. This strategy maintains our flexibility to add new PUD locations and convert other locations to proved developed reserves as our plans deem appropriate and opportunistic.

We have built an extensive proprietary technical database that includes 591 in-house, core-calibrated petrophysical logs, 1,133 square miles of 3D seismic, 53 microseismic surveys, more than 1,090 open and cased-hole logging suites, including 144 dipole sonic logs, 5,005 feet of proprietary whole cores in 15 wells, 945 sidewall cores, 39 single-zone tests and 46 production logs. Our strategic interest in utilizing our significant technical database is directed at understanding the principles that control hydraulic fracture geometry and potential resource recovery that can then be leveraged during all operational phases of development, with the goal of maximizing the value of our entire asset base. Our reservoir characterization process encompasses three fundamental areas: (i) multivariate analytics (including

our proprietary Earth Model), (ii) reservoir simulation and (iii) completions optimization (incorporating leading-edge hydraulic fracture modeling).
We have developed a number of proprietary workflows within our completions optimization and reservoir simulation process. We have constructed a series of calibrated three-dimensional geocellular models incorporating data that represent reservoir, geomechanical and natural fracturing conditions, which enable us to forward-model fracture geometries by applying physics-based rules. These detailed three-dimensional models of hydraulic fracture geometries have subsequently been history matched and calibrated to oil production. We believe that by forward-modeling various completions designs and then comparing back to our extensive data set, fundamental insights can be gained into how to best design completions to deliver the appropriate resource recovery and to enhance value for the total resource. We consider our database a fundamental technical advantage, enabling the above-described workflows to yield high-quality calibrated results.

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A key component of our reservoir characterization process is internally referred to as the "Earth Model," which represents proprietary integrated workflows combining geoscience, production, operations and engineering data utilizing multivariate analytics. The goal of the Earth Model is to develop a predictive three-dimensional model that can forecast production rates through associating empirical subsurface data with proved methods. We have continued to develop the Earth Model during the last five years by applying a multivariate analytics approach to integrating data that represents mechanical rock properties, natural fractures, reservoir properties, completions, production, flow back and operational execution components.

We consider both the Earth Model and completions optimization workflows to be potentially significant tools in designing multi-well development plans with the goal of maximizing value by optimizing completion designs by landing point, increasing lateral lengths where possible and geo-steering targets while integrating horizontal and vertical spacing considerations for well laterals.

We anticipate that 100% of our horizontal wells to be drilled in 2017 will utilize at least some aspects of the Earth Model and completions optimization. If our preliminary applications of the Earth Model and completions optimization workflows are replicated in forward-looking well planning, we anticipate this will positively impact our ability to select higher value multi-well development plans.

Midstream and marketing

We are actively involved in seeking additional midstream solutions for our oil, NGL and natural gas production. Capitalizing on our large contiguous acreage blocks, we have built crude oil, natural gas and/or water systems in four production corridors on our Permian-Garden City acreage. These production corridors are designed to provide a combination of services including high-pressure centralized natural gas lift systems, crude oil and natural gas gathering and water delivery and takeaway capacity, with certain corridors also capable of accessing recycling facilities. In 2015, we commenced operations at our water treatment facility, which is capable of recycling more than 30,000 Bbls of water per day and has a storage capacity of 1.4 million Bbls. We believe the fact that these production corridors and associated facilities and infrastructure are already in place will enable us to enhance the value of the 2017 drilling program.

Additionally, we have built and maintain more than 40 miles of crude oil gathering pipelines to connect Laredo-operated wells in our Permian-Garden City asset, providing a safer and more economic transportation alternative than trucking. We have also installed and maintain 170 miles of natural gas gathering pipelines across our Permian-Garden City acreage, providing us with takeaway optionality that enables us to maintain lower operating pressures and more consistent well performance.

LMS is a 49% owner in the Medallion-Midland Basin crude oil gathering system which commenced operations in March of 2015. Upon completion of current projects, the system will have more than 650 miles of laid pipeline in the following counties in Texas: Crane, Glasscock, Howard, Irion, Martin, Midland, Mitchell, Reagan, Scurry and Upton. In 2016, the system transported 39.3 million Bbls of crude oil. See Notes 14 and 15.a to our consolidated financial statements included elsewhere in this Annual Report for a discussion of Medallion.

Our midstream and marketing activities continue to focus on achieving increased efficiencies and cost reductions for (i) the transportation and marketing of our oil and natural gas through the utilization of our oil and natural gas gathering systems to provide access to multiple markets and reduce the potential for production shut-ins caused by downstream capacity issues and (ii) the handling of fresh, recycled and produced water.

We market the majority of production from properties we operate for both our account and the account of the other working interest owners in our operated properties. We sell substantially all of our production under contracts ranging from one month to several years, all at fluctuating market prices. We normally sell production to a relatively limited number of customers, as is customary in the exploration, development and production business; however, we believe that our customer diversification affords us optionality in our sales destination. We have committed a portion of our Permian crude oil production under firm transportation agreements, including with Medallion, which agreements will enhance our ability to move our crude oil out of the Permian Basin and give us access to potentially more favorable Gulf Coast pricing.

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As of December 31, 2016, we were committed to deliver for sale or transportation the following fixed quantities of production under certain contractual arrangements that specify the delivery of a fixed and determinable quantity:

	Total	2017	2018	2019	2020 and after
Crude oil (MBbl):					
Sales commitments	38,133	6,935	6,935	6,935	17,328
Transportation commitments:					
Field	92,438	13,344	12,410	11,874	54,810
To U.S. gulf coast	29,810	3,650	3,650	3,650	18,860
Natural gas (MMcf):					
Sales commitments	71,666	5,612	5,615	5,615	54,824
Total commitments (MBOE)(1)	172,325	24,864	23,931	23,394	100,136

(1) BOE equivalents are calculated using a conversion rate of six Mcf per one Bbl.

We have firm field transportation agreements that enable us or the purchasers of our oil production to move oil from our production area to the major market hub of Colorado City, Texas. We also have a firm transportation agreement to move oil from Colorado City, Texas to the U.S. Gulf Coast. We expect to fulfill these firm transportation commitments primarily by utilizing the volumes under our firm sales commitments.

Our production has been equivalent or greater than our delivery commitments during the three most recent years, and we expect such production will continue to exceed our future commitments. However, in certain instances, we have made payments for natural gas minimum volume commitments and have used spot market oil purchases to meet commitments in certain locations or due to favorable pricing. We anticipate continuing this practice in the future. Also, if our production is not sufficient to satisfy our delivery commitments, we can and may use spot market purchases to fulfill the commitments.

In the current market environment, we believe that we could sell our production to numerous companies so that the loss of any one of our major purchasers would not have a material adverse effect on our financial condition and results of operations solely by reason of such loss. For information regarding each of our customers that accounted for 10% or more of our oil, NGL and natural gas revenues during the last three calendar years, see Note 11 to our consolidated financial statements included elsewhere in this Annual Report. See "Item 1A. Risk Factors—Risks related to our business—The inability of our significant customers to meet their obligations to us may materially adversely affect our financial results."

Corporate history and structure

Laredo Petroleum, Inc. is a Delaware corporation formed in 2011 for the purpose of merging with Laredo Petroleum, LLC (a Delaware limited liability company formed in 2007) to consummate an IPO in December 2011. Laredo Petroleum, Inc. was the survivor of such merger and currently has two wholly-owned subsidiaries, LMS and GCM. As of December 31, 2016, affiliates of Warburg Pincus LLC ("Warburg Pincus), our founding member, owned 36.2% of our common stock.

On August 1, 2013, we completed the sale of our assets in the Anadarko Basin in the Texas Panhandle and Western Oklahoma (the "Anadarko Basin Sale"), which represented 15% of our proved reserve volumes as of December 31, 2012.

Laredo Petroleum, Inc. is the borrower under our Fourth Amended and Restated Senior Secured Credit Facility (as amended, the "Senior Secured Credit Facility"), as well as the issuer of our $350 million of 6 1/4% senior unsecured notes due 2023 (the "March 2023 Notes"), our $500 million of 7 3/8% senior unsecured notes due 2022 (the "May 2022 Notes") and our $450 million of 5 5/8% senior unsecured notes due 2022 (the "January 2022 Notes"). We refer to the March 2023 Notes, the May 2022 Notes and the January 2022 Notes collectively as the "Senior Unsecured Notes." Our subsidiaries, LMS and GCM, are guarantors of the obligations under our Senior Secured Credit Facility and Senior Unsecured Notes. On April 6, 2015 (the "Redemption Date"), we used the proceeds of the March 2023 Notes offering to fund a portion of the complete redemption of the Company's then outstanding $550 million of 9

1/2% senior unsecured notes due 2019 (the "January 2019 Notes") at a redemption price of 104.75% of the principal amount of such notes, plus accrued and unpaid interest.

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Our business strategy

Our goal is to enhance shareholder value by (i) protecting and potentially growing our reserves, production and cash flow and (ii) enhancing our midstream and marketing segment by executing the following strategy:

Exploration and production

Maximize the potential net asset value of our asset base by capitalizing on our technical expertise and taking advantage of our drilling optionality and operational flexibility

- We will continue to leverage our operating and technical expertise to further delineate and develop our core acreage position. We are enhancing value by capitalizing on our extensive database for the development and application of our Earth Model in identifying the optimal landing point and completions optimization techniques, thereby capturing more hydrocarbons within the target acreage than might otherwise be possible.
- We believe that the most efficient and cost-effective way to develop our acreage is through the use of multi-well packages in the same or multiple formations, including multiple landing points in a single formation. This approach allows for economies of scale as well as reducing production issues related to pressure depletion.
- Subject to adverse changes in commodity prices and/or service costs, we believe that our entire acreage position, comprised of multiple formations, will be a part of our future development.
- In order to increase our operational flexibility, in the past two years we deliberately reduced our PUD bookings within our reserves. While this decision impacts our total booked reserves in the short term, we believe that it enhances our ability to grow our proved developed reserves and overall resources by providing us with crucial flexibility in tailoring our drilling and operating plans in a manner that is most conducive to maximizing the net asset value of our asset base.

Proactively manage risk to limit downside

- We actively attempt to limit our business and operating risks by focusing on safety, flexibility in our financial profile, operational efficiencies, hedging, controlling costs and developing oil and natural gas takeaway capacity with multiple delivery points.

Deploy our capital in a conservative and strategic manner while maintaining a strong liquidity position and continuing to delever

- We believe that maintaining a strong liquidity position is critical. Therefore, we will be highly selective in the projects that we fund and will review opportunities to bolster our liquidity and financial position through asset dispositions, utilizing our Senior Secured Credit Facility and accessing the capital markets.

Continue to hedge our production to protect cash flows, diminish the effects of commodity price fluctuations and maintain upside exposure

- During 2016, we realized a significant benefit through our hedging program and the certainty that it provided to our cash flow. In the future, we will seek hedging opportunities to further protect our cash flows from commodity price fluctuations while maintaining upside exposure if commodity prices increase.

Evaluate value-enhancing acquisitions, divestitures, mergers and joint-ventures

- We will continue to monitor the market for strategic acquisitions that we believe could be accretive and enhance shareholder value. However, as a result of our past years of data collection and delineation drilling, we have established the production capability of a substantial portion of our acreage in multiple formations, which provides us with a significant drilling inventory.

Midstream and marketing

Increase the use of our previously built infrastructure and evaluate opportunities for strategic expansion

- We believe that our infrastructure provides us with optionality and efficiencies in developing and transporting production from our Permian-Garden City acreage position, as well as providing water transportation and recycling services for a significant portion of our planned drilling activities. Because of the value we ascribe to this infrastructure, we will continue to look for strategic expansion opportunities while maintaining our core strategy of providing marketing optionality for our oil, NGL and natural gas production.

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Participate in the value growth of Medallion-Midland Basin system

- We believe the Medallion-Midland Basin system is a premier and valuable asset that provides benefits to us by transporting our production to multiple markets. Additionally, through our 49% ownership of Medallion, we benefit from the growth in value of the Medallion-Midland Basin system as Midland Basin production continues to increase.

Our competitive strengths

We have a number of competitive strengths in each of our segments that we believe will assist in the successful execution of our business strategy.

Exploration and production

Our extensive Permian technical database and Earth Model

- We have made a substantial upfront investment to understand the geology, geophysics and reservoir parameters of the rock formations and production characteristics that define our drilling and development program. We have utilized and will continue to utilize this information in the ongoing refinement of the Earth Model, which has assisted us in optimizing our well results and is expected to provide corresponding additional future benefits.

Contiguous acreage position with high working interests and extensive interests in leases held by production containing multiple formations, resulting in a substantial drilling inventory

- We have 127,847 net acres in the Permian-Garden City area that are largely contiguous with a high average working interest percentage (95% for Laredo-operated properties), are 85% held by production and have identified up to seven targets to date from which we can produce, resulting in a significant drilling inventory. Our contiguous acreage position also allows us to drill long laterals (10,000 feet or greater) in many locations, which we believe provide an even greater rate of return as we continue to refine our spacing, drilling and completions techniques.

Drilling and lease operating efficiencies afforded by our acreage position and production corridors that enable low-cost operations

- By making upfront investments in production infrastructure on our contiguous acreage position, we are now able to drill and operate in a more efficient and low-cost manner. We believe that this infrastructure will enable us to continue to be a low-cost operator while at the same time drilling productive new wells.

Significant operational control

- We operate wells that represent 99% of the economic value of our proved developed reserves as of December 31, 2016, based on our reserve report prepared by Ryder Scott. We believe that maintaining operating control permits us to better pursue our strategy of enhancing returns through operational and cost efficiencies and maximizing cost-efficient ultimate hydrocarbon recoveries through reservoir analysis and evaluation and continuous improvement of drilling, completions and stimulation techniques. We expect to maintain operating control over most of our potential drilling locations.

Strong corporate governance and institutional investor support

- Our board of directors is well qualified and represents a meaningful resource to our management team. Our board of directors, which is comprised of representatives of Warburg Pincus, other independent directors and our Chief Executive Officer, has extensive oil and natural gas industry and general business expertise. We actively engage our board of directors, on a regular basis, for their expertise on strategic, financial, governance and risk management activities. In addition, Warburg Pincus has many years of relevant experience in financing and supporting exploration and production companies and management teams. During the last two decades, Warburg Pincus has been the lead investor in many such companies, including two previous companies operated by members of our management team.

Midstream and marketing

Our production corridors and water treatment facility enable us to more efficiently develop our acreage and utilize/dispose of water, thus reducing our capital and operating expenses

- We believe that our previously built production corridors increase field level operating efficiencies in oil and natural gas gathering and takeaway capacity, water supply and operations. We have demonstrated that our production corridors provide us with identified areas within which we can achieve material cost savings and efficiencies through

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the use of our previously built infrastructure, including water recycling. In addition, drilling wells within these corridors increases our production consistency and enables us to better plan our development program.

- The use and disposal of water is one of the most challenging aspects of horizontal drilling in the Permian Basin and our production corridors provide us with a reliable and consistent means to ensure that we have the water we need to complete our wells while also providing low-cost takeaway capacity for flowback and produced water.

Extensive infrastructure in place

- We own and operate more than 230 miles of pipeline in our crude oil and natural gas gathering, fuel gas and gas lift systems in the Permian Basin as of December 31, 2016. These systems and pipelines provide greater operational efficiency and potentially better pricing for our production and enable us to coordinate our activities to connect our wells to market upon completion with minimal pipeline delays.
- Through our association with Medallion, and upon completion of current projects, we will have access to more than 650 miles of oil gathering systems and pipelines connected to Colorado City, Texas. As a 49% owner of Medallion, we benefit financially from the system including through our share of the net income from the shipment of all crude oil on the system.

Firm transportation for a majority of our oil

- As production in the Permian Basin has increased, the need for firm takeaway capacity has become even more important. We have 30,000 Bbls per day of intra-basin firm transportation for oil and access to four points of delivery. We also have 10,000 Bbls per day of firm transportation from Colorado City, Texas to five points of delivery in the U.S. Gulf Coast. We believe this type of certainty provides us with an advantage in formulating our present and future drilling and operating plans.

Other properties

In addition to our Permian-Garden City acreage, as of December 31, 2016, we held 15,193 net acres in the Palo Duro Basin. Approximately 72% of this acreage will expire in 2017, absent drilling or renegotiation of the applicable leases. We anticipate little or no activity on these properties in 2017.

Our operations

Estimated proved reserves

Our reserves are reported in three streams: crude oil, NGL and natural gas. In this Annual Report, the information with respect to our estimated proved reserves presented below has been prepared by Ryder Scott, in accordance with applicable SEC rules and regulations.

SEC guidelines require companies to use the unweighted arithmetic average first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period before differentials ("Benchmark Prices"). The Benchmark Prices are then adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead ("Realized Prices"). The Realized Prices are held constant and utilized to calculate estimated reserves and the associated future cash flows. The following table presents the Benchmark Prices and Realized Prices for the periods presented:

	As of December 31,	
	2016	2015
Benchmark Prices:		
Oil ($/Bbl)	$39.25	$46.79
NGL ($/Bbl)	$18.24	$18.75
Natural gas ($/MMBtu)	$2.33	$2.47
Realized Prices:		
Oil ($/Bbl)	$37.44	$45.58
NGL ($/Bbl)	$11.72	$12.50
Natural gas ($/Mcf)	$1.78	$1.89

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Our net proved reserves were estimated at 167,100 MBOE on a three-stream basis as of December 31, 2016, of which 84% were classified as proved developed reserves and 38% are attributable to oil reserves. The following table presents summary data for our core operating area as of December 31, 2016.

	As of December 31, 2016	
Area:	Proved reserves (MBOE)	% of total
Permian Basin	167,100	100%
Other properties	—	— %
Total	167,100	100%

Our estimated proved reserves as of December 31, 2016 assume our ability to fund the capital costs necessary for their development and are affected by pricing assumptions. See "Item 1A. Risk Factors—Risks related to our business—Estimating reserves and future net revenues involves uncertainties. Decreases in commodity prices, or negative revisions to reserve estimates or assumptions as to future oil, NGL and natural gas prices, may lead to decreased earnings, losses or impairment of oil and natural gas assets."

The following table sets forth additional information regarding our estimated proved reserves as of December 31, 2016 and 2015. Ryder Scott estimated 100% of our proved reserves as of December 31, 2016 and 2015. The reserve estimates as of December 31, 2016 and 2015 were prepared in accordance with the applicable SEC rules regarding oil, NGL and natural gas reserve reporting.

	As of December 31,	
	2016	2015
Proved developed producing:		
Oil (MBbl)	53,156	40,493
NGL (MBbl)	42,950	29,009
Natural gas (MMcf)	270,291	178,519
Total proved developed producing (MBOE)	141,155	99,255
Proved developed non-producing:		
Oil (MBbl)	—	451
NGL (MBbl)	—	340
Natural gas (MMcf)	—	2,094
Total proved developed non-producing (MBOE)	—	1,140
Proved undeveloped:		
Oil (MBbl)	10,784	11,695
NGL (MBbl)	7,400	6,718
Natural gas (MMcf)	46,566	41,339
Total proved undeveloped (MBOE)	25,945	25,303
Estimated proved reserves:		
Oil (MBbl)	63,940	52,639
NGL (MBbl)	50,350	36,067
Natural gas (MMcf)	316,857	221,952
Total estimated proved reserves (MBOE)	167,100	125,698
Percent developed	84 %	80 %

Technology used to establish proved reserves

Under SEC rules, proved reserves are those quantities of oil, NGL and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible within five years 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, NGL and/or natural gas actually

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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.

To establish reasonable certainty with respect to our estimated proved reserves, our internal reserve engineers and Ryder Scott, our independent reserve engineers, 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 primarily by performance from analogous wells in the surrounding area and the use of 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.

As discussed previously in this Annual Report, during 2015 commodity prices for crude oil, NGL and natural gas experienced sharp declines, and this downward trend accelerated further into 2016, with crude oil prices reaching a twelve-year low in February 2016. In the second half of 2016 and into the first quarter of 2017 commodity prices increased and stabilized at relatively higher prices but significantly lower than 2014 . However, prices continue to remain volatile. Our capital budget for 2017, excluding acquisitions and investments in Medallion, is $530 million, representing a 42% increase over 2016 capital expenditures, excluding acquisitions.

Beginning in 2016, we purposely significantly reduced the portion of our reserves that have historically been categorized as "proved undeveloped" or "PUD." We adjusted our long-range five-year SEC PUD bookings methodology because we believe it enables us to develop our acreage in the most efficient manner possible and determine which potential locations best enhance our overall value. We believe that we can optimize the value for our shareholders by maintaining greater flexibility in choosing the specific drilling locations that will most efficiently develop our properties, particularly as technology changes and we continue to further understand our acreage.

As our activities to date have indicated, the majority of our acreage represents a resource play. In the near-term, our goal is to drill those locations that we anticipate have the potential to provide the greatest shareholder value. We have determined that the most efficient way to accomplish this is to maintain the flexibility to choose those locations based upon our continuing insight as we drill and collect data across our acreage, regardless of SEC reserve-booking status. Reducing our future PUD commitments provides us the most flexibility to maximize our rate of return at prevailing conditions and minimize the requirement to drill wells previously assigned, under very different circumstances, as specific PUD locations. Accordingly, for 2017 we have further reduced our booked PUD locations to those we have reasonable certainty to believe that we will develop and have made a specific capital commitment to drill within one year. This strategy maintains our flexibility to add new PUD locations and convert other locations to proved developed reserves as our plans deem appropriate and opportunistic.

Qualifications of technical persons and internal controls over reserves estimation process

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, our independent reserve engineers, estimated 100% of our proved reserve information as of December 31, 2016 and 2015 included in this Annual Report. 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 work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to Ryder Scott in their reserves estimation process. Our technical team meets regularly with representatives of Ryder Scott to review properties and discuss methods and assumptions used in Ryder Scott's preparation of the year-end reserves estimates. The Ryder Scott reserve report is reviewed with representatives of Ryder Scott and our internal technical staff before dissemination of the information.

Our Vice President of Reservoir Engineering is the technical person primarily responsible for overseeing the preparation of our reserves estimates. He has more than 17 years of practical experience with eight years of this experience being in the estimation and evaluation of reserves. He has a Bachelors of Science in Chemical Engineering from Rice University, a Masters of Business Administration from the Kellogg School of Management and a Masters of Engineering Management from Northwestern University. Our Vice President of Reservoir Engineering reports to our Senior Vice President - Exploration & Land. Reserves estimates are reviewed and approved by our senior engineering staff, other members of senior

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management and our technical staff, our audit committee and our Chief Executive Officer and then submitted to our board of directors for final approval.

Proved undeveloped reserves

Our proved undeveloped reserves increased from 25,303 MBOE as of December 31, 2015, to 25,945 MBOE as of December 31, 2016. We estimate that we incurred $170.4 million of costs to convert 17,941 MBOE of proved undeveloped reserves from 26 locations into proved developed reserves in 2016. New proved undeveloped reserves of 11,638 MBOE were added during the year from 10 new horizontal Wolfcamp and four new horizontal Cline locations. Positive revisions to proved undeveloped reserves of 6,945 MBOE were due to the combined effect of removing two proved undeveloped locations due to changes in drilling plans, reinterpreting 10 undeveloped locations and adding seven undeveloped locations that were removed from reserves in a previous year. A final investment decision has been made on these 31 locations and they are scheduled to be drilled and completed in 2017.

Estimated total future development and abandonment costs related to the development of proved undeveloped reserves as shown in our December 31, 2016 reserve report are $199 million. Based on this report and our PUD booking methodology, the capital estimated to be spent in 2017 to develop the proved undeveloped reserves is $197 million and $0 for each of 2018, 2019, 2020 and 2021. Based on our anticipated cash flows and capital expenditures, as well as the availability of capital markets transactions, all of the proved undeveloped locations are expected to be drilled within a one-year period in 2017. Reserve calculations at any end-of-year period are representative of our development plans at that time. Changes in circumstance, including commodity pricing, oilfield service costs, technology, acreage position and availability and other economic and regulatory factors may lead to changes in development plans.

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Sales volume, revenues and price history

The following table sets forth information regarding sales volumes, revenues, average sales prices and average costs per BOE sold for the years ended December 31, 2016, 2015 and 2014. For the 2014 period, our reserves and production were reported in two streams: crude oil and liquids-rich natural gas, and for 2015 and 2016 our reserves and production were reported in three streams: crude oil, NGL and natural gas. For additional information on price calculations, see the information in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	For the years ended December 31,		
(unaudited)	2016	2015	2014
Sales volumes:(1)			
Oil (MBbl)	8,442	7,610	6,901
NGL (MBbl)	4,784	4,267	—
Natural gas (MMcf)	29,535	26,816	28,965
Oil equivalents (MBOE)(2)(3)	18,149	16,346	11,729
Average daily sales volumes (BOE/D)(3)	49,586	44,782	32,134
Oil, NGL and natural gas sales (in thousands):(1)			
Oil	$318,466	$329,301	$571,620
NGL	$56,982	$50,604	$—
Natural gas	$51,037	$51,829	$165,583
Average sales prices without hedges:(1)			
Index oil ($/Bbl)(4)	$43.32	$48.80	$93.00
Oil, realized ($/Bbl)(5)	$37.73	$43.27	$82.83
Index NGL ($/Bbl)(4)	$18.97	$18.81	$—
NGL, realized ($/Bbl)(5)	$11.91	$11.86	$—
Index natural gas ($/MMBtu)(4)	$2.46	$2.66	$4.41
Natural gas, realized ($/Mcf)(5)	$1.73	$1.93	$5.72
Average price, realized ($/BOE)(5)	$23.50	$26.41	$62.86
Average sales prices with hedges:(1)(6)			
Oil, hedged ($/Bbl)	$58.07	$74.41	$85.77
NGL, hedged ($/Bbl)	$11.91	$11.86	$—
Natural gas, hedged ($/Mcf)	$2.20	$2.42	$5.73
Average price, hedged ($/BOE)	$33.73	$41.71	$64.62
Average costs per BOE sold:(1)			
Lease operating expenses	$4.15	$6.63	$8.23
Production and ad valorem taxes	$1.58	$2.01	$4.29
Midstream service expenses	$0.22	$0.36	$0.46
General and administrative:			
Cash	$3.45	$4.03	$7.07
Non-cash stock-based compensation, net of amounts capitalized	$1.61	$1.50	$1.97
Depletion, depreciation and amortization	$8.17	$16.99	$21.01

(1) For the period prior to January 1, 2015, we presented our sales volumes, sales, average sales prices and average costs per BOE sold for oil and natural gas, which combined NGL with the natural gas stream, and did not separately report NGL. This change impacts the comparability of 2016 and 2015 with 2014.

(2) BOE is calculated using a conversion rate of six Mcf per one Bbl.

(3) The volumes presented are based on actual results and are not calculated using the rounded numbers presented in the table above.

(4)

Index oil prices are the simple average of the daily settlement price for NYMEX West Texas Intermediate Light Sweet Crude Oil each month for the period indicated. Index NGL prices are the simple arithmetic average of the monthly

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average of the daily high and low prices for each NGL component during the month of delivery as reported for Mont Belvieu, Texas by the Oil Price Information Service using the Purity Ethane price for the ethane component and the Non-TET prices for the propane, butane and natural gasoline components multiplied by the simple arithmetic average of the monthly average percentage makeup of each NGL component in Laredo's composite NGL barrel. Index natural gas prices are the simple arithmetic average of each month's settlement price of the NYMEX Henry Hub natural gas First Nearby Month Contract upon expiration.

(5) Realized oil, NGL and natural gas prices are the actual prices realized at the wellhead adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. The prices presented are based on actual results and are not calculated using the rounded numbers presented in the table above.

(6) Hedged prices reflect the after-effects of our hedging transactions on our average sales prices. Our calculation of such after-effects includes current period settlements of matured derivatives in accordance with GAAP and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to instruments that settled in the period. The prices presented are based on actual results and are not calculated using the rounded numbers presented in the table above.

Productive wells

The following table sets forth certain information regarding productive wells in each of our core areas as of December 31, 2016. All but three of our wells are classified as oil wells, all of which also produce liquids-rich natural gas and condensate. Wells are classified as oil or natural gas wells according to the predominant production stream. We also own royalty and overriding royalty interests in a small number of wells in which we do not own a working interest.

	Total producing wells				Average WI %
	Gross			Net	
	Vertical	Horizontal	Total	Total	
Permian Basin:					
Operated Permian-Garden City	854	281	1,135	1,074	95 %
Non-operated Permian-Garden City	53	6	59	14	24 %
Other properties	—	—	—	—	— %
Total	907	287	1,194	1,088	91 %

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own an interest as of December 31, 2016 for each of our core operating areas, including acreage held by production ("HBP"). A majority of our developed acreage is subject to liens securing our Senior Secured Credit Facility.

	Developed acres		Undeveloped acres		Total acres		% HBP
	Gross	Net	Gross	Net	Gross	Net	
Permian Basin	123,749	108,096	21,443	19,751	145,192	127,847	85%
Other properties	—	—	22,966	15,193	22,966	15,193	—%
Total	123,749	108,096	44,409	34,944	168,158	143,040	76%

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Undeveloped acreage expirations

The following table sets forth the gross and net undeveloped acreage in our core operating areas as of December 31, 2016 that will expire over the next four years unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates.

	2017		2018		2019		2020	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian Basin	3,212	3,291	12,173	10,815	961	279	—	—
Other properties	15,794	10,902	6,652	4,122	520	170	—	—
Total	19,006	14,193	18,825	14,937	1,481	449	—	—

Of the total undeveloped acreage identified as expiring over the next four years, 357 net acres have associated PUD reserves as of December 31, 2016, and these locations are scheduled to be drilled in 2017 to hold the associated leases. These PUD reserves represent 3.4% of our overall PUD reserves.

At December 31, 2015, 40 net acres of leasehold were identified as attributable to PUD reserves and potentially expiring. All of the PUD reserves on those acres were drilled and completed in 2016.

Drilling activity

The following table summarizes our drilling activity for the years ended December 31, 2016, 2015 and 2014. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells.

	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	45	44.5	93	80.4	219	183.9
Dry	—	—	—	—	—	—
Total development wells	45	44.5	93	80.4	219	183.9
Exploratory wells:						
Productive	—	—	2	2.0	2	1.8
Dry	1	0.5	—	—	1	1.0
Total exploratory wells	1	0.5	2	2.0	3	2.8

Title to properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often cursory investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include customary royalty interests, liens incident to operating agreements and for current taxes, obligations or duties under applicable laws, development obligations under oil and gas leases or net profit interests.

Oil and natural gas leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil, NGL and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 12.5% to 25%, resulting in a net revenue interest to us generally ranging from 75% to 87.5%. As of December 31, 2016, 76% of all of our net leasehold acreage was held by production and 85% of our Permian-Garden City acreage was held by production.

Seasonality

Demand for oil and natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. These seasonal anomalies can increase

competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Competition

The oil and natural gas industry is intensely competitive, and we compete with a wide range of companies in our industry, including those that have greater resources than we do and those that are smaller with fewer ongoing obligations. Many of the larger companies not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. Many of the smaller companies have a lower cost structure and more liquidity. These companies may be able to pay more for productive properties and exploratory locations or evaluate, bid for and purchase a greater number of properties and locations 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 and production activities during periods of low market prices. 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. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because of the inherent advantages of some of our competitors, those companies may have an advantage in bidding for exploratory and producing properties.

Hydraulic fracturing

We use hydraulic fracturing as a means to maximize the productivity of almost every well that we drill and complete. Hydraulic fracturing is a necessary part of the completion process for our producing properties in Texas because our properties are dependent upon our ability to effectively fracture the producing formations in order to produce at economic rates. We are currently conducting hydraulic fracturing activity in the completion of our wells in the Permian Basin. While hydraulic fracturing is not required to maintain any of our leasehold acreage that is currently held by production from existing wells, it will be required in the future to develop the proved non-producing and proved undeveloped reserves associated with this acreage. Nearly all of our proved developed non-producing and proved undeveloped reserves associated with future drilling, recompletion and refracture stimulation projects require hydraulic fracturing.

We have and continue to follow standard industry practices and applicable legal requirements. State and federal regulators impose requirements on our operations designed to ensure protection of human health and the environment. These protective measures include setting surface casing at a depth sufficient to protect fresh water formations, and cementing the well to create a permanent isolating barrier between the casing pipe and surrounding geological formations. It is believed that this well design effectively eliminates a pathway for the fracturing fluid to contact any aquifers during the hydraulic fracturing operations. For recompletions of existing wells, the production casing is pressure tested prior to perforating the new completion interval.

Injection rates and pressures are monitored instantaneously and in real time at the surface during our hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string. Hydraulic fracturing operations would be shut down immediately if an abrupt change occurred to the injection pressure or annular pressure.

Certain state regulations require disclosure of the components in the solutions used in hydraulic fracturing operations. Approximately 99% of the hydraulic fracturing fluids we use are made up of water and sand. The remainder of the constituents in the fracturing fluid are managed and used in accordance with applicable requirements. In accordance with Texas regulations, we report the constituents of the hydraulic fracturing fluids utilized in our well completions on FracFocus (www.fracfocus.org). Hydraulic fracture stimulation requires the use of a significant volume of water. Upon flowback of the water, we dispose of it by recycling or by discharging into approved disposal wells, so as to minimize the potential for impact to nearby surface water. We currently do not discharge water to the surface. Based upon results of testing the performance of recycled flowback/produced water in our fracing operations on a limited number of wells, we have constructed and operate a water recycle facility on one of our production corridors and anticipate expanding our recycling activities in the future.

For information regarding existing and proposed governmental regulations regarding hydraulic fracturing and related environmental matters, please read "-Regulation of environmental and occupational health and safety matters-Water and other waste discharges and spills." For related risks to our stockholders, please read "Item 1A. Risk Factors—Risks related to our business—Federal and state legislation and regulatory initiatives relating to hydraulic fracturing and water disposal wells could prohibit projects or result in materially increased costs and additional operating restrictions or delays because of the significance of hydraulic fracturing and water disposal wells in our business."

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Regulation of the oil and natural gas industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, 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. The State of Texas has regulations governing environmental and conservation matters, including provisions for the pooling of oil and natural gas properties, the permitting of allocation wells, the establishment of maximum allowable rates of production from oil and natural gas wells (including the proration of production to the market demand for oil and natural gas), the regulation of well spacing, the handling and disposing or discharge of waste materials 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, Texas imposes a production or severance tax with respect to the production and sale of oil, NGL and natural gas within its jurisdiction. Texas further regulates drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. 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.

The regulatory burden on the industry increases the cost of doing business and affects profitability. Additional proposals and proceedings that affect the natural gas industry are regularly considered by the new administration, Congress, the states, the Environmental Protection Agency ("EPA"), Federal Energy Regulatory Commission ("FERC") and the courts. We cannot predict when or whether any such proposals may become effective.

We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered, and such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impacts of compliance.

Regulation of environmental and occupational health and safety matters

Our operations are subject to numerous stringent federal, state and local statutes and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment or occupational health and safety. Numerous governmental agencies, such as the EPA, issue regulations that often require difficult and costly compliance measures, the noncompliance with which carries substantial administrative, civil and criminal penalties and may result in injunctive obligations to remediate noncompliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines, govern the sourcing and disposal of water used in the drilling, completion and production process, limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier, seismically active areas and other protected areas, require some form of remedial action to prevent or mitigate pollution from current or former operations such as plugging abandoned wells or closing earthen pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of production. Certain of these laws and regulations impose strict liability (i.e., no showing of "fault" is required) that, in some circumstances, may be joint and several. Public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. Changes in environmental laws and regulations occur frequently, and to the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and clean-up requirements, our business and prospects, as well as the oil and natural gas industry in general, could be materially adversely affected.

Hazardous substance and waste handling

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes, and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict and, in some cases, joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, referred to as CERCLA or the Superfund law, and comparable state laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons deemed "responsible parties." These persons include current owners or operators of the site where a release of hazardous substances occurred, prior owners or operators that owned or operated the site at the time of the release or disposal of hazardous substances, and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to strict and joint and several 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 the costs they incur from the responsible classes of persons. Despite the "petroleum exclusion" of Section 101(14) of CERCLA, which currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. In addition, we may have liability for releases of hazardous substances at our properties by prior owners or operators or other third parties. Finally, it is not uncommon for neighboring landowners and other third parties to file common law based claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

The Oil Pollution Act of 1990 (the "OPA") is the primary federal law imposing oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. Under the OPA, strict, joint and several liability may be imposed on "responsible parties" for all containment and clean-up costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters and natural resource damages, resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" includes the owner or operator of an onshore facility. The OPA establishes a liability limit for onshore facilities, but these liability limits may not apply if: a spill is caused by a party's gross negligence or willful misconduct; the spill resulted from violation of a federal safety, construction or operating regulation; or a party fails to report a spill or to cooperate fully in a clean-up. We are also subject to analogous state statutes that impose liabilities with respect to oil spills.

We also generate solid wastes, including hazardous wastes, which are subject to the requirements of the Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes. Although RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA's hazardous waste regulations. These wastes, instead, are regulated under RCRA's less stringent solid waste provisions, state laws or other federal laws. It is also possible that these wastes, which could include wastes currently generated during our operations, will be designated as "hazardous wastes" in the future and, therefore, be subject to more rigorous and costly disposal requirements. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration and production wastes as "hazardous wastes." Also, in January 2017, the EPA agreed in a consent decree to review its regulation of oil and gas waste. It has until March 2019 to determine whether any revisions are necessary. Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

We believe that we are in substantial compliance with the requirements of CERCLA, RCRA, OPA and related state and local laws and regulations, and that we hold all necessary and up-to-date permits, registrations and other authorizations required under such laws and regulations. Although we believe that the current costs of managing our wastes as they are presently classified are reflected in our budget, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Water and other waste discharges and spills

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act, the Safe Drinking Water Act ("SDWA"), the OPA and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. The State of Texas also maintains groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The underground injection of fluids is subject to permitting and other requirements under state laws and regulation. Obtaining permits has the potential to delay the development of oil and natural gas projects. These same regulatory programs also limit the total volume of water that can be discharged, hence limiting the rate of development, and require us to incur compliance costs.

These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances and may impose substantial potential liability for the costs of removal, remediation and damages. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and the underground injection of fluids and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of significant quantities of oil. We maintain all required discharge permits necessary to conduct our operations, and we believe we are in substantial compliance with their terms.

Hydraulic fracturing

Hydraulic fracturing is a practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The SDWA regulates the underground injection of substances through the Underground Injection Control Program (the "UIC"). However, hydraulic fracturing is generally exempt from regulation under the UIC, and thus the process is typically regulated by state oil and gas commissions. Nevertheless, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the UIC. Under this assertion of authority, the EPA requires facilities to obtain permits to use diesel fuel in hydraulic fracturing operations, specifically in Class II wells, which are those wells injecting fluids associated with oil and natural gas production activities. The U.S. Energy Policy Act of 2005, which exempts hydraulic fracturing from regulation under the SDWA, prohibits the use of diesel fuel in the fracturing process without a UIC permit. On February 12, 2014, the EPA published a revised UIC Program permitting guidance for oil and natural gas hydraulic fracturing activities using diesel fuel. The guidance document describes how Class II regulations may be tailored to address the purported unique risks of diesel fuel injection during the hydraulic fracturing process. Although the EPA is not the permitting authority for UIC Class II programs in Texas, where we maintain acreage, the EPA is encouraging state programs to review and consider use of this permit guidance. Furthermore, legislation has been proposed in recent sessions of Congress to repeal the hydraulic fracturing exemption from the SDWA, provide for federal regulation of hydraulic fracturing and require public disclosure of the chemicals used in the fracturing process.

In addition, the EPA plans to develop a Notice of Proposed Rulemaking by June 2018, which would describe a proposed mechanism-regulatory, voluntary, or a combination of both-to collect data on hydraulic fracturing chemical substances and mixtures. Also, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities. We cannot predict the impact that these standards may have on our business at this time, but these standards could have a material impact on our business, financial condition and results of operation.

Also, on March 26, 2015, the Bureau of Land Management (the "BLM") published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing, implementation of a casing and cementing program, management of recovered fluids, and submission to the BLM of detailed information about the proposed operation, including wellbore geology, the location of faults and fractures, and the depths of all usable water. On June 21, 2016, the United States District Court for Wyoming set aside the rule, holding that the BLM lacked Congressional authority to promulgate the rule. The BLM has appealed the decision to the Tenth Circuit Court of Appeals.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. For example, the EPA is currently reviewing the potential adverse effects that hydraulic fracturing may have on water quality and public health. On December 13, 2016, the EPA released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. Also, on

February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, 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 SDWA or other regulatory mechanism.

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Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances, impose additional requirements on hydraulic fracturing activities or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process. For example, pursuant to legislation adopted by the State of Texas in June 2011, beginning February 1, 2012, companies were required to disclose to the RRC and the public the chemical components used in the hydraulic fracturing process, as well as the volume of water used. Also, in May 2013, the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. The new rules took effect in January 2014. Additionally, on October 28, 2014, the RRC adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed, new disposal well. The disposal well rule amendments, which became effective on November 17, 2014, also clarify the RRC's authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The RRC has used this authority to deny permits for waste disposal wells. In addition to state law, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular.

A number of lawsuits and enforcement actions have been initiated across the country alleging that hydraulic fracturing practices have induced seismic activity and adversely impacted drinking water supplies, use of surface water, and the environment generally. Several states and municipalities have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances. If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to drill and produce from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings. In addition, if hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. These developments, as well as new laws or regulations, could cause us to incur substantial compliance costs, and compliance or the consequences of failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the potential impact on our business that may arise if federal or state legislation governing hydraulic fracturing is enacted into law.

Air emissions

The federal Clean Air Act, as amended, and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations, through the issuance of permits 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. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of oil and natural gas projects.

In August 2012, the EPA published final rules 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 ("NESHAP"). The rule includes NSPS for completions of hydraulically fractured gas wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rule seeks to achieve a 95% reduction in volatile organic compounds ("VOC") emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of these requests for reconsideration. In particular, on May

12, 2016, the EPA amended its regulations to impose new standards for methane and VOC emissions for certain new, modified and reconstructed equipment, processes and activities across the oil and natural gas sector. On the same day, the EPA finalized a plan to implement its minor new source review program on federal and Indian lands for oil and natural gas production, and it issued for public comment an information request that will require companies to provide extensive information instrumental for the development of regulations to reduce methane emissions from existing oil and gas sources. In addition, on November 15, 2016, the BLM finalized a rule to reduce the flaring, venting and leaking of methane from oil and gas operations on federal and Indian lands. The rule requires operators to use currently available technologies and equipment to reduce flaring, periodically inspect their operations for leaks, and replace outdated equipment that vents large quantities of gas into the air. The rule also clarifies when operators owe the government royalties for flared gas. State and industry groups have challenged this rule in federal court, asserting that the BLM lacks authority to prescribe air quality regulations. These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or

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modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or utilize specific equipment or technologies to control emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions.

We have incurred additional capital expenditures to insure compliance with these new regulations as they come into effect. We may also be required to incur additional capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits addressing other air emission related issues, which may have a material adverse effect on our operations. Obtaining permits also has the potential to delay the development of oil and natural gas projects. We believe that we currently are in substantial compliance with all air emissions regulations and that we hold all necessary and valid construction and operating permits for our current operations.

Regulation of "greenhouse gas" emissions

Congress has from time to time considered legislation to reduce emissions of greenhouse gases ("GHGs") and almost one-half of the states have already taken legal measures to reduce emissions of GHGs through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Some states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources.

In addition, in December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In response to its endangerment finding, the EPA adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act. The motor vehicle rule, which became effective in July 2010, purports to limit emissions of GHGs from motor vehicles. The EPA adopted the stationary source rule (or the "tailoring rule") in May 2010, and it became effective in January 2011. The tailoring rule established new GHG emissions thresholds that determine when stationary sources must obtain permits under the Prevention of Significant Deterioration ("PSD") and Title V programs of the Clean Air Act. On June 23, 2014, in Utility Air Regulatory Group v. EPA ("UARG v. EPA"), the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD and Title V programs. On August 26, 2016, the EPA proposed changes needed to bring the EPA’s air permitting regulations in line with the Supreme Court’s decision on greenhouse gas permitting. The proposed rule was published in the Federal Register on October 3, 2016 and the public comment period closed on December 2, 2016.

In September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including NGL fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA published a final rule expanding the GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. In October 2015, the EPA amended the GHG reporting rule to add reporting of GHG emissions from gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines.

The EPA has continued to adopt GHG regulations applicable to other industries, such as its August 2015 adoption of three separate, but related, actions to address carbon dioxide pollution from power plants, including final Carbon Pollution Standards for new, modified and reconstructed power plants, a final Clean Power Plan to cut carbon dioxide pollution from existing power plants, and a proposed federal plan to implement the Clean Power Plan emission guidelines. Upon publication of the Clean Power Plan on October 23, 2015, more than two dozen States as well as industry and labor groups challenged the Clean Power Plan in the D.C. Circuit Court of Appeals. On February 9, 2016, the U.S. Supreme Court stayed the Clean Power Plan pending disposition of the legal challenges. Nevertheless, as a result of the continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility.

In December 2015, the United States participated in the 21st Conference of the Parties ("COP-21") of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature, and to conserve and enhance sinks and reservoirs of

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GHGs. The Paris Agreement went into effect on November 4, 2016. The Paris Agreement establishes a framework for the parties to cooperate and report actions to reduce GHG emissions. Also, on June 29, 2016, the leaders of the United States, Canada and Mexico announced an Action Plan to, among other things, boost clean energy, improve energy efficiency and reduce greenhouse gas emissions. The Action Plan specifically calls for a reduction in methane emissions from the oil and gas sector by 40% to 45% by 2025.

Restrictions on GHG emissions that may be imposed could adversely affect the oil and gas industry. The adoption of legislation or regulatory programs to reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations. It remains unclear whether and how the results of the 2016 U.S. presidential and congressional elections could impact the regulation of greenhouse gas emissions at the federal and state level.

In addition, claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals may seek to enforce environmental laws and regulations against us and could allege personal injury or property damages. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Moreover, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornados and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

Occupational Safety and Health Act

We are also subject to the requirements of the federal Occupational Safety and Health Act, as amended ("OSHA") and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Departments of Interior and Agriculture, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency prepares an environmental assessment to evaluate the potential direct, indirect and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a more detailed environmental impact study that is made available for public review and comment. Any exploration and production activities, as well as proposed exploration and development plans, on federal lands would require governmental permits that are subject to the requirements of NEPA. This environmental impact assessment process has the potential to delay the development of oil and natural gas projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

Endangered Species Act

The Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species or its habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development. If we were to have a portion of our leases designated as critical or suitable habitat, it could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas, which could adversely impact the value of our leases.

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Summary

In summary, we believe we are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2016, 2015 or 2014.

Regulation of oil and gas pipelines

Our oil and gas pipelines are subject to construction, installation, operation and safety regulation by the U.S. Department of Transportation ("DOT") and various other federal, state and local agencies. Congress has enacted several pipeline safety acts over the years. Currently, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") under DOT administers pipeline safety requirements for natural gas and hazardous liquid pipelines. These regulations, among other things, address pipeline integrity management and pipeline operator qualification rules. In June 2016, Congress approved new pipeline safety legislation, the "Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016" (the "PIPES Act"), which provides the PHMSA with additional authority to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of gas or hazardous liquids pipeline facilities. Significant expenses could be incurred in the future if additional safety measures are required or if safety standards are raised and exceed the current pipeline control system capabilities.

Recently, the PHMSA has proposed additional regulations for gas pipeline safety. For example, in March 2016, the PHMSA proposed a rule that would expand integrity management requirements beyond "High Consequence Areas" to apply to gas pipelines in newly defined "Moderate Consequence Areas." The public comment period closed on July 7, 2016. Also, on January 10, 2017, the PHMSA approved final rules expanding its safety regulations for hazardous liquid pipelines by, among other things, expanding the required use of leak detection systems, requiring more frequent testing for corrosion and other flaws and requiring companies to inspect pipelines in areas affected by extreme weather or natural disasters. The final rule will become effective six months after publication in the Federal Register. Because the executive branch of the Trump administration has prohibited such publication until it has had time to review the pending regulations, it is not clear when, or if, the final rules will become effective.

Disclosures required pursuant to Section 13(r) of the Securities Exchange Act of 1934

Pursuant to Section 13(r) of the Exchange Act, we are required to include certain disclosures in our periodic reports if we or any of our "affiliates" (as defined in Rule 12b-2 under the Exchange Act) knowingly engaged in certain specified activities, transactions or dealings relating to Iran or with certain individuals or entities targeted by United States' economic sanctions during the period covered by the report. Disclosure is generally required even where the activities, transactions or dealings were conducted in compliance with applicable law. Neither we nor any of our controlled affiliates or subsidiaries knowingly engaged in any of the specified activities relating to Iran or otherwise engaged in any activities associated with Iran during the reporting period. However, because the SEC defines the term "affiliate" broadly, it includes any entity controlled by us as well as any person or entity that controlled us or is under common control with us.

The description of the activities below has been provided to us by Warburg Pincus, affiliates of which: (i) beneficially own more than 10% of our outstanding common stock and are members of our board of directors and (ii) beneficially own more than 10% of the equity interests of, and have the right to designate members of the board of directors of Santander Asset Management Investment Holdings Limited ("SAMIH"). SAMIH may therefore be deemed to be under "common control" with us; however, this statement is not meant to be an admission that common control exists. The disclosure below relates solely to activities conducted by SAMIH and its affiliates. The disclosure does not relate to any activities conducted by Laredo or by Warburg Pincus and does not involve our or Warburg Pincus' management. Neither Laredo nor Warburg Pincus had any involvement in or control over the disclosed activities of SAMIH, and neither Laredo nor Warburg Pincus has independently verified or participated in the preparation of the disclosure. Neither Laredo nor Warburg Pincus is representing as to the accuracy or completeness of the disclosure nor do we or Warburg Pincus undertake any obligation to correct or update it.

Laredo understands that one or more SEC-reporting affiliates of SAMIH intends to disclose in its next annual or quarterly SEC report that:

(a) "Santander UK plc ("Santander UK") holds two savings accounts and one current account for two customers resident in the United Kingdom ("U.K.") who are currently designated by the United States ("U.S.") under the Specially Designated Global Terrorist ("SDGT") sanctions program. Revenues and profits generated by Santander UK on these accounts in the year ended December 31, 2016 were negligible relative to the overall revenues and profits of Banco Santander SA.

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(b) Santander UK held a savings account for a customer resident in the U.K. who is currently designated by the U.S. under the SDGT sanctions program. The savings account was closed on July 26, 2016. Revenue generated by Santander UK on this account in the year ended December 31, 2016 was negligible relative to the overall revenues and profits of Banco Santander SA.
(c) Santander UK held a current account for a customer resident in the U.K. who is currently designated by the U.S. under the SDGT sanctions program. The current account was closed on December 22, 2016. Revenue generated by Santander UK on this account in the year ended December 31, 2016 was negligible relative to the overall revenues and profits of Banco Santander SA.
(d) Santander UK holds two frozen current accounts for two U.K. nationals who are designated by the U.S. under the SDGT sanctions program. The accounts held by each customer have been frozen since their designation and have remained frozen through the year ended December 31, 2016. The accounts are in arrears (£1,844.73 in debit combined) and are currently being managed by Santander UK Collections & Recoveries department. Revenues and profits generated by Santander UK on these accounts in the year ended December 31, 2016 were negligible relative to the overall revenues and profits of Banco Santander SA.
(e) During the year ended December 31, 2016, Santander UK had an Office of Foreign Assets Control match on a power of attorney account. A party listed on the account is currently designated by the U.S. under the SDGT sanctions program and the Iranian Financial Sanctions Regulations ("IFSR"). The power of attorney was removed from the account on July 29, 2016. During the year ended December 31, 2016, related revenues and profits generated by Santander UK were negligible relative to the overall revenues and profits of Banco Santander SA.
(f) An Iranian national, resident in the UK, who is currently designated by the U.S. under the IFSR and the Weapons of Mass Destruction Proliferators Sanctions Regulations, held a mortgage with Santander UK that was issued prior to such designation. The mortgage account was redeemed and closed on April 13, 2016. No further draw down has been made (or would be allowed) under this mortgage although Santander UK continued to receive repayment installments prior to redemption. Revenues generated by Santander UK on this account in the year ended December 31, 2016 were negligible relative to the overall revenues of Banco Santander SA. The same Iranian national also held two investment accounts with Santander ISA Managers Limited. The funds within both accounts were invested in the same portfolio fund. The accounts remained frozen until the investments were closed on May 12, 2016 and bank checks issued to the customer. Revenues generated by Santander UK on these accounts in the year ended December 31, 2016 were negligible relative to the overall revenues and profits of Banco Santander SA.
(g) In addition, during the year ended December 31, 2016, Santander UK held a basic current account for an Iranian national, resident in the UK, previously designated under the Iranian Transactions and Sanctions Regulations. The account was closed in September 2016. Revenues generated by Santander UK on this account in the year ended December 31, 2016 were negligible relative to the overall revenues and profits of Banco Santander SA."

Employees

As of December 31, 2016, we had 324 full-time employees. We also employed a total of 29 contract personnel who assist our full-time employees with respect to specific tasks and perform various field and other services. Our future success will depend partially on our ability to identify, attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory.

Our offices

Our executive offices are located at 15 W. Sixth Street, Suite 900, Tulsa, Oklahoma 74119, and the phone number at this address is (918) 513-4570. We also lease corporate offices in Midland, Texas. On January 20, 2015, we announced the closing of our Dallas, Texas area office. We are currently still subject to the lease covering this office space, but are actively exploring alternative arrangements for its use.

Available information

We are required to file annual, quarterly and current reports, proxy statements and 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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Our common stock is listed and traded on the New York Stock Exchange under the symbol "LPI." Our reports, proxy statements and other information filed with the SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

We also make available on our website (http://www.laredopetro.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 Conduct and Business Ethics, Code of Ethics For Senior Financial Officers, Corporate Governance Guidelines and the charters of our audit committee, compensation committee and nominating and corporate governance committee 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 our corporate secretary at our executive office at 15 W. Sixth Street, Suite 900, Tulsa, Oklahoma 74119. Information contained on our website is not incorporated by reference into this Annual Report. We intend to disclose on our website any amendments or waivers to our Code of Ethics that are required to be disclosed pursuant to Item 5.05 of Form 8-K.

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Item 1A. Risk Factors

Our business involves a high degree of risk. If any of the following risks, or any risks described elsewhere in this Annual Report, were actually to occur, our business, financial condition or results of operations could be materially adversely affected and the trading price of our shares could decline resulting in the loss of part or all of your investment. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial may also adversely affect us.

Risks related to our business

Oil, NGL and natural gas prices are volatile. The continuing and extended volatility in oil, NGL and natural gas prices has adversely affected, and may continue to adversely affect, our business, financial condition and results of operations and may in the future affect our ability to meet our capital expenditure obligations and financial commitments as well as negatively impact our stock price further.

The prices we receive for our oil, NGL and natural gas production heavily influence our revenue, profitability, access to capital and future rate of growth. Oil, NGL and natural gas are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the market for oil, NGL and natural gas has been volatile, and this volatility exhibited a negative trend in the second half of 2014 which has continued into the first quarter of 2017. While prices have increased from recent lows, they are still significantly below previous highs. The market will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic and financial conditions impacting the global supply and demand for oil, NGL and natural gas;
- actions of the Organization of Petroleum Exporting Countries and state-controlled oil companies relating to oil, NGL and natural gas production and price controls;
- the level of global oil, NGL and natural gas exploration and production;
- the level of global oil, NGL and natural gas supplies, in particular due to supply growth from the United States;
- foreign and domestic supply capabilities for oil, NGL and natural gas;
- the price and quantity of U.S. imports and exports of oil, natural gas, including liquefied natural gas, and NGL;
- political conditions in or affecting other oil, NGL and natural gas-producing countries, including the current conflicts in the Middle East, and conditions in South America, Africa, Ukraine and Russia;
- the extent to which U.S. shale producers act as "swing producers" adding or subtracting to the world supply of oil, NGL and natural gas;
- future regulations prohibiting or restricting our ability to apply hydraulic fracturing to our wells;
- current and future regulations regarding well spacing;
- prevailing prices on local oil, NGL and natural gas price indexes in the areas in which we operate;
- localized and global supply and demand fundamentals and transportation availability;
- weather conditions;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- domestic, local and foreign governmental regulation and taxes.

Lower oil, NGL and natural gas prices have and will continue to reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our oil, NGL and natural gas reserves as existing reserves are depleted. A continuing decrease in oil, NGL and natural gas prices could render uneconomic a large portion of our exploration, development and exploitation projects. This has already resulted in us having to make significant downward adjustments to our estimated proved reserves, and we may need to make further downward adjustments in the future. Furthermore, under our Senior Secured Credit Facility, scheduled borrowing base redeterminations occur on each May 1 and November 1, and the lenders have the right to call for an interim redetermination of the borrowing base one time between any two redetermination dates and in other specified circumstances. A reduced borrowing base could trigger repayment obligations under our Senior Secured Credit Facility. Also, lower oil, NGL and natural gas prices may cause a further decline in our stock price. In addition, it is uncertain what impact the 2016 U.S. presidential and congressional elections will have on the energy industry.

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Currently, we receive incremental cash flows as a result of our hedging activity. To the extent we are unable to obtain future hedges at attractive prices or our derivative activities are not effective, our cash flows and financial condition may be adversely impacted.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of oil, NGL and natural gas, we enter into derivative instrument contracts for a portion of our oil, NGL and natural gas production, including swaps, collars, puts and basis swaps. In accordance with applicable accounting principles, we are required to record our derivatives at fair market value, and they are included on our consolidated balance sheet as assets or liabilities and in our consolidated statements of operations as gain (loss) on derivatives. Gain (loss) on derivatives are included in our cash flows from operating activities. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair market value of our derivative instruments, including a decrease in earnings if the price of commodities increases above the price of hedges that we have in place. Although our current hedges provide us with a benefit as they are priced above the current depressed prices for oil, NGL and natural gas, as these hedges expire, there is significant uncertainty that we will be able to put new hedges in place that will provide us with similar benefit.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counter-party to the derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

For additional information regarding our hedging activities, please see "Item 7. Management's discussion and analysis of financial condition and results of operations—Results of operations—Commodity derivatives."

Estimating reserves and future net revenues involves uncertainties. Decreases in oil, NGL and natural gas prices, increases in service costs or negative revisions to reserve estimates or assumptions as to future oil, NGL and natural gas prices, may lead to decreased earnings and losses or impairment of oil, NGL and natural gas assets.

The reserve data included in this Annual Report represent estimates. Reserves estimation is a subjective process of evaluating underground accumulations of oil, NGL and natural gas that cannot be measured in an exact manner. Reserves that are "proved reserves" are those estimated quantities of oil, NGL and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions and that relate to specific locations for which the extraction of hydrocarbons must have commenced or the operator must be reasonably certain will commence within a five-year period.

The estimation process relies on interpretations of available geological, geophysical, engineering and production data. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of developmental expenditures, including higher decline curves in the first year of production and many other factors beyond the control of the producer. In addition, the estimates of future net revenues from our proved reserves and the present value of such estimates are based upon certain assumptions about future production levels, prices and costs that may not prove to be correct. Further, initial production rates reported by us or other operators may not be indicative of future or long-term production rates. A production decline may be rapid and irregular when compared to a well's initial production.

For the year ended December 31, 2016, the Company's positive revision of 34,082 MBOE of previously estimated quantities is primarily attributable to the combination of positive performance, lower operating costs and other changes to proved developed producing wells. However, in both 2014 and 2015 the Company had negative revisions of estimated quantities primarily due to a sharp decline in commodity prices. Although the Company had a positive revision in 2016, it is possible that the Company will have negative revisions in the future.

Negative revisions in the estimated quantities of proved reserves have the effect of increasing the rates of depletion on the affected properties, which decrease earnings or result in losses through higher depletion expense. These revisions, as well as revisions in the assumptions of future cash flows of these reserves, may also trigger impairment losses on certain properties, which would result in a non-cash charge to earnings. See Note 20.d to our consolidated financial statements included elsewhere in this Annual Report.

As a result of the sustained decrease in prices for oil, NGL and natural gas, we have taken and may be required to take further write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment.

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Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we have been required to, and may be required to further, write-down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings.

Oil, NGL and natural gas prices significantly declined starting in mid-2014 and have not regained previous highs. Primarily as a result of these lower prices, our December 31, 2015 estimated proved reserves decreased 171 MMBOE from our December 31, 2014 reserves, converted to three streams. Our net book value of evaluated oil and natural gas properties exceeded the full cost ceiling amount as of March 31, 2016 and each of the last three quarters of 2015 and as a result, we recorded non-cash full cost ceiling impairments of $161.1 million and $2.4 billion for the years ended December 31, 2016 and 2015, respectively. If prices decline below current levels and all other factors remain the same, we may incur further charges in the future. Such charges could have a material adverse effect on our results of operations for the periods in which they are taken. See Note 2.g to our consolidated financial statements included elsewhere in this Annual Report for additional information.

Any significant reduction in our borrowing base under our Senior Secured Credit Facility as a result of a periodic borrowing base redetermination or otherwise will negatively impact our liquidity and, consequently, our ability to fund our operations, and we may not have sufficient funds to repay borrowings under our Senior Secured Credit Facility or any other obligation if required as a result of a borrowing base redetermination.

Availability under our Senior Secured Credit Facility is currently subject to a borrowing base of $815.0 million. The borrowing base is subject to scheduled semiannual (May 1 and November 1) and other elective borrowing base redeterminations based upon, among other things, projected revenues from, and asset values of, the oil and natural gas properties securing the Senior Secured Credit Facility. The lenders under our Senior Secured Credit Facility can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our Senior Secured Credit Facility. Reductions in estimates of our oil, NGL and natural gas reserves will result in a reduction in our borrowing base (if prices are kept constant). Reductions in our borrowing base could also arise from other factors, including but not limited to:

- lower commodity prices or production;
- increased leverage ratios;
- inability to drill or unfavorable drilling results;
- changes in crude oil, NGL and natural gas reserve engineering;
- increased operating and/or capital costs;
- the lenders' inability to agree to an adequate borrowing base; or
- adverse changes in the lenders' practices (including required regulatory changes) regarding estimation of reserves.

As of February 14, 2017, we had $15.0 million of borrowings outstanding under our Senior Secured Credit Facility. We may make further borrowings under our Senior Secured Credit Facility in the future. Any significant reduction in our borrowing base as a result of such borrowing base redeterminations or otherwise will negatively impact our liquidity and our ability to fund our operations and, as a result, would have a material adverse effect on our financial position, results of operation and cash flow. Further, if the outstanding borrowings under our Senior Secured Credit Facility were to exceed the borrowing base as a result of any such redetermination, we could be required to repay the excess. We may not have sufficient funds to make such repayments. If we do not have sufficient funds and we are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

Our business requires significant capital expenditures and we may be unable to obtain needed capital or financing on satisfactory terms or at all.

Our exploration, development, marketing, transportation and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations, borrowings on our Senior Secured Credit Facility, equity offerings and proceeds from the sale of our Senior Unsecured Notes. We do not have commitments from anyone to contribute capital to us. Future cash flows are subject to a number of variables, including the level of production from existing wells, prices of oil, NGL and natural gas and our success in developing and producing new reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may have limited ability to obtain the additional capital necessary to sustain our operations at current levels. We may not be able to obtain debt or equity financing on terms favorable to us or at all. The failure to obtain additional capital could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a decline in our oil, NGL and natural gas production or reserves and, in some areas, a loss of properties.

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Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce our cash flow and/or liquidity available for drilling and place us at a competitive disadvantage. For example, as of February 14, 2017 we had an $815.0 million borrowing base with $15.0 million outstanding on our Senior Secured Credit Facility, subject to compliance with financial covenants. The impact of a 1.0% increase in interest rates on an assumed borrowing of the full $815.0 million would result in increased annual interest expense of $8.15 million and a decrease in our income before income taxes. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in our cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

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

We incurred net losses from our inception to December 31, 2006 of $1.8 million and for each of the years ended December 31, 2007, 2008, 2009, 2015 and 2016 of $6.1 million, $192.0 million, $184.5 million, $2.2 billion and $260.7 million, respectively. Our development of and participation in an increasingly larger number of locations has required and will continue to require substantial capital expenditures. The uncertainty and factors described throughout this section may impede our ability to economically find, develop, exploit and acquire oil, NGL and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows from operating activities in the future. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical accounting policies and estimates."

We require a significant amount of cash to service our indebtedness. Our ability to generate cash depends on many factors beyond our control.

Our ability to make payments on and to refinance our indebtedness and to fund planned capital expenditures depends on our ability to generate cash in the future. This, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control. We cannot assure you that we will generate sufficient cash flow from operations or that future funding will be available to us under our Senior Secured Credit Facility, equity offerings or other actions in an amount sufficient to enable us to pay our indebtedness or to fund our other liquidity needs. We may need to refinance all or a portion of our indebtedness at or before maturity. We cannot assure you that we will be able to refinance any of our indebtedness on commercially reasonable terms or at all.

Our debt agreements contain restrictions that limit our flexibility in operating our business.

Our Senior Secured Credit Facility and the indentures governing our Senior Unsecured Notes each contain, and any future indebtedness we incur may contain, various covenants that limit our ability to engage in specified types of transactions. These covenants limit our ability to, among other things:

- incur additional indebtedness;
- pay dividends on, repurchase or make distributions in respect of our capital stock or make other restricted payments;
- make certain investments, including in Medallion;
- sell certain assets;
- create liens;
- consolidate, merge, sell or otherwise dispose of all or substantially all of our assets; and
- enter into certain transactions with our affiliates.

As a result of these covenants and a covenant in our Senior Secured Credit Facility that limits our ability to hedge, we are limited in the manner in which we may conduct our business and we may be unable to engage in favorable business activities or finance future operations or our capital needs. In addition, the covenants in our Senior Secured Credit Facility require us to maintain a minimum working capital ratio and minimum interest coverage ratio and also limit our capital expenditures. A breach of any of these covenants could result in a default under one or more of these agreements, including as a result of cross default provisions and, in the case of our Senior Secured Credit Facility, permit the lenders to cease making loans to us. Upon the occurrence of an event of default under our Senior Secured

Credit Facility, the lenders could elect to declare all amounts outstanding under our Senior Secured Credit Facility to be immediately due and payable and terminate all commitments to extend further credit. Such actions by those lenders could cause cross defaults under our other indebtedness, including the Senior Unsecured Notes. If we were unable to repay those amounts, the lenders under our Senior Secured Credit Facility could proceed against the collateral granted to them to secure that indebtedness. We pledged a significant portion of our

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assets as collateral under our Senior Secured Credit Facility. If the lenders under our Senior Secured Credit Facility accelerate the repayment of the borrowings thereunder, the proceeds from the sale or foreclosure upon such assets will first be used to repay debt under our Senior Secured Credit Facility, and we may not have sufficient assets to repay our unsecured indebtedness thereafter. In addition, our Senior Secured Credit Facility terminates in November 2018. While we anticipate putting in place a replacement credit facility, there is no guarantee that we will be able to do so and even if we are able to do so such new credit facility may contain terms and covenants that are more restrictive than the Senior Secured Credit Facility.

If we were to experience an ownership change, we could be limited in our ability to use net operating losses arising prior to the ownership change to offset future taxable income. In addition, our ability to use net operating loss carry forwards to reduce future tax payments may be limited if our taxable income does not reach sufficient levels.

As of December 31, 2016, we had a net operating loss ("NOL") carryforward for federal income tax purposes of $1.6 billion. If we were to experience an "ownership change," as determined under Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"), our ability to offset taxable income arising after the ownership change with NOLs arising prior to the ownership change would be limited, possibly substantially. An ownership change would establish an annual limitation on the amount of our pre-change NOL we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate. In general, an ownership change will occur if there is a cumulative increase in our ownership of more than 50 percentage points by one or more "5% shareholders" (as defined in the Code) at any time during a rolling three-year period. In addition, under the Code, NOL can generally be carried forward to offset future taxable income for a period of 20 years. Our ability to use our NOL during this period will be dependent on our ability to generate taxable income, and the NOL could expire before we generate sufficient taxable income. As of December 31, 2016, based on evidence available to us, including projected future cash flows from our oil and natural gas reserves and the timing of those cash flows, we believe a portion of our NOL is not fully realizable. As a result, as of December 31, 2016 a valuation allowance has been recorded against our NOL tax assets. See Note 7 to our consolidated financial statements included elsewhere in this Annual Report for additional information.

The potential drilling locations for our future wells that we have tentatively internally identified will be drilled, if at all, over many years. This makes them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, which in certain instances could prevent production prior to the expiration date of leases for such locations.

Although our management team has established certain potential drilling locations as a part of our long-range planning related to future drilling activities on our existing acreage, our ability to drill and develop these locations depends on a number of uncertainties, including oil, NGL and natural gas prices, the availability and cost of capital, drilling and production costs, the availability of drilling services and equipment, drilling results (including the impact of increased horizontal drilling and longer laterals), lease expirations, gathering systems, marketing and pipeline transportation constraints, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous potential drilling locations we have currently identified will ever be drilled or if we will be able to produce oil, NGL or natural gas from these or any other potential drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. As such, it is likely our actual drilling activities, especially in the long term, could materially differ from those presently anticipated.

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

Our future financial condition and results of operations will depend on the success of our exploration, exploitation, development and production activities. Our oil, NGL and natural gas exploration, exploitation, development and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil, NGL and natural gas production. Our decisions to purchase, explore, develop or otherwise exploit locations or properties will depend in part on the evaluation of information obtained through geophysical and geological analyses, production data, engineering studies and our Earth Model, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see "—Estimating reserves and future net revenues involves uncertainties. Decreases in oil, NGL and natural gas prices, or negative revisions to reserves estimates or assumptions as to future oil, NGL and natural gas prices, may lead to decreased earnings, losses or impairment of oil, NGL and natural gas assets." In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences. Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- declines in oil, NGL and natural gas prices;
- limited availability of financing or capital at acceptable rates or terms;
- limitations in the market for oil, NGL and natural gas;
- delays imposed by or resulting from compliance with regulatory and contractual requirements and related

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lawsuits, which may include limitations on hydraulic fracturing or the discharge of greenhouse gases;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- fires and blowouts;
- adverse weather conditions, such as hurricanes, blizzards and ice storms; and
- title problems.

We are involved as a passive minority-interest partner in joint ventures and are subject to risks associated with joint venture partnerships.

We are involved as a passive minority-interest partner in joint venture relationships and may initiate future joint venture projects. Entering into a joint venture as a passive minority-interest partner involves certain risks that include: the need to contribute funds to the joint venture to support its operating and capital needs; the inability to exercise voting control over the joint venture; economic or business interests that are not aligned with our venture partners, including the holding period and timing of ultimate sale of the ventures' underlying assets; and the inability for the venture partner to fulfill its commitments and obligations due to financial or other difficulties. Our interest in Medallion is as a passive minority-interest partner. See Note 14 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding Medallion.

In many instances (including Medallion), we depend on the venture partner for elements of the arrangements that are important to the success of the joint venture, such as agreed payments of substantial development costs pertaining to the joint venture and its share of other costs of the joint venture. The performance of these venture partner obligations or the ability of the venture partner to meet its obligations under these arrangements is outside our control. If the venture partner does not meet or satisfy its obligations under these arrangements, the performance and success of these arrangements, and their value to us, may be adversely affected.

If our current or future venture partners are unable to meet their obligations because of insolvency, bankruptcy or other reasons, we may be forced to undertake the obligations ourselves and/or incur additional expenses in order to have some other party perform such obligations. In addition, the insolvency of a venture partner could result in our liability to governmental authorities for compliance with environmental, safety and other regulatory requirements, to the joint venture’s suppliers and vendors and to other third parties. In such cases, we may also be required to enforce our rights, which may cause disputes among our venture partners and us. If any of these events occur, they may adversely impact us, our financial performance and results of operations, the joint ventures and/or our ability to enter into future joint ventures. Likewise, we may have similar obligations to third parties for properties we operate.

Some of our drilling and development activities are subject to joint ventures or operations controlled by third parties, which could negatively impact our control over these operations and have a material adverse effect on our business, results of operations, financial condition and prospects.

A portion of our drilling and development activities is conducted through joint operating agreements under which we own partial interests in oil and natural gas properties. If we do not operate the properties in which we own an interest, (i) we have limited ability to influence or control the day-to-day operation of such properties, including compliance with environmental, safety and other regulations, (ii) we cannot control the amount of capital expenditures that we are required to fund with respect to properties or the future development plans for the properties, (iii) we are dependent on third parties to fund their required share of capital expenditures the same as our dependency on third parties where we are the operator and (iv) we may have restrictions or limitations on our ability to sell our interests in these jointly owned assets. The failure of an operator of our wells to adequately perform operations or an operator's breach of the applicable agreements could materially reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others, therefore, depends upon a number of factors outside of our control, including the operator's timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells and use of technology. Because we do not have a majority interest in most wells that we do not operate, we may not be in a position to remove the operator in the event of poor performance.

In addition, the insolvency of an operator of any of our properties, the failure of an operator of any of our properties to adequately perform operations or an operator’s breach of applicable agreements could reduce our production and revenue and result in our liability to governmental authorities for compliance with environmental, safety and other regulatory requirements, to the operator's suppliers and vendors and to royalty owners under oil and gas leases jointly owned with the operator or another insolvent owner. Finally, an operator of our properties may have the right, if another non-operator fails to pay its share

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of costs because of its insolvency or otherwise, to require us to pay our proportionate share of the defaulting party's share of costs.

The inability of our significant customers to meet their obligations to us may materially adversely affect our financial results.

In addition to credit risk related to receivables from commodity derivative contracts, our principal exposure to credit risk is through net joint operations receivables ($12.2 million as of December 31, 2016), the sale of purchased oil and other products ($16.2 million in receivables as of December 31, 2016) and the sale of our oil, NGL and natural gas production ($47.0 million in receivables as of December 31, 2016), which we market to energy marketing companies, refineries and affiliates. Joint interest receivables arise from billing entities who own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We are generally unable to control which co-owners participate in our wells. We are also subject to credit risk due to the concentration of our oil, NGL and natural gas production receivables with several significant customers. The three largest purchasers of our oil, NGL and natural gas production accounted for 48.5%, 23.0% and 17.0%, respectively, of our total oil, NGL and natural gas revenues for the year ended December 31, 2016, and our sales of purchased oil are made to one customer. See Note 11 to our consolidated financial statements included elsewhere in this Annual Report for additional information. The inability or failure of our significant customers or joint working interest owners to meet their obligations to us or their insolvency or liquidation may materially adversely affect our financial results. Current economic circumstances may further increase these risks.

Our operations are substantially dependent on the availability, use and disposal of water. New legislation and regulatory initiatives or restrictions relating to water disposal wells could have a material adverse effect on our future business, financial condition, operating results and prospects.

Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners and other sources for use in our operations. During the past several years, Texas has experienced the lowest inflows of water in recent history. As a result of these conditions, some local water districts may begin restricting the use of water subject to their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil, NGL and natural gas, which could have an adverse effect on our results of operations, cash flows and financial condition.

Additionally, our drilling procedures produce large volumes of water that we must properly dispose. The Clean Water Act of 1977, as amended, the Safe Drinking Water Act of 1974, as amended, the Oil Pollution Act of 1990, as amended, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the U.S. Environmental Protection Agency (the "EPA") or the state. Furthermore, the State of Texas maintains groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The underground injection of fluids is subject to permitting and other requirements under state laws and regulation. Obtaining permits has the potential to delay the development of oil, NGL and natural gas projects. These same regulatory programs also limit the total volume of water that can be discharged, hence limiting the rate of development, and require us to incur compliance costs. In October 2014, the RRC adopted new regulations effective as of November 17, 2014 that require additional supporting documentation, including records from the U.S. Geological Survey regarding previous seismic events in the area, as part of applications for new disposal wells. The new regulations also clarify the RRC's ability to modify, suspend or terminate a disposal well permit if scientific data indicates it is likely to contribute to seismic activity. The RRC has used this authority to deny permits for waste disposal sites.

Moreover, the EPA is examining regulatory requirements for "indirect dischargers" of wastewater - i.e., those that send their discharges to private or publicly owned treatment facilities, which treat the wastewater before discharging it to regulated waters. On June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and gas extraction wastewater. The EPA is collecting data and information related to the extent

to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities.
Because of the necessity to safely dispose of water produced during drilling and production activities, these regulations, or others like them, could have a material adverse effect on our future business, financial condition, operating results and prospects. See "Item 1. Business—Regulation of the oil and natural gas industry" for a further description of the laws and regulations that affect us.

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Federal and state legislation and regulatory initiatives relating to hydraulic fracturing and water disposal wells could prohibit projects or result in materially increased costs and additional operating restrictions or delays because of the significance of hydraulic fracturing and water disposal wells in our business.

Hydraulic fracturing is a practice that is used to stimulate production of oil and/or natural gas from tight formations. The process involves the injection of water, propants and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. Nearly all of our proved non-producing and proved undeveloped reserves associated with future drilling, recompletion and refracture stimulation projects require hydraulic fracturing. If we are unable to apply hydraulic fracturing to our wells or the process is prohibited or significantly regulated or restricted, we would lose the ability to (i) drill and complete the projects for such proved reserves and (ii) maintain the associated acreage, which would have a material adverse effect on our future business, financial condition, operating results and prospects.

The federal Safe Drinking Water Act ("SDWA") regulates the underground injection of substances through the Underground Injection Control ("UIC") Program. However, hydraulic fracturing is generally exempt from regulation under the UIC Program, and thus the process is typically regulated by state oil and gas commissions. Nevertheless, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the UIC Program. Under this assertion of authority, the EPA requires facilities to obtain permits to use diesel fuel in hydraulic fracturing operations. The U.S. Energy Policy Act of 2005, which exempts hydraulic fracturing from regulation under the SDWA, prohibits the use of diesel fuel in the fracturing process without a UIC permit. On February 12, 2014, the EPA published a revised UIC Program guidance for oil, NGL and natural gas hydraulic fracturing activities using diesel fuel. The guidance document describes how regulations of Class II wells, which are those wells injecting fluids associated with oil, NGL and natural gas production activities, may be tailored to address the purported unique risks of diesel fuel injection during the hydraulic fracturing process. Although the EPA is not the permitting authority for UIC Class II programs in Texas, where we maintain acreage, the EPA is encouraging state programs to review and consider use of the above-mentioned guidance. Furthermore, legislation has been proposed in recent sessions of Congress to repeal the hydraulic fracturing exemption from the SDWA, provide for federal regulation of hydraulic fracturing, and require public disclosure of the chemicals used in the fracturing process.

In addition, the EPA plans to develop a Notice of Proposed Rulemaking by June 2018, which would describe a proposed mechanism-regulatory, voluntary, or a combination of both to collect data on hydraulic fracturing chemical substances and mixtures.

Also, on March 26, 2015, the Bureau of Land Management (the "BLM") published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing, implementation of a casing and cementing program, management of recovered fluids, and submission to the BLM of detailed information about the proposed operation, including wellbore geology, the location of faults and fractures, and the depths of all usable water. On June 21, 2016, the United States District Court for Wyoming set aside the rule, holding that the BLM lacked Congressional authority to promulgate the rule. The BLM has appealed the decision to the Tenth Circuit Court of Appeals.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. For example, the EPA is currently reviewing the potential adverse effects that hydraulic fracturing may have on water quality and public health. On December 13, 2016, the EPA released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, 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 SDWA or other regulatory mechanism.

On August 16, 2012, the EPA published final rules that subject oil, NGL 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 ("NESHAP") programs. The rule includes NSPS Standards for completions of hydraulically fractured gas wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rule seeks to achieve a 95% reduction in volatile organic compounds ("VOC") emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of these requests for reconsideration. In particular, on May 12, 2016, the EPA amended its regulations to impose new standards for methane and VOC emissions for certain new, modified and reconstructed equipment, processes and activities across the oil and natural gas sector. On the same day, the EPA finalized a plan to implement its minor new source review program on federal and Indian lands for oil and natural gas production, and it issued for public comment an information request that will require companies to provide extensive information instrumental for the development of regulations to reduce methane emissions from existing oil and gas sources.

Also, on November 15, 2016, the BLM finalized a rule to reduce the flaring, venting and leaking of methane from oil and gas operations on federal and Indian lands. The rule requires operators to use currently available technologies and equipment to reduce flaring, periodically inspect their operations for leaks and replace outdated equipment that vents large quantities of gas into the air. The rule also clarifies when operators owe the government royalties for flared gas. State and industry groups have challenged this rule in federal court, asserting that the BLM lacks authority to prescribe air quality regulations.

These standards, 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 expected to produce air emissions, impose stringent air permit requirements, or utilize specific equipment or technologies to control emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances, impose additional requirements on hydraulic fracturing activities or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process. For example, pursuant to legislation adopted by the State of Texas in June 2011, the chemical components used in the hydraulic fracturing process, as well as the volume of water used, must be disclosed to the RRC and the public beginning February 1, 2012. Furthermore, on May 23, 2013, the RRC issued the "well integrity rule," which updates the RRC's Rule 13 requirements for drilling, putting pipe down and cementing wells. The rule also includes new testing and reporting requirements, such as (i) the requirement to submit to the RRC cementing reports after well completion or after cessation of drilling, whichever is later, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. The "well integrity rule" took effect in January 2014. Additionally, on October 28, 2014, the RRC adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed, new disposal well. The disposal well rule amendments, which became effective on November 17, 2014, also clarify the RRC's authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The RRC has used this authority to deny permits for waste disposal wells. In addition to state law, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular.

A number of lawsuits and enforcement actions have been initiated across the country alleging that hydraulic fracturing practices have induced seismic activity and adversely impacted drinking water supplies, use of surface water and the environment generally. Several states and municipalities have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances. If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted or laws or regulations are adopted to restrict water disposal wells, such laws could make it more difficult or costly for us to drill and produce from conventional or tight formations as well as make it easier for third parties opposing the oil, NGL and natural gas industry to initiate legal proceedings. In addition, if these matters are regulated at the federal level, fracturing and disposal activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also result in permitting delays and potential other increases in costs. These developments, as well as new laws or regulations, could cause us to incur substantial compliance costs, and compliance or the consequences of failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the potential impact on our business that may arise if federal or state legislation or regulations governing hydraulic fracturing or water disposal wells are enacted into law.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our oil, NGL and natural gas exploration, production and gathering operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations. Failure to comply with laws and regulations applicable to our operations, including any evolving interpretation and

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enforcement by governmental authorities, could have a material adverse effect on our business, financial condition and results of operations.

See "Item 1. Business—Regulation of the oil and natural gas industry" and other risk factors described in this "Item 1A. Risk Factors" for a further description of the laws and regulations that affect us.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil, NGL and natural gas operations in our operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. Permanent restrictions imposed to protect threatened or endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising 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 our reserves.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Section 1(b) of the Natural Gas Act of 1938 (the "NGA") exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission ("FERC"). We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish whether a pipeline performs a gathering function and therefore is exempt from the FERC's jurisdiction under the NGA. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is a fact-based determination. The classification of facilities as unregulated gathering is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress, which could cause our revenues to decline and operating expenses to increase and may materially adversely affect our business, financial condition or results of operations. In addition, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting and daily scheduled flow and capacity posting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability, which could have a material adverse effect on our business, financial condition or results of operations.

The adoption of climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil, NGL and natural gas we produce.

Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, through the planned development of GHG emission inventories and/or regional GHG cap and trade programs or other mechanisms. Most cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Some states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources.

In addition, in December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In response to its endangerment finding, the EPA recently adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act. The motor vehicle rule, which became effective in July 2010, purports to limit emissions of GHGs from motor vehicles. The EPA adopted the stationary source rule (or the "tailoring rule") in May 2010, and it became effective in January 2011. The tailoring rule established new GHG emissions thresholds that determine when stationary sources must obtain permits under the Prevention of Significant Deterioration ("PSD") and Title V programs of the Clean Air Act. On June 23, 2014, in Utility Air Regulatory Group v. EPA ("UARG v. EPA"), the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD and Title V programs. On August 26, 2016, the EPA proposed changes needed to bring the EPA's air permitting regulations in line with the Supreme Court's decision on greenhouse gas permitting. The proposed rule was published in the Federal Register on October 3, 2016 and the public comment period closed on December 2, 2016.

In September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including NGL fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA published a final rule expanding the GHG reporting rule to include onshore oil, NGL and natural gas production, processing, transmission, storage and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. In October 2015, the EPA amended the GHG reporting rule to add the reporting of GHG emissions from gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines.

The EPA has continued to adopt GHG regulations applicable to other industries, such as its August 2015 adoption of three separate, but related, actions to address carbon dioxide pollution from power plants, including final Carbon Pollution Standards for new, modified and reconstructed power plants, a final Clean Power Plan to cut carbon dioxide pollution from existing power plants, and a proposed federal plan to implement the Clean Power Plan emission guidelines. Upon publication of the Clean Power Plan on October 23, 2015, more than two dozen States as well as industry and labor groups challenged the Clean Power Plan in the D.C. Circuit Court of Appeals. On February 9, 2016, the U.S. Supreme Court stayed the Clean Power Plan pending disposition of the legal challenges. Nevertheless, as a result of the continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility.

In December 2015, the United States participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature, and to conserve and enhance sinks and reservoirs of GHGs. The Paris Agreement went into effect on November 4, 2016. The Paris Agreement establishes a framework for the parties to cooperate and report actions to reduce GHG emissions. Also, on June 29, 2016, the leaders of the United States, Canada and Mexico announced an Action Plan to, among other things, boost clean energy, improve energy efficiency and reduce greenhouse gas emissions. The Action Plan specifically calls for a reduction in methane emissions from the oil and gas sector by 40% to 45% by 2025.

Restrictions on GHG emissions that may be imposed could adversely affect the oil and gas industry. The adoption of legislation or regulatory programs to reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil, NGL and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations. It remains unclear whether and how the results of the 2016 U.S. presidential and congressional elections could impact the regulation of greenhouse gas emissions at the federal and state level.

In addition, claims have been made against certain energy companies alleging that GHG emissions from oil, NGL and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals may seek to enforce environmental laws and regulations against us and could allege personal injury or property damages. While we are currently not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Moreover, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

Our oil, NGL and natural gas is sold to a limited number of geographic markets so an oversupply in any of those areas could have a material negative effect on the price we receive.

Our oil, NGL and natural gas is sold to a limited number of geographic markets which each have a fixed amount of storage and processing capacity. As a result, if such markets become oversupplied with oil, NGL and/or natural gas, it could have a material negative effect on the price we receive for our products and therefore an adverse effect on our financial condition. There is a risk that refining capacity in the U.S. Gulf Coast may be insufficient to refine all of the light sweet crude

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oil being produced in the United States. If light sweet crude oil production remains at current levels or continues to increase, demand for our light crude oil production could result in widening price discounts to the world crude prices and potential shut-in of production due to a lack of sufficient markets despite the lift on prior restrictions on the exporting of oil and natural gas.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our business activities.

We may incur significant delays, costs and liabilities as a result of federal, state and local environmental, health and safety requirements applicable to our exploration, development, marketing, transportation and production activities. These laws and regulations may require us to obtain a variety of permits or other authorizations governing our air emissions, water discharges, waste disposal or other environmental impacts associated with drilling, production and transporting product pipelines or other operations; regulate the sourcing and disposal of water used in the drilling, fracturing and completion processes; limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier, seismically active areas, and other protected areas; require remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; and/or impose substantial liabilities for spills, pollution or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of oil or natural gas production. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations.

Under certain environmental laws that impose strict as well as joint and several liability, we may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. In addition, accidental spills or releases from our operations could expose us to significant liabilities under environmental laws. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil, NGL and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

See "Item 1. Business—Regulation of environmental and occupational health and safety matters" for a further description of the laws and regulations that affect us.

If we are unable to drill new allocation wells it could have a material adverse impact on our future production results.

In the State of Texas, allocation wells allow an oil and gas producer to drill a horizontal well under two or more leaseholds that are not pooled. We are active in drilling and producing allocation wells. If there are regulatory changes with regard to allocation wells, the RRC denies or significantly delays the permitting of allocation wells or if legislation is enacted that negatively impacts the current process under which allocation wells are currently permitted, it could have an adverse impact on our ability to drill long horizontal lateral wells on some of our leases, which in turn could have a material adverse impact on our anticipated future production.

Unless we replace our oil, NGL and natural gas production, our reserves and production will continue to decline, which would adversely affect our future cash flows and results of operations.

Producing oil, NGL and natural gas reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploration, development and exploitation activities or continually acquire properties containing proved reserves, our proved reserves will continue to decline as those reserves are produced. Our future oil, NGL and natural gas reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production. 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.

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A decrease in our production of oil, NGL and natural gas could negatively impact our ability to meet our contractual obligations to deliver oil, NGL and natural gas and our ability to retain our leases.
A portion of our oil, NGL and gas production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss or unavailability of pipeline or gathering system access and capacity, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions, including low oil, NGL and gas prices. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow. Furthermore, if we were required to shut in wells, we might also be obligated to pay shut-in royalties to certain mineral interest owners to maintain our leases.
In addition, we have entered into agreements with third party shippers, including Medallion, and purchasers that require us to deliver minimum amounts of crude oil and natural gas. Pursuant to these agreements, we must deliver specific amounts, either from our own production or from oil we acquire, over the next thirteen years. If we are unable to fulfill all of our contractual delivery obligations from our own production, we may be required to pay penalties or damages pursuant to these agreements or we may have to purchase oil from third parties to fulfill our delivery obligations. This could adversely impact our cash flows, profit margins and net income.
We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.
We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil, NGL and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil, NGL and natural gas, including the possibility of:
- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters; and
- terrorist attacks targeting oil, NGL and natural gas related facilities and infrastructure.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:
- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage and associated clean-up responsibilities;
- regulatory investigations, penalties or other sanctions;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.
The marketability of our production is dependent upon transportation and other facilities, certain of which we do not control. If these facilities are unavailable, our operations could be interrupted and our revenues reduced.
The marketability of our oil, NGL and natural gas production depends on a variety of factors, including the availability, proximity, capacity and quality constraints of transportation and storage facilities owned by us or third parties. We do not control many of the trucks and other third-party transportation facilities necessary for the transportation of our products and our access to them may be limited or denied. Our failure to provide or obtain such services on acceptable terms could materially harm our business.
Insufficient production from our wells to support the construction of pipeline facilities by our purchasers or a

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significant disruption in the availability of our or third-party transportation facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil, NGL and natural gas and thereby cause a significant interruption in our operations. The crude oil pipelines that transport our crude oil to market have quality specifications, including a Reid Vapor Pressure ("RVP") specification. While our tank batteries and equipment are designed to deliver crude oil that meets all pipeline specifications, including RVP, there is a risk that our crude oil production at any of our tank batteries could have an RVP that exceeds the pipeline specifications. The pipelines have the right under their tariffs to request that crude oil that does not meet their quality specifications, including RVP, be shut in until such crude is brought within quality specifications. If, in the future, we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or specifications or encounter production related difficulties, we may be required to shut in or curtail production. Any such shut-in or curtailment, or an inability to obtain favorable terms for delivery of the oil, NGL and natural gas produced from our fields, could materially and adversely affect our financial condition and results of operations.

Derivatives reform legislation and related regulations could have an adverse effect on our ability to hedge risks associated with our business.

The July 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market and mandates that the Commodity Futures Trading Commission (the "CFTC"), the SEC, and federal regulators of financial institutions (the "Prudential Regulators") adopt rules or regulations implementing the Dodd-Frank Act and providing definitions of terms used in the Dodd-Frank Act. The Dodd-Frank Act establishes margin requirements and requires clearing and trade execution practices for certain market participants and may result in certain market participants needing to curtail or cease their derivatives activities.

Although some of the rules necessary to implement the Dodd-Frank Act remain to be adopted, the CFTC, the SEC and the Prudential Regulators have issued many rules to implement the Dodd-Frank Act, including a rule, which we refer to as the "Mandatory Clearing Rule," requiring clearing of hedges, or swaps, that are subject to it (currently, only certain interest rate and credit default swaps, which we do not presently have), a rule, which we refer to as the "End User Exception," establishing an "end user" exception to the Mandatory Clearing Rule, a rule, which we refer to as the "Margin Rule," setting forth collateral requirements in connection with swaps that are not cleared and also an exception to the Margin Rule for end users that are not financial end users, which exception we refer to as the "Non-Financial End User Exception," and a rule, subsequently vacated by the United States District Court for the District of Columbia and remanded to the CFTC for further proceedings, imposing position limits. The CFTC proposed a new version of this rule, with respect to which the comment period closed but the rule was not adopted, and another new version of this rule, which we refer to as the "Re-Proposed Position Limit Rule," with respect to which the comment period has closed but a final rule has not been issued. The Re-Proposed Position Limit Rule provides an exemption from the position limits for swaps that constitute “bona fide hedging positions” within the definition of such term under the Re-Proposed Position Limit Rule, subject to the party claiming the exemption complying with the applicable filing, recordkeeping and reporting requirements of the Re-Proposed Position Limit Rule.

We qualify for the End User Exception and will utilize it if the Mandatory Clearing Rule is expanded to cover swaps in which we participate, we qualify for the Non-Financial End User Exception and will not be required to post margin in connection with uncleared swaps under the Margin Rule, and our existing and anticipated hedging positions constitute "bona fide hedging positions" under the Re-Proposed Position Limit Rule and we intend to undertake the filing, recordkeeping and reporting necessary to utilize the bona fide hedging position exemption under the Re-Proposed Position Limit Rule if and when it becomes effective, so we do not expect to be directly affected by any of such rules. However, most if not all of our hedge counterparties will be subject to mandatory clearing in connection with their hedging activities with parties who do not qualify for the End User Exception and will be required to post margin in connection with their hedging activities with other swap dealers, major swap participants, financial end users and other persons that do not qualify for the Non-Financial End User Exception. In addition, the European Union and other non-U.S. jurisdictions have enacted laws and regulations (including laws and regulations giving the European Union financial authorities the power to write down amounts we may be owed on hedging agreements with counterparties subject to such laws and regulations and/or require that we accept equity interests in such counterparties in lieu of cash in satisfaction of such amounts), which we refer to collectively as "Foreign Regulations," which may apply to our transactions with counterparties subject to such Foreign Regulations, which we refer to as "Foreign Counterparties." The Dodd-Frank Act, the rules which have been adopted and not vacated, and, to the extent that the Re-Proposed Position Limit Rule is effected, such proposed rule could significantly increase the cost of our derivative contracts, materially alter the terms of our derivative contracts, reduce the availability of derivatives to us that we have historically used to protect against risks that we encounter in our business, reduce our ability to monetize or restructure our existing derivative contracts and increase our exposure to less creditworthy counterparties. The Foreign Regulations could have similar effects. We have stopped entering into new hedging transactions with Foreign Counterparties and do not currently intend to resume hedging with Foreign Counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations and Foreign Regulations, our results of operations may become more volatile and our cash flows may be less predictable, which

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could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

Our producing properties are in a concentrated geographic area, making us vulnerable to risks associated with operating in one major geographic area.

Our producing properties are geographically concentrated in the Permian Basin. At December 31, 2016, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, water shortages or other drought-related conditions or interruption of the processing or transportation of oil or natural gas.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil, NGL and natural gas operations in our operating areas can be adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. This limits our ability to operate in those areas and can later intensify competition during certain months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Our use of 2D and 3D seismic and other data, including our Earth Model, is subject to interpretation and may not accurately identify the presence of oil, NGL and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2D and 3D seismic data and other data, such as that incorporated into our Earth Model that provide either visualization techniques and/or statistical analyses are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable geoscientists to know whether hydrocarbons are, in fact, present in those structures or the amount of hydrocarbons. We employ 3D seismic technology with respect to certain of our projects. The implementation and practical use of 3D seismic technology is relatively unproven, which can lessen its effectiveness, at least in the near term, and increase our costs. In addition, the use of 3D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur greater drilling and exploration expenses as a result of such expenditures, which may result in a reduction in our returns. As a result, our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline.

The Earth Model is reliant upon data that is subject to interpretation and is itself the product of interpretation. Therefore, there is no guarantee that the data it produces or our interpretation of that data will be correct. The Earth Model is a relatively new process, and there is no guarantee that the initial rates of correlation will be duplicated.

We often gather 3D seismic data over large areas. Our interpretation of seismic data delineates those portions of an area that we believe are desirable for drilling. Therefore, we may choose not to acquire option or lease rights prior to acquiring seismic data, and in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in the location. If we are not able to lease those locations on acceptable terms, we will have made substantial expenditures to acquire and analyze 3D data without having an opportunity to attempt to benefit from those expenditures.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services as well as fees for the cancellation of such services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

The demand for and availability of qualified and experienced personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil, NGL and natural gas prices, causing periodic shortages. From time to time, there have been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. In particular, in recent years the high level of drilling activity in the Permian Basin has resulted in equipment shortages in those areas. We have committed in the past, and we may in the future commit, to drilling contracts with various third parties that contain penalties for early terminations. These penalties could negatively impact our financial statements upon contract termination. Rig shortages as well as rig related fees could result in delays or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our

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business, financial condition or results of operations.

Competition in the oil and natural gas industry is intense, making it difficult for us to acquire properties, market oil, NGL and natural gas and secure trained personnel.

Our ability to acquire additional locations and to find and develop reserves in the future may depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil, NGL and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil, NGL and natural gas industry, especially in our focus areas. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive oil, NGL and natural gas properties and exploratory locations and to evaluate, bid for and purchase a greater number of properties and locations than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

Technological advancements and trends in our industry affect the demand for certain types of equipment.

Technological advancements and trends in our industry affect the demand for certain types of equipment. Especially in times when commodity prices are high, the demand for drilling rigs that are able to drill horizontally in the Permian Basin increases. In addition, oil and gas exploration and production companies have increased the use of "pad drilling" in recent years whereby a series of horizontal wells are drilled in succession by walking or skidding a drilling rig at a single-site location. If we are unable to secure such rigs in a timely or cost-efficient manner it could have a material adverse effect on our business.

The loss of senior management or technical personnel could adversely affect operations.

We depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including Randy Foutch, our Chairman and Chief Executive Officer, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

A significant reduction by Warburg Pincus of its ownership interest in us could adversely affect us.

Warburg Pincus is our largest stockholder and two members of our board of directors are affiliates of Warburg Pincus. As of December 31, 2016, Warburg Pincus owned 36.2% of our outstanding common stock. We believe that Warburg Pincus' substantial ownership interest in us provides them with an economic incentive to assist us to be successful. However, Warburg Pincus is not obligated to maintain its ownership interest in us and may elect at any time to change its ownership position in our stock. If Warburg Pincus sells all or a substantial portion of its ownership interest in us, Warburg Pincus may have less incentive to assist in our success and its affiliates that are members of our board of directors may resign. Such actions could adversely affect our ability to successfully implement our business strategies, which could adversely affect our cash flows or results of operations.

We may be subject to risks in connection with acquisitions of properties.

The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil, NGL and natural gas prices and their applicable differentials;
- timing of development;
- capital and operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. Our assessment will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis. Even in those circumstances in which we have contractual indemnification rights for pre-closing liabilities, it remains possible that the seller will not be able to fulfill its contractual obligations. Problems with properties we acquire could have a material adverse effect on our business, financial

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condition and results of operations.

We may incur significant additional amounts of debt.

As of February 14, 2017, we had total long-term indebtedness of $1.3 billion. In addition, we may be able to incur substantial additional indebtedness, including secured indebtedness, in the future. The restrictions on the incurrence of additional indebtedness contained in the indentures governing our Senior Unsecured Notes and in our Senior Secured Credit Facility are subject to a number of significant qualifications and exceptions, and under certain circumstances, the amount of indebtedness that could be incurred in compliance with these restrictions could be substantial. If new debt is added to our existing debt levels, the related risks that we face would increase and may make it more difficult to satisfy our existing financial obligations. In addition, the restrictions on the incurrence of additional indebtedness contained in the indentures governing the Senior Unsecured Notes apply only to debt that constitutes indebtedness under the indentures.

We may incur more taxes and certain of our projects may become uneconomic if certain federal income tax deductions currently available with respect to oil and natural gas exploration and development are eliminated as a result of future legislation.

Legislation has been proposed that would, if enacted, eliminate certain key U.S. federal income tax preferences currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain U.S. production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. In addition, the former President of the United States recently proposed adding a $10.25 per Bbl tax on crude oil produced in the United States. Policy positions taken by the new presidential administration and congress in the United States may result in significant changes in the rules governing U.S. federal income taxation, including changes to the tax rates, the ability to take certain deductions and/or the border adjustment tax. It is unclear whether any of the foregoing changes will actually be enacted or how soon any such changes could become effective. Any such change or similar other change could materially adversely affect our financial condition and results of operations by increasing the costs we incur which would in turn make it uneconomic to drill some locations if commodity prices are not sufficiently high, resulting in lower revenues and decreases in production and reserves. In addition, it is uncertain what impact the 2016 U.S. presidential and congressional elections will have on the energy industry.

Loss of our information and computer systems could adversely affect our business.

We are heavily dependent on our information systems and computer based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure or we were subject to cyberspace breaches or attacks, possible consequences include our loss of communication links, inability to find, produce, process and sell oil, NGL and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

Our business could be negatively impacted by security threats, including cyber-security threats, and other disruptions.

As an oil and natural gas producer, we face various security threats, including cyber-security threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the safety of our employees, threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines, and threats from terrorist acts. Cyber-security attacks in particular are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows.

Risks relating to our common stock

The concentration of our capital stock ownership among our largest stockholder will limit other stockholders' ability to influence corporate matters.

As of December 31, 2016, Warburg Pincus owned 36.2% of our outstanding common stock. Consequently, Warburg Pincus has significant influence over all matters that require approval by our stockholders, including the election of directors and approval of significant corporate transactions. This concentration of ownership limits the ability of other stockholders to

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influence corporate matters.

Furthermore, conflicts of interest could arise in the future between us, on the one hand, and Warburg Pincus and its affiliates, including its portfolio companies, on the other hand, concerning among other things, potential competitive business activities or business opportunities. Warburg Pincus LLC is a private equity firm that has invested in, among other things, companies in the energy industry. As a result, Warburg Pincus' existing and future portfolio companies which it controls may compete with us for investment or business opportunities. These conflicts of interest may not be resolved in our favor.

We have also renounced our interest in certain business opportunities. Our amended and restated certificate of incorporation provides that, to the fullest extent permitted by applicable law, we renounce any interest or expectancy in any business opportunity, transaction or other matter in which Warburg Pincus or any private fund that it manages or advises, any of their respective officers, directors, partners and employees, and any portfolio company in which such persons or entities have an equity interest (other than us and our subsidiaries) (each, a "specified party") participates or desires or seeks to participate and that involves any aspect of the energy business or industry, even if the opportunity is one that we might reasonably have pursued or had the ability or desire to pursue if granted the opportunity to do so, and no such specified party shall be liable to us for breach of any fiduciary or other duty, as a director or officer or controlling stockholder or otherwise, by reason of the fact that such specified party pursues or acquires any such business opportunity, directs any such business opportunity to another person or fails to present any such business opportunity, or information regarding any such business opportunity, to us. Notwithstanding the foregoing, we do not renounce any interest or expectancy in any business opportunity, transaction or other matter that is offered in writing solely to (i) one of our directors or officers who is not also a specified party or (ii) a specified party who is one of our directors, officers or employees and is offered such business opportunity solely in his or her capacity as our director, officer or employee. By renouncing our interest and expectancy in any business opportunity that from time to time may be presented to Warburg Pincus and its affiliates, our business and prospects could be adversely affected if attractive business opportunities are procured by such parties for their own benefit rather than for ours.

Our amended and restated certificate of incorporation, amended and restated bylaws, and Delaware state law contain provisions that may have the effect of delaying or preventing a change in control and may adversely affect the market price of our capital stock.

Our amended and restated certificate of incorporation authorizes our board of directors to issue preferred stock without any further vote or action by the stockholders. The rights of the holders of our common stock will be subject to the rights of the holders of any preferred stock that may be issued in the future. The issuance of preferred stock could delay, deter or prevent a change in control and could adversely affect the voting power or economic value of our shares.

In addition, some provisions of our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- limitations on the ability of our stockholders to call special meetings;
- a separate vote of 75% of the voting power of the outstanding shares of capital stock in order for stockholders to amend the bylaws in certain circumstances;
- our board of directors is divided into three classes with each class serving staggered three-year terms;
- stockholders do not have the right to take any action by written consent; and
- advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

Delaware law prohibits us from engaging in any business combination with any "interested stockholder," meaning generally that a stockholder who owns 15% of our stock cannot acquire us for a period of three years from the date such stockholder became an interested stockholder, unless various conditions are met, such as the approval of the transaction by our board of directors. Warburg Pincus, however, is not subject to this restriction.

The availability of shares for sale in the future could reduce the market price of our common stock.

Our board of directors has the authority, without action or vote of our stockholders, to issue all or any part of our authorized but unissued shares of common stock. In the future, we may issue securities to raise cash for acquisitions, to pay down debt, to fund capital expenditures or general corporate expenses, in connection with the exercise of stock options or to satisfy our obligations under our incentive plans. We may also acquire interests in other companies by using a combination of cash and our common stock or just our common stock. We may also issue securities convertible into, exchangeable for, or that represent the right to receive, our common stock. Any of these events may dilute your ownership interest in our Company, reduce our earnings per share and have an adverse impact on the price of our common stock.

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Because we have no plans to pay, and are currently restricted from paying dividends on our common stock, investors must look solely to stock appreciation for a return on their investment in us.

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. Covenants contained in our Senior Secured Credit Facility and the indentures governing our Senior Unsecured Notes restrict the payment of dividends. Investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment. Investors seeking cash dividends should not purchase our common stock.

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Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

The information required by Item 2. is contained in "Item 1. Business".

Item 3. Legal Proceedings

From time to time, we are subject to various legal proceedings arising in the ordinary course of business, including proceedings for which we have insurance coverage. As of the date hereof, we are not party to any legal proceedings that we currently believe will have a material adverse effect on our business, financial position, results of operations or liquidity.

Item 4. Mine Safety Disclosures

Not applicable.

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Part II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market for Registrant's Common Equity. Our common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "LPI." The following table sets forth the range of high and low sales prices of our common stock as reported by the NYSE:

	Price per share	
	High	Low
2016:		
Fourth Quarter	$16.47	$11.46
Third Quarter	$13.70	$9.20
Second Quarter	$13.73	$7.26
First Quarter	$9.80	$3.90
2015:		
Fourth Quarter	$14.19	$7.01
Third Quarter	$12.66	$6.35
Second Quarter	$16.18	$12.34
First Quarter	$14.84	$8.02

On February 15, 2017, the last sale price of our common stock, as reported on the NYSE, was $14.33 per share.

Holders. As of February 13, 2017, there were 38 holders of record of our common stock.

Dividends. We have not paid any cash dividends since our inception. Covenants contained in our Senior Secured Credit Facility and the indentures governing our Senior Unsecured Notes restrict the payment of cash dividends on our common stock. See "Item 1A. Risk Factors—Risks related to our business—Our debt agreements contain restrictions that limit our flexibility in operating our business" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Cash flows—Debt." We currently intend to retain all future earnings for the development and growth of our business, and we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future.

Repurchase of Equity Securities.

Period	Total number of shares withheld[1]	Average price per share	Total number of shares purchased as part of publicly announced plans	Maximum number of shares that may yet be purchased under the plan
October 1, 2016 - October 31, 2016	1,087	$ 12.86	—	—
November 1, 2016 - November 30, 2016	263	$ 13.10	—	—
December 1, 2016 - December 31, 2016	263	$ 15.44	—	—
Total	1,613			

(1) Represents shares that were withheld by us to satisfy employee tax withholding obligations that arose upon the lapse of restrictions on restricted stock.

Unregistered Sales of Equity Securities and Use of Proceeds. None.

Stock Performance Graph. The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act or Exchange Act, except to the extent that we specifically request that such information be treated as "soliciting material" or specifically incorporate such information by reference into such a filing.

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The performance graph below compares the cumulative five-year total returns to our common stockholders relative to the cumulative total returns on the Standard and Poor's 500 Index (the "S&P 500") and the Standard and Poor's Oil & Gas Exploration & Production Select Industry Index (the "S&P O&G E&P"). The comparison was prepared based upon the following assumptions:

1. $100 was invested in our common stock, the S&P 500 and the S&P O&G E&P from December 30, 2011 to December 30, 2016; and
2. Dividends, if any, are reinvested.

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Item 6. Selected Historical Financial Data

The selected historical consolidated financial data presented below is not intended to replace our consolidated financial statements. You should read the following data along with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and related notes, each of which is included elsewhere in this Annual Report. We believe that the assumptions underlying the preparation of our financial statements are reasonable. The financial information included in this Annual Report may not be indicative of our future results of operations, financial position or cash flows.

Presented below is our historical financial data for the periods and as of the dates indicated. The historical financial data for the years ended December 31, 2016, 2015 and 2014 and the balance sheet data as of December 31, 2016 and 2015 are derived from our consolidated financial statements and the notes thereto included elsewhere in this Annual Report. The historical financial data for the years ended December 31, 2013 and 2012 and the balance sheet data as of December 31, 2014, 2013 and 2012 are derived from our consolidated financial statements not included in this Annual Report.

	For the years ended December 31,				
(in thousands, except per share data)	2016	2015	2014	2013	2012
Statement of operations data:[1]					
Total revenues	$597,378	$606,640	$793,885	$665,257	$583,894
Total costs and expenses[2]	685,340	3,078,154	567,499	450,906	411,954
Operating income (loss)	(87,962)	(2,471,514)	226,386	214,351	171,940
Non-operating income (expense), net	(172,777)	84,633	203,473	(23,267)	(77,176)
Income (loss) from continuing operations before income taxes	(260,739)	(2,386,881)	429,859	191,084	94,764
Income tax benefit (expense)	—	176,945	(164,286)	(74,507)	(33,003)
Income (loss) from continuing operations	(260,739)	(2,209,936)	265,573	116,577	61,761
Income (loss) from discontinued operations, net of tax	—	—	—	1,423	(107)
Net income (loss)	$(260,739)	$(2,209,936)	$265,573	$118,000	$61,654
Net income (loss) per common share:					
Basic:					
Income (loss) from continuing operations	$(1.16)	$(11.10)	$1.88	$0.88	$0.49
Income from discontinued operations, net of tax	—	—	—	0.01	—
Net income (loss) per share	$(1.16)	$(11.10)	$1.88	$0.89	$0.49
Diluted:					
Income (loss) from continuing operations	$(1.16)	$(11.10)	$1.85	$0.87	$0.48
Income from discontinued operations, net of tax	—	—	—	0.01	—
Net income (loss) per share	$(1.16)	$(11.10)	$1.85	$0.88	$0.48

(1) The oil and natural gas properties that were a component of the Anadarko Basin Sale are not presented as held for sale nor are their results of operations presented as discontinued operations for the historical periods presented pursuant to the rules governing full cost accounting for oil and gas properties. The results of operations of the associated pipeline assets and various other associated property and equipment are presented as results of discontinued operations, net of tax. For further discussion of the Anadarko Basin Sale see Note C.3 to our consolidated financial statements included in our 2013 Annual Report on Form 10-K.

(2) Includes full cost ceiling impairment expense of $161.1 million and $2.4 billion for the years ended December 31, 2016 and 2015, respectively.

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	As of December 31,				
(in thousands)	2016	2015	2014	2013	2012
Balance sheet data:					
Cash and cash equivalents	$32,672	$31,154	$29,321	$198,153	$33,224
Property and equipment, net	$1,366,867	$1,200,255	$3,354,082	$2,204,324	$2,113,891
Total assets(1)	$1,782,346	$1,813,287	$3,910,701	$2,606,610	$2,318,368
Total current liabilities	$187,945	$216,815	$353,834	$253,969	$262,068
Long-term debt, net(1)	$1,353,909	$1,416,226	$1,779,447	$1,038,022	$1,196,824
Stockholders' equity	$180,573	$131,447	$1,563,201	$1,272,256	$831,723

	For the years ended December 31,				
(in thousands)	2016	2015	2014	2013(2)	2012
Other financial data:					
Net cash provided by operating activities	$356,295	$315,947	$498,277	$364,729	$376,776
Net cash used in investing activities	$(564,402)	$(667,507)	$(1,406,961)	$(329,884)	$(940,751)
Net cash provided by financing activities	$209,625	$353,393	$739,852	$130,084	$569,197

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(1) Amounts prior to 2015 have been reclassified to conform to the 2016 and 2015 presentation. See Notes 2.c, 2.k, 5.h, 7 and 14 to our consolidated financial statements included in our 2015 Annual Report on Form 10-K for further information.

(2) Net cash used in investing activities for the year ended December 31, 2013 is offset by proceeds received for the Anadarko Basin Sale. For further discussion of the Anadarko Basin Sale see Note C.3 to our consolidated financial statements included in our 2013 Annual Report on Form 10-K.

Non-GAAP financial measure

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for deferred income tax expense or benefit, depletion, depreciation and amortization, bad debt expense, impairment expense, non-cash stock-based compensation, accretion of asset retirement obligations, restructuring expenses, gains or losses on derivatives, cash settlements received for matured derivatives, cash settlements on early terminated and modified derivatives, cash premiums paid for derivatives, interest expense, write-off of debt issuance costs, gains or losses on disposal of assets, loss on early redemption of debt, buyout of minimum volume commitment, income or loss from equity method investee and proportionate Adjusted EDITDA of equity method investee. Adjusted EBITDA provides no information regarding a company’s capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. Adjusted EBITDA does not represent funds available for discretionary use because those funds are required for debt service, capital expenditures and working capital, income taxes, franchise taxes and other commitments and obligations. However, our management believes Adjusted EBITDA is useful to an investor in evaluating our operating performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods, book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and
- is used by our management for various purposes, including as a measure of operating performance, in presentations to our board of directors and as a basis for strategic planning and forecasting.

There are significant limitations to the use of Adjusted EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations to different companies and the different methods of calculating Adjusted EBITDA reported by different companies. Our measurements of Adjusted EBITDA for financial reporting as compared to compliance under our debt agreements differ.

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For the year ended December 31, 2016, we changed the methodology for calculating Adjusted EBITDA by including adjustments for both accretion of asset retirement obligations and our proportionate share of our equity method investee's Adjusted EBITDA. Accordingly, the prior periods' Adjusted EBITDA has been modified for comparability.

The following presents a reconciliation of Net income (loss) (GAAP) for continuing and discontinued operations to Adjusted EBITDA (non-GAAP):

	For the years ended December 31,				
(in thousands, unaudited)	2016	2015	2014	2013	2012
Net income (loss)	$(260,739)	$(2,209,936)	$265,573	$118,000	$61,654
Plus:					
Deferred income tax (benefit) expense	—	(176,945)	164,286	75,288	32,949
Depletion, depreciation and amortization	148,339	277,724	246,474	234,571	243,649
Bad debt expense	—	255	342	653	—
Impairment expense	162,027	2,374,888	3,904	—	—
Non-cash stock-based compensation, net of amounts capitalized	29,229	24,509	23,079	21,433	10,056
Accretion of asset retirement obligations	3,483	2,423	1,787	1,475	1,200
Restructuring expenses	—	6,042	—	—	—
Mark-to-market on derivatives:					
(Gain) loss on derivatives, net	87,425	(214,291)	(327,920)	(79,878)	(8,388)
Cash settlements received for matured derivatives, net	195,281	255,281	28,241	4,046	27,025
Cash settlements received for early terminations and modifications of derivatives, net	80,000	—	76,660	6,008	—
Cash premiums paid for derivatives	(89,669)	(5,167)	(7,419)	(11,292)	(9,135)
Interest expense	93,298	103,219	121,173	100,327	85,572
Write-off of debt issuance costs	842	—	124	1,502	—
Loss on disposal of assets, net	790	2,127	3,252	1,508	52
Loss on early redemption of debt	—	31,537	—	—	—
Buyout of minimum volume commitment	—	3,014	—	—	—
(Income) loss from equity method investee	(9,403)	(6,799)	192	(29)	—
Proportionate Adjusted EBITDA of equity method investee[(1)]	20,367	9,383	462	29	—
Adjusted EBITDA	$461,270	$477,264	$600,210	$473,641	$444,634

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(1) Proportionate Adjusted EBITDA of Medallion, our equity method investee, is calculated as follows:

	For the years ended December 31,				
(in thousands, unaudited)	2016	2015	2014	2013	2012
Income (loss) from equity method investee	$9,403	$6,799	$(192)	$ 29	$ —
Adjusted for proportionate share of:					
Depreciation and amortization	10,964	4,061	654	—	—
Buyout of minimum volume commitment	—	(1,477)	—	—	—
Proportionate Adjusted EBITDA of equity method investee	$20,367	$9,383	$462	$ 29	$ —

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Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and notes thereto appearing elsewhere in this Annual Report. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions or beliefs about future events may, and often do, vary from actual results and the differences can be material. See "Cautionary Statement Regarding Forward-Looking Statements" and "Item 1A. Risk Factors." All amounts, dollars and percentages presented in this Annual Report are rounded and therefore approximate.

Executive overview

We are an independent energy company focused on the acquisition, exploration and development of oil and natural gas properties, and the transportation of oil, NGL and natural gas from such properties, primarily in the Permian Basin in West Texas. Since our inception, we have grown primarily through our drilling program coupled with select strategic acquisitions and joint ventures.

Our financial and operating performance for the year ended December 31, 2016 included the following:

- Oil, NGL and natural gas sales of $426.5 million, compared to $431.7 million for the year ended December 31, 2015;
- Average daily sales volumes of 49,586 BOE/D, compared to 44,782 BOE/D for the year ended December 31, 2015;
- Net loss of $260.7 million, including a non-cash full cost ceiling impairment of $161.1 million, compared to a net loss of $2.2 billion, including a non-cash full cost ceiling impairment of $2.4 billion, for the year ended December 31, 2015;
- Adjusted EBITDA (a non-GAAP financial measure) of $461.3 million, compared to $477.3 million for the year ended December 31, 2015. See "Item 6. Selected Historical Financial Data" for a reconciliation of Adjusted EBITDA; and
- Proved developed and undeveloped reserves of 167,100 MBOE, compared to 125,698 MBOE for the year ended December 31, 2015. See Note 20.d to our consolidated financial statements included elsewhere in this Annual Report for discussion of changes in our estimated reserve quantities of oil, NGL and natural gas.

Recent developments

Our board of directors approved a $530.0 million capital budget for 2017 excluding acquisitions and investments in Medallion.

On January 17, 2017, we completed the sale of 2,900 net acres and working interests in 16 producing vertical wells in the Midland Basin to a third-party buyer for a purchase price of $59.6 million. After transaction costs reflecting an economic effective date of October 1, 2016, the proceeds were $59.4 million net of working capital and closing adjustments and subject to final closing adjustments. A portion of these proceeds were used to pay down $55.0 million on the Senior Secured Credit Facility.

Acquisitions

Our use of capital for development and acquisitions allows us to direct our capital resources toward what we believe to be the most attractive opportunities as market conditions evolve. We have historically developed properties that we believe will meet or exceed our rate of return criteria. For acquisitions of properties with additional development and exploration potential, we have focused on acquiring properties that we expect to operate so that we can control the timing and implementation of capital spending. We also make acquisitions in core, mature areas where management can leverage knowledge and experience to identify upside potential in the assets.

During the year ended December 31, 2016, we completed acquisitions of 9,200 net acres of additional leasehold interests and working interests in 81 producing vertical wells in western Glasscock and Reagan counties (which included production of 300 net BOE/D) within the Company's core development area for an aggregate purchase price of $124.7 million subject to customary closing adjustments.

For further discussion of this acquisition and prior period acquisitions and divestitures, see Note 4 to our consolidated financial statements included elsewhere in this Annual Report.

2016 equity offerings

May 2016 equity offering

On May 16, 2016, we completed the sale of 10,925,000 shares of our common stock (including the underwriter's option) (the "May 2016 Equity Offering") for net proceeds of $119.3 million, after underwriting discounts, commissions and offering expenses, which were used to repay borrowings under our Senior Secured Credit Facility.

July 2016 equity offering

On July 19, 2016, we completed the sale of 13,000,000 shares of our common stock (the "July 2016 Equity Offering") for net proceeds of $136.3 million, after underwriting discounts, commissions and offering expenses, which, together with the net proceeds from the underwriters' option exercise, were used to repay borrowings under our Senior Secured Credit Facility. On August 9, 2016, the underwriters exercised their option to purchase an additional 1,950,000 shares of our common stock which resulted in net proceeds of $20.5 million, after underwriting discounts, commissions and offering expenses.

Senior Secured Credit Facility reaffirmation

On October 24, 2016, pursuant to a regular semi-annual redetermination, our lenders reaffirmed the borrowing base under our Senior Secured Credit Facility at $815.0 million. Our aggregate elected commitment of $815.0 million remained unchanged.

Pricing, reserves and non-cash full cost ceiling impairment

Our results of operations are heavily influenced by oil, NGL and natural gas prices. Oil, NGL and natural gas price fluctuations are caused by changes in global and regional supply and demand, market uncertainty, economic conditions and a variety of additional factors. Historically, commodity prices have experienced significant fluctuations, and additional changes in commodity prices may affect the economic viability of, and our ability to fund, our drilling projects, as well as the economic valuation and economic recovery of oil, NGL and natural gas reserves. We have entered into a number of derivative contracts that have enabled us to offset a portion of the changes in our cash flow caused by price fluctuations for our sales of oil, NGL and natural gas as discussed in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Our reserves as of December 31, 2016 and 2015 are reported in three streams: oil, NGL and natural gas. Our sales volumes, prices and reserves as of December 31, 2014 were reported in two streams: crude oil and liquids-rich natural gas with the economic value of the NGL in our natural gas included in the wellhead natural gas price. This change impacts the comparability of 2016 and 2015 with 2014.

Our net book value of evaluated oil and natural gas properties did not exceed the full cost ceiling amount as of December 31, 2016, September 30, 2016 or June 30, 2016. Our net book value of evaluated oil and natural gas properties exceeded the full cost ceiling amount as of March 31, 2016 and as a result, we recorded a non-cash full cost ceiling impairment of $161.1 million. Oil, NGL and natural gas prices have somewhat stabilized in comparison to prices during 2016. However, if these prices decline from the current levels or if adverse economic conditions occur (such as increases in drilling production and/or service costs) we could incur future full cost ceiling impairments. See Note 2.g to our consolidated financial statements included elsewhere in this Annual Report for prices used to value our reserves and additional discussion of our full cost impairments in the first quarter of 2016 and in prior periods.

Core area of operations

The oil and liquids-rich Permian Basin is characterized by multiple target horizons, extensive production histories, long-lived reserves, high drilling success rates and high initial production rates. As of December 31, 2016, we had assembled 127,847 net acres in the Permian Basin.

Sources of our revenue

Our revenues are derived from the sale of produced oil, NGL and natural gas within the continental United States, the sale of purchased oil and providing midstream services to third parties. Our revenues do not include the effects of derivatives. For the year ended December 31, 2016, our revenues were comprised of sales of 53% produced oil, 10% produced NGL, 9% produced natural gas, 27% purchased oil and 1% midstream services. Our oil, NGL and natural gas revenues may vary significantly from period to period as a result of changes in volumes of production and/or changes in commodity prices. Our sales of purchased oil revenue may vary due to changes in oil prices and market differentials. Our midstream service revenues

may vary due to oil throughput fees and the level of services provided to third parties for (i) gathered natural gas, (ii) gas lift fees and (iii) water services.

Principal components of our cost structure

Lease operating expenses. These are daily costs incurred to bring oil, NGL and natural gas out of the ground and to market, together with the daily costs incurred to maintain our producing properties. Such costs also include maintenance, repairs and non-routine workover expenses related to our oil and natural gas properties.

Production and ad valorem taxes. Production taxes are paid on oil, NGL and natural gas sold based on a percentage of revenues from products sold at market prices or at fixed rates established by federal, state or local taxing authorities. We take full advantage of all credits and exemptions in our various taxing jurisdictions. In general, the production taxes we pay correlate to the changes in oil, NGL and natural gas revenues. Ad valorem taxes are property taxes based on the assessed taxable value of our reserves attributed to our oil and natural gas properties.

Midstream service expenses. These are costs incurred to operate and maintain our (i) oil and natural gas gathering and transportation systems and related facilities, (ii) centralized oil storage tanks, (iii) natural gas lift, rig fuel and centralized compression infrastructure and (iv) water storage, recycling and transportation facilities.

Minimum volume commitments. We have committed to deliver for sale or transportation fixed volumes of product under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. If not fulfilled, we are subject to deficiency payments. These commitments are normal and customary for our business. In certain instances, we have used spot market purchases to meet our commitments in certain locations or due to favorable pricing. Management anticipates continuing this practice in the future. Also, if our production is not sufficient to satisfy our delivery commitments, we can and may use spot market purchases to fulfill the commitments.

Costs of purchased oil. These are costs associated with purchasing oil from third parties and the transportation costs required to bring it to market.

Drilling rig fees. These are costs incurred for the early termination of drilling rig contracts.

General and administrative ("G&A"). These are costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other fees for professional services, legal compliance and compensation expense related to employee and director stock awards, performance share awards and option awards granted, which have been recognized on a straight-line basis over the vesting period associated with the award, and, in prior periods, performance unit awards in which the fair value was re-measured at the end of each reporting period until settlement.

Accretion of asset retirement obligations. Accretion is a non-cash charge that represents changes in our asset retirement liability due to the passage of time.

Depletion, depreciation and amortization. Under the full cost accounting method, we capitalize all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of finding oil and natural gas within a cost center and then systematically expense those costs on a units of production basis based on evaluated oil, NGL and natural gas reserve quantities. We calculate depletion on the following types of costs: (i) all capitalized costs, other than the cost of investments in unevaluated properties and major development projects for which evaluated reserves cannot yet be assigned, less accumulated depletion; (ii) the estimated future expenditures to be incurred in developing evaluated reserves; and (iii) the estimated dismantlement and abandonment costs, net of estimated salvage values. We calculate depreciation on the cost of fixed assets related to our pipelines and other fixed assets utilizing the straight-line method over the useful life of the asset, or in the case of leasehold improvements over the shorter of the estimated useful lives of the assets or the terms of the related leases.

Impairment expense. The full cost ceiling is based principally on the estimated future net revenues from our proved oil and natural gas properties discounted at 10%. Our Realized Prices (as defined below) are utilized to calculate the discounted future net revenues in our full cost ceiling calculation. In the event the unamortized cost of our evaluated oil and natural gas properties being depleted exceeds the full cost ceiling, the excess is charged to expense in the period such excess occurs. Once incurred, a write-down of oil and natural gas properties is not reversible.

Long-lived assets are considered impaired when their net carrying value is greater than the future undiscounted cash flows. Once an asset is recognized as impaired, costs are incurred to write the asset down. With the continuing volatility in commodity prices, we may incur additional write-downs on our oil and natural gas properties. Materials and supplies inventory and line-fill are recorded at the lower of cost or net realizable value ("NRV"), with costs determined using the weighted-average cost method.

Other income (expense)

Gain (loss) on derivatives, net. We utilize derivatives to reduce our exposure to fluctuations in the price of crude oil, NGL and natural gas. This amount represents (i) the recognition of gains and losses associated with our open derivatives as commodity prices change and derivatives expire or new contracts are entered into, and (ii) our gains and losses on the settlement, termination and modification of these derivatives. We classify these gains and losses as operating activities in our consolidated statements of cash flows.

Income (loss) from equity method investee. We have invested in a company where we own 49% of the ownership units. As such, we account for this investment under the equity method of accounting with our proportionate share of net income (loss) reflected in the consolidated statements of operations as "Income (loss) from equity method investee" and the carrying amount reflected in the consolidated balance sheets as "Investment in equity method investee." See Note 14 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding this investment.

Interest expense. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our Senior Secured Credit Facility and our Senior Unsecured Notes. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to the lenders and bondholders in interest expense, net of amounts capitalized. In addition, we include the amortization of: (i) debt issuance costs (including origination, amendment and professional fees), (ii) deferred premiums associated with our derivative contracts, (iii) commitment fees and (iv) annual agency fees in interest expense.

Interest and other income. This represents the interest received on our cash and cash equivalents as well as other miscellaneous income.

Loss on early redemption of debt. This represents the loss on extinguishment recognized in the early redemption of our January 2019 Notes in April 2015, related to the difference between the redemption price and the net carrying amount.

Write-off of debt issuance costs. Debt issuance fees, which are stated at cost, net of amortization, are amortized over the life of the respective debt agreements utilizing the effective interest and straight-line methods. Write-offs of such costs can occur when borrowing terms change and/or debt has been extinguished.

Loss on disposal of assets, net. This represents losses recorded from selling or disposing of property and equipment or inventory. Sale proceeds are compared with the recorded net book value of the asset and the appropriate gain (loss) is recorded.

Income tax benefit (expense). Income taxes in our financial statements are generally presented on a consolidated basis. We are subject to federal and state corporate income taxes and Texas franchise tax. These taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating losses and tax credit carry-forwards. Under this method, deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax laws or tax rates is recognized in income in the period that includes the enactment date.

On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realization of the deferred tax assets and adjusts the amount of such allowances, if necessary. We considered all available evidence, both positive and negative, in determining whether, based on the weight of that evidence, a valuation allowance was needed on either the federal or Oklahoma net operating loss carry-forwards. Such consideration included estimated future projected earnings based on existing reserves and projected future cash flows from our oil and natural gas reserves (including the timing of those cash flows), the reversal of deferred tax liabilities recorded as of December 31, 2016, our ability to capitalize intangible drilling costs rather than expensing these costs in order to prevent an operating loss carry-forward from expiring unused and future projections of Oklahoma sourced income. During the year ended December 31, 2016, we determined it is more likely than not that we will not realize our net deferred tax assets and, as a result, a valuation allowance of $87.5 million was recorded. As of December 31, 2016, a total valuation allowance of $764.8 million has been recorded against the deferred tax asset. See Note 7 to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our valuation allowance.

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Results of operations consolidated

For the year ended December 31, 2016 as compared to the year ended December 31, 2015, and for the year ended December 31, 2015 as compared to the year ended December 31, 2014

Oil, NGL and natural gas sales volumes, revenues and pricing

The following table sets forth information regarding oil, NGL and natural gas sales volumes, revenues and average sales prices per BOE sold, for the periods presented:

	For the years ended December 31,		
	2016	2015	2014
Sales volumes:(1)			
Oil (MBbl)	8,442	7,610	6,901
NGL (MBbl)	4,784	4,267	—
Natural gas (MMcf)	29,535	26,816	28,965
Oil equivalents (MBOE)(2)(3)	18,149	16,346	11,729
Average daily sales volumes (BOE/D)(3)	49,586	44,782	32,134
% Oil	47 %	47 %	59 %
Oil, NGL and natural gas sales (in thousands):(1)			
Oil	$318,466	$329,301	$571,620
NGL	56,982	50,604	—
Natural gas	51,037	51,829	165,583
Total oil, NGL and natural gas sales	$426,485	$431,734	$737,203
Average sales prices:(1)			
Oil, realized ($/Bbl)(4)	$37.73	$43.27	$82.83
NGL, realized ($/Bbl)(4)	$11.91	$11.86	$—
Natural gas, realized ($/Mcf)(4)	$1.73	$1.93	$5.72
Average price, realized ($/BOE)(4)	$23.50	$26.41	$62.86
Oil, hedged ($/Bbl)(5)	$58.07	$74.41	$85.77
NGL, hedged ($/Bbl)(5)	$11.91	$11.86	$—
Natural gas, hedged ($/Mcf)(5)	$2.20	$2.42	$5.73
Average price, hedged ($/BOE)(5)	$33.73	$41.71	$64.62

(1) For the period prior to January 1, 2015, we presented our sales volumes, sales and average sales prices for oil and natural gas, which combined NGL with the natural gas stream, and did not separately report NGL. This change impacts the comparability of 2016 and 2015 with 2014.

(2) BOE is calculated using a conversion rate of six Mcf per one Bbl.

(3) The volumes presented are based on actual results and are not calculated using the rounded numbers presented in the table above.

(4) Realized oil, NGL and natural gas prices are the actual prices realized at the wellhead adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. The prices presented are based on actual results and are not calculated using the rounded numbers presented in the table above.

(5) Hedged prices reflect the after-effects of our hedging transactions on our average sales prices. Our calculation of such after-effects includes current period settlements of matured derivatives in accordance with GAAP and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to instruments that settled in the period. The prices presented are based on actual results and are not calculated using the rounded numbers presented in the table above.

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The following table presents cash settlements received for matured derivatives and premiums incurred previously or upon settlement attributable to instruments that settled during the periods utilized in our calculation of the hedged prices presented above:

	For the years ended December 31,		
(in thousands)	2016	2015	2014
Cash settlements received for matured derivatives:			
Oil	$181,401	$241,391	$26,803
Natural gas	13,880	13,890	1,438
Total	$195,281	$255,281	$28,241
Premiums paid attributable to contracts that matured during the respective period:			
Oil	$(9,669)	$(4,464)	$(6,497)
Natural gas	—	(703)	(922)
Total	$(9,669)	$(5,167)	$(7,419)

Changes in average realized sales prices and sales volumes caused the following changes to our oil, NGL and natural gas revenues between the years ended December 31, 2016, 2015 and 2014:

(in thousands)	Oil	NGL	Natural gas	Total net effect of change
2014 Revenue	$571,620	$—	$165,583	$737,203
Effect of changes in average realized sales prices	(301,036)	50,603	(101,631)	(352,064)
Effect of changes in sales volumes	58,660	—	(12,293)	46,367
Other	57	1	170	228
2015 Revenue	329,301	50,604	51,829	431,734
Effect of changes in average realized sales prices	(46,838)	238	(6,048)	(52,648)
Effect of changes in sales volumes	36,003	6,140	5,256	47,399
2016 Revenue	$318,466	$56,982	$51,037	$426,485

Oil revenue. Our oil revenue is a function of oil production volumes sold and average sales prices received for those volumes. The decrease in oil revenue of $10.8 million, or 3.3%, for the year ended December 31, 2016 as compared to the year ended December 31, 2015, is mainly due to a 13% decrease in average oil prices realized, partially offset by an 11% increase in oil sales volumes. The decrease in oil revenue of $242.3 million, or 42%, for the year ended December 31, 2015 as compared to the year ended December 31, 2014, is mainly due to a 48% decrease in average oil prices realized, partially offset by a 10% increase in oil sales volumes.

NGL and natural gas revenues. On January 1, 2015, we began utilizing three-stream reporting, which impacts the comparability of 2016 and 2015 with 2014. Our NGL and natural gas revenues are a function of NGL and natural gas production volumes sold and average sales prices received for those volumes. The increase in NGL revenue of $6.4 million, or 12.6%, for the year ended December 31, 2016, as compared to the year ended December 31, 2015, is mainly due to a 12% increase in NGL sales volumes. The decrease in natural gas revenue of $0.8 million, or 1.5%, for the year ended December 31, 2016 as compared to the year ended December 31, 2015, is mainly due to a 11% decrease in average natural gas prices realized, partially offset by a 10% increase in natural gas sales volumes. The decrease in NGL and natural gas revenues from the year ended December 31, 2015 as compared to the year ended December 31, 2014, is mainly due to a decrease in average prices realized on our NGL and natural gas sales volumes. Stripping out the NGL component from our liquids-rich natural gas results in a lower price received for residue natural gas during the year ended December 31, 2015 as compared to the year ended December 31, 2014 in which we received revenues from liquids-rich natural gas. The decrease in prices is partially offset by an increase in NGL and natural gas sales volumes during the year ended December 31, 2015 as compared to the year ended December 31, 2014, converted to a three-stream basis.

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Costs and expenses

The following table sets forth information regarding costs and expenses and average costs per BOE sold for the periods presented:

	For the years ended December 31,		
(in thousands except for per BOE sold data)	2016	2015	2014
Costs and expenses:			
Lease operating expenses	$75,327	$108,341	$96,503
Production and ad valorem taxes	28,586	32,892	50,312
Midstream service expenses	4,077	5,846	5,429
Minimum volume commitments	2,209	5,235	2,552
Costs of purchased oil	169,536	174,338	53,967
Drilling rig fees	—	—	527
General and administrative:			
Cash	62,527	65,916	82,965
Non-cash stock-based compensation, net of amounts capitalized	29,229	24,509	23,079
Restructuring expenses	—	6,042	—
Accretion of asset retirement obligations	3,483	2,423	1,787
Depletion, depreciation and amortization	148,339	277,724	246,474
Impairment expense	162,027	2,374,888	3,904
Total	$685,340	$3,078,154	$567,499
Average costs per BOE sold:(1)			
Lease operating expenses	$4.15	$6.63	$8.23
Production and ad valorem taxes	1.58	2.01	4.29
Midstream service expenses	0.22	0.36	0.46
General and administrative:			
Cash	3.45	4.03	7.07
Non-cash stock-based compensation, net of amounts capitalized	1.61	1.50	1.97
Depletion, depreciation and amortization	8.17	16.99	21.01
Total	$19.18	$31.52	$43.03

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(1) For the period prior to January 1, 2015, we presented our average costs per BOE sold, which combined NGL with the natural gas stream, and did not separately report NGL. This change impacts the comparability of 2016 and 2015 with 2014.

Lease operating expenses. Lease operating expenses, which include workover expenses, decreased by $33.0 million, or 30%, for the year ended December 31, 2016 compared to 2015. Previous investments in field infrastructure, primarily in our four production corridors, including water takeaway and recycling facilities and centralized compression, have lowered expenses and reduced well downtime. We continue to focus on economic efficiencies associated with the usage and procurement of products and services related to lease operating expenses.

Lease operating expenses increased by $11.8 million, or 12%, for the year ended December 31, 2015 compared to 2014. On a three-stream per BOE sold comparable basis, lease operating expenses decreased to $6.63 per BOE sold for the year ended December 31, 2015 compared to $6.98 per BOE sold for the year ended December 31, 2014 due to (i) derived efficiencies from wells drilled along our production corridors resulting in reduced service costs from water handling and disposal and utilization of our centralized compression facilities, (ii) our initiative to reduce field electricity costs by working with electric service providers to build infrastructure to our facilities, (iii) reduced fuel costs from natural gas lift and (iv) lower workover expenses.

Production and ad valorem taxes. Production and ad valorem taxes decreased by $4.3 million, or 13%, for the year ended December 31, 2016 compared to 2015. This change is mainly due to a $5.0 million decrease in ad valorem taxes for the year ended December 31, 2016 compared to 2015, which are based on and fluctuate in proportion to the taxable value assessed by the various counties where our properties are located.

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Production and ad valorem taxes decreased by $17.4 million, or 35%, for the year ended December 31, 2015 compared to 2014. This change is mainly due to a $16.9 million decrease in production taxes for the year ended December 31, 2015 compared to 2014, which are based on and fluctuate in proportion to our oil, NGL and natural gas revenue.

Midstream service expenses. See "—Results of operations - midstream and marketing" for a discussion of these expenses.

Minimum volume commitments. Minimum volume commitments decreased by $3.0 million for the year ended December 31, 2016 compared to 2015, and increased by $2.7 million for the year ended December 31, 2015 compared to 2014. These changes are mainly a result of our 2015 buyout of a minimum volume commitment to Medallion related to natural gas gathering infrastructure constructed by Medallion on acreage we do not plan to develop. See Notes 12.d and 14 to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our minimum volume commitments.

Costs of purchased oil. See "—Results of operations - midstream and marketing" for a discussion of these expenses.

General and administrative ("G&A"). The table below shows the changes in the significant components of G&A expense for the periods presented:

(in thousands)	Year ended December 31, 2016 compared to 2015	Year ended December 31, 2015 compared to 2014
Changes in G&A:		
Stock-based compensation, net of amounts capitalized	$ 4,720	$ 1,430
Performance unit awards	(4,081)	3,481
Salaries, benefits and bonuses, net of amounts capitalized	3,578	(4,084)
Professional fees	(2,200)	(6,066)
Charitable contributions	175	(3,208)
Other	(861)	(7,172)
Total changes in G&A	$ 1,331	$ (15,619)

G&A expense, excluding stock-based compensation, net of amounts capitalized, decreased by $3.4 million, or 5%, for the year ended December 31, 2016 compared to 2015. This change is primarily due to decreases in expenses related to our 2013 performance unit awards and professional fees, partially offset by an increase in salaries, benefits and bonuses, net of amounts capitalized. Expense incurred for our 2013 performance unit awards was $4.1 million for the year ended December 31, 2015. There was no comparable expense during the year ended December 31, 2016 as these types of awards are no longer a part of our compensation at this time. The performance criteria of these awards were satisfied on December 31, 2015 and paid during the first quarter of 2016.

Stock-based compensation, net of amounts capitalized, increased by $4.7 million, or 19%, for the year ended December 31, 2016 compared to 2015. This increase is mainly due to the issuance of restricted stock awards, stock option awards and performance share awards during the year ended December 31, 2016. For further discussion of our stock-based compensation, see Note 6 to our consolidated financial statements included elsewhere in this Annual Report.

G&A expense, excluding stock-based compensation, net of amounts capitalized, decreased by $17.0 million, or 21%, for the year ended December 31, 2015 compared to 2014. This change is primarily due to (i) professional fees paid to a consulting company in 2014 that was engaged to assist us with the optimization of our development operations, (ii) reduced personnel expenses as a result of the reduction in force (the "RIF") which occurred early in the first quarter of 2015 and (iii) our $3.0 million charitable contribution pledge expensed in 2014, which will be paid in annual installments through 2024. These contributors are partially offset by an increase in the fair value of the 2013 performance unit awards as of December 31, 2015 compared to 2014, based on the performance of our stock price relative to the peer group specified in the award agreement and utilized in the forward-looking Monte Carlo simulation.

Stock-based compensation, net of amounts capitalized, increased by $1.4 million, or 6%, for the year ended December 31, 2015 compared to 2014 due to the varying service periods of our award types, partially offset by forfeitures of restricted stock awards and stock option awards as a result of the first-quarter 2015 RIF.

The fair values for each of our restricted stock awards issued were calculated based on the value of our stock price on the grant date in accordance with GAAP and are being expensed on a straight-line basis over their associated requisite service periods. The fair values for each of our stock option awards were determined using a Black-Scholes valuation model in accordance with GAAP and are being expensed on a straight-line basis over their associated four-year requisite service periods.

Our performance share awards are accounted for as equity awards and are included in stock-based compensation expense. The fair values of the performance share awards issued were based on a projection of the performance of our stock price relative to a peer group, defined in each performance share awards' agreement, utilizing a forward-looking Monte Carlo simulation. The fair values for each of our performance share awards will not be re-measured after their initial grant-date valuation and are being expensed on a straight-line basis over their associated three-year requisite service periods.

Our performance unit awards were accounted for as liability awards and settled in cash at the end of their requisite service periods. The fair value and corresponding liability related to the 2013 performance unit awards as of December 31, 2015 was $6.4 million. The 2013 performance unit awards had a performance period of January 1, 2013 to December 31, 2015 and, as their performance criteria were satisfied, they were paid at $143.75 per unit during the first quarter of 2016. The fair value and corresponding liability related to the 2012 performance unit awards as of December 31, 2014 was $2.7 million. The 2012 performance unit awards had a performance period of January 1, 2012 to December 31, 2014 and, as their performance criteria were satisfied, they were paid at $100 per unit during the first quarter of 2015.

See Notes 2.r and 6 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our stock and performance-based compensation.

Restructuring expenses. For the year ended December 31, 2015, we incurred restructuring expenses of $6.0 million related to the first-quarter 2015 RIF, which was undertaken to reduce expenses and better position ourselves for future operations in a low commodity price environment. No comparable expenses were recorded for the years ended December 31, 2016 and 2014. See Note 13 to our consolidated financial statements included elsewhere in this Annual Report for further discussion of the RIF.

Depletion, depreciation and amortization ("DD&A"). The following table provides components of our DD&A expense for the periods presented:

	For the years ended December 31,		
(in thousands)	2016	2015	2014
Depletion of evaluated oil and natural gas properties	$134,105	$263,666	$237,067
Depreciation of midstream service assets	8,331	7,529	4,303
Depreciation and amortization of other fixed assets	5,903	6,529	5,104
Total DD&A	$148,339	$277,724	$246,474

DD&A decreased by $129.4 million, or 47%, for the year ended December 31, 2016 as compared to 2015 mainly due to the impact of our full cost ceiling impairments of $161.1 million and $2.4 billion for the years ended December 31, 2016 and 2015, respectively. DD&A increased by $31.3 million, or 13%, for the year ended December 31, 2015 as compared to 2014 mainly due to (i) the reduction in our reserves volume, (ii) the impact of $152.5 million in unevaluated properties' carrying costs being added to the depletion base during the year ended December 31, 2015 and (iii) higher total production levels. These contributors were partially offset by the impact of our 2015 full cost ceiling impairments.

Impairment expense. Our net book value of evaluated oil and natural gas properties exceeded the full cost ceiling amount as of March 31, 2016 and each of the quarters ended in 2015, and as a result, we recorded non-cash full cost ceiling impairments of $161.1 million and $2.4 billion for the years ended December 31, 2016 and 2015, respectively. There were no comparable full cost ceiling impairments in 2014. For further discussion of our non-cash full cost ceiling impairments, see Note 2.g to our consolidated financial statements included elsewhere in this Annual Report.

During the years ended December 31, 2016, 2015 and 2014, we reduced materials and supplies inventory by $1.0 million, $2.8 million and $1.8 million, respectively, in order to reflect the balance at lower of cost or market. For the years ended December 31, 2015 and 2014, we recorded lower of cost or market adjustments of $1.3 million and $2.1 million, respectively, related to our line-fill inventory. There were no comparable line-fill inventory impairments in 2016. See Note 2.j to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our inventory impairments.

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Non-operating income (expense). The following table sets forth the components of non-operating income (expense) for the periods presented:

	For the years ended December 31,		
(in thousands)	2016	2015	2014
Non-operating income (expense):			
Gain (loss) on derivatives, net	$(87,425)	$214,291	$327,920
Income (loss) from equity method investee	9,403	6,799	(192)
Interest expense	(93,298)	(103,219)	(121,173)
Interest and other income	175	426	294
Loss on early redemption of debt	—	(31,537)	—
Write-off of debt issuance costs	(842)	—	(124)
Loss on disposal of assets, net	(790)	(2,127)	(3,252)
Non-operating income (expense), net	$(172,777)	$84,633	$203,473

Gain (loss) on derivatives, net. The table below presents the changes in the components of gain (loss) on derivatives, net for the periods presented:

(in thousands)	Year ended December 31, 2016 compared to 2015	Year ended December 31, 2015 compared to 2014
Changes in gain or loss on derivatives, net:		
Fair value of derivatives outstanding	$ (321,716)	$ (264,009)
Early terminations of derivatives received	80,000	(76,660)
Cash settlements received for matured derivatives, net	(60,000)	227,040
Total changes in gain or loss on derivatives, net	$ (301,716)	$ (113,629)

The changes in fair value of derivatives outstanding are the result of new and expiring contracts and the changing relationship between our outstanding contract prices and the future market prices in the forward curves, which we use to calculate the fair value of our derivatives. In general, if no contracts were entered into, we experience gains during periods of decreasing market prices and losses during periods of increasing market prices. Cash settlements received for matured derivatives are based on the cash settlement prices of our matured derivatives compared to the prices specified in the derivative contracts.

During the year ended December 31, 2016, we received proceeds from a hedge restructuring in which we early terminated floors of certain derivative contract collars, resulting in a termination amount due to us of $80.0 million. The $80.0 million was settled in full by applying the proceeds to the premiums on two new derivative contracts entered into as part of the hedge restructuring. During the year ended December 31, 2014, we received $76.7 million in net proceeds from the early termination of our oil basis swap differential between the Light Louisiana Sweet Argus and the Brent International Petroleum Exchange index oil prices and the related physical contract. There were no comparable early termination amounts in 2015.

See Notes 2.f, 8 and 9 to our consolidated financial statements included elsewhere in this Annual Report and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional information regarding our derivatives.

Income (loss) from equity method investee. See "—Results of operations - midstream and marketing" for a discussion of this income (loss).

Interest expense. The table below shows the changes in the significant components of interest expense for the periods presented:

(in thousands)	Year ended December 31, 2016 compared to 2015	Year ended December 31, 2015 compared to 2014
Changes in interest expense:		
January 2019 Notes	$ (13,865)	$ (38,002)
March 2023 Notes	4,740	17,135
Senior Secured Credit Facility, net of capitalized interest	(615)	1,969
January 2022 Notes	—	1,477
Other	(181)	(533)
Total changes in interest expense	$ (9,921)	$ (17,954)

Interest expense decreased by $9.9 million, or 10%, for the year ended December 31, 2016 compared to 2015, and decreased by $18.0 million, or 15%, for the year ended December 31, 2015 compared to 2014. These decreases are primarily due to the early redemption of the January 2019 Notes on April 6, 2015, which are partially offset by the issuance of the March 2023 Notes. The March 2023 Notes, which began accruing interest on March 18, 2015, have both a lower interest rate and a lower principal amount than the January 2019 Notes.

Loss on early redemption of debt. During the year ended December 31, 2015, we redeemed the entire $550.0 million outstanding principal amount of the January 2019 Notes at a redemption price of 104.750% of the principal amount, plus accrued and unpaid interest up to the Redemption Date. We recognized a loss on extinguishment of $31.5 million related to the difference between the redemption price and the net carrying amount of the January 2019 Notes. There were no comparable early redemption of debt amounts in 2016 and 2014.

Write-off of debt issuance costs. We wrote-off $0.8 million of debt issuance costs during the year ended December 31, 2016 as a result of changes in the borrowing base and aggregate elected commitment of the Senior Secured Credit Facility. We wrote-off $0.1 million of debt issuance costs during the year ended December 31, 2014 as a result of changes in the borrowing base of the Senior Secured Credit Facility due to the issuance of the January 2022 Notes. No debt issuance costs were written-off in 2015.

Loss on disposal of assets, net. Loss on disposal of assets, net decreased by $1.3 million for the year ended December 31, 2016 compared to 2015, and decreased $1.1 million for the year ended December 31, 2015 compared to 2014. From time to time, we dispose of materials and supplies inventory and other fixed assets. The associated gain or loss recorded during the period fluctuates depending upon the volume of the assets disposed, their associated net book value and, in the case of a disposal by sale, the sale price.

Income tax benefit (expense). The table below shows income tax benefit (expense) for the periods presented:

(in thousands)	For the years ended December 31, 2016	2015	2014
Income tax benefit (expense)	$ —	$ 176,945	$ (164,286)

During the years ended December 31, 2016 and 2015, we determined it was more likely than not that our net deferred tax assets were not realizable, therefore we recorded valuation allowances of $87.5 million and $676.0 million, respectively, to reduce certain deferred tax assets to amounts that are more likely than not to be realized. Our effective tax rate is affected by changes in valuation allowances, recurring permanent differences and discrete items that may occur in any given year, but are not consistent from year to year. The effective tax rate for our operations was 0%, 7% and 38% for the years ended December 31, 2016, 2015 and 2014, respectively. For further discussion of our valuation allowance, see Note 7 to our consolidated financial statements located elsewhere in this Annual Report.

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Results of operations - midstream and marketing

The following table presents selected financial information regarding our midstream and marketing operating segment for the periods presented:

	For the years ended December 31,		
(in thousands)	2016	2015	2014
Revenues:			
Natural gas sales	$1,141	$1,692	$1,660
Midstream service revenues	49,971	27,965	7,838
Sales of purchased oil	162,551	168,358	54,437
Total revenues	$213,663	$198,015	$63,935
Expenses:			
Midstream service expenses	$29,693	$17,557	$7,089
Costs of purchased oil	169,536	174,338	53,967
General and administrative[1]	7,855	8,174	6,969
Depreciation and amortization[2]	8,932	8,093	4,640
Impairment expense	—	2,592	2,102
Other operating costs and expenses[3]	209	1,178	2,618
Operating loss	$(2,562)	$(13,917)	$(13,450)
Other financial information:			
Income (loss) from equity method investee	$9,403	$6,799	$(192)
Interest expense[4]	$(5,813)	$(5,179)	$(3,613)
Loss on early redemption of debt[5]	$—	$(1,481)	$—
Income tax (expense) benefit[6]	$—	$4,993	$6,265

(1) G&A was allocated based on the number of employees in the midstream and marketing segment as of December 31, 2016, 2015 and 2014. Certain components of G&A expense, primarily payroll, deferred compensation and vehicle expenses, were not allocated but were actual expenses for each segment. Land and geology expenses were not allocated to the midstream and marketing segment.

(2) Depreciation and amortization were actual expenses for the midstream and marketing segment with the exception of the allocation of depreciation of other fixed assets, which was based on the number of employees in the midstream and marketing segment as of December 31, 2016, 2015 and 2014.

(3) Other operating costs and expenses consist of (i) accretion of asset retirement obligations for the year ended December 31, 2016, (ii) minimum volume commitments, restructuring expense and accretion of asset retirement obligations for the year ended December 31, 2015 and (iii) minimum volume commitments and accretion of asset retirement obligations for the year ended December 31, 2014. These are actual costs and expenses and were not allocated.

(4) Interest expense was allocated to the midstream and marketing segment based on gross property and equipment and life-to-date contributions to the Company's equity method investee as of December 31, 2016, 2015 and 2014.

(5) Loss on early redemption of debt was allocated to the midstream and marketing segment based on gross property and equipment and life-to-date contributions to the Company's equity method investee as of December 31, 2015.

(6) Income tax (expense) benefit for the midstream and marketing segment was calculated by multiplying income or loss before income taxes by 36% for the years ended December 31, 2015 and 2014.

Natural gas sales. These revenues are related to our midstream and marketing segment providing our exploration and production segment with processed natural gas for use in the field. The corresponding cost component of these transactions are included in "Midstream service expenses." See Note 16 to our consolidated financial statements included elsewhere in this Annual Report for additional information on the operating segments.

Midstream service revenues. Our midstream service revenues from operations increased by $22.0 million for the year ended December 31, 2016 compared to 2015. This increase is mainly due to (i) water service revenue that we began recognizing in the third quarter of 2015 and (ii) an increase in volumes of natural gas provided for natural gas lift mainly in our production corridors over the prior period. Our midstream service revenues from operations increased by $20.1 million for the year ended December 31, 2015 compared to 2014. This increase is mainly due to (i) water service revenue that we began recognizing in the third quarter of 2015, (ii) oil throughput fees generated by our oil gathering line which was not operational until July of 2014, (iii) higher volumes of gathered natural gas and (iv) an increase in volumes of natural gas provided for natural gas lift mainly in our production corridors that were not operational until September of 2014.

Sales of purchased oil. Sales of purchased oil decreased by $5.8 million for the year ended December 31, 2016 compared to 2015 due to the decrease in oil prices. During the fourth quarter of 2014, we began to purchase oil from third parties in West Texas, transport it on on the Bridgetex Pipeline and sell it to a third party in the Houston market.

Midstream service expenses. Midstream service expenses increased by $12.1 million and $10.5 million for the year ended December 31, 2016 compared to 2015 and for the year ended December 31, 2015 compared to 2014, respectively. Midstream service expenses primarily represent costs incurred to operate and maintain our (i) oil and natural gas gathering and transportation systems and related facilities, (ii) centralized oil storage tanks, (iii) natural gas lift, rig fuel and centralized compression infrastructure and (iv) water storage, recycling and transportation facilities. The increases are due to continued expansion of the midstream service component of our business.

Costs of purchased oil. Costs of purchased oil decreased by $4.8 million for the year ended December 31, 2016 compared to 2015 due to the decrease in oil prices. These costs include purchasing oil from third parties and transporting it on the Bridgetex Pipeline.

Depreciation and amortization. Depreciation and amortization increased by $0.8 million and $3.5 million for the year ended December 31, 2016 compared to 2015 and for the year ended December 31, 2015 compared to 2014, respectively, due to the continued expansion of our midstream service infrastructure.

Income (loss) from equity method investee. We own 49% of the ownership units of Medallion. As such, we account for this investment under the equity method of accounting with our proportionate share of net income (loss) reflected in the consolidated statements of operations as "Income (loss) from equity method investee" and the carrying amount reflected in the consolidated balance sheets as "Investment in equity method investee." Income from equity method investee increased by $2.6 million, or 38%, for the year ended December 31, 2016 compared to 2015. During the year ended December 31, 2016, Medallion continued expansion activities on existing portions of its pipeline infrastructure in order to gather additional third-party oil production. Medallion began recognizing revenue during the first quarter of 2015 due to its main pipeline becoming fully operational. The Medallion-Midland Basin system transported an average of 107,000 barrels of oil per day ("BOPD") and 42,000 BOPD during the years ended December 31, 2016 and 2015, respectively. See Note 14 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding this investment.

Interest expense. Interest expense increased by $0.6 million and $1.6 million for the year ended December 31, 2016 compared to 2015 and for the year ended December 31, 2015 compared to 2014, respectively. Consolidated interest, which has decreased for the year ended December 31, 2016 compared to 2015 and for the year ended December 31, 2015 compared to 2014, is allocated to the midstream and marketing segment based on its gross property and equipment and life-to-date contributions to its equity method investee. We have expanded the midstream and marketing component of our business, built out our service facilities and have continued our capital contributions to Medallion since prior periods, thereby increasing the interest expense that is allocated to this segment. See "—Results of operations consolidated" for a discussion of these decreases.

Loss on early redemption of debt. We recognized a loss on extinguishment related to the difference between the redemption price and the net carrying amount of the extinguished January 2019 Notes during the year ended December 31, 2015. Loss on early redemption of debt was allocated to the midstream and marketing segment based on gross property and equipment and life-to-date contributions to our equity method investee as of December 31, 2015.

Liquidity and capital resources

Our primary sources of liquidity have been cash flows from operations, proceeds from equity offerings, proceeds from senior unsecured note offerings, borrowings under our Senior Secured Credit Facility and proceeds from asset dispositions. We believe cash flows from operations (including our hedging program) and availability under our Senior Secured Credit Facility provide sufficient liquidity to manage our cash needs and contractual obligations and to fund expected capital expenditures. Our primary operational uses of capital have been for the acquisition, exploration and development of oil and natural gas properties, LMS' infrastructure development and investments in Medallion. A significant portion of our capital expenditures can be adjusted and managed by us. We continually monitor the capital markets and our capital structure and consider which financing alternatives, including equity and debt capital resources, joint ventures and asset sales, are available to meet our future planned or accelerated capital expenditures. We may make changes to our capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity and/or achieving cost efficiency. Such financing alternatives, including capital market transactions and debt repurchases, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material. See Notes 3, 4.b and 5 to our consolidated financial statements included elsewhere in this Annual Report regarding our current year and prior year equity offerings, prior year divestiture and debt (including our prior year debt redemption), respectively.

We continually seek to maintain a financial profile that provides operational flexibility. However, as evidenced by the decline in our Realized Prices used in our reserves compared to the prior year, the decrease in oil, NGL and natural gas prices may have a negative impact on our ability to raise additional capital and/or maintain our desired levels of liquidity. As of February 14, 2017, we had $800.0 million available for borrowings under our Senior Secured Credit Facility. We believe that our operating cash flow and the aforementioned liquidity sources provide us with the financial resources to implement our planned exploration and development activities. We use derivatives to reduce exposure to fluctuations in the prices of oil, NGL and natural gas. As of February 15, 2017 utilizing the mid-point of our first-quarter guidance, approximately 79% of our anticipated oil production for the first three months of 2017 is hedged at a weighted-average floor price of $55.82 per Bbl, approximately 16% of our anticipated NGL production for the first three months of 2017 is hedged for (i) 111,000 Bbls of ethane at a weighted-average floor price of $11.24 per Bbl and (ii) 93,750 Bbls of propane at a weighted-average floor price of $22.26 per Bbl and approximately 85% of our anticipated natural gas production for the first three months of 2017 is hedged at a weighted-average floor price of $2.75 per MMBtu. Approximately 77% of total anticipated oil production in the first quarter of 2017 retains significant upside to an increase in the price of oil with those volumes either having a weighted-average ceiling price of $86.00 per Bbl or no ceiling at all.

See Note 8.a to our consolidated financial statements included elsewhere in this Annual Report for information regarding our derivative settlement indices and our open hedge positions as of December 31, 2016. There were no new hedge transactions between January 1, 2017 and February 15, 2017.

By removing a significant portion of the price volatility associated with future production, we expect to mitigate, but not eliminate, the potential effects of variability in cash flows from operations due to fluctuations in commodity prices. Our derivative positions will help us stabilize a portion of our expected cash flows from operations in the event of future declines in the price of oil, NGL and natural gas. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" below.

Cash flows

Our cash flows for the periods presented are as follows:

	For the years ended December 31,		
(in thousands)	2016	2015	2014
Net cash provided by operating activities	$356,295	$315,947	$498,277
Net cash used in investing activities	(564,402)	(667,507)	(1,406,961)
Net cash provided by financing activities	209,625	353,393	739,852
Net increase (decrease) in cash and cash equivalents	$1,518	$1,833	$(168,832)

Cash flows provided by operating activities

The increase of $40.3 million from 2015 to 2016 consisted of notable cash changes of (i) a decrease of $64.5 million in cash settlements received for matured and early terminations of derivatives, net of deferred premiums paid, (ii) an increase in working capital changes of $56.7 million and (iii) an increase of $3.7 million in settlement of performance unit awards.

The decrease of $182.3 million from 2014 to 2015 is mainly due to the price related decrease in oil, NGL and natural gas revenue, however notable cash flow changes consist of (i) a net increase of $150.4 million of proceeds from derivative settlements due to maturity or early termination, (ii) an increase of $31.5 million related to our loss on the early redemption of our January 2019 Notes and (iii) $56.6 million in decreased changes in working capital.

Our operating cash flows are sensitive to a number of variables, the most significant of which are the volatility of oil, NGL and natural gas prices and production levels. Regional and worldwide economic activity, weather, infrastructure, capacity to reach markets, costs of operations, legislation and regulations and other variable factors significantly impact the prices of these commodities. These factors are not within our control and are difficult to predict. For additional information on the impact of changing prices on our financial position, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

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Cash flows used in investing activities

Net cash used in investing activities decreased $103.1 million from 2015 to 2016 and is mainly attributable to (i)decreased capital expenditures due to our decreased capital budget and (ii) decreased contributions to Medallion. These decreases were partially offset by (i) 2016 acquisitions of oil and natural gas properties and (ii) 2015 proceeds from the sale of non-strategic and primarily non-operated properties and associated production. See Notes 4.a and 4.b to our consolidated financial statements included elsewhere in this Annual Report for discussion of our current period acquisitions and prior period divestiture. See Notes 14 and 15.a to our consolidated financial statements included elsewhere in this Annual Report for additional discussion regarding Medallion.

Net cash used in investing activities decreased $739.5 million from 2014 to 2015 and is mainly attributable to decreased capital expenditures due to our decreased capital budget. This decrease was partially offset by $64.8 million in proceeds from our 2015 sale of non-strategic and primarily non-operated properties and increased contributions to Medallion. Medallion significantly expanded its pipeline network during 2015.

Our cash used in investing activities for the periods presented are summarized in the table below:

	For the years ended December 31,		
(in thousands)	2016	2015	2014
Deposit received for sale of oil and natural gas properties	$3,000	$—	$—
Capital expenditures:			
Acquisitions of oil and natural gas properties	(124,660)	—	(6,493)
Acquisition of mineral interests	—	—	(7,305)
Oil and natural gas properties	(360,679)	(588,017)	(1,251,757)
Midstream service assets	(5,240)	(35,459)	(60,548)
Other fixed assets	(7,611)	(9,125)	(27,444)
Investment in equity method investee	(69,609)	(99,855)	(55,164)
Proceeds from dispositions of capital assets, net of selling costs	397	64,949	1,750
Net cash used in investing activities	$(564,402)	$(667,507)	$(1,406,961)

Capital budget

Our board of directors approved a capital budget of approximately $530.0 million for calendar year 2017, excluding acquisitions and investments in Medallion. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted. In addition, as a 49% owner of Medallion, we do not direct the expansion activities of this entity and therefore cannot predict future capital commitments related to Medallion.

The amount, timing and allocation of capital expenditures, other than with respect to Medallion, are largely discretionary and within management's control. If oil, NGL and natural gas prices decline below our acceptable levels, or costs increase above our acceptable levels, we may choose to defer a portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flow. Subject to financing alternatives, we may also increase our capital expenditures significantly to take advantage of opportunities we consider to be attractive. We consistently monitor and may adjust our projected capital expenditures in response to success or lack of success in drilling activities, changes in prices, availability of financing and joint venture opportunities, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, reduction of service costs, contractual obligations, internally generated cash flow and other factors both within and outside our control. For additional information on the impact of changing prices on our financial position, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Cash flows provided by financing activities

For the year ended December 31, 2016, our primary sources of cash provided by financing activities were the combined proceeds from our July 2016 Equity Offering and May 2016 Equity Offering of $276.1 million and borrowings on our Senior Secured Credit Facility of $239.7 million. The cash inflows were partially offset by the payments on our Senior Secured Credit Facility of $304.7 million.

For the year ended December 31, 2015, net cash provided by financing activities was the result of proceeds from our March 2015 equity offering of $754.2 million, our issuance of our March 2023 Notes of $350.0 million and borrowings on our Senior Secured Credit Facility of $310.0 million. The cash inflows were offset by the redemption of our January 2019 Notes of

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$576.2 million, payments on our Senior Secured Credit Facility of $475.0 million and payments for debt issuance costs totaling $6.8 million.

For the year ended December 31, 2014, net cash provided by financing activities was the result of the issuance of our January 2022 Notes of $450.0 million, borrowings of $300.0 million on our Senior Secured Credit Facility and proceeds from the exercise of employee stock options of $1.9 million. These cash inflows were partially offset by payments for debt issuance costs totaling $7.8 million.

Our cash provided by financing activities for the periods presented is summarized in the table below:

	For the years ended December 31,		
(in thousands)	2016	2015	2014
Borrowings on Senior Secured Credit Facility	$239,682	$310,000	$300,000
Payments on Senior Secured Credit Facility	(304,682)	(475,000)	—
Issuance of March 2023 Notes	—	350,000	—
Issuance of January 2022 Notes	—	—	450,000
Redemption of January 2019 Notes	—	(576,200)	—
Proceeds from issuance of common stock, net of offering costs	276,052	754,163	—
Purchase of treasury stock	(1,635)	(2,811)	(4,242)
Proceeds from exercise of employee stock options	208	—	1,885
Payments for debt issuance costs	—	(6,759)	(7,791)
Net cash provided by financing activities	$209,625	$353,393	$739,852

Debt

As of December 31, 2016, we were a party only to our Senior Secured Credit Facility and the indentures governing our Senior Unsecured Notes.

As of December 31, 2016, we had $1.4 billion in debt outstanding, $745.0 million available for borrowings under our Senior Secured Credit Facility and $32.7 million in cash on hand for total available liquidity of $777.7 million.

As of February 14, 2017, we had $1.3 billion in debt outstanding, $800.0 million available for borrowings under our Senior Secured Credit Facility and $23.9 million in cash on hand for total available liquidity of $823.9 million. Future declines in oil, NGL and natural gas prices may negatively impact our future borrowing base redeterminations.

Senior Secured Credit Facility. As of December 31, 2016, our Senior Secured Credit Facility, which matures November 4, 2018, had a maximum credit amount of $2.0 billion and a borrowing base and aggregate elected commitment of $815.0 million. As of December 31, 2016, 2015 and 2014, borrowings outstanding under our Senior Secured Credit Facility totaled $70.0 million, $135.0 million and $300.0 million, respectively.

The borrowing base under our Senior Secured Credit Facility is subject to a semi-annual redetermination based on the lenders' evaluation of our oil, NGL and natural gas reserves. The lenders have the right to call for an interim redetermination of the borrowing base once between any two redetermination dates and in other specified circumstances. On October 24, 2016, pursuant to a regular semi-annual redetermination, the lenders reaffirmed the borrowing base under our Senior Secured Credit Facility at $815.0 million. Our aggregate elected commitment of $815.0 million remained unchanged. The next semi-annual redetermination will occur by May 1, 2017.

Principal amounts borrowed under our Senior Secured Credit Facility are payable on the final maturity date with such borrowings bearing interest that is payable, at our election, either on the last day of each fiscal quarter at an Adjusted Base Rate or at the end of one-, two-, three-, six- or, to the extent available, 12-month interest periods (and in the case of six- and 12-month interest periods, every three months prior to the end of such interest period) at an Adjusted London Interbank Offered Rate, in each case, plus an applicable margin, which ranges from 0.5% to 1.5% for Adjusted Base Rate loans and from 1.5% to 2.5% for Adjusted London Interbank Offered Rate loans, based on the ratio of the outstanding revolving credit on our Senior Secured Credit Facility to the elected commitment. We are also required to pay an annual commitment fee based on the unused portion of the bank's commitment of 0.375% to 0.5%.

Our Senior Secured Credit Facility is secured by a first-priority lien on certain of our assets, including oil and natural gas properties constituting at least 80% of the present value of our proved reserves owned now or in the future. Our Senior

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Secured Credit Facility contains both financial and non-financial covenants. We were in compliance with these covenants as of December 31, 2016, 2015 and 2014.

As of December 31, 2016, we were subject to the following financial ratios on a consolidated basis:

- a current ratio at the end of each fiscal quarter, as defined by the agreement, that is not permitted to be less than 1.00 to 1.00; and
- at the end of each fiscal quarter, the ratio of earnings before interest, taxes, depletion, depreciation, amortization and exploration expenses and other non-cash charges ("EBITDAX") for the four fiscal quarters ending on the relevant date to the sum of net interest expense plus letter of credit fees, in each case for such period, is not permitted to be less than 2.50 to 1.00.

Our Senior Secured Credit Facility contains various non-financial covenants that limit our ability to:

- incur indebtedness;
- pay dividends and repay certain indebtedness;
- grant certain liens;
- merge or consolidate;
- engage in certain asset dispositions;
- use proceeds for any purpose other than to finance the acquisition, exploration and development of mineral interests and for working capital and general corporate purposes;
- make certain investments, including in Medallion;
- enter into transactions with affiliates;
- engage in certain transactions that violate ERISA or the Code or enter into certain employee benefit plans and transactions;
- enter into certain swap agreements or hedge transactions;
- incur, become or remain liable under any operating lease that would cause rentals payable to be greater than $20.0 million in a fiscal year;
- acquire all or substantially all of the assets or capital stock of any person, other than assets consisting of oil and natural gas properties and certain other oil and natural gas related acquisitions and investments; and
- repay or redeem our Senior Unsecured Notes, or amend, modify or make any other change to any of the terms in our Senior Unsecured Notes that would change the term, life, principal, rate or recurring fee, add call or pre-payment premiums, or shorten any interest periods.

As of December 31, 2016, we were in compliance with the terms of our Senior Secured Credit Facility. If an event of default exists under our Senior Secured Credit Facility, the lenders will be able to accelerate the maturity of our Senior Secured Credit Facility and exercise other rights and remedies. As of December 31, 2016, each of the following would be an event of default:

- failure to pay any principal of any note or any reimbursement obligation under any letter of credit when due or any interest, fees or other amount within certain grace periods;
- failure to perform or otherwise comply with the covenants in our Senior Secured Credit Facility and other loan documents, subject, in certain instances, to certain grace periods;
- a representation, warranty, certification or statement is proved to be incorrect in any material respect when made;
- failure to make any payment in respect of any other indebtedness in excess of $25.0 million, any event occurs that permits or causes the acceleration of any such indebtedness or any event of default or termination event under a hedge agreement occurs in which the net hedging obligation owed is greater than $25.0 million;
- voluntary or involuntary bankruptcy or insolvency events involving us or our subsidiary and in the case of an involuntary proceeding, such proceeding remains undismissed and unstayed for the applicable grace period;
- one or more adverse judgments in excess of $25.0 million to the extent not covered by acceptable third party insurers, are rendered and are not satisfied, stayed or paid for the applicable grace period;
- incurring environmental liabilities that exceed $25.0 million to the extent not covered by acceptable third-party insurers;

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- the loan agreement or any other loan paper ceases to be in full force and effect, or is declared null and void, or is contested or challenged, or any lien ceases to be a valid, first-priority, perfected lien;
- failure to cure any borrowing base deficiency in accordance with our Senior Secured Credit Facility;
- a change of control, as defined in our Senior Secured Credit Facility; and
- an "event of default" under the indentures governing our Senior Unsecured Notes.

Additionally, our Senior Secured Credit Facility provides for the issuance of letters of credit, limited in the aggregate to the lesser of $20.0 million and the total availability under the facility. No letters of credit were outstanding as of December 31, 2016. See Note 5.f to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our Senior Secured Credit Facility.

Senior Unsecured Notes. The following table presents principal amounts and applicable interest rates for our outstanding Senior Unsecured Notes as of December 31, 2016:

(in millions, except for interest rates)	Principal	Interest rate
January 2022 Notes	$450.0	5.625%
May 2022 Notes	500.0	7.375%
March 2023 Notes	350.0	6.250%
Total Senior Unsecured Notes	$1,300.0	

Utilizing proceeds from the March 2023 Notes and the March 2015 equity offering, we redeemed the January 2019 Notes in full on April 6, 2015. See Note 5.e to our consolidated financial statements included elsewhere in this Annual Report for information regarding the early redemption of the January 2019 Notes.

Refer to Note 5 included elsewhere in this Annual Report for further discussion of the March 2023 Notes, January 2022 Notes, May 2022 Notes, January 2019 Notes and our Senior Secured Credit Facility.

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Obligations and commitments

We had the following significant contractual obligations and commitments as of December 31, 2016:

(in thousands)	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
Senior Secured Credit Facility[1]	$—	$70,000	$—	$—	$70,000
Senior Unsecured Notes[2]	84,063	168,125	168,125	1,363,906	1,784,219
Drilling contracts[3]	7,896	—	—	—	7,896
Firm sale and transportation commitments[4]	58,523	115,454	112,867	154,184	441,028
Derivatives[5]	6,442	2,683	—	—	9,125
Asset retirement obligations[6]	1,603	5,683	8,214	36,707	52,207
Lease commitments[7]	3,127	6,298	3,857	7,022	20,304
Total	$161,654	$368,243	$293,063	$1,561,819	$2,384,779

(1) Includes outstanding principal amount at December 31, 2016. This table does not include future loan advances, repayments, commitment fees or other fees on our Senior Secured Credit Facility as we cannot determine with accuracy the timing of such items. Additionally, this table does not include interest expense as it is a floating rate instrument and we cannot determine with accuracy the future interest rates to be charged. As of December 31, 2016, the principal on our Senior Secured Credit Facility is due on November 4, 2018.

(2) Values presented include both our principal and interest obligations.

(3) As of December 31, 2016, we had drilling rigs under term contracts which expire during 2017. The value in the table represents the gross amount that we are committed to pay. However, we will record our proportionate share based on our working interest in our consolidated financial statements as incurred. See Note 12.c to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our drilling contracts.

(4) As of December 31, 2016, we have committed to deliver for sale or transportation fixed volumes of product under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. If not fulfilled, we are subject to deficiency payments. See "Item 1A. Risk Factors" and Note 12.d to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our firm sale and transportation commitments.

(5) Represents payments due for deferred premiums on our commodity hedging contracts. See Note 9.a to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our deferred premiums.

(6) Amounts represent our estimate of future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See Note 2.m to our consolidated financial statements included elsewhere in this Annual Report for additional information.

(7) See Note 12.a to our consolidated financial statements included elsewhere in this Annual Report for a description of our lease obligations.

Critical accounting policies and estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our consolidated financial statements.

In management's opinion, the more significant reporting areas impacted by our judgments and estimates are (i) the choice of accounting method for oil and natural gas activities, (ii) estimation of oil, NGL and natural gas reserve quantities and standardized measure of future net revenues, (iii) impairment of oil and natural gas properties, (iv) revenue recognition, (v) estimation of income taxes, (vi) asset retirement obligations, (vii) valuation of derivatives and deferred premiums, (viii) valuation of stock-based compensation and, in prior periods, performance unit compensation and (ix) fair value of assets acquired and liabilities assumed in an acquisition. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates as additional information becomes known.

There have been no material changes in our critical accounting policies and procedures during the year ended December 31, 2016. For our other critical accounting policies and procedures, please see our disclosure of critical accounting policies in "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations". Additionally, see Note 2.b to our consolidated financial statements included elsewhere in this Annual Report for a discussion of additional accounting policies and estimates made by management.

Method of accounting for oil and natural gas properties

The accounting for our business is subject to special accounting rules that are unique to the oil and natural gas industry. There are two allowable methods of accounting for oil and natural gas business activities: the successful efforts method and the full cost method. We follow the full cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration or development activities and do not include any costs related to production, general corporate overhead or similar activities.

Under the full cost method, capitalized costs are amortized on a composite unit of production method based on proved oil, NGL and natural gas reserves. If we maintain the same level of production year over year, the depletion expense may be significantly different if our estimate of remaining reserves or future development costs changes significantly. Proceeds from the sale of properties are accounted for as reductions of capitalized costs unless such sales involve a significant change in the relationship between costs and evaluated reserves, in which case a gain or loss is recognized. The costs of unevaluated properties not being depleted are excluded from amortization until the properties are evaluated. We review all of our unevaluated properties quarterly to determine whether or not and to what extent evaluated reserves have been assigned to the properties, and otherwise if impairment has occurred.

Oil, NGL and natural gas reserve quantities and standardized measure of future net revenue

On an annual basis, our independent reserve engineers prepare the estimates of oil, NGL and natural gas reserves and associated future net cash flows. The SEC has defined proved reserves as the estimated quantities of oil, NGL and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The process of estimating oil, NGL and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates. If such changes are material, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

Impairment of oil and natural gas properties

We review the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues less estimated future expenditures to be incurred in developing and producing the evaluated reserves, less any related income tax effects. For the years ended December 31, 2016 and 2015, we recorded a full cost impairment expense of $161.1 million and $2.4 billion, respectively. For the year ended December 31, 2014, the results of the ceiling test concluded that the carrying amount of our oil and natural gas properties was significantly below the calculated ceiling test value and as such, our properties were not impaired and a write-down was not required. In calculating future net revenues, current prices are calculated as the average oil, NGL and natural gas prices during the 12-month period prior to the end of the current reporting period, determined as the unweighted arithmetic average first-day-of-the-month prices for the prior 12-month period and costs used are those as of the end of the appropriate quarterly period. See Note 2.g to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our impairment of oil and natural gas properties.

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Revenue recognition

Revenue from our interests in producing wells is recognized when the product is delivered, at which time the customer has taken title and assumed the risks and rewards of ownership and collectability is reasonably assured. The sales prices for oil, NGL and natural gas are adjusted for transportation and other related deductions. These deductions are based on contractual or historical data and do not require significant judgment. Subsequently, these revenue deductions are adjusted to reflect actual charges based on third-party documents. As there is a ready market for oil, NGL and natural gas, we sell the majority of production soon after it is produced at various locations.

Midstream service revenues are recorded at the time products are sold or services are provided to third parties at a fixed or determinable price, delivery or performance has occurred, title has transferred and collectability of the revenue is probable. Revenues and expenses attributable to oil purchases and sales are reported on a gross basis when we take title to the products and have risks and rewards of ownership.

Income taxes

As of December 31, 2016 and 2015, we had a net deferred tax asset of zero.

As part of the process of preparing the consolidated financial statements, we are required to estimate the federal and state income taxes in each of the jurisdictions in which we operate. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items such as derivative instruments, depletion, depreciation and amortization, and certain accrued liabilities for tax and financial accounting purposes. These differences and our net operating loss carry-forwards result in deferred tax assets and liabilities, which are included in our consolidated balance sheet. We must then assess, using all available negative and positive evidence, the likelihood that the deferred tax assets will be recovered from future taxable income. If we believe that recovery is not likely, we must establish a valuation allowance. Generally, to the extent we establish a valuation allowance or increase or decrease this allowance in a period, we must include an expense or reduction of expense within the tax provision in the consolidated statement of operations.

Under accounting guidance for income taxes, an enterprise must use judgment in considering the relative impact of negative and positive evidence. The weight given to the potential effect of negative and positive evidence should be commensurate with the extent to which it can be objectively verified. The more negative evidence that exists (i) the more positive evidence is necessary and (ii) the more difficult it is to support a conclusion that a valuation allowance is not needed for all or a portion of the deferred tax asset. Among the more significant types of evidence that we consider are:

- our earnings history exclusive of the loss that created the future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition;
- the ability to recover our net operating loss carry-forward deferred tax assets in future years;
- the existence of significant proved oil, NGL and natural gas reserves;
- our ability to use tax planning strategies, such as electing to capitalize intangible drilling costs as opposed to expensing such costs;
- current price protection utilizing oil and natural gas hedges; and
- future revenue and operating cost projections that indicate we will produce more than enough taxable income to realize the deferred tax asset based on existing sales prices and cost structures.
- current market prices for oil, NGL and natural gas

During 2016, in evaluating whether it was more-likely-than-not that our deferred tax asset was recoverable from future net income, we considered our earnings history for the current and most recent two years.

In performing our analysis, we used inputs from third-party sources that came primarily from our reserve reports that were independently estimated by Ryder Scott. Based on our forecasted results from multiple analyses, during the year ended December 31, 2016, we determined it is more likely than not that we will not realize our net deferred tax assets. Therefore, a valuation allowance of $87.5 million was recorded in 2016 in addition to the valuation allowance of $676.0 million recorded in 2015.

We will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods.

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Variable interest entities

An entity is referred to as a VIE pursuant to accounting guidance for consolidation if it possesses one of the following criteria: (i) it is thinly capitalized, (ii) the residual equity holders do not control the entity, (iii) the equity holders are shielded from the economic losses, (iv) the equity holders do not participate fully in the entity's residual economics, or (v) the entity was established with non-substantive voting interests. We would consolidate a VIE when we are the primary beneficiary of a VIE. A primary beneficiary has the power to direct the activities that most significantly impact the activities of the VIE and the right to receive the benefits or the obligation to absorb the losses of the entity that could be potentially significant to the VIE. We continually monitor our unconsolidated VIE exposure in order to determine if any events have occurred that could cause the primary beneficiary to change. See Notes 14 and 15.a to our consolidated financial statements included elsewhere in this Annual Report for a discussion of our unconsolidated VIE, Medallion.

Asset retirement obligations ("ARO")

We record the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred with the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. For oil and natural gas properties, this is the period in which the well is drilled or acquired. For midstream service assets, this is the period in which the asset is placed in service. The ARO represents the estimated amount we will incur to plug, abandon and remediate the properties at the end of their productive lives, in accordance with applicable state laws. The liability is accreted to its present value each period and for oil and natural gas properties the capitalized cost is depleted on the unit of production method or for midstream service assets depreciated over its useful life. The accretion expense is recorded in the line item "Accretion of asset retirement obligations" in our consolidated statement of operations.

We determine the ARO by calculating the present value of estimated cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. Included in the fair value calculation are assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Derivatives

We record all derivatives on the balance sheet as either assets or liabilities measured at their estimated fair value. We have not designated any derivatives as hedges for accounting purposes, and we do not enter into such instruments for speculative trading purposes. Gains and losses from the settlement, terminations and modifications of commodity derivatives and gains and losses from valuation changes in the remaining unsettled commodity derivatives are reported under "Non-operating income (expense)" in our consolidated statements of operations.

Stock-based compensation

We measure stock-based compensation expense at the grant date based on the fair value of an award and recognize the compensation expense on a straight-line basis over the service period, which is usually the vesting period. The fair value of the awards is based on the value of our common stock on the grant date. The determination of the fair value of an award requires significant estimates and subjective judgments regarding, among other things, the appropriate option pricing model, the expected life of the award and forfeiture rate assumptions. We utilize the Black-Scholes option pricing model to measure the fair value of stock options granted under our 2011 Omnibus Equity Incentive Plan. We capitalize a portion of stock-based compensation for employees who are directly involved in the acquisition, exploration or development of our oil and natural gas properties into the full cost pool. Capitalized stock-based compensation is included as an addition to "Oil and natural gas properties" in the consolidated balance sheets.

As there are inherent uncertainties related to these performance criteria and our judgment in applying them to the fair value determinations, there is risk that the recorded stock compensation may not accurately reflect the amount ultimately earned by the employee. Refer to Note 6 of our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our stock-based compensation.

Performance share and performance unit awards

Our performance share awards are accounted for as equity awards and will be settled in stock subject to a combination of market and service vesting criteria. The fair value of the performance share awards issued during 2016, 2015 and 2014 were based on a projection of the performance of our stock price relative to our peer group utilized in a forward-looking Monte Carlo simulation. The fair values of the performance share awards are not re-measured after the initial valuation of the awards and are expensed on a straight-line basis over their respective three-year requisite service periods. Compensation expense for

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performance share awards is included in "General and administrative" expense in our consolidated statements of operations. Refer to Note 6.c of our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our performance share awards.

In prior periods, for performance unit awards issued to management, we utilized a Monte Carlo simulation prepared by an independent third party to determine the fair value of the awards at the grant date and to re-measure the fair value at the end of each reporting period until settlement in accordance with GAAP. The volatility criteria utilized in the Monte Carlo simulation is based on the stock prices' expected volatility. The performance unit awards are classified as liability awards as they have a combination of performance and service criteria and were settled in cash at the end of their respective three-year requisite service periods based on the achievement of certain performance criteria. The liability and related compensation expense for each period for these awards was recognized by dividing the fair value of the total liability by the requisite service period and recording the pro rata share for the period for which service has already been provided. Compensation expense for the performance units is included in "General and administrative" expense in our consolidated statements of operations. Refer to Note 6.e of our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our performance unit awards.

Recent accounting pronouncements

We adopted new guidance regarding the (i) accounting treatment of cloud computing arrangements that include or exclude a software license in the first quarter of 2016, (ii) simplification of income tax consequences to stock compensation awards in the third quarter of 2016, (iii) classification of certain cash receipts and cash payments on the consolidated statements of cash flows in the third quarter of 2016 and (iv) simplification of the measurement of inventory which was mainly included to change the subsequent measurement of inventory from lower of cost or market to NRV in the fourth quarter of 2016. For additional discussion of these early adoptions and other recent accounting pronouncements, see Note 18 to our consolidated financial statements included elsewhere in this Annual Report.

Inflation

Inflation in the U.S. has been relatively low in recent years and did not have a material impact on our results of operations for the period from December 31, 2014 through the year ended December 31, 2016. Although the impact of inflation has been insignificant in recent years, it continues to be a factor in the U.S. economy and historically, we have experienced inflationary pressure on the costs of oilfield services and equipment as drilling activity increases in the areas in which we operate.

Off-balance sheet arrangements

Currently, we do not have any off-balance sheet arrangements other than operating leases, drilling contracts and firm sale and transportation commitments, which are described in "—Obligations and commitments." See Notes 12.a, 12.c and 12.d to our consolidated financial statements included elsewhere in this Annual Report and "Item 1. Business—Our core assets—Midstream and marketing" for additional information.

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Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term "market risk," in our case, refers to the risk of loss arising from adverse changes in oil, NGL and natural gas prices and in interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for hedging purposes, rather than for speculative trading.

Commodity price exposure

Due to the inherent volatility in oil, NGL and natural gas prices, we use derivatives, such as puts, swaps, collars and, in prior periods, basis swaps, to hedge price risk associated with a significant portion of our anticipated production. By removing a portion of the price volatility associated with future production, we expect to reduce, but not eliminate, the potential effects of variability in cash flows from operations due to fluctuations in commodity prices. We have not elected hedge accounting on these derivatives and, therefore, the gains and losses on open positions are reflected in earnings. At each period end, we estimate the fair values of our derivatives using an independent third-party valuation and recognize the associated gain or loss in our consolidated statements of operations included elsewhere in this Annual Report.

The fair values of our derivatives are largely determined by estimates of the forward curves of the relevant price indices. As of December 31, 2016, a 10% change in the forward curves associated with our derivatives would have changed our net positions to the following amounts:

(in thousands)	10% Increase	10% Decrease
Derivatives	$(37,827)	$48,627

As of December 31, 2016 and 2015, the fair values of our open derivative contracts were $3.0 million and $276.2 million, respectively. Refer to Notes 2.f, 8 and 9 of our consolidated financial statements included elsewhere in this Annual Report for additional disclosures regarding our derivatives.

Interest rate risk

Our Senior Secured Credit Facility bears interest at a floating rate and, as of December 31, 2016, we had $70.0 million outstanding on our Senior Secured Credit Facility. Our January 2022 Notes, May 2022 Notes and March 2023 Notes bear fixed interest rates and we had $450.0 million, $500.0 million and $350.0 million outstanding, respectively, on these notes as of December 31, 2016, as shown in the table below.

	Expected maturity			
(in millions except for interest rates)	2018	2022	2023	Total
January 2022 Notes - fixed rate	$—	$450.0	$—	$450.0
Interest rate	—%	5.625 %	— %	5.625 %
May 2022 Notes - fixed rate	$—	$500.0	$—	$500.0
Interest rate	—%	7.375 %	— %	7.375 %
March 2023 Notes - fixed rate	$—	$—	$350.0	$350.0
Interest rate				