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.

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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						Year ended December 31, 2016
	Estimated net proved reserves[1]				Producing wells		
	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

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(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 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

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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,

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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 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.

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.

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.

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 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.