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

☒ **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 ☒ 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 ☒

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

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 ☒	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 ☒

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

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

Documents Incorporated by Reference:

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

Laredo Petroleum, Inc.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

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

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

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

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

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

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

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

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

"*BOE/D*"—BOE per day.

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

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

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

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

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

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

"*Exploratory well*"—A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

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

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

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

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

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

"*HBP*"—Acreage that is held by production.

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

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

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

"*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.

"*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.

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;

- 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.

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.

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.

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

	As of December 31, 2016						
	Estimated net proved reserves[1]				Producing wells		Year ended December 31, 2016 average daily production (BOE/D)
	MBOE	% of total reserves	% Oil	Net acreage	Gross	Net	
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.

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.

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

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

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

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

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

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

Corporate history and structure

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

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

Laredo Petroleum, Inc. is the borrower under our Fourth Amended and Restated Senior Secured Credit Facility (as amended, the "Senior Secured Credit Facility"), as well as the issuer of our $350 million of 6 1/4% senior unsecured notes due 2023 (the "March 2023 Notes"), our $500 million of 7 3/8% senior unsecured notes due 2022 (the "May 2022 Notes") and our $450 million of 5 5/8% senior unsecured notes due 2022 (the "January 2022 Notes"). We refer to the March 2023 Notes, the May 2022 Notes and the January 2022 Notes collectively as the "Senior Unsecured Notes." Our subsidiaries, LMS and GCM, are guarantors of the obligations under our Senior Secured Credit Facility and Senior Unsecured Notes. On April 6, 2015 (the "Redemption Date"), we used the proceeds of the March 2023 Notes offering to fund a portion of the complete redemption of the Company’s then outstanding $550 million of 9 1/2% senior unsecured notes due 2019 (the "January 2019 Notes") at a redemption price of 104.75% of the principal amount of such notes, plus accrued and unpaid interest.

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.

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 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

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	
	Proved reserves	% of total
Area:	(MBOE)	
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 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.

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

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				
	Gross			Net	
	Vertical	Horizontal	Total	Total	Average WI %
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		
	Gross	Net	Gross	Net	Gross	Net	% HBP
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%

Undeveloped acreage expirations

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

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

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

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

Drilling activity

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

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

Title to properties

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

Oil and natural gas leases

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

Seasonality

Demand for oil and natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Competition

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

Hydraulic fracturing

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

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

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

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

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

Regulation of the oil and natural gas industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, the production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. The State of Texas has regulations governing environmental and conservation matters, including provisions for the pooling of oil and natural gas properties, the permitting of allocation wells, the establishment of maximum allowable rates of production from oil and natural gas wells (including the proration of production to the market demand for oil and natural gas), the regulation of well spacing, the handling and disposing or discharge of waste materials and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, Texas imposes a production or severance tax with respect to the production and sale of oil, NGL and natural gas within its jurisdiction. Texas further regulates drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

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

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

Regulation of environmental and occupational health and safety matters

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

Hazardous substance and waste handling

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

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

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

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

Water and other waste discharges and spills

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

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

Hydraulic fracturing

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

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

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

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

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

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.

(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.

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.

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.

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

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 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.

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

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

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

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

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

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

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

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

These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or utilize specific equipment or technologies to control emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Our oil, NGL and natural gas is sold to a limited number of geographic markets which each have a fixed amount of storage and processing capacity. As a result, if such markets become oversupplied with oil, NGL and/or natural gas, it could have a material negative effect on the price we receive for our products and therefore an adverse effect on our financial condition. There is a risk that refining capacity in the U.S. Gulf Coast may be insufficient to refine all of the light sweet crude oil being produced in the United States. If light sweet crude oil production remains at current levels or continues to increase, demand for our light crude oil production could result in widening price discounts to the world crude prices and potential shut-in of production due to a lack of sufficient markets despite the lift on prior restrictions on the exporting of oil and natural gas.

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

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

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

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

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

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

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

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

A decrease in our production of oil, NGL and natural gas could negatively impact our ability to meet our contractual obligations to deliver oil, NGL and natural gas and our ability to retain our leases.

A portion of our oil, NGL and gas production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss or unavailability of pipeline or gathering system access and capacity, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions, including low oil, NGL and gas prices. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow. Furthermore, if we were required to shut in wells, we might also be obligated to pay shut-in royalties to certain mineral interest owners to maintain our leases.

In addition, we have entered into agreements with third party shippers, including Medallion, and purchasers that require us to deliver minimum amounts of crude oil and natural gas. Pursuant to these agreements, we must deliver specific amounts, either from our own production or from oil we acquire, over the next thirteen years. If we are unable to fulfill all of our contractual delivery obligations from our own production, we may be required to pay penalties or damages pursuant to these agreements or we may have to purchase oil from third parties to fulfill our delivery obligations. This could adversely impact our cash flows, profit margins and net income.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil, NGL and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil, NGL and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters; and
- terrorist attacks targeting oil, NGL and natural gas related facilities and infrastructure.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage and associated clean-up responsibilities;
- regulatory investigations, penalties or other sanctions;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

The marketability of our production is dependent upon transportation and other facilities, certain of which we do not control. If these facilities are unavailable, our operations could be interrupted and our revenues reduced.

The marketability of our oil, NGL and natural gas production depends on a variety of factors, including the availability, proximity, capacity and quality constraints of transportation and storage facilities owned by us or third parties. We do not control many of the trucks and other third-party transportation facilities necessary for the transportation of our products and our access to them may be limited or denied. Our failure to provide or obtain such services on acceptable terms could materially harm our business.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

We may incur significant additional amounts of debt.

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

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

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

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

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

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

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

Risks relating to our common stock

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

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

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

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

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

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

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

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

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

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

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

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

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

Item 1B. ***Unresolved Staff Comments***

Not applicable.

Item 2. ***Properties***

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

Item 3. ***Legal Proceedings***

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

Item 4. ***Mine Safety Disclosures***

Not applicable.

Part II

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

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

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

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

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

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

Repurchase of Equity Securities.

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

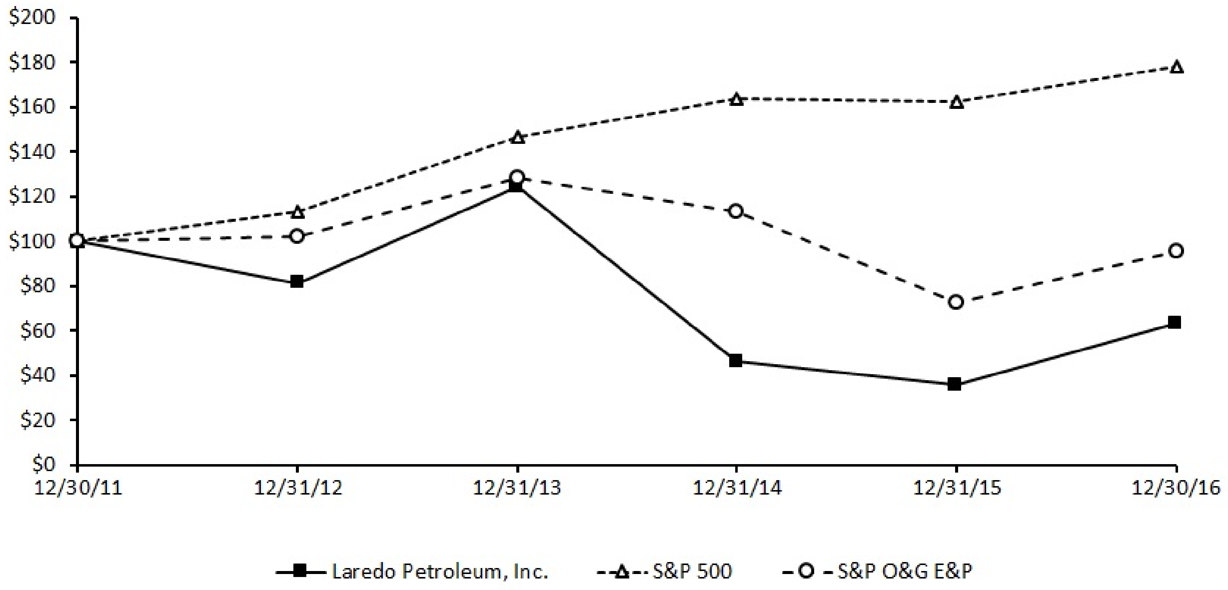
(1) Represents shares that were withheld by us to satisfy employee tax withholding obligations that arose upon the lapse of restrictions on restricted stock.

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

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

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

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



Item 6. ***Selected Historical Financial Data***

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

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

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

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

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

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

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

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

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

Non-GAAP financial measure

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

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

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

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

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

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

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

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

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

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

Executive overview

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

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

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

Recent developments

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

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

Acquisitions

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

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

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

2016 equity offerings

May 2016 equity offering

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

July 2016 equity offering

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

Senior Secured Credit Facility reaffirmation

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

Pricing, reserves and non-cash full cost ceiling impairment

Our results of operations are heavily influenced by oil, NGL and natural gas prices. Oil, NGL and natural gas price fluctuations are caused by changes in global and regional supply and demand, market uncertainty, economic conditions and a variety of additional factors. Historically, commodity prices have experienced significant fluctuations, and additional changes in commodity prices may affect the economic viability of, and our ability to fund, our drilling projects, as well as the economic valuation and economic recovery of oil, NGL and natural gas reserves.

We have entered into a number of derivative contracts that have enabled us to offset a portion of the changes in our cash flow caused by price fluctuations for our sales of oil, NGL and natural gas as discussed in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

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

Our net book value of evaluated oil and natural gas properties did not exceed the full cost ceiling amount as of

December 31, 2016, September 30, 2016 or June 30, 2016. Our net book value of evaluated oil and natural gas properties exceeded the full cost ceiling amount as of March 31, 2016 and as a result, we recorded a non-cash full cost ceiling impairment of $161.1 million. Oil, NGL and natural gas prices have somewhat stabilized in comparison to prices during 2016. However, if these prices decline from the current levels or if adverse economic conditions occur (such as increases in drilling production and/or service costs) we could incur future full cost ceiling impairments. See Note 2.g to our consolidated financial statements included elsewhere in this Annual Report for prices used to value our reserves and additional discussion of our full cost impairments in the first quarter of 2016 and in prior periods.

Core area of operations

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

Sources of our revenue

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

Principal components of our cost structure

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

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

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

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

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

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

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

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

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

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

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

Other income (expense)

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

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

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

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

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

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

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

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

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

Results of operations consolidated

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Costs and expenses

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Results of operations - midstream and marketing

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Liquidity and capital resources

Our primary sources of liquidity have been cash flows from operations, proceeds from equity offerings, proceeds from senior unsecured note offerings, borrowings under our Senior Secured Credit Facility and proceeds from asset dispositions. We believe cash flows from operations (including our hedging program) and availability under our Senior Secured Credit Facility provide sufficient liquidity to manage our cash needs and contractual obligations and to fund expected capital expenditures. Our primary operational uses of capital have been for the acquisition, exploration and development of oil and natural gas properties, LMS' infrastructure development and investments in Medallion.

A significant portion of our capital expenditures can be adjusted and managed by us. We continually monitor the capital markets and our capital structure and consider which financing alternatives, including equity and debt capital resources, joint ventures and asset sales, are available to meet our future planned or accelerated capital expenditures. We may make changes to our capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity and/or achieving cost efficiency. Such financing alternatives, including capital market transactions and debt repurchases, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material. See Notes 3, 4.b and 5 to our consolidated financial statements included elsewhere in this Annual Report regarding our current year and prior year equity offerings, prior year divestiture and debt (including our prior year debt redemption), respectively.

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

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

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

Cash flows

Our cash flows for the periods presented are as follows:

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

Cash flows provided by operating activities

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

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

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

Cash flows used in investing activities

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

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

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

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

Capital budget

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

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

Cash flows provided by financing activities

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

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

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

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

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

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

Debt

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Obligations and commitments

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

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

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

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

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

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

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

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

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

Critical accounting policies and estimates

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

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

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

Method of accounting for oil and natural gas properties

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

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

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

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

Impairment of oil and natural gas properties

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

Revenue recognition

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

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

Income taxes

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

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

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

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

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

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

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

Variable interest entities

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

Asset retirement obligations ("ARO")

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

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

Derivatives

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

Stock-based compensation

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

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

Performance share and performance unit awards

Our performance share awards are accounted for as equity awards and will be settled in stock subject to a combination of market and service vesting criteria. The fair value of the performance share awards issued during 2016, 2015 and 2014 were based on a projection of the performance of our stock price relative to our peer group utilized in a forward-looking Monte Carlo simulation. The fair values of the performance share awards are not re-measured after the initial valuation of the awards and are expensed on a straight-line basis over their respective three-year requisite service periods. Compensation expense for performance share awards is included in "General and administrative" expense in our consolidated statements of operations. Refer to Note 6.c of our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our performance share awards.

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

Recent accounting pronouncements

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

Inflation

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

Off-balance sheet arrangements

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

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

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

Commodity price exposure

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

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

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

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

Interest rate risk

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

	Expected maturity			
(in millions except for interest rates)	2018	2022	2023	Total
January 2022 Notes - fixed rate	$ —	$ 450.0	$ —	$ 450.0
Interest rate	—%	5.625%	—%	5.625%
May 2022 Notes - fixed rate	$ —	$ 500.0	$ —	$ 500.0
Interest rate	—%	7.375%	—%	7.375%
March 2023 Notes - fixed rate	$ —	$ —	$ 350.0	$ 350.0
Interest rate	—%	—%	6.250%	6.250%
Senior Secured Credit Facility - variable rate	$ 70.0	$ —	$ —	$ 70.0
Average interest rate(1)	2.026%	—%	—%	2.026%

(1) For the year ended December 31, 2016.

Counterparty and customer credit risk

As of December 31, 2016, our principal exposures to credit risk were through receivables of (i) $47.0 million from the sale of our oil, NGL and natural gas production that we market to energy marketing companies and refineries, (ii) $29.7 million from the fair values of our open derivative contracts, (iii) $16.2 million from sales of purchased oil and other products, (iv) $12.2 million from joint-interest partners and (v) $11.1 million from matured derivatives.

We are subject to credit risk due to the concentration of (i) our oil, NGL and natural gas receivables with three significant customers and (ii) our purchased oil receivable with one significant customer. On occasion we require our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

We have entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of our derivative counterparties, each of whom is also a lender in our Senior Secured Credit Facility. The terms of the ISDA Agreements provide the non-defaulting or non-affected party the right to terminate the agreement upon the occurrence of certain events of default and termination events by a party and also provide for the marking to market of outstanding positions and the offset of the mark to market amounts owed to and by the parties (and in certain cases, the affiliates of the non-defaulting or non-affected party) upon termination.

Refer to Note 11 to our consolidated financial statements included elsewhere in this Annual Report for additional disclosures regarding credit risk.

Item 8. ***Financial Statements and Supplementary Data***

Our consolidated financial statements and supplementary financial data are included in this Annual Report beginning on page F-1.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2016, management assessed the effectiveness of the Company's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in the 2013 "Internal Control - Integrated Framework," issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment and those criteria, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2016.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Grant Thornton LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report, has issued their report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2016. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2016, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Laredo Petroleum, Inc.

We have audited the internal control over financial reporting of Laredo Petroleum, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2016, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended December 31, 2016, and our report dated February 16, 2017 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 16, 2017

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

We had no changes in, and no disagreements with, our accountants on accounting and financial disclosure.

Item 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of December 31, 2016 at the reasonable assurance level.

Design and Evaluation of Internal Control Over Financial Reporting. Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, our management has included a report of their assessment of the design and effectiveness of our internal controls over financial reporting as part of this Annual Report for the fiscal year ended December 31, 2016. Grant Thornton LLP, the Company's independent registered public accounting firm, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting. Management’s report and the independent registered public accounting firm's attestation report are included in "Item 8. Financial Statements and Supplementary Data" in this Annual Report under the caption entitled "Management’s Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm," respectively, and are incorporated herein by reference.

Changes in Internal Control over Financial Reporting. There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

Item 9B. ***Other Information***

None.

Part III

Item 10. *Directors, Executive Officers and Corporate Governance*

Information regarding our Code of Conduct and Business Ethics, Code of Ethics For Senior Financial Officers and Corporate Governance Guidelines for our principal executive officer and principal financial and accounting officer are described in "Item 1. Business" in this Annual Report. Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 10 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2016.

Item 11. *Executive Compensation*

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 11 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2016.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 12 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2016.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 13 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2016.

Item 14. *Principal Accounting Fees and Services*

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 14 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2016.

Part IV

Item 15. *Exhibits, Financial Statement Schedules*

(a)(1) Financial Statements

Our consolidated financial statements are included under Part II, Item 8 of this Annual Report. For a listing of these statements and accompanying footnotes, see "Index to Consolidated Financial Statements" on page F-1 of this Annual Report.

(a)(2) Financial Statement Schedules

All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(a)(3) Exhibits

Exhibit Number	Description
2.1	Agreement and Plan of Merger by and between Laredo Petroleum, LLC and Laredo Petroleum Holdings, Inc., dated as of December 19, 2011 (incorporated by reference to Exhibit 2.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
3.1	Amended and Restated Certificate of Incorporation of Laredo Petroleum Holdings, Inc. (incorporated by reference to Exhibit 3.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
3.2	Certificate of Ownership and Merger, dated as of December 30, 2013 (incorporated by reference to Exhibit 3.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on January 6, 2014).
3.3	Second Amended and Restated Bylaws of Laredo Petroleum, Inc. (incorporated by reference to Exhibit 3.3 of Laredo's Annual Report on Form 10-K (File No. 001-35380) filed on February 17, 2016).
4.1	Form of Common Stock Certificate (incorporated by reference to Exhibit 4.1 of Laredo's Registration Statement on Form 8-A12B/A (File No. 001-35380) filed on January 7, 2014).
4.2	Amended and Restated Indenture, dated as of June 24, 2014, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 of Laredo's Quarterly Report on Form 10-Q (File No. 001-35380) filed on August 7, 2014).
4.3	Sixth Supplemental Indenture, dated as of December 3, 2014, among Laredo Petroleum, Inc., Garden City Minerals, LLC, Laredo Midstream Services, LLC and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 of Laredo’s Annual Report on Form 10-K (File No. 001-35380) filed on February 26, 2015).
4.4	Indenture, dated as of April 27, 2012, among Laredo Petroleum, Inc., the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on April 30, 2012).
4.5	Second Supplemental Indenture, dated as of December 31, 2013, among Laredo Petroleum Holdings, Inc., Laredo Petroleum, Inc., Laredo Midstream Services, LLC and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on January 6, 2014).
4.6	Amended and Restated Supplemental Indenture, dated as of June 24, 2014, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 of Laredo's Quarterly Report on Form 10-Q (File No. 001-35380) filed on August 7, 2014).

Exhibit Number	Description
4.7	Fourth Supplemental Indenture, dated as of December 3, 2014, among Laredo Petroleum, Inc., Garden City Minerals, LLC, Laredo Midstream Services, LLC and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.7 of Laredo’s Annual Report on Form 10-K (File No. 001-35380) filed on February 26, 2015).
4.8	Indenture, dated as of January 23, 2014, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on January 24, 2014).
4.9	First Supplemental Indenture, dated as of December 3, 2014, among Laredo Petroleum, Inc., Garden City Minerals, LLC, Laredo Midstream Services, LLC and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.9 of Laredo’s Annual Report on Form 10-K (File No. 001-35380) filed on February 26, 2015).
4.10	Indenture, dated as of March 18, 2015, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC, Garden City Minerals, LLC and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 of Laredo’s Current Report on Form 8-K (File No. 001-35380) filed on March 24, 2015).
4.11	First Supplemental Indenture, dated as of March 18, 2015, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC, Garden City Minerals, LLC and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 of Laredo’s Current Report on Form 8-K (File No. 001-35380) filed on March 24, 2015).
10.1	Fourth Amended and Restated Credit Agreement, dated as of December 31, 2013, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the other financial institutions signatory thereto (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on January 6, 2014).
10.2	First Amendment to Fourth Amended and Restated Credit Agreement, dated as of January 31, 2014, among Laredo Petroleum, Inc., Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and the banks signatory thereto (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on February 4, 2014).
10.3	Second Amendment to Fourth Amended and Restated Credit Agreement, dated as of May 8, 2014, among Laredo Petroleum, Inc., Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and the banks signatory thereto (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on May 8, 2014).
10.4	Third Amendment to Fourth Amended and Restated Credit Agreement, dated as of May 4, 2015, among Laredo Petroleum, Inc., Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC, Garden City Minerals, LLC and the banks signatory thereto (incorporated by reference to Exhibit 10.3 of Laredo’s Quarterly Report on Form 10-Q (File No. 001-35380) filed on May 7, 2015).
10.5	Fourth Amendment to Fourth Amended and Restated Credit Agreement, dated as of October 30, 2015, among Laredo Petroleum, Inc., Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC, Garden City Minerals, LLC and the banks signatory thereto (incorporated by reference to Exhibit 10.1 of Laredo’s Quarterly Report on Form 10-Q (File No. 001-35380) filed on November 5, 2015).
10.6	Waiver Letter to Fourth Amended and Restated Credit Agreement, dated as of March 3, 2015, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the banks signatory thereto (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on March 4, 2015).
10.7	Memorandum of Borrowing Base Reduction, dated May 2, 2016, from Wells Fargo Bank, N.A. to Laredo Petroleum, Inc. (incorporated by reference to Exhibit 10.1 of Laredo's Quarterly Report on Form 10-Q (File No. 001-35380) filed on May 5, 2016).
10.8	Form of Registration Rights Agreement dated December 20, 2011 among Laredo Petroleum Holdings, Inc. and the signatories thereto (incorporated by reference to Exhibit 10.5 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
10.9#	Form of Indemnification Agreement between Laredo Petroleum Holdings, Inc. and each of the officers and directors thereof (incorporated by reference to Exhibit 10.6 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
10.10#	Laredo Petroleum, Inc. Omnibus Equity Incentive Plan, as amended and restated as of March 30, 2016 (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on May 25, 2016).

Exhibit Number	Description
10.11#	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on February 9, 2012).
10.12#	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.3 of Laredo's Quarterly Report on Form 10-Q (File No. 001-35380) filed on August 9, 2012).
10.13#	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.2 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on May 25, 2016).
10.14#	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.2 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on February 9, 2012).
10.15#	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.3 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on May 25, 2016).
10.16#	Form of Performance Compensation Award Agreement (incorporated by reference to Exhibit 10.3 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on February 9, 2012).
10.17#	Form of Performance Share Unit Award Agreement (incorporated by reference to Exhibit 10.4 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on May 25, 2016).
10.18#*	Laredo Petroleum, Inc. Change in Control Executive Severance Plan, as amended June 21, 2015, December 14, 2015 and September 9, 2016.
10.19#	Form of 2013 Performance Compensation Award Agreement (incorporated by reference to Exhibit 10.16 of Laredo's Annual Report on Form 10-K (File No. 001-35380) filed on March 12, 2013).
10.20	Non-Exclusive Aircraft Lease Agreement, dated January 1, 2015 between Lariat Ranch, LLC and Laredo Petroleum, Inc. (incorporated by reference to Exhibit 10.14 of Laredo’s Annual Report on Form 10-K (File No. 001-35380) filed on February 26, 2015).
21.1*	List of Subsidiaries of Laredo Petroleum, Inc.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Ryder Scott Company, L.P.
31.1*	Certification of Chief Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
31.2*	Certification of Chief Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
32.1**	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18. U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Summary Report of Ryder Scott Company, L.P.
101.INS*	XBRL Instance Document.
101.CAL*	XBRL Schema Document.
101.SCH*	XBRL Calculation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.
101.LAB*	XBRL Labels Linkbase Document.
101.PRE*	XBRL Presentation Linkbase Document.

* Filed herewith.
** Furnished herewith.
# Management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

LAREDO PETROLEUM, INC.

Date: February 16, 2017

By: /s/ Randy A. Foutch

Randy A. Foutch
Chief Executive Officer

KNOWN ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Randy A. Foutch, Richard C. Buterbaugh, Kenneth E. Dornblaser and Michael T. Beyer, each of whom may act without joinder of the other, as their true and lawful attorneys-in-fact and agents, each with full power of substitution and resubstitution, for such person and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signatures	Title	Date
/s/ Randy A. Foutch Randy A. Foutch	Chairman and Chief Executive Officer (principal executive officer)	2/16/2017
/s/ Richard C. Buterbaugh Richard C. Buterbaugh	Executive Vice President and Chief Financial Officer (principal financial officer)	2/16/2017
/s/ Michael T. Beyer Michael T. Beyer	Vice President - Controller and Chief Accounting Officer (principal accounting officer)	2/16/2017
/s/ Peter R. Kagan Peter R. Kagan	Director	2/16/2017
/s/ James R. Levy James R. Levy	Director	2/16/2017
/s/ B.Z. (Bill) Parker B.Z. (Bill) Parker	Director	2/16/2017
/s/ Pamela S. Pierce Pamela S. Pierce	Director	2/16/2017
/s/ Dr. Myles W. Scoggins Dr. Myles W. Scoggins	Director	2/16/2017
/s/ Edmund P. Segner, III Edmund P. Segner, III	Director	2/16/2017
/s/ Donald D. Wolf Donald D. Wolf	Director	2/16/2017

LAREDO PETROLEUM, INC.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Laredo Petroleum, Inc.

We have audited the accompanying consolidated balance sheets of Laredo Petroleum, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Laredo Petroleum, Inc. and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 16, 2017 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 16, 2017

Laredo Petroleum, Inc.
Consolidated balance sheets
(in thousands, except share data)

	December 31, 2016	December 31, 2015
Assets		
Current assets:		
Cash and cash equivalents	$ 32,672	$ 31,154
Accounts receivable, net	86,867	87,699
Derivatives	20,947	198,805
Other current assets	14,291	14,574
Total current assets	154,777	332,232
Property and equipment:		
Oil and natural gas properties, full cost method:		
Evaluated properties	5,488,756	5,103,635
Unevaluated properties not being depleted	221,281	140,299
Less accumulated depletion and impairment	(4,514,183)	(4,218,942)
Oil and natural gas properties, net	1,195,854	1,024,992
Midstream service assets, net	126,240	131,725
Other fixed assets, net	44,773	43,538
Property and equipment, net	1,366,867	1,200,255
Derivatives	8,718	77,443
Investment in equity method investee	243,953	192,524
Other assets, net	8,031	10,833
Total assets	$ 1,782,346	$ 1,813,287
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable	$ 15,054	$ 14,181
Undistributed revenue and royalties	26,838	34,540
Accrued capital expenditures	30,845	61,872
Derivatives	20,993	—
Other current liabilities	94,215	106,222
Total current liabilities	187,945	216,815
Long-term debt, net	1,353,909	1,416,226
Derivatives	5,694	—
Asset retirement obligations	50,604	44,759
Other noncurrent liabilities	3,621	4,040
Total liabilities	1,601,773	1,681,840
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $0.01 par value, 50,000,000 shares authorized and zero issued as of December 31, 2016 and 2015	—	—
Common stock, $0.01 par value, 450,000,000 shares authorized and 241,929,070 and 213,808,003 issued and outstanding as of December 31, 2016 and 2015, respectively	2,419	2,138
Additional paid-in capital	2,396,236	2,086,652
Accumulated deficit	(2,218,082)	(1,957,343)
Total stockholders' equity	180,573	131,447
Total liabilities and stockholders' equity	$ 1,782,346	$ 1,813,287

The accompanying notes are an integral part of these consolidated financial statements.

Laredo Petroleum, Inc.
Consolidated statements of operations
(in thousands, except per share data)

	For the years ended December 31,		
	2016	2015	2014
Revenues:			
Oil, NGL and natural gas sales	$ 426,485	$ 431,734	$ 737,203
Midstream service revenues	8,342	6,548	2,245
Sales of purchased oil	162,551	168,358	54,437
Total revenues	597,378	606,640	793,885
Costs and expenses:			
Lease operating expenses	75,327	108,341	96,503
Production and ad valorem taxes	28,586	32,892	50,312
Midstream service expenses	4,077	5,846	5,429
Minimum volume commitments	2,209	5,235	2,552
Costs of purchased oil	169,536	174,338	53,967
Drilling rig fees	—	—	527
General and administrative	91,756	90,425	106,044
Restructuring expenses	—	6,042	—
Accretion of asset retirement obligations	3,483	2,423	1,787
Depletion, depreciation and amortization	148,339	277,724	246,474
Impairment expense	162,027	2,374,888	3,904
Total costs and expenses	685,340	3,078,154	567,499
Operating income (loss)	(87,962)	(2,471,514)	226,386
Non-operating income (expense):			
Gain (loss) on derivatives, net	(87,425)	214,291	327,920
Income (loss) from equity method investee	9,403	6,799	(192)
Interest expense	(93,298)	(103,219)	(121,173)
Interest and other income	175	426	294
Loss on early redemption of debt	—	(31,537)	—
Write-off of debt issuance costs	(842)	—	(124)
Loss on disposal of assets, net	(790)	(2,127)	(3,252)
Non-operating income (expense), net	(172,777)	84,633	203,473
Income (loss) before income taxes	(260,739)	(2,386,881)	429,859
Income tax benefit (expense):			
Deferred	—	176,945	(164,286)
Total income tax benefit (expense)	—	176,945	(164,286)
Net income (loss)	$ (260,739)	$ (2,209,936)	$ 265,573
Net income (loss) per common share:			
Basic	$ (1.16)	$ (11.10)	$ 1.88
Diluted	$ (1.16)	$ (11.10)	$ 1.85
Weighted-average common shares outstanding:			
Basic	225,512	199,158	141,312
Diluted	225,512	199,158	143,554

The accompanying notes are an integral part of these consolidated financial statements.

Laredo Petroleum, Inc.
Consolidated statements of stockholders' equity
(in thousands)

	Common Stock		Additional paid-in capital	Treasury Stock (at cost)		(Accumulated deficit) retained earnings	Total
	Shares	Amount		Shares	Amount		
Balance, December 31, 2013	142,671	$ 1,427	$ 1,283,809	—	$ —	$ (12,980)	$ 1,272,256
Restricted stock awards	1,234	12	(12)	—	—	—	—
Restricted stock forfeitures	(148)	(1)	1	—	—	—	—
Vested restricted stock exchanged for tax withholding	—	—	—	166	(4,242)	—	(4,242)
Retirement of treasury stock	(166)	(2)	(4,240)	(166)	4,242	—	—
Exercise of employee stock options	95	1	1,884	—	—	—	1,885
Stock-based compensation	—	—	27,729	—	—	—	27,729
Net income	—	—	—	—	—	265,573	265,573
Balance, December 31, 2014	143,686	1,437	1,309,171	—	—	252,593	1,563,201
Restricted stock awards	1,902	19	(19)	—	—	—	—
Restricted stock forfeitures	(553)	(6)	6	—	—	—	—
Vested restricted stock exchanged for tax withholding	—	—	—	227	(2,811)	—	(2,811)
Retirement of treasury stock	(227)	(2)	(2,809)	(227)	2,811	—	—
Equity issuance, net of offering costs	69,000	690	753,473	—	—	—	754,163
Stock-based compensation	—	—	26,830	—	—	—	26,830
Net loss	—	—	—	—	—	(2,209,936)	(2,209,936)
Balance, December 31, 2015	213,808	2,138	2,086,652	—	—	(1,957,343)	131,447
Restricted stock awards	2,982	30	(30)	—	—	—	—
Restricted stock forfeitures	(457)	(5)	5	—	—	—	—
Vested restricted stock exchanged for tax withholding	—	—	—	296	(1,635)	—	(1,635)
Retirement of treasury stock	(296)	(3)	(1,632)	(296)	1,635	—	—
Exercise of employee stock options	17	—	208	—	—	—	208
Equity issuances, net of offering costs	25,875	259	275,793	—	—	—	276,052
Stock-based compensation	—	—	35,240	—	—	—	35,240
Net loss	—	—	—	—	—	(260,739)	(260,739)
Balance, December 31, 2016	241,929	$ 2,419	$ 2,396,236	—	$ —	$ (2,218,082)	$ 180,573

The accompanying notes are an integral part of these consolidated financial statements.

Laredo Petroleum, Inc.
Consolidated statements of cash flows
(in thousands)

	For the years ended December 31,		
	2016	2015	2014
Cash flows from operating activities:			
Net income (loss)	$ (260,739)	$ (2,209,936)	$ 265,573
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred income tax (benefit) expense	—	(176,945)	164,286
Depletion, depreciation and amortization	148,339	277,724	246,474
Impairment expense	162,027	2,374,888	3,904
Loss on early redemption of debt	—	31,537	—
Bad debt expense	—	255	342
Non-cash stock-based compensation, net of amounts capitalized	29,229	24,509	23,079
Mark-to-market on derivatives:			
(Gain) loss on derivatives, net	87,425	(214,291)	(327,920)
Cash settlements received for matured derivatives, net	195,281	255,281	28,241
Cash settlements received for early terminations of derivatives, net	80,000	—	76,660
Change in net present value of derivative deferred premiums	232	203	220
Cash premiums paid for derivatives	(89,669)	(5,167)	(7,419)
Amortization of debt issuance costs	4,279	4,727	5,137
Write-off of debt issuance costs	842	—	124
(Income) loss from equity method investee	(9,403)	(6,799)	192
Cash settlement of performance unit awards	(6,394)	(2,738)	—
Other, net	4,596	4,554	5,442
Decrease (increase) in accounts receivable	832	38,975	(49,953)
Increase in other assets	(1,013)	(2,309)	(16,688)
Increase (decrease) in accounts payable	873	(24,827)	23,006
(Decrease) increase in undistributed revenues and royalties	(7,735)	(30,898)	30,314
Increase (decrease) in other accrued liabilities	17,712	(26,996)	23,837
(Decrease) increase in other noncurrent liabilities	(419)	119	2,825
Increase in fair value of performance unit awards	—	4,081	601
Net cash provided by operating activities	356,295	315,947	498,277
Cash flows from investing activities:			
Deposit received for sale of oil and natural gas properties	3,000	—	—
Capital expenditures:			
Acquisitions of oil and natural gas properties	(124,660)	—	(6,493)
Acquisition of mineral interests	—	—	(7,305)
Oil and natural gas properties	(360,679)	(588,017)	(1,251,757)
Midstream service assets	(5,240)	(35,459)	(60,548)
Other fixed assets	(7,611)	(9,125)	(27,444)
Investment in equity method investee	(69,609)	(99,855)	(55,164)
Proceeds from dispositions of capital assets, net of selling costs	397	64,949	1,750
Net cash used in investing activities	(564,402)	(667,507)	(1,406,961)
Cash flows from financing activities:			
Borrowings on Senior Secured Credit Facility	239,682	310,000	300,000
Payments on Senior Secured Credit Facility	(304,682)	(475,000)	—
Issuance of March 2023 Notes	—	350,000	—
Issuance of January 2022 Notes	—	—	450,000
Redemption of January 2019 Notes	—	(576,200)	—
Proceeds from issuance of common stock, net of offering costs	276,052	754,163	—
Purchase of treasury stock	(1,635)	(2,811)	(4,242)
Proceeds from exercise of employee stock options	208	—	1,885
Payments for debt issuance costs	—	(6,759)	(7,791)
Net cash provided by financing activities	209,625	353,393	739,852
Net increase (decrease) in cash and cash equivalents	1,518	1,833	(168,832)
Cash and cash equivalents, beginning of period	31,154	29,321	198,153
Cash and cash equivalents, end of period	$ 32,672	$ 31,154	$ 29,321

The accompanying notes are an integral part of these consolidated financial statements.

Note 1—Organization

Laredo Petroleum, Inc. ("Laredo"), together with its wholly-owned subsidiaries, Laredo Midstream Services, LLC ("LMS") and Garden City Minerals, LLC ("GCM"), 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. LMS and GCM (together, the "Guarantors") guarantee all of Laredo's debt instruments. In these notes, the "Company" refers to Laredo, LMS and GCM collectively, unless the context indicates otherwise. All amounts, dollars and percentages presented in these consolidated financial statements and the related notes are rounded and therefore approximate.

The Company operates in two business segments: (i) exploration and production and (ii) midstream and marketing. The exploration and production segment is engaged in the acquisition, exploration and development of oil and natural gas properties. The midstream and marketing segment provides Laredo's exploration and production segment and third parties with products and services that need to be delivered by midstream infrastructure, including oil and natural gas gathering services as well as rig fuel, natural gas lift and water delivery and takeaway.

Note 2—Basis of presentation and significant accounting policies

a. Basis of presentation

The accompanying consolidated financial statements were derived from the historical accounting records of the Company and reflect the historical financial position, results of operations and cash flows for the periods described herein. The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). All material intercompany transactions and account balances have been eliminated in the consolidation of accounts. Unless otherwise indicated, the information in these notes relates to the Company's continuing operations. The Company uses the equity method of accounting to record its net interests when the Company holds 20% to 50% of the voting rights and/or has the ability to exercise significant influence but does not control the entity. Under the equity method, the Company's proportionate share of the investee's net income (loss) is included in the consolidated statements of operations. See Note 14 for additional discussion of the Company's equity method investment.

b. Use of estimates in the preparation of consolidated financial statements

The preparation of the accompanying consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions about future events. These estimates and the underlying assumptions affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Although management believes these estimates are reasonable, actual results could differ.

Significant estimates include, but are not limited to, (i) estimates of the Company's reserves of oil, natural gas liquids ("NGL") and natural gas, (ii) future cash flows from oil and natural gas properties, (iii) depletion, depreciation and amortization, (iv) impairments, (v) asset retirement obligations, (vi) stock-based compensation, (vii) deferred income taxes, (viii) fair value of assets acquired and liabilities assumed in an acquisition and (ix) fair values of derivatives, deferred premiums and performance unit awards. As fair value is a market-based measurement, it is determined based on the assumptions that would be used by market participants. These estimates and assumptions are based on management's best judgment. Management evaluates its estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic environment. Such estimates and assumptions are adjusted when facts and circumstances dictate. Illiquid credit markets and volatile equity and energy markets have combined to increase the uncertainty inherent in such estimates and assumptions. Management believes its estimates and assumptions to be reasonable under the circumstances. As future events and their effects cannot be determined with precision, actual values and results could differ from these estimates. Any changes in estimates resulting from future changes in the economic environment will be reflected in the financial statements in future periods.

c. Reclassifications

Certain amounts in the accompanying consolidated financial statements have been reclassified to conform to the 2016 presentation. These reclassifications had no impact to previously reported balance sheets, net income (loss) or stockholders' equity.

d. Cash and cash equivalents

The Company defines cash and cash equivalents to include cash on hand, cash in bank accounts and highly liquid investments with original maturities of three months or less. The Company maintains cash and cash equivalents in bank deposit accounts and money market funds that may not be federally insured. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk on such accounts. See Note 11 for discussion regarding the Company's exposure to credit risk.

e. Accounts receivable

The Company sells produced oil, NGL and natural gas and purchased oil to various customers and participates with other parties in the development and operation of oil and natural gas properties. The Company's accounts receivable are generally unsecured. Accounts receivable for joint interest billings are recorded as amounts billed to customers less an allowance for doubtful accounts.

The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses, current receivables aging and existing industry and economic data. The Company reviews its allowance for doubtful accounts quarterly. Past due amounts greater than 90 days and over a specified amount are reviewed individually for collectability. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential for recovery is remote.

Accounts receivable consisted of the following components as of December 31:

(in thousands)	2016	2015
Oil, NGL and natural gas sales	$ 46,999	$ 25,582
Sales of purchased oil and other products	16,213	11,775
Joint operations, net(1)	12,175	21,375
Matured derivatives	11,059	27,469
Other	421	1,498
Total	$ 86,867	$ 87,699

(1) Accounts receivable for joint operations are presented net of an allowance for doubtful accounts of $0.2 million as of December 31, 2016 and 2015. As the operator of the majority of its wells, the Company has the ability to realize some or all of these receivables through the netting of production revenues.

f. Derivatives

The Company uses derivatives to reduce exposure to fluctuations in the prices of oil, NGL and natural gas. By removing a significant portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flows from operations due to fluctuations in commodity prices. These transactions are in the form of puts, swaps, collars and, in prior periods, basis swaps.

Derivatives are recorded at fair value and are presented on a net basis on the consolidated balance sheets as assets or liabilities. The Company nets the fair value of derivatives by counterparty where the right of offset exists. The Company determines the fair value of its derivatives by utilizing pricing models for substantially similar instruments. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. See Note 9 for discussion regarding the fair value of the Company's derivatives.

The Company's derivatives were not designated as hedges for accounting purposes for any of the periods presented. Accordingly, the changes in fair value are recognized in the consolidated statements of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities. See Notes 8 and 9 for discussion regarding the Company's derivatives.

g. Oil and natural gas properties

The Company uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs incurred for the purpose of exploring for or developing oil, NGL and natural gas properties, are capitalized and depleted on a composite unit of production method based on proved oil, NGL and natural gas reserves. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals and other costs related to such activities. Costs, including related employee costs, associated with production and general corporate activities are expensed in the period incurred. Sales of oil and natural gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil, NGL and natural gas.

The Company computes the provision for depletion of oil and natural gas properties using the units of production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the depletion base until the properties associated with these costs are evaluated. Approximately $221.3 million and $140.3 million of such costs were excluded from the depletion base as of December 31, 2016 and 2015, respectively. The depletion base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values. Total accumulated depletion and impairment for oil and natural gas properties was $4.5 billion and $4.2 billion for the years ended December 31, 2016 and 2015, respectively. Depletion expense for oil and natural gas properties was $134.1 million, $263.7 million and $237.1 million for the years ended December 31, 2016, 2015 and 2014, respectively. Depletion per barrel of oil equivalent for the Company's oil and natural gas properties was $7.39, $16.13 and $20.21 for the years ended December 31, 2016, 2015 and 2014, respectively.

The following table presents capitalized employee-related costs for the periods presented:

	For the years ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Capitalized employee-related costs	$ 19,222	$ 10,688	$ 16,345

The Company excludes the costs directly associated with acquisition and evaluation of unevaluated properties from the depletion calculation until it is determined whether or not proved reserves can be assigned to the properties. The Company capitalizes a portion of its interest costs to its unevaluated properties. Capitalized interest becomes a part of the cost of the unevaluated properties and is subject to depletion when proved reserves can be assigned to the associated properties. All items classified as unevaluated property are assessed on a quarterly basis for possible impairment. See Note 20.b for further information regarding unevaluated property costs. The assessment includes consideration of the following factors, among others: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of evaluated reserves and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion.

The full cost ceiling is based principally on the estimated future net revenues from proved oil and natural gas properties discounted at 10%. The Securities and Exchange Commission ("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 utilized to calculate the discounted future net revenues in the full cost ceiling calculation.

In the event the unamortized cost of evaluated oil and natural gas properties being depleted exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period such excess occurs. Once incurred, a write-down of oil and natural gas properties is not reversible.

The following table presents the Benchmark Prices and Realized Prices as of the dates presented:

	December 31, 2016	December 31, 2015	December 31, 2014[1]
Benchmark Prices:			
Oil ($/Bbl)	$ 39.25	$ 46.79	$ 91.48
NGL ($/Bbl)	$ 18.24	$ 18.75	$ —
Natural gas ($/MMBtu)	$ 2.33	$ 2.47	$ 4.25
Realized Prices:			
Oil ($/Bbl)	$ 37.44	$ 45.58	$ 89.57
NGL ($/Bbl)	$ 11.72	$ 12.50	$ —
Natural gas ($/Mcf)	$ 1.78	$ 1.89	$ 6.39

(1) For periods prior to January 1, 2015, the Company presented reserves 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 prior periods.

Full cost ceiling impairment expense for the years ended December 31, 2016 and 2015 in the consolidated statements of operations was $161.1 million and $2.4 billion, respectively. There were no full cost ceiling impairments recorded during the year ended December 31, 2014. These amounts are included in the "Impairment expense" line item in the consolidated statements of operations and in the financial information provided for the Company's exploration and production segment presented in Note 16.

h. Midstream service assets

Midstream service assets, which consist of oil and natural gas pipeline gathering assets, related equipment, oil delivery stations, water storage and treatment facilities and their related asset retirement cost, are recorded at cost, net of impairment. See Note 2.m for discussion regarding midstream service asset retirement cost. Depreciation of assets is recorded using the straight-line method based on estimated useful lives of 10 to 20 years, as applicable. Expenditures for significant betterments or renewals, which extend the useful lives of existing fixed assets, are capitalized and depreciated. Upon retirement or disposition, the cost and related accumulated depreciation are removed from the accounts and any gain or loss is recognized in "Loss on disposal of assets, net" in the consolidated statements of operations. Depreciation expense for midstream service assets was $8.3 million, $7.5 million and $4.3 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Midstream service assets consisted of the following as of December 31:

(in thousands)	2016	2015
Midstream service assets	$ 150,629	$ 147,811
Less accumulated depreciation and impairment	(24,389)	(16,086)
Total, net	$ 126,240	$ 131,725

i. Other fixed assets

Other fixed assets are recorded at cost and are subject to depreciation and amortization. Land is recorded at cost and is not subject to depreciation. Depreciation and amortization of other fixed assets is provided using the straight-line method based on estimated useful lives of three to ten years, as applicable. Leasehold improvements are capitalized and amortized over the shorter of the estimated useful lives of the assets or the terms of the related leases. Expenditures for significant betterments or renewals, which extend the useful lives of existing fixed assets, are capitalized and depreciated. Upon retirement or disposition, the cost and related accumulated depreciation and amortization are removed from the accounts and any gain or loss is recognized in "Loss on disposal of assets, net" in the consolidated statements of operations. Depreciation and amortization expense for other fixed assets was $5.9 million, $6.5 million and $5.1 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Other fixed assets consisted of the following as of December 31:

(in thousands)	2016	2015
Computer hardware and software	$ 12,710	$ 12,148
Aircraft	11,352	4,952
Real estate and buildings	7,618	7,618
Leasehold improvements	7,549	7,710
Vehicles	7,413	9,266
Other	5,849	5,105
Depreciable total	52,491	46,799
Less accumulated depreciation and amortization	(22,632)	(18,169)
Depreciable total, net	29,859	28,630
Land	14,914	14,908
Total, net	$ 44,773	$ 43,538

j. Long-lived assets and inventory

Impairment losses are recorded on property and equipment used in operations and other long-lived assets when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying amount. Impairment is measured based on the excess of the carrying amount over the fair value of the asset.

Beginning in the fourth quarter of 2016, the Company early-adopted a new accounting standard that simplified the measurement of inventory and has applied its provisions prospectively. The main substantive provision of this guidance is for an entity to change the subsequent measurement of inventory, within the scope of this guidance, from lower of cost or market ("LCM") to the lower of cost or net realizable value. Net realizable value ("NRV") is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. There was no effect to the consolidated financials statements upon adoption of this guidance. See additional discussion in Note 18.

Materials and supplies inventory, which is used in the Company's production activities of oil and natural gas properties and midstream service assets, is carried at the lower of cost or NRV, with cost determined using the weighted-average cost method, and is included in "Other current assets" and "Other assets, net" on the consolidated balance sheets. The NRV for materials and supplies inventory is determined utilizing a replacement cost approach (Level 2).

Beginning in 2016, the Company has frac pit water inventory, which is used in developing oil and natural gas properties and is carried at lower of cost or NRV, with cost determined using the weighted-average cost method, and is included in "Other current assets" on the consolidated balance sheets. The market price for frac pit water inventory is determined utilizing a replacement cost approach (Level 2).

The minimum volume of product in a pipeline system that enables the system to operate is known as line-fill and is generally not available to be withdrawn from the pipeline system until the expiration of the transportation contract. Beginning in the fourth quarter of 2014, the Company owns oil line-fill in third-party pipelines, which is accounted for at lower of cost or NRV, with cost determined using the weighted-average cost method, and is included in "Other assets, net" on the consolidated balance sheets. The net realizable value is determined utilizing a quoted market price adjusted for regional price differentials (Level 2).

The following table presents inventory impairments recorded as of the periods presented:

(in thousands)	For the years ended December 31, 2016	2015	2014
Inventory impairments:			
Materials and supplies(1)	$ 963	$ 2,819	$ 1,802
Line-fill(2)	—	1,314	2,102
Total inventory impairments	$ 963	$ 4,133	$ 3,904

(1) Included in "Impairment expense" in the consolidated statements of operations and in "Impairment expense" for the Company's exploration and production segment presented in Note 16.

(2) Included in "Impairment expense" in the consolidated statements of operations and in "Impairment expense" for the Company's midstream and marketing segment presented in Note 16.

For the year ended December 31, 2015, the Company recorded an impairment, based on an internally developed cash flow model, of $1.3 million related to its compressed natural gas station. This amount is included in "Impairment expense" in the consolidated statements of operations and as "Impairment expense" for the Company's midstream and marketing segment presented in Note 16. There were no comparable impairments recorded for the years ended December 31, 2016 or 2014.

k. Debt issuance costs

Debt issuance fees, which are recorded at cost, net of amortization, are amortized over the life of the respective debt agreements utilizing the effective interest and straight-line methods. The Company capitalized $6.8 million of debt issuance costs during the year ended December 31, 2015 mainly as a result of the issuance of the March 2023 Notes (as defined below). The Company capitalized $7.8 million of debt issuance costs during the year ended December 31, 2014 mainly as a result of the issuance of the January 2022 Notes (as defined below). No debt issuance costs were capitalized in the year ended December 31, 2016. The Company had total debt issuance costs of $18.8 million and $23.9 million, net of accumulated amortization of $21.3 million and $17.0 million, as of December 31, 2016 and 2015, respectively.

The Company wrote-off $0.8 million of debt issuance costs during the year ended December 31, 2016 as a result of changes in the borrowing base and aggregate elected commitment of the Senior Secured Credit Facility (as defined below), which are included in the consolidated statements of operations in the "Write-off of debt issuance costs" line item. The Company wrote-off $6.6 million of debt issuance costs during the year ended December 31, 2015 as a result of the early redemption of the January 2019 Notes (as defined below), which are included in the consolidated statements of operations in the "Loss on early redemption of debt" line item. During the year ended December 31, 2014, $0.1 million of debt issuance costs were written-off as a result of changes in the borrowing base of the Senior Secured Credit Facility due to the issuance of the January 2022 Notes, which are included in the consolidated statements of operations in the "Write-off of debt issuance costs" line item.

Debt issuance costs related to the Company's senior unsecured notes are presented in "Long-term debt, net" on the Company's consolidated balance sheets. Debt issuance costs related to the Senior Secured Credit Facility are presented in "Other assets, net" on the Company's consolidated balance sheets. See Note 5.h for additional discussion of debt issuance costs.

Future amortization expense of debt issuance costs as of the period presented is as follows:

(in thousands)	December 31, 2016
2017	$ 4,238
2018	4,068
2019	2,915
2020	3,005
2021	3,102
Thereafter	1,483
Total	$ 18,811

l. Other current assets and liabilities

Other current assets consisted of the following components as of December 31:

(in thousands)	2016	2015
Inventory[1]	$ 8,063	$ 6,974
Prepaid expenses and other	6,228	7,600
Total other current assets	$ 14,291	$ 14,574

(1) See Note 2.j for discussion of inventory held by the Company.

Other current liabilities consisted of the following components as of December 31:

(in thousands)	2016	2015
Accrued compensation and benefits	$ 25,947	$ 14,342
Accrued interest payable	24,152	24,208
Purchased oil payable	17,213	12,189
Lease operating expense payable	10,572	13,205
Capital contribution payable to equity method investee[1]	—	27,583
Other accrued liabilities	16,331	14,695
Total other current liabilities	$ 94,215	$ 106,222

(1) See Notes 14 and 15.a for additional discussion regarding the Company's equity method investee.

m. Asset retirement obligations

Asset retirement obligations associated with the retirement of tangible long-lived assets are recognized as a liability in the period in which they are incurred and become determinable. The associated asset retirement costs are part of the carrying amount of the long-lived asset. Subsequently, the asset retirement cost included in the carrying amount of the related long-lived asset is charged to expense through depletion, or for midstream service assets through depreciation, of the associated asset. Changes in the liability due to the passage of time are recognized as an increase in the carrying amount of the liability and as corresponding accretion expense.

The fair value of additions to the asset retirement obligation liability is measured using valuation techniques consistent with the income approach, which converts future cash flows into a single discounted amount. Significant inputs to the valuation include: (i) estimated plug and abandonment cost per well based on Company experience, (ii) estimated remaining life per well, (iii) estimated removal and/or remediation costs for midstream service assets, (iv) estimated remaining life of midstream service assets, (v) future inflation factors and (vi) the Company's average credit adjusted risk-free rate. Inherent in the fair value calculation of asset retirement obligations are numerous assumptions and judgments including, in addition to those noted above, the ultimate settlement of these amounts, the ultimate timing of such settlement and changes in legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing asset retirement obligation liability, a corresponding adjustment will be made to the asset balance.

The Company is obligated by contractual and regulatory requirements to remove certain pipeline and gathering assets and perform other remediation of the sites where such pipeline and gathering assets are located upon the retirement of those assets. However, the fair value of the asset retirement obligation cannot currently be reasonably estimated because the settlement dates are indeterminate. The Company will record an asset retirement obligation for pipeline and gathering assets in the periods in which settlement dates are reasonably determinable.

The following reconciles the Company's asset retirement obligation liability as of December 31:

(in thousands)	2016	2015
Liability at beginning of year	$ 46,306	$ 32,198
Liabilities added due to acquisitions, drilling, midstream service asset construction and other	1,528	2,236
Accretion expense	3,483	2,423
Liabilities settled upon plugging and abandonment	(1,242)	(146)
Liabilities removed due to sale of property	—	(2,005)
Revision of estimates[1]	2,132	11,600
Liability at end of year	$ 52,207	$ 46,306

(1) The revision of estimates that occurred during the year ended December 31, 2015 was mainly related to a change in the estimated remaining life per well due to declining commodity prices.

n. *Fair value measurements*

The carrying amounts reported in the consolidated balance sheets for cash and cash equivalents, accounts receivable, accounts payable, undistributed revenue and royalties, accrued capital expenditures and other accrued assets and liabilities approximate their fair values. See Note 5.g for fair value disclosures related to the Company's debt obligations. The Company carries its derivatives at fair value. See Note 9 for details regarding the fair value of the Company's derivatives.

o. *Treasury stock*

Laredo's employees may elect to have the Company withhold shares of stock to satisfy their tax withholding obligations that arise upon the lapse of restrictions on their stock awards. Such treasury stock is recorded at cost and retired upon acquisition.

p. *Revenue recognition*

Oil, NGL and natural gas revenues are recorded using the sales method. Under this method, the Company recognizes revenues based on actual volumes of oil, NGL and natural gas sold to purchasers. For natural gas sales, the Company and other joint interest owners may sell more or less than their entitlement share of the volumes produced. Under the sales method, when a working interest owner has overproduced in excess of its share of remaining estimated reserves, the overproduced party recognizes the excessive imbalance as a liability. If the underproduced working interest owner determines that an overproduced owner's share of remaining net reserves is insufficient to settle the imbalance, the underproduced owner recognizes a receivable, net of any allowance from the overproduced working interest owner. The Company is also subject to natural gas pipeline imbalances, which are recorded as accounts receivable or payable at values consistent with contractual arrangements with the owner of the pipeline. The Company did not have any producer or pipeline imbalance positions as of December 31, 2016 or 2015.

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

q. *Fees received for the operation of jointly-owned oil and natural gas properties*

The Company receives fees for the operation of jointly-owned oil and natural gas properties and records such reimbursements as a reduction of general and administrative expenses.

The following amounts have been recorded for the periods presented:

	For the years ended December 31,		
(in thousands)	2016	2015	2014
Fees received for the operation of jointly-owned oil and natural gas properties	$ 2,477	$ 3,125	$ 3,265

r. Compensation awards

Stock-based compensation expense, net of amounts capitalized, is included in "General and administrative" in the Company's consolidated statements of operations over the awards' vesting periods and is based on the awards' grant date fair value. The Company utilizes the closing stock price on the grant date, less an expected forfeiture rate, to determine the fair values of service vesting restricted stock awards and a Black-Scholes pricing model to determine the fair values of service vesting restricted stock option awards. The Company utilizes a Monte Carlo simulation prepared by an independent third party to determine the fair values of the performance share awards and, in prior periods, performance unit awards. The Company capitalizes a portion of stock-based compensation for employees who are directly involved in the acquisition, exploration and development of its oil and natural gas properties into the full cost pool. Capitalized stock-based compensation is included as an addition to "Oil and natural gas properties" in the consolidated balance sheets. See Note 6 for further discussion regarding the restricted stock awards, restricted stock option awards, performance share awards and performance unit awards.

s. Income taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating losses and tax credit carry-forwards. Under this method, deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income (loss) in the period that includes the enactment date.

The Company evaluates uncertain tax positions for recognition and measurement in the consolidated financial statements. To recognize a tax position, the Company determines whether it is more likely than not that the tax position will be sustained upon examination, including resolution of any related appeals or litigation, based on the technical merits of the position. A tax position that meets the more-likely-than-not threshold is measured to determine the amount of benefit to be recognized in the consolidated financial statements. The amount of tax benefit recognized with respect to any tax position is measured as the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement. The Company has no unrecognized tax benefits related to uncertain tax positions in the consolidated financial statements at December 31, 2016 or 2015. See Note 7 for additional information regarding the Company's income taxes.

t. Environmental

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, among other things, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed in the period incurred. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. Management believes no materially significant liabilities of this nature existed as of December 31, 2016 or 2015.

u. Non-cash investing and supplemental cash flow information

The following presents the non-cash investing and supplemental cash flow information for the periods presented:

	For the years ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Non-cash investing information:			
Change in accrued capital expenditures	$ (31,027)	$ (86,369)	$ 31,913
Change in accrued capital contribution to equity method investee[(1)]	$ (27,583)	$ 27,583	$ (2,597)
Capitalized asset retirement cost	$ 3,660	$ 13,836	$ 9,118
Supplemental cash flow information:			
Cash paid for interest, net of $294, $236 and $150 of capitalized interest, respectively	$ 89,432	$ 112,457	$ 104,936

(1) See Notes 14 and 15.a for additional discussion of the Company's equity method investee.

Note 3—Equity offerings

a. July 2016 Equity Offering

On July 19, 2016, the Company completed the sale of 13,000,000 shares of Laredo's common stock (the "July 2016 Equity Offering") for net proceeds of $136.3 million, after underwriting discounts, commissions and offering expenses. On August 9, 2016, the underwriters exercised their option to purchase an additional 1,950,000 shares of Laredo's common stock, which resulted in net proceeds to the Company of $20.5 million, after underwriting discounts, commissions and offering expenses.

b. May 2016 Equity Offering

On May 16, 2016, the Company completed the sale of 10,925,000 shares of Laredo's common stock (the "May 2016 Equity Offering") for net proceeds of $119.3 million, after underwriting discounts, commissions and offering expenses.

c. March 2015 Equity Offering

On March 5, 2015, the Company completed the sale of 69,000,000 shares of Laredo's common stock (the "March 2015 Equity Offering") for net proceeds of $754.2 million, after underwriting discounts, commissions and offering expenses. Entities affiliated with Warburg Pincus LLC ("Warburg Pincus") purchased 29,800,000 shares in the March 2015 Equity Offering.

There were no comparative offerings of Laredo's stock during the year ended December 31, 2014.

Note 4—Acquisitions and divestiture

a. 2016 Acquisitions of evaluated and unevaluated oil and natural gas properties

The Company accounts for acquisitions of evaluated and unevaluated oil and natural gas properties under the acquisition method of accounting. Accordingly, the Company conducts assessments of net assets acquired and recognizes amounts for identifiable assets acquired and liabilities assumed at the estimated acquisition date fair values, while transaction costs associated with the acquisitions are expensed as incurred.

The Company makes various assumptions in estimating the fair values of assets acquired and liabilities assumed. The most significant assumptions relate to the estimated fair value of evaluated and unevaluated oil and natural gas properties. The fair value of these properties are measured using a discounted cash flow model that converts future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) forecasted oil, NGL and natural gas reserve quantities; (ii) future commodity strip prices as of the closing dates adjusted for transportation and regional price differentials; (iii) forecasted ad valorem taxes, production taxes, income taxes, general and administrative expenses, operating expenses and development costs; and (iv) a peer group weighted-average cost of capital rate subject to additional project-specific risk factors. To compensate for the inherent risk of estimating the value of the unevaluated properties, the discounted future net revenues of proved undeveloped and probable reserves are reduced by additional reserve adjustment factors. These assumptions represent Level 3 inputs under the fair value hierarchy, as described in Note 9.

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

The following table reflects an aggregate of the final estimate of the fair values of the assets and liabilities acquired during the year ended December 31, 2016:

(in thousands)	Fair value of acquisitions
Fair value of net assets:	
Evaluated oil and natural gas properties	$ 4,800
Unevaluated oil and natural gas properties	119,923
Asset retirement cost	1,105
Total assets acquired	125,828
Asset retirement obligations	(1,105)
Net assets acquired	$ 124,723
Fair value of consideration paid for net assets:	
Cash consideration	$ 124,723

b. 2015 Divestiture of non-strategic assets

On September 15, 2015, the Company completed the sale of non-strategic and primarily non-operated properties and associated production totaling 6,060 net acres and 123 producing wells in the Midland Basin to a third-party buyer for a purchase price of $65.5 million. After transaction costs reflecting an economic effective date of July 1, 2015, the net proceeds were $64.8 million, net of working capital adjustments and post-closing adjustments. The purchase price, excluding post-closing adjustments, was allocated to oil and natural gas properties pursuant to the rules governing full cost accounting.

Effective at closing, the operations and cash flows of these properties were eliminated from the ongoing operations of the Company, and the Company has no continuing involvement in the properties. This divestiture does not represent a strategic shift and will not have a major effect on the Company's operations or financial results.

The following table presents revenues and expenses of the oil and natural gas properties sold included in the accompanying consolidated statements of operations for the periods presented:

	For the years ended December 31,	
(in thousands)	2015	2014
Oil, NGL and natural gas sales	$ 5,138	$ 19,337
Expenses[(1)]	$ 5,791	$ 11,082

(1) Expenses include (i) lease operating expense, (ii) production and ad valorem tax expense, (iii) accretion expense and (iv) depletion expense.

c. Summary of 2014 acquisitions

The following table presents the Company's material 2014 acquisitions. For further discussion of the estimates of fair value of the acquired assets and liabilities of these acquisitions, see Note 3 to the consolidated financial statements included in the Company's 2014 Annual Report on Form 10-K.

(in thousands)	Accounting treatment	Cash consideration
August 28, 2014 acquisition of leasehold interests	Acquisition of assets	$ 192,484
June 23, 2014 acquisition of evaluated and unevaluated oil and natural gas properties	Acquisition method	$ 1,800
June 11, 2014 acquisition of evaluated and unevaluated oil and natural gas properties	Acquisition method	$ 4,693
February 25, 2014 acquisition of mineral interests	Acquisition of assets	$ 7,305

Note 5—Debt

a. Interest expense

The following amounts have been incurred and charged to interest expense for the periods presented:

	For the years ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Cash payments for interest	$ 89,726	$ 112,693	$ 105,086
Amortization of debt issuance costs and other adjustments	3,922	4,243	4,433
Change in accrued interest	(56)	(13,481)	11,804
Interest costs incurred	93,592	103,455	121,323
Less capitalized interest	(294)	(236)	(150)
Total interest expense	$ 93,298	$ 103,219	$ 121,173

b. March 2023 Notes

On March 18, 2015, the Company completed an offering of $350.0 million in aggregate principal amount of 6 1/4% senior unsecured notes due 2023 (the "March 2023 Notes"), and entered into an Indenture (the "Base Indenture"), as supplemented by the Supplemental Indenture (the "Supplemental Indenture" and, together with the Base Indenture, the "Indenture"), among Laredo, LMS and GCM, as guarantors, and Wells Fargo Bank, National Association, as trustee. The March 2023 Notes will mature on March 15, 2023 with interest accruing at a rate of 6 1/4% per annum and payable semi-annually in cash in arrears on March 15 and September 15 of each year, commencing September 15, 2015. The March 2023 Notes are fully and unconditionally guaranteed on a senior unsecured basis by the Guarantors and certain of the Company's future restricted subsidiaries, subject to certain automatic customary releases, including the sale, disposition, or transfer of all of the capital stock or of all or substantially all of the assets of a subsidiary guarantor to one or more persons that are not the Company or a restricted subsidiary, exercise of legal defeasance or covenant defeasance options or satisfaction and discharge of the Indenture, designation of a subsidiary guarantor as a non-guarantor restricted subsidiary or as an unrestricted subsidiary in accordance with the Indenture, release from guarantee under the Senior Secured Credit Facility, or liquidation or dissolution (collectively, the "Releases").

The March 2023 Notes were offered and sold pursuant to a prospectus supplement dated March 4, 2015 and the base prospectus dated March 22, 2013, relating to the Company's effective shelf registration statement on Form S-3 (File No. 333-187479). The Company received net proceeds of $343.6 million from the offering, after deducting the underwriters' discount and the estimated outstanding offering expenses. In April 2015, the Company used the proceeds of the offering to fund a portion of the Company's redemption of the January 2019 Notes (as defined below). See Note 5.e for additional discussion of this early redemption.

The Company may redeem, at its option, all or part of the March 2023 Notes at any time on or after March 15, 2018, at the applicable redemption price plus accrued and unpaid interest to, but not including, the date of redemption. Further, before March 15, 2018, the Company may on one or more occasions redeem up to 35% of the aggregate principal amount of the March 2023 Notes in an amount not exceeding the net proceeds from one or more private or public equity offerings at a redemption price of 106.25% of the principal amount of the March 2023 Notes, plus accrued and unpaid interest to the date of redemption, if at least 65% of the aggregate principal amount of the March 2023 Notes remains outstanding immediately after such redemption and the redemption occurs within 180 days of the closing date of each such equity offering.

c. January 2022 Notes

On January 23, 2014, the Company completed an offering of $450.0 million in aggregate principal amount of 5 5/8% senior unsecured notes due 2022 (the "January 2022 Notes"), and entered into an Indenture (the "2014 Indenture") among Laredo, LMS as guarantor and Wells Fargo Bank, National Association, as trustee. The January 2022 Notes will mature on January 15, 2022 with interest accruing at a rate of 5 5/8% per annum and payable semi-annually in cash in arrears on January 15 and July 15 of each year, commencing July 15, 2014. The January 2022 Notes are fully and unconditionally guaranteed on a senior unsecured basis by the Guarantors and certain of the Company's future restricted subsidiaries, subject to certain Releases.

The January 2022 Notes were issued pursuant to the 2014 Indenture in a transaction exempt from the registration requirements of the Securities Act of 1933, as amended (the "Securities Act"). The January 2022 Notes were offered and sold only to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to persons outside the United States pursuant to Regulation S under the Securities Act. The Company received net proceeds of $442.2 million from the offering, after deducting the initial purchasers' discount and the estimated outstanding offering expenses. The Company used the net proceeds of the offering for general working capital purposes.

Laredo has the option to redeem all or part of the January 2022 Notes at any time on and after January 15, 2017, at the applicable redemption price plus accrued and unpaid interest to the date of redemption.

d. May 2022 Notes

On April 27, 2012, the Company completed an offering of $500.0 million in aggregate principal amount of 7 3/8% senior unsecured notes due 2022 (the "May 2022 Notes"). The May 2022 Notes will mature on May 1, 2022 and bear an interest rate of 7 3/8% per annum, payable semi-annually, in cash in arrears on May 1 and November 1 of each year, commencing November 1, 2012. The May 2022 Notes are fully and unconditionally guaranteed on a senior unsecured basis by the Guarantors and certain of the Company's future restricted subsidiaries, subject to certain Releases.

The May 2022 Notes were issued under, and are governed by, an indenture and supplement thereto, each dated April 27, 2012 (collectively, and as further supplemented, the "2012 Indenture"), among Laredo Inc, Wells Fargo Bank, National Association, as trustee, and the guarantors named therein. The 2012 Indenture contains customary terms, events of default and covenants relating to, among other things, the incurrence of debt, the payment of dividends or similar restricted payments, entering into transactions with affiliates and limitations on asset sales. Indebtedness under the May 2022 Notes may be accelerated in certain circumstances upon an event of default as set forth in the 2012 Indenture.

Laredo will have the option to redeem the May 2022 Notes, in whole or in part, at any time on or after May 1, 2017, at the redemption prices (expressed as percentages of principal amount) of 103.688% for the 12-month period beginning on May 1, 2017, 102.458% for the 12-month period beginning on May 1, 2018, 101.229% for the 12-month period beginning on May 1, 2019 and 100.000% beginning on May 1, 2020 and at any time thereafter, together with any accrued and unpaid interest, if any, to the date of redemption. In addition, before May 1, 2017, Laredo may redeem all or any part of the May 2022 Notes at a redemption price equal to the sum of the principal amount thereof, plus a make-whole premium at the redemption date, plus accrued and unpaid interest, if any, to the redemption date. Laredo may also be required to make an offer to purchase the May 2022 Notes upon a change of control triggering event.

e. January 2019 Notes

On January 20, 2011, the Company completed an offering of $350.0 million in aggregate principal amount of 9 1/2% senior unsecured notes due 2019 (the "January Notes") and on October 19, 2011, the Company completed an offering of an additional $200.0 million in aggregate principal amount of 9 1/2% senior unsecured notes due 2019 (the "October Notes" and together with the January Notes, the "January 2019 Notes"). The January 2019 Notes were due to mature on February 15, 2019 and bore an interest rate of 9 1/2% per annum, payable semi-annually, in cash in arrears on February 15 and August 15 of each year. The January 2019 Notes were fully and unconditionally guaranteed on a senior unsecured basis by the Guarantors and certain of the Company's future restricted subsidiaries, subject to certain Releases.

The January 2019 Notes were issued under and were governed by an indenture dated January 20, 2011 (as supplemented, the "2011 Indenture") among Laredo Inc, Wells Fargo Bank, National Association, as trustee, and guarantors named therein. The Indenture contains customary terms, events of default and covenants relating to, among other things, the incurrence of debt, the payment of or similar restricted payments, the undertaking of transactions with Laredo's unrestricted affiliates and limitations on asset sales.

On April 6, 2015 (the "Redemption Date"), utilizing a portion of the proceeds from the March 2015 Equity Offering and the March 2023 Notes offering, the entire $550.0 million outstanding principal amount of the January 2019 Notes was redeemed at a redemption price of 104.750% of the principal amount of the January 2019 Notes, plus accrued and unpaid interest up to the Redemption Date. The Company recognized a loss on extinguishment of $31.5 million related to the difference between the redemption price and the net carrying amount of the extinguished January 2019 Notes.

f. Senior Secured Credit Facility

As of December 31, 2016, the Fourth Amended and Restated Credit Agreement (as amended, the "Senior Secured Credit Facility"), which matures on November 4, 2018, had a maximum credit amount of $2.0 billion, a borrowing base and an aggregate elected commitment of $815.0 million with $70.0 million outstanding and was subject to an interest rate of 2.31%. The borrowing base is subject to a semi-annual redetermination occurring by May 1 and November 1 of each year based on the lenders' evaluation of the Company's oil and natural gas reserves. As defined in the Senior Secured Credit Facility, (i) the Adjusted Base Rate advances under the facility bear interest payable quarterly at an Adjusted Base Rate plus applicable margin, which ranges from 0.5% to 1.5%, based on the ratio of outstanding revolving credit to the total commitment under the Senior Secured Credit Facility; and (ii) the Eurodollar advances under the facility bear interest, at the Company's election, at the end of one-month, two-month, three-month, six-month or, to the extent available, 12-month interest periods (and in the case of six-month and 12-month interest periods, every three months prior to the end of such interest period) at an Adjusted London Interbank Offered Rate plus an applicable margin, which ranges from 1.5% to 2.5%, based on the ratio of outstanding revolving credit to the total commitment under the Senior Secured Credit Facility. Laredo is also required to pay an annual commitment fee on the unused portion of the financial institutions' commitment of 0.375% to 0.5%, based on the ratio of outstanding revolving credit to the total commitment under the Senior Secured Credit Facility.

The Senior Secured Credit Facility is secured by a first-priority lien on Laredo and the Guarantors' assets (other than LMS's interest in Medallion (defined below)) and stock, including oil, NGL and natural gas properties, constituting at least 80% of the present value of the Company's evaluated reserves. Further, the Company is subject to various financial and non-financial covenants on a consolidated basis, including a current ratio at the end of each calendar quarter, of not less than 1.00 to 1.00. As defined by the Senior Secured Credit Facility, the current ratio represents the ratio of current assets to current liabilities, inclusive of available capacity and exclusive of current balances associated with derivative positions. Additionally, at the end of each calendar quarter, the Company must maintain a ratio of (I) its consolidated net income (loss) (a) plus each of the following; (i) any provision for (or less any benefit from) income or franchise taxes; (ii) consolidated net interest expense; (iii) depletion, depreciation and amortization expense; (iv) exploration expenses; and (v) other non-cash charges, and (b) minus other non-cash income ("EBITDAX"), as defined in the Senior Secured Credit Facility, to (II) the sum of consolidated net interest expense plus letter of credit fees of not less than 2.50 to 1.00, in each case for the four quarters then ending. The Company was in compliance with these covenants for all periods presented.

Additionally, the Senior Secured Credit Facility provides for the issuance of letters of credit, limited to the lesser of total capacity or $20.0 million. No letters of credit were outstanding as of December 31, 2016 or 2015. See Note 19.a for discussion of a payment made to the Senior Secured Credit Facility subsequent to December 31, 2016.

g. Fair value of debt

The Company has not elected to account for its debt instruments at fair value. The following table presents the carrying amounts and fair values of the Company's debt as of the periods presented:

	December 31, 2016		December 31, 2015	
(in thousands)	**Long-term debt**	**Fair value**	**Long-term debt**	**Fair value**
January 2022 Notes	$ 450,000	$ 456,382	$ 450,000	$ 388,301
May 2022 Notes	500,000	521,413	500,000	460,000
March 2023 Notes	350,000	365,649	350,000	301,000
Senior Secured Credit Facility	70,000	69,975	135,000	134,993
Total value of debt	$ 1,370,000	$ 1,413,419	$ 1,435,000	$ 1,284,294

The fair values of the debt outstanding on the January 2022 Notes, the May 2022 Notes and the March 2023 Notes were determined using the December 31, 2016 and 2015 quoted market price (Level 1) for each respective instrument. The fair values of the outstanding debt on the Senior Secured Credit Facility as of December 31, 2016 and 2015 were estimated utilizing pricing models for similar instruments (Level 2). See Note 9 for information about fair value hierarchy levels.

h. Long-term debt, net

The following table summarizes the net presentation of the Company's long-term debt and debt issuance costs on the consolidated balance sheets as of the periods presented:

	December 31, 2016			December 31, 2015		
(in thousands)	Long-term debt	Debt issuance costs, net	Long-term debt, net	Long-term debt	Debt issuance costs, net	Long-term debt, net
January 2022 Notes	$ 450,000	$ (4,963)	$ 445,037	$ 450,000	$ (5,939)	$ 444,061
May 2022 Notes	500,000	(6,164)	493,836	500,000	(7,066)	492,934
March 2023 Notes	350,000	(4,964)	345,036	350,000	(5,769)	344,231
Senior Secured Credit Facility(1)	70,000	—	70,000	135,000	—	135,000
Total	$ 1,370,000	$ (16,091)	$ 1,353,909	$ 1,435,000	$ (18,774)	$ 1,416,226

(1) Debt issuance costs related to our Senior Secured Credit Facility of $2.7 million and $5.2 million as of December 31, 2016 and 2015, respectively, are recorded net in "Other assets, net" on the consolidated balance sheets.

Note 6—Employee compensation

The Company has a Long-Term Incentive Plan (the "LTIP"), which provides for the granting of incentive awards in the form of restricted stock awards, stock option awards, performance share awards, performance unit awards and other awards. During the year ended December 31, 2016, Laredo's stockholders approved an increase in the maximum number of shares of Laredo's common stock issuable under the LTIP from 10,000,000 shares to 24,350,000 shares.

The Company recognizes the fair value of stock-based compensation awards expected to vest over the requisite service period as a charge against earnings, net of amounts capitalized. The Company's stock-based compensation awards are accounted for as equity instruments and, in prior periods, its performance unit awards were accounted for as liability awards. Stock-based compensation is included in "General and administrative" in the consolidated statements of operations. The Company capitalizes a portion of stock-based compensation for employees who are directly involved in the acquisition, exploration or development of oil and natural gas properties into the full cost pool. Capitalized stock-based compensation is included as an addition to "Oil and natural gas properties" in the consolidated balance sheets.

a. Restricted stock awards

All service vesting restricted stock awards are treated as issued and outstanding in the accompanying consolidated financial statements. Per the award agreement terms, if an employee terminates employment prior to the restriction lapse date for reasons other than death or disability, the awarded shares are forfeited and canceled and are no longer considered issued and outstanding. If the employee's termination of employment is by reason of death or disability, all of the holder's restricted stock will automatically vest. Historically, restricted stock awards granted to officers and employees vest in a variety of vesting schedules including (i) 33%, 33% and 34% per year beginning on the first anniversary date of the grant, (ii) 50% in year two and 50% in year three, (iii) fully on the first anniversary of the grant date and (iv) fully on the third anniversary of the grant date. Restricted stock awards granted to non-employee directors vest fully on the first anniversary of the grant date.

The following table reflects the restricted stock award activity for the years ended December 31, 2014, 2015 and 2016:

(in thousands, except for weighted-average grant date fair values)	Restricted stock awards	Weighted-average grant date fair value (per award)
Outstanding as of December 31, 2013	1,799	$ 19.17
Granted	1,234	$ 25.68
Forfeited	(148)	$ 22.56
Vested	(680)	$ 19.13
Outstanding as of December 31, 2014	2,205	$ 22.63
Granted	1,902	$ 11.98
Forfeited	(553)	$ 20.48
Vested	(1,015)	$ 22.32
Outstanding as of December 31, 2015	2,539	$ 15.26
Granted	2,982	$ 12.28
Forfeited	(457)	$ 13.95
Vested[(1)]	(1,186)	$ 16.07
Outstanding as of December 31, 2016	3,878	$ 12.88

(1) The total intrinsic value of vested restricted stock awards for the year ended December 31, 2016 was $7.3 million.

The Company utilizes the closing stock price on the grant date to determine the fair value of service vesting restricted stock awards. As of December 31, 2016, unrecognized stock-based compensation related to the restricted stock awards expected to vest was $29.7 million. Such cost is expected to be recognized over a weighted-average period of 1.88 years.

b. Stock option awards

Stock option awards granted under the LTIP vest and are exercisable in four equal installments on each of the four anniversaries of the grant date. The following table reflects the stock option award activity for the years ended December 31, 2014, 2015 and 2016:

(in thousands, except for weighted-average price and weighted-average remaining contractual term)	Stock option awards	Weighted-average price (per option)	Weighted-average remaining contractual term (years)
Outstanding as of December 31, 2013	1,229	$ 19.32	8.82
Granted	336	$ 25.60	
Exercised	(95)	$ 19.93	
Expired or canceled	(30)	$ 21.15	
Forfeited	(73)	$ 19.68	
Outstanding as of December 31, 2014	1,367	$ 20.76	8.17
Granted	632	$ 11.93	
Exercised	—	$ —	
Expired or canceled	(82)	$ 19.92	
Forfeited	(139)	$ 18.17	
Outstanding as of December 31, 2015	1,778	$ 17.86	7.91
Granted	1,016	$ 4.18	
Exercised	(17)	$ 11.93	
Expired or canceled	(109)	$ 21.71	
Forfeited	(298)	$ 12.49	
Outstanding as of December 31, 2016	2,370	$ 12.54	7.71
Vested and exercisable at end of period[(1)]	831	$ 19.43	6.25
Expected to vest at end of period[(2)]	1,536	$ 8.78	8.51

(1) The vested and exercisable stock option awards as of December 31, 2016 had $0.3 million aggregate intrinsic value.

(2) The stock option awards expected to vest as of December 31, 2016 had $10.0 million aggregate intrinsic value.

The Company utilizes the Black-Scholes option pricing model to determine the fair value of stock option awards and is recognizing the associated expense on a straight-line basis over the four-year requisite service period of the awards. Determining the fair value of equity-based awards requires judgment, including estimating the expected term that stock option awards will be outstanding prior to exercise and the associated volatility. As of December 31, 2016, unrecognized stock-based compensation related to stock option awards expected to vest was $9.8 million. Such cost is expected to be recognized over a weighted-average period of 2.76 years.

The assumptions used to estimate the fair value of stock option awards granted during the period are as follows:

	May 25, 2016	April 1, 2016	February 27, 2015	February 27, 2014
Risk-free interest rate[1]	1.58%	1.44%	1.70%	1.88%
Expected option life[2]	6.25 years	6.25 years	6.25 years	6.25 years
Expected volatility[3]	61.94%	61.34%	52.59%	53.21%
Fair value per stock option award	$ 9.75	$ 4.44	$ 6.15	$ 13.41

(1) U.S. Treasury yields as of the grant date were utilized for the risk-free interest rate assumption, correlating the treasury yield terms to the expected life of the stock option award.

(2) As the Company had limited or no exercise history at the time of valuation relating to terminations and modifications, expected stock option award life assumptions were developed using the simplified method in accordance with GAAP.

(3) The Company utilized its own volatility in order to develop the expected volatility for the May 25, 2016, April 1, 2016 and February 27, 2015 grants. The February 27, 2014 grant utilized a peer historical look-back, which was weighted with the Company's own volatility, in order to develop the expected volatility.

In accordance with the LTIP and stock option agreement, the stock option awards granted will become exercisable in accordance with the following schedule based upon the number of full years of the optionee's continuous employment or service with the Company, following the date of grant:

Full years of continuous employment	Incremental percentage of option exercisable	Cumulative percentage of option exercisable
Less than one	—%	—%
One	25%	25%
Two	25%	50%
Three	25%	75%
Four	25%	100%

No shares of common stock may be purchased unless the optionee has remained in continuous employment with the Company for one year from the grant date. Unless terminated sooner, the stock option award will expire if and to the extent it is not exercised within 10 years from the grant date. The unvested portion of a stock option award shall expire upon termination of employment, and the vested portion of a stock option award shall remain exercisable for (i) one year following termination of employment by reason of the holder's death or disability, but not later than the expiration of the option period, or (ii) 90 days following termination of employment for any reason other than the holder's death or disability, and other than the holder's termination of employment for cause. Both the unvested and the vested but unexercised portion of a stock option award shall expire upon the termination of the option holder's employment or service by the Company for cause.

c. Performance share awards

The performance share awards granted to management on May 25, 2016 and April 1, 2016 (collectively the "2016 Performance Share Awards"), on February 27, 2015 (the "2015 Performance Share Awards") and on February 27, 2014 (the "2014 Performance Share Awards") are subject to a combination of market and service vesting criteria. A Monte Carlo simulation prepared by an independent third party was utilized to determine the grant date fair value of these awards. The Company has determined these awards are equity awards and recognizes the associated expense on a straight-line basis over the three-year requisite service period of the awards. These awards will be settled, if at all, in stock at the end of the requisite service period based on the achievement of certain performance criteria.

The 1,670,577 outstanding 2016 Performance Share Awards have a performance period of January 1, 2016 to December 31, 2018, and any shares earned under such awards are expected to be issued in the first quarter of 2019 if the performance criteria are met. The 454,164 outstanding 2015 Performance Share Awards have a performance period of January 1, 2015 to December 31, 2017, and any shares earned under such awards are expected to be issued in the first quarter of 2018 if the performance criteria are met. The 200,516 outstanding 2014 Performance Share Awards had a performance period of January 1, 2014 to December 31, 2016 and, as their performance criteria were satisfied, 75% of the shares will be issued during the first quarter of 2017 if the February 27, 2017 vesting criteria is satisfied.

The following table reflects the performance share award activity for the years ended December 31, 2014, 2015 and 2016:

(in thousands, except for weighted-average grant date fair values)	Performance share awards		Weighted-average grant date fair value (per award)
Outstanding as of December 31, 2013	—	$	—
Granted	272	$	28.56
Forfeited	—	$	—
Vested	—	$	—
Outstanding as of December 31, 2014	272	$	28.56
Granted	602	$	16.23
Forfeited	—	$	—
Vested	—	$	—
Outstanding as of December 31, 2015	874	$	20.06
Granted	1,801	$	17.71
Forfeited	(350)	$	19.34
Vested	—	$	—
Outstanding as of December 31, 2016	2,325	$	18.35

As of December 31, 2016, unrecognized stock-based compensation related to the performance share awards expected to vest was $26.2 million. Such cost is expected to be recognized over a weighted-average period of 2.03 years.

The assumptions used to estimate the fair value of the performance share awards granted are as follows:

		May 25, 2016		April 1, 2016		February 27, 2015		February 27, 2014
Risk-free rate[1]		1.02%		0.87%		0.95%		0.63%
Dividend yield		—%		—%		—%		—%
Expected volatility[2]		74.73%		71.54%		53.78%		38.21%
Laredo stock closing price as of the grant date	$	12.36	$	7.71	$	11.93	$	25.60
Fair value per performance share	$	17.86	$	9.83	$	16.23	$	28.56

(1) The risk-free rate was derived using a term-matched zero-coupon yield derived from the U.S. Treasury constant maturities yield curve on the grant date.

(2) The Company utilized its own historical volatility over a look-back period equal to the length of the remaining performance period from the grant date in order to develop the expected volatility for these grants.

d. *Stock-based compensation expense*

The following has been recorded to stock-based compensation expense for the periods presented:

	For the years ended December 31,					
(in thousands)		2016		2015		2014
Restricted stock award compensation	$	21,609	$	17,534	$	21,982
Stock option award compensation		4,519		4,074		3,639
Restricted performance share award compensation		9,112		5,222		2,108
Total stock-based compensation, gross		35,240		26,830		27,729
Less amounts capitalized in oil and natural gas properties		(6,011)		(2,321)		(4,650)
Total stock-based compensation, net of amounts capitalized	$	29,229	$	24,509	$	23,079

e. Performance unit awards

The performance unit awards issued to management on February 15, 2013 (the "2013 Performance Unit Awards") and on February 3, 2012 (the "2012 Performance Unit Awards") were subject to a combination of market and service vesting criteria.

These awards were accounted for as liability awards as they were settled in cash at the end of the requisite service period based on the achievement of certain performance criteria. A Monte Carlo simulation prepared by an independent third party was utilized to determine the fair values of these awards at the grant date and to re-measure the fair values at the end of each reporting period until settlement in accordance with GAAP. The volatility criteria utilized in the Monte Carlo simulation was based on the volatility of the Company's stock price and the stock price volatilities of a group of peer companies defined in each respective award agreement. The liability and related compensation expense of these awards for each period was recognized by dividing the fair value of the total liability by the requisite service period and recording the pro rata share for the period for which service had already been provided.

The 44,481 settled 2013 Performance Unit Awards had a performance period of January 1, 2013 to December 31, 2015 and, as their performance criteria were satisfied, they were paid at $143.75 per unit during the first quarter of 2016. The 27,381 settled 2012 Performance Unit Awards had a performance period of January 1, 2012 to December 31, 2014 and, as their performance criteria were satisfied, they were paid at $100.00 per unit during the first quarter of 2015. The liability related to the 2013 Performance Unit Awards as of December 31, 2015 was $6.4 million and represents the cash payment made in the first quarter of 2016.

The following has been recorded to performance unit award compensation expense for the periods presented:

	For the years ended December 31,	
(in thousands)	**2015**	**2014**
2013 Performance Unit Award compensation expense	$ 4,081	$ 409
2012 Performance Unit Award compensation expense	—	192
Total performance unit award compensation expense	$ 4,081	$ 601

For the years ended December 31, 2015 and 2014, compensation expense for the performance unit awards is recognized in "General and administrative" in the Company's consolidated statements of operations, and as of December 31, 2015, the corresponding liability is included in "Other current liabilities" on the consolidated balance sheets.

f. Defined contribution plan

The Company sponsors a 401(k) defined contribution plan for the benefit of substantially all employees at the date of hire. The plan allows eligible employees to make pre-tax and after-tax contributions up to 100% of their annual compensation, not to exceed annual limits established by the federal government. The Company makes matching contributions of up to 6% of an employee's compensation and may make additional discretionary contributions for eligible employees. Employees are 100% vested in the employer contributions upon receipt.

The following table presents the cost recognized for the Company's defined contribution plan for the periods presented:

	For the years ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Contributions	$ 1,789	$ 1,847	$ 2,202

Note 7—Income taxes

The Company is subject to federal and state income taxes and the Texas franchise tax. Income tax benefit (expense) for the periods presented consisted of the following:

	For the years ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Current taxes:			
Federal	$ —	$ —	$ —
State	—	—	—
Deferred taxes:			
Federal	—	152,590	(147,445)
State	—	24,355	(16,841)
Income tax benefit (expense)	$ —	$ 176,945	$ (164,286)

Income tax benefit (expense) differed from amounts computed by applying the applicable federal income tax rate of 35% for the years ended December 31, 2016, 2015 and 2014 to pre-tax earnings as a result of the following:

	For the years ended December 31,		
(in thousands)	2016	2015	2014
Income tax benefit (expense) computed by applying the statutory rate	$ 91,259	$ 835,408	$ (150,450)
Increase in deferred tax valuation allowance	(86,569)	(668,702)	(1,139)
Stock-based compensation tax deficiency	(4,144)	(3,274)	(266)
State income tax and increase in valuation allowance	(370)	13,975	(11,099)
Non-deductible stock-based compensation	—	(256)	(509)
Other items	(176)	(206)	(823)
Income tax benefit (expense)	$ —	$ 176,945	$ (164,286)

The effective tax rate for the Company's operations was 0%, 7% and 38% for the years ended December 31, 2016, 2015 and 2014, respectively. The Company's effective tax rate is affected by changes in valuation allowances, recurring permanent differences and by discrete items that may occur in any given year, but are not consistent from year to year.

A valuation allowance is established to reduce deferred tax assets if it is determined that it is more likely than not that the related tax benefit will not be realized. On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realizability of the deferred tax assets and adjusts the amount of such allowances, if necessary. During the year ended December 31, 2016, in evaluating whether it was more likely than not that the Company’s net deferred tax assets were realizable through future net income, management considered all available positive and negative evidence, including (i) its earnings history, (ii) its ability to recover net operating loss carry-forwards, (iii) the existence of significant proved oil, NGL and natural gas reserves, (iv) its ability to use tax planning strategies, (v) its current price protection utilizing oil, NGL and natural gas hedges, (vi) its future revenue and operating cost projections and (vii) the current market prices for oil, NGL and natural gas. Based on all the evidence available, during the year ended December 31, 2016, management determined it was more likely than not that the net deferred tax assets were not realizable, therefore a valuation allowance of $87.5 million was recorded. During the year ended December 31, 2015, a valuation allowance of $676.0 million was recorded. The Company maintains a valuation allowance to reduce certain deferred tax assets to amounts that are more likely than not to be realized. As of December 31, 2016, a total valuation allowance of $764.8 million has been recorded against the deferred tax asset.

The Company early-adopted a new accounting standard that simplified the accounting for stock-based compensation. As a result, the Company recorded a cumulative-effect adjustment to retained earnings as of January 1, 2016 for all windfall tax benefits that were not previously recognized because the related tax deduction had not reduced current taxes payable. The resulting deferred tax asset was assessed for realizability in accordance with GAAP. Due to the Company's valuation allowance position, a cumulative-effect adjustment was recorded to retained earnings as of January 1, 2016, and therefore, the net effect of the early adoption of this new accounting standard was zero. See Note 18 for additional discussion of the early adoption of this new accounting standard.

The following table presents significant components of the Company's net deferred tax asset as of December 31:

(in thousands)	2016	2015
Net operating loss carry-forward	$ 573,521	$ 479,022
Oil and natural gas properties, midstream service assets and other fixed assets	186,473	306,997
Equity method investee	(24,293)	(31,711)
Stock-based compensation	15,639	11,597
Accrued bonus	8,834	4,763
Materials and supplies impairment	1,982	1,647
Capitalized interest	1,767	2,525
Derivatives	150	(98,675)
Other	743	1,173
Net deferred tax asset before valuation allowance	764,816	677,338
Valuation allowance	(764,816)	(677,338)
Net deferred tax asset	$ —	$ —

The following presents the Company's federal net operating loss carry-forwards and their applicable expiration dates as of the period presented:

(in thousands)	December 31, 2016
2026	$ 2,741
2027	38,651
2028	228,661
2029	101,932
2030	80,963
Thereafter	1,180,937
Total	$ 1,633,885

The Company had federal net operating loss carry-forwards totaling $1.6 billion and state of Oklahoma net operating loss carry-forwards totaling $42.6 million as of December 31, 2016. These carry-forwards begin expiring in 2026. As of December 31, 2016, the Company believes a portion of the net operating loss carry-forwards are not fully realizable. The Company considered all available evidence, both positive and negative, in determining whether, based on the weight of that evidence, a valuation allowance was needed. Such consideration included projected future cash flows from its oil, NGL and natural gas reserves (including the timing of those cash flows), the reversal of deferred tax liabilities recorded as of December 31, 2016, the Company's ability to capitalize intangible drilling costs, rather than expensing these costs in order to prevent an operating loss carry-forward from expiring unused, and future projections of Oklahoma sourced income.

The Company files a single return. The Company's income tax returns for the years 2013 through 2016 remain open and subject to examination by federal tax authorities and/or the tax authorities in Oklahoma and Texas, which are the jurisdictions where the Company has or had operations. Additionally, the statute of limitations for examination of federal net operating loss carry-forwards typically does not begin to run until the year the attribute is utilized in a tax return. See Note 2.s for further discussion of accounting policies regarding income taxes.

Note 8—Derivatives

a. Commodity derivatives

The Company engages in derivative transactions such as puts, swaps, collars and, in prior periods, basis swaps to hedge price risks due to unfavorable changes in oil, NGL and natural gas prices related to its production. As of December 31, 2016, the Company had 20 open derivative contracts with financial institutions that extend from January 2017 to December 2018. None of these contracts were designated as hedges for accounting purposes. The contracts are recorded at fair value on the consolidated balance sheets and gains and losses are recognized in earnings. Gains and losses on derivatives are reported on the consolidated statements of operations on the "Gain (loss) on derivatives, net" line item.

Each put transaction has an established floor price. The Company pays the counterparty a premium, which can be deferred until settlement, to enter into the put transaction. When the settlement price is below the floor price, the counterparty pays the Company an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the floor price, the put option expires.

Each swap transaction has an established fixed price. When the settlement price is below the fixed price, the counterparty pays the Company an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, the Company pays its counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

Each collar transaction has an established price floor and ceiling. When the settlement price is below the price floor established by these collars, the Company receives an amount from its counterparty equal to the difference between the settlement price and the price floor multiplied by the hedged contract volume. When the settlement price is above the price ceiling established by these collars, the Company pays its counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the hedged contract volume.

In prior years, the oil basis swap transactions had an established fixed basis differential. The Company's oil basis swaps' differential was between the West Texas Intermediate-Argus Americas Crude (Midland) ("WTI Midland") index crude oil price and the West Texas Intermediate NYMEX ("WTI NYMEX") index crude oil price. When the WTI NYMEX price less the fixed basis differential was greater than the actual WTI Midland price, the difference multiplied by the hedged contract volume was paid to the Company by the counterparty. When the WTI NYMEX price less the fixed basis differential was less than the actual WTI Midland price, the difference multiplied by the hedged contract volume was paid by the Company to the counterparty.

The Company's oil derivatives are settled based on the month's average daily NYMEX index price for the First Nearby Month of the West Texas Intermediate Light Sweet Crude Oil Futures Contract. The Company's NGL derivatives are settled based on the month's average daily OPIS index price for Mont Belvieu Purity Ethane and TET Propane. The Company's natural gas derivatives are settled based on the Inside FERC index price for West Texas Waha for the calculation period.

During the year ended December 31, 2016, the Company successfully completed a hedge restructuring by early terminating the floors of certain derivative contract collars that resulted in a termination amount of $80.0 million, which was settled in full by applying the proceeds to prepay the premiums on two new derivatives entered into during the restructuring.

During the year ended December 31, 2016, the following derivatives were terminated:

	Aggregate volumes (Bbl)	Floor price ($/Bbl)	Contract period
Oil:			
Put portion of the associated collars	2,263,000	$ 80.00	January 2017 - December 2017

During the year ended December 31, 2016, the following derivatives were entered into:

	Aggregate volumes[1]	Floor price[2]	Ceiling price[2]	Contract period
Oil:[3]				
Put	600,000	$ 40.00	$ —	May 2016 - December 2016
Put[4]	2,263,000	$ 60.00	$ —	January 2017 - December 2017
Swap	1,003,750	$ 51.90	$ 51.90	January 2017 - December 2017
Swap	1,003,750	$ 51.17	$ 51.17	January 2017 - December 2017
Collar	1,168,000	$ 50.00	$ 60.75	January 2017 - December 2017
Put[5]	2,098,750	$ 60.00	$ —	January 2017 - December 2018
Swap	1,095,000	$ 52.12	$ 52.12	January 2018 - December 2018
NGL:				
Swap - Ethane	444,000	$ 11.24	$ 11.24	January 2017 - December 2017
Swap - Propane	375,000	$ 22.26	$ 22.26	January 2017 - December 2017
Natural gas:[6]				
Put	8,040,000	$ 2.50	$ —	January 2017 - December 2017
Collar	5,256,000	$ 2.50	$ 3.05	January 2017 - December 2017
Collar	3,723,000	$ 3.00	$ 3.54	January 2017 - December 2017
Collar	4,562,500	$ 3.00	$ 3.55	January 2017 - December 2017
Put	8,220,000	$ 2.50	$ —	January 2018 - December 2018
Collar	4,635,500	$ 2.50	$ 3.60	January 2018 - December 2018

(1) Oil and NGL are in Bbl and natural gas is in MMBtu.

(2) Oil and NGL are in $/Bbl and natural gas is in $/MMBtu.

(3) There were $2.9 million in deferred premiums associated with these contracts upon inception.

(4) As part of the Company's hedge restructuring, this put replaced the early terminated put portion of the restructured derivative contract collars. A premium of $40.0 million was paid at contract inception.

(5) As part of the Company's hedge restructuring, a premium of $40.0 million was paid at contract inception.

(6) There were $5.1 million in deferred premiums associated with these contracts upon inception.

During the year ended December 31, 2014, the Company unwound a physical commodity contract and the associated oil basis swap financial derivative contract that hedged the differential between the Light Louisiana Sweet Argus and the Brent International Petroleum Exchange index oil prices. Prior to its unwind, the physical commodity contract qualified to be scoped out of mark-to-market accounting in accordance with the normal purchase and normal sale scope exemption. Once modified to settle financially in the unwind agreement, the contract ceased to qualify for the normal purchase and normal sale scope exemption, therefore requiring it to be marked-to-market. The Company received net proceeds of $76.7 million from the early termination of these contracts. The Company agreed to settle the contracts early due to the counterparty's decision to exit the physical commodity trading business.

The following represents cash settlements received for derivatives, net for the periods presented:

	For the years ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Cash settlements received for matured derivatives, net[1]	$ 195,281	$ 255,281	$ 28,241
Cash settlements received for early terminations of derivatives, net[2]	80,000	—	76,660
Cash settlements received for derivatives, net	$ 275,281	$ 255,281	$ 104,901

(1) The settlement amount does not include premiums paid attributable to contracts that matured during the respective period.

(2) The settlement amount for the year ended December 31, 2016 includes $4.0 million in deferred premiums that were settled net with the early terminated contracts from which they derive.

The following table summarizes open positions as of December 31, 2016, and represents, as of such date, derivatives in place through December 2018 on annual production volumes:

	Year 2017	Year 2018
Oil positions:		
Puts:		
Hedged volume (Bbl)	1,049,375	1,049,375
Weighted-average price ($/Bbl)	$ 60.00	$ 60.00
Swaps:		
Hedged volume (Bbl)	2,007,500	1,095,000
Weighted-average price ($/Bbl)	$ 51.54	$ 52.12
Collars:		
Hedged volume (Bbl)	3,796,000	—
Weighted-average floor price ($/Bbl)	$ 56.92	$ —
Weighted-average ceiling price ($/Bbl)	$ 86.00	$ —
Totals:		
Total volume hedged with floor price (Bbl)	6,852,875	2,144,375
Weighted-average floor price ($/Bbl)	$ 55.82	$ 55.98
Total volume hedged with ceiling price (Bbl)	5,803,500	1,095,000
Weighted-average ceiling price ($/Bbl)	$ 74.08	$ 52.12
NGL positions:		
Swaps - Ethane:		
Hedged volume (Bbl)	444,000	—
Weighted-average price ($/Bbl)	$ 11.24	$ —
Swaps - Propane:		
Hedged volume (Bbl)	375,000	—
Weighted-average price ($/Bbl)	$ 22.26	$ —
Totals:		
Total volume hedged with floor price (Bbl)	819,000	—
Total volume hedged with ceiling price (Bbl)	819,000	—
Natural gas positions:		
Puts:		
Hedged volume (MMBtu)	8,040,000	8,220,000
Weighted-average price ($/MMBtu)	$ 2.50	$ 2.50
Collars:		
Hedged volume (MMBtu)	19,016,500	4,635,500
Weighted-average floor price ($/MMBtu)	$ 2.86	$ 2.50
Weighted-average ceiling price ($/MMBtu)	$ 3.54	$ 3.60
Totals:		
Total volumed hedged with floor price (MMBtu)	27,056,500	12,855,500
Weighted-average floor price ($/MMBtu)	$ 2.75	$ 2.50
Total volume hedged with ceiling price (MMBtu)	19,016,500	4,635,500
Weighted-average ceiling price ($/MMBtu)	$ 3.54	$ 3.60

b. Balance sheet presentation

In accordance with the Company's standard practice, its derivatives are subject to counterparty netting under agreements governing such derivatives. The Company's oil, NGL and natural gas derivatives are presented on a net basis as "Derivatives" on the consolidated balance sheets. See Note 9.a for a summary of the fair value of derivatives on a gross basis.

By using derivatives to hedge exposures to changes in commodity prices, the Company exposes itself to credit risk and market risk. For the Company, market risk is the exposure to changes in the market price of oil, NGL and natural gas, which are subject to fluctuations from a variety of factors, including changes in supply and demand. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, thereby creating credit risk. The Company's counterparties are participants in the Senior Secured Credit Facility, which is secured by the Company's oil, NGL and natural gas reserves; therefore, the Company is not required to post any collateral. The Company does not require collateral from its derivative counterparties. The Company minimizes the credit risk in derivatives by: (i) limiting its exposure to any single counterparty, (ii) entering into derivatives only with counterparties that meet the Company's minimum credit quality standard or have a guarantee from an affiliate that meets the Company's minimum credit quality standard and (iii) monitoring the creditworthiness of the Company's counterparties on an ongoing basis.

Note 9—Fair value measurements

The Company accounts for its oil, NGL and natural gas derivatives at fair value. The fair value of derivatives is determined utilizing pricing models for similar instruments. The models use a variety of techniques to arrive at fair value, including quotes and pricing analysis. Inputs to the pricing models include publicly available prices and forward curves generated from a compilation of data gathered from third parties.

The Company has categorized its assets and liabilities measured at fair value, based on the priority of inputs to the valuation technique, into a three-level fair value hierarchy. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3).

Assets and liabilities recorded at fair value on the consolidated balance sheets are categorized based on inputs to the valuation techniques as follows:

Level 1— Assets and liabilities recorded at fair value for which values are based on unadjusted quoted prices for identical assets or liabilities in an active market that management has the ability to access. Active markets are considered to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2— Assets and liabilities recorded at fair value for which values are based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the assets or liabilities. Substantially all of these inputs are observable in the marketplace throughout the full term of the price risk management instrument and can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace.

Level 3— Assets and liabilities recorded at fair value for which values are based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement. Unobservable inputs are not corroborated by market data. These inputs reflect management's own assumptions about the assumptions a market participant would use in pricing the asset or liability.

When the inputs used to measure fair value fall within different levels of the hierarchy in a liquid environment, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measurement in its entirety. The Company conducts a review of fair value hierarchy classifications on an annual basis. Changes in the observability of valuation inputs may result in a reclassification for certain financial assets or liabilities. Transfers between fair value hierarchy levels are recognized and reported in the period in which the transfer occurred. No transfers between fair value hierarchy levels occurred during the years ended December 31, 2016, 2015 or 2014.

a. Fair value measurement on a recurring basis

The following tables summarize the Company's fair value hierarchy by commodity on a gross basis and the net presentation on the consolidated balance sheets for derivative assets and liabilities measured at fair value on a recurring basis as of the periods presented:

(in thousands)	Level 1	Level 2	Level 3	Total gross fair value	Amounts offset	Net fair value presented on the consolidated balance sheets
As of December 31, 2016:						
Assets						
Current:						
Oil derivatives	$ —	$ 22,527	$ —	$ 22,527	$ —	$ 22,527
NGL derivatives	—	—	—	—	—	—
Natural gas derivatives	—	270	—	270	(270)	—
Oil deferred premiums	—	—	—	—	(1,580)	(1,580)
Natural gas deferred premiums	—	—	—	—	—	—
Noncurrent:						
Oil derivatives	$ —	$ 8,718	$ —	$ 8,718	$ —	$ 8,718
NGL derivatives	—	—	—	—	—	—
Natural gas derivatives	—	1,377	—	1,377	(1,377)	—
Oil deferred premiums	—	—	—	—	—	—
Natural gas deferred premiums	—	—	—	—	—	—
Liabilities						
Current:						
Oil derivatives	$ —	$ (9,789)	$ —	$ (9,789)	$ —	$ (9,789)
NGL derivatives	—	(2,803)	—	(2,803)	—	(2,803)
Natural gas derivatives	—	(3,639)	—	(3,639)	270	(3,369)
Oil deferred premiums	—	—	(3,569)	(3,569)	1,580	(1,989)
Natural gas deferred premiums	—	—	(3,043)	(3,043)	—	(3,043)
Noncurrent:						
Oil derivatives	$ —	$ (4,552)	$ —	$ (4,552)	$ —	$ (4,552)
NGL derivatives	—	—	—	—	—	—
Natural gas derivatives	—	(133)	—	(133)	1,377	1,244
Oil deferred premiums	—	—	—	—	—	—
Natural gas deferred premiums	—	—	(2,386)	(2,386)	—	(2,386)
Net derivative position	$ —	$ 11,976	$ (8,998)	$ 2,978	$ —	$ 2,978

(in thousands)	Level 1	Level 2	Level 3	Total gross fair value	Amounts offset	Net fair value presented on the consolidated balance sheets
As of December 31, 2015:						
Assets						
Current:						
Oil derivatives	$ —	$ 194,940	$ —	$ 194,940	$ —	$ 194,940
Natural gas derivatives	—	13,166	—	13,166	—	13,166
Oil deferred premiums	—	—	—	—	(9,301)	(9,301)
Natural gas deferred premiums	—	—	—	—	—	—
Noncurrent:						
Oil derivatives	$ —	$ 80,302	$ —	$ 80,302	$ —	$ 80,302
Natural gas derivatives	—	2,459	—	2,459	—	2,459
Oil deferred premiums	—	—	—	—	(4,877)	(4,877)
Natural gas deferred premiums	—	—	—	—	(441)	(441)
Liabilities						
Current:						
Oil derivatives	$ —	$ —	$ —	$ —	$ —	$ —
Natural gas derivatives	—	—	—	—	—	—
Oil deferred premiums	—	—	(9,301)	(9,301)	9,301	—
Natural gas deferred premiums	—	—	—	—	—	—
Noncurrent:						
Oil derivatives	$ —	$ —	$ —	$ —	$ —	$ —
Natural gas derivatives	—	—	—	—	—	—
Oil deferred premiums	—	—	(4,877)	(4,877)	4,877	—
Natural gas deferred premiums	—	—	(441)	(441)	441	—
Net derivative position	$ —	$ 290,867	$ (14,619)	$ 276,248	$ —	$ 276,248

These items are included as "Derivatives" on the consolidated balance sheets. Significant Level 2 assumptions associated with the calculation of discounted cash flows used in the mark-to-market analysis of derivatives include each derivative contract's corresponding commodity index price, appropriate risk-adjusted discount rates and other relevant data.

The Company's deferred premiums associated with its derivative contracts are categorized as Level 3, as the Company utilizes a net present value calculation to determine the valuation. They are considered to be measured on a recurring basis as the derivative contracts they derive from are measured on a recurring basis. As derivative contracts containing deferred premiums are entered into, the Company discounts the associated deferred premium to its net present value at the contract trade date, using the Senior Secured Credit Facility rate at the trade date (historical input rates range from 1.69% to 3.56%), and then records the change in net present value to interest expense over the period from trade until the final settlement date at the end of the contract. After this initial valuation, the net present value of each deferred premium is not adjusted; therefore, significant increases (decreases) in the Senior Secured Credit Facility rate would result in a significantly lower (higher) fair value measurement for each new contract entered into that contained a deferred premium; however, the valuation for the deferred premiums already recorded would remain unaffected. While the Company believes the sources utilized to arrive at the fair value estimates are reliable, different sources or methods could have yielded different fair value estimates; therefore, on a quarterly basis, the valuation is compared to counterparty valuations and a third-party valuation of the deferred premiums for reasonableness.

The following table presents actual cash payments required for deferred premiums for the calendar years presented:

(in thousands)	December 31, 2016
2017	$ 6,442
2018	2,683
Total	$ 9,125

A summary of the changes in assets classified as Level 3 measurements for the periods presented are as follows:

	For the years ended December 31,		
(in thousands)	2016	2015	2014
Balance of Level 3 at beginning of period	$ (14,619)	$ (9,285)	$ (12,684)
Change in net present value of derivative deferred premiums	(232)	(203)	(220)
Total purchases and settlements:			
Purchases	(7,715)	(10,298)	(3,800)
Settlements[(1)]	13,568	5,167	7,419
Balance of Level 3 at end of period	$ (8,998)	$ (14,619)	$ (9,285)

(1) The amount for the year ended December 31, 2016 includes $3.9 million that represents the present value of deferred premiums settled in the Company's restructuring upon their early termination.

b. Fair value measurement on a nonrecurring basis

The Company accounts for the impairment of long-lived assets, if any, at fair value on a nonrecurring basis. For purposes of fair value measurement, it was determined that the impairment of long-lived assets is classified as Level 3, based on the use of internally developed cash flow models. The Company accounts for the impairment of inventory, if any, at lower of cost or NRV on a nonrecurring basis. For purposes of market measurement, it was determined that the impairment of inventory is classified as Level 2, based on the use of a replacement cost approach. See Note 2.j for discussion regarding the Company's impairment of (i) materials and supplies for the years ended December 31, 2016, 2015 and 2014, (ii) line-fill for the years ended December 31, 2015 and 2014 and (iii) other fixed assets for the year ended December 31, 2015.

The accounting policies for impairment of oil and natural gas properties are discussed in Note 2.g. Significant inputs included in the calculation of discounted cash flows used in the impairment analysis include the Company's estimate of operating and development costs, anticipated production of evaluated reserves and other relevant data. See Note 2.g for discussion regarding the prices used in the calculation of discounted cash flows.

The Company accounts for acquisitions of evaluated and unevaluated oil and natural gas properties under the acquisition method of accounting. Accordingly, the Company conducts assessments of net assets acquired and recognizes amounts for identifiable assets acquired and liabilities assumed at the estimated acquisition date fair values, while transaction costs associated with the acquisitions are expensed as incurred. See Note 4.a for additional discussion of the Company's acquisitions.

Note 10—Net income (loss) per common share

Basic net income (loss) per common share is computed by dividing net income (loss) by the weighted-average number of common shares outstanding for the period. Diluted net income (loss) per common share reflects the potential dilution of non-vested restricted stock awards, performance share awards and outstanding stock options. For the years ended December 31, 2016 and 2015, all of these potentially dilutive items were anti-dilutive due to the Company's net loss and, therefore, were excluded from the calculation of diluted net loss per common share.

The effect of the Company's outstanding stock options was excluded from the calculation of diluted net income per common share for the year ended December 31, 2014. The inclusion of these options would be anti-dilutive due to the following: (i) utilizing the treasury stock method, the sum of the assumed proceeds exceeded the average stock price during the period for the restricted stock option awards granted in February 2013 and (ii) the exercise prices were greater than the average market price during the period for the restricted stock option awards granted in February 2012 and February 2014. For the year ended December 31, 2014, the 2014 Performance Share Awards' total shareholder return was below their agreement's payout threshold, and therefore the 2014 Performance Share Awards were excluded from the calculation of diluted net income per share. See Note 6 for further discussion regarding the restricted stock awards, restricted stock option awards and performance share awards.

The following is the calculation of basic and diluted weighted-average common shares outstanding and net income (loss) per common share for the periods presented:

	For the years ended December 31,		
(in thousands, except for per share data)	2016	2015	2014
Net income (loss) (numerator):			
Net income (loss)—basic and diluted	$ (260,739)	$ (2,209,936)	$ 265,573
Weighted-average common shares outstanding (denominator):(1)			
Basic	225,512	199,158	141,312
Non-vested restricted stock awards	—	—	2,242
Diluted	225,512	199,158	143,554
Net income (loss) per common share:			
Basic	$ (1.16)	$ (11.10)	$ 1.88
Diluted	$ (1.16)	$ (11.10)	$ 1.85

(1) Weighted-average common shares outstanding used in the computation of basic and diluted net income (loss) per common share attributable to stockholders was computed taking into account equity offerings that occurred during the years ended December 31, 2016 and 2015. There were no comparable equity offerings during the year ended December 31, 2014. See Note 3 for additional discussion of the Company's equity offerings.

Note 11—Credit risk

The Company's oil, NGL and natural gas sales are made to a variety of purchasers, including intrastate and interstate pipelines or their marketing affiliates and independent marketing companies. The Company's joint operations accounts receivable are from a number of oil and natural gas companies, partnerships, individuals and others who own interests in the oil and natural gas properties operated by the Company. The Company's sales of purchased oil are made to one customer. Management believes that any credit risk imposed by a concentration in the oil and natural gas industry is offset by the creditworthiness of the Company's customer base and industry partners. The Company routinely assesses the recoverability of all material trade and other receivables to determine collectability.

The Company uses derivatives to hedge its exposure to oil, NGL and natural gas price volatility. These transactions expose the Company to potential credit risk from its counterparties. In accordance with the Company's standard practice, its derivatives are subject to counterparty netting under agreements governing such derivatives; therefore, the credit risk associated with its derivative counterparties is somewhat mitigated. See Notes 2.f, 8 and 9 for additional information regarding the Company's derivatives.

For the year ended December 31, 2016, the Company had three customers that accounted for (i) 48.5%, 23.0% and 17.0% of total oil, NGL and natural gas sales, and (ii) 45.7%, 24.7% and 22.6% of oil, NGL and natural gas sales accounts receivable as of December 31, 2016. For the year ended December 31, 2015, the Company had (A) two customers that accounted for (i) 37.5% and 20.3% of total oil, NGL and natural gas sales, and (ii) 35.3% and 23.7% of oil, NGL and natural gas sales accounts receivable, and (B) two other customers accounting for 18.5% and 10.7% of oil, NGL and natural gas sales accounts receivable as of December 31, 2015. For the year ended December 31, 2014, the Company had (A) two customers that accounted for (i) 36.0% and 13.7% of total oil, NGL and natural gas sales, and (ii) 16.4% and 22.5% of oil, NGL and natural gas sales accounts receivable, and (B) three other customers accounting for 13.5%, 12.5% and 11.6% of oil, NGL and natural gas sales accounts receivable as of December 31, 2014. These customers and percentages reported are related to the Company's exploration and production segment, see Note 16.

As of December 31, 2016, the Company had one partner whose joint operations accounts receivable accounted for 19.3% of the Company's total joint operations accounts receivable. As of December 31, 2015, the Company had two partners whose joint operations accounts receivable accounted for 18.9% and 17.1% of the Company's total joint operations accounts receivable. These customers and percentages reported are related to the Company's exploration and production segment, see Note 16.

For the year ended December 31, 2016, the Company had one customer that accounted for 100.0% of total sales of purchased oil, with the same customer accounting for 99.7% of purchased oil and other product sales receivable as of December 31, 2016. For the year ended December 31, 2015, the Company had one customer that accounted for 100.0% of total sales of purchased oil, with the same customer accounting for 99.6% of purchased oil and other product sales receivable as of December 31, 2015. For the year ended December 31, 2014, the Company had one customer that accounted for 100.0% of total sales of purchased oil, with the same customer accounting for 97.3% of purchased oil and other product sales receivable as of December 31, 2014. The customer and percentages reported relate to the Company's midstream and marketing segment, see Note 16.

The Company's cash balances are insured by the FDIC up to $250,000 per bank. The Company had cash balances on deposit with a certain bank as of December 31, 2016 that exceeded the balance insured by the FDIC in the amount of $40.1 million. Management believes that the risk of loss is mitigated by the bank's reputation and financial position.

Note 12—Commitments and contingencies

a. Lease commitments

The Company leases office space under operating leases expiring on various dates through 2027. Minimum annual lease commitments for the calendar years presented are:

(in thousands)	December 31, 2016
2017	$ 3,127
2018	3,177
2019	3,121
2020	2,031
2021	1,826
Thereafter	7,022
Total	$ 20,304

The following has been recorded to rent expense for the periods presented:

	For the years ended December 31,		
(in thousands)	2016	2015	2014
Rent expense	$ 2,664	$ 2,880	$ 3,042

The Company's office space lease agreements contain scheduled escalation in lease payments during the term of the lease. In accordance with GAAP, the Company records rent expense on a straight-line basis and a deferred lease liability for the difference between the straight-line amount and the actual amounts of the lease payments. Rent expense is included in the consolidated statements of operations in the "General and administrative" line item.

b. Litigation

From time to time the Company is involved in legal proceedings and/or may be subject to industry rulings that could bring rise to claims in the ordinary course of business. The Company has concluded that the likelihood is remote that the ultimate resolution of any pending litigation or pending claims will be material or have a material adverse effect on the Company's business, financial position, results of operations or liquidity.

c. Drilling contracts

The Company has committed to several drilling contracts with a third party to facilitate the Company's drilling plans. Certain of these contracts contain early termination clauses that require the Company to potentially pay penalties to the third party should the Company cease drilling efforts. These penalties would negatively impact the Company's financial statements upon early contract termination. In the fourth quarter of 2014, the Company announced a reduced 2015 capital expenditure budget compared to 2014. As a result, the Company began releasing rigs as drilling contracts came close to expiration and incurred charges of $0.5 million which were recorded for the year ended December 31, 2014 on the consolidated statements of operations as "Drilling rig fees." No comparable amounts were recorded for the years ended December 31, 2016 or 2015. Future commitments of $7.9 million as of December 31, 2016 are not recorded in the accompanying consolidated balance sheets. Management does not currently anticipate the early termination of any existing contracts in 2017 that would result in a substantial penalty.

d. Firm sale and transportation commitments

The Company has committed to deliver for sale or transportation fixed volumes of product under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. If not fulfilled, the Company is subject to deficiency payments. These commitments are normal and customary for the Company's business. In certain instances, the

Company has used spot market purchases to meet its commitments in certain locations or due to favorable pricing. Management anticipates continuing this practice in the future. Also, if production is not sufficient to satisfy the Company's delivery commitments, the Company can and may use spot market purchases to fulfill the commitments. During the years ended December 31, 2016, 2015 and 2014, the Company incurred $2.2 million, $5.2 million and $2.6 million, respectively, in deficiency payments which are reported on the consolidated statements of operations on the "Minimum volume commitments" line item. During the year ended December 31, 2015, $3.0 million of the deficiency payments was a result of a negotiated buyout of a minimum volume commitment for future periods to Medallion (as defined below). See Note 14 for additional discussion regarding Medallion, the Company's equity method investment. Future commitments of $441.0 million as of December 31, 2016 are not recorded in the accompanying consolidated balance sheets.

e. Federal and state regulations

Oil and natural gas exploration, production and related operations are subject to extensive federal and state laws, rules and regulations. Failure to comply with these laws, rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases the cost of doing business and affects profitability. The Company believes that it is in compliance with currently applicable federal and state regulations related to oil and natural gas exploration and production, and that compliance with the current regulations will not have a material adverse impact on the financial position or results of operations of the Company. These rules and regulations are frequently amended or reinterpreted; therefore, the Company is unable to predict the future cost or impact of complying with these regulations.

f. Other commitments

See Notes 2.u, 14 and 15.a for the amount of and discussion regarding outstanding commitments to the Company's equity method investment.

Note 13—2015 Restructuring

Following the fourth-quarter 2014 drop in oil prices, in an effort to reduce costs and to better position the Company for ongoing efficient growth, on January 20, 2015, the Company executed a company-wide restructuring and reduction in force (the "RIF") that included (i) the relocation of certain employees from the Company's Dallas, Texas area office to the Company's other existing offices in Tulsa, Oklahoma and Midland, Texas; (ii) closing the Company's Dallas, Texas area office; (iii) a workforce reduction of approximately 75 employees and (iv) the release of 24 contract personnel. The RIF was communicated to employees on January 20, 2015 and was generally effective immediately. The Company's compensation committee approved the RIF and the related severance package. The Company incurred $6.0 million in expenses during the year ended December 31, 2015 related to the RIF. There were no comparative amounts recorded in the years ended December 31, 2016 or 2014.

Note 14—Variable interest entity

An entity is referred to as a variable interest entity ("VIE") pursuant to accounting guidance for consolidation if it possesses one of the following criteria: (i) it is thinly capitalized, (ii) the residual equity holders do not control the entity, (iii) the equity holders are shielded from the economic losses, (iv) the equity holders do not participate fully in the entity's residual economics, or (v) the entity was established with non-substantive voting interests. In order to determine if a VIE should be consolidated, an entity must determine if it is the primary beneficiary of the VIE. The primary beneficiary of a VIE is that variable interest-holder possessing a controlling financial interest through: (i) its power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (ii) its obligation to absorb losses or its right to receive benefits from the VIE that could potentially be significant to the VIE. In order to determine whether the Company owns a variable interest in a VIE, a qualitative analysis is performed of the entity's design, organizational structure, primary decision makers and relevant agreements. The Company continually monitors its VIE exposure to determine if any events have occurred that could cause the primary beneficiary to change.

LMS contributed $69.6 million and $99.9 million during the years ended December 31, 2016 and 2015, respectively, to Medallion Gathering & Processing, LLC, a Texas limited liability company formed on October 12, 2012, and its wholly-owned subsidiaries (together, "Medallion"). Medallion's pipeline is located in the Midland Basin.

LMS holds 49% of Medallion's ownership units. Medallion was established for the purpose of developing midstream solutions and providing midstream infrastructure to bring oil, NGL and natural gas to market. LMS and the other 51% interest-holder have agreed that the voting rights of Medallion, the profit and loss sharing and the additional capital contribution requirements shall be equal to the ownership unit percentage held. Additionally, Medallion requires a super-majority vote of 75% for all key operating and business decisions. The Company has determined that Medallion is a VIE. However, LMS is not considered to be the primary beneficiary of the VIE because LMS does not have the power to direct the activities that most significantly affect Medallion's economic performance. As such, Medallion is accounted for under the equity method of accounting with the Company's proportionate share of Medallion's net income (loss) reflected in the consolidated statements of operations as "Income (loss) from equity method investee" and the carrying amount reflected in the consolidated balance sheets as "Investment in equity method investee." The Company has elected to classify distributions received from Medallion using the cumulative earnings approach. No such distributions have been received to date.

During the years ended December 31, 2016 and 2015, Medallion continued expansion activities on existing portions of its pipeline infrastructure in order to gather and transport additional third-party oil production. During the year ended December 31, 2015, Medallion began recognizing revenue due to its pipeline, located in the Midland Basin, becoming fully operational.

During the year ended December 31, 2015, the Company negotiated a buyout of a minimum volume commitment to Medallion, which was related to natural gas gathering infrastructure Medallion constructed on acreage that the Company does not plan to develop. The portion of the buyout that was related to the Company's minimum volume commitment for future periods was $3.0 million and is included in the consolidated statements of operations in the line item "Minimum volume commitments" for the period in which the buyout was settled. See Note 15.a for discussion of items included in the Company's consolidated financial statements related to Medallion.

The following table summarizes items included in Medallion's consolidated statements of operations, which are not recorded in the Company's consolidated financial statements, for the periods presented:

	For the years ended December 31,		
(in thousands)	**2016**[(1)]	**2015**[(2)]	**2014**
Total revenues	$ 56,075	$ 38,306	$ 4,623
Gross profit[(3)]	55,821	30,869	4,623
Net income (loss)[(4)]	19,601	13,409	(333)

(1) Medallion's consolidated statement of operations for the year ended December 31, 2016 was unaudited as of February 16, 2017.

(2) Medallion's audited consolidated statement of operations for the year ended December 31, 2015 was finalized after the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2015.

(3) Medallion's pipeline did not become operational until 2015, accordingly no costs of goods sold were recorded for the year ended December 31, 2014.

(4) As Medallion's financial statements are unaudited at the time of filing the Company's Annual Report on Form 10-K, the Company's proportionate share of Medallion's net income (loss) reflected in the Company's consolidated statements of operations for the years ended December 31, 2016, 2015 and 2014 includes immaterial prior period Medallion audit adjustments.

The following table summarizes items included in Medallion's consolidated balance sheets, which are not recorded in the Company's consolidated financial statements:

	As of December 31,			
(in thousands)	**2016[1]**		**2015[2]**	
Assets:				
Current assets	$	51,390	$	82,145
Noncurrent assets		460,995		352,121
Total assets	$	512,385	$	434,266
Liabilities:				
Current liabilities	$	14,523	$	41,772
Noncurrent liabilities		—		—
Total liabilities	$	14,523	$	41,772

(1) Medallion's consolidated balance sheet as of December 31, 2016 was unaudited as of February 16, 2017.

(2) Medallion's audited consolidated balance sheet as of December 31, 2015 was finalized after the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2015.

Note 15—Related Parties

a. Medallion

The following table summarizes items included in the consolidated statements of operations related to Medallion for the periods presented:

	For the years ended December 31,					
(in thousands)	**2016**		**2015**		**2014**	
Midstream service revenues	$	—	$	487	$	—
Minimum volume commitments	$	—	$	5,235	$	2,552
Interest and other income	$	—	$	158	$	—

The following table summarizes items included in the consolidated balance sheets related to Medallion as of the dates presented:

	December 31,			
(in thousands)	**2016**		**2015**	
Accounts receivable, net	$	—	$	1,163
Accrued capital expenditures	$	586	$	—
Other current liabilities[1]	$	118	$	27,583

(1) Amounts included in "Other current liabilities" above represent LMS' accrued line-fill purchase in Medallion's pipeline, accrued third-party fees due to Medallion as of December 31, 2016 and capital contribution payable to Medallion as of December 31, 2015.

b. Archrock Partners, L.P.

The Company has a compression arrangement with affiliates of Archrock Partners, L.P., formerly Exterran Partners L.P., ("Archrock"). One of Laredo's directors is on the board of directors of Archrock GP LLC, an affiliate of Archrock.

The following table summarizes the lease operating expenses related to Archrock included in the consolidated statements of operations for the periods presented:

	For the years ended December 31,					
(in thousands)	**2016**		**2015**		**2014**	
Lease operating expenses	$	1,975	$	1,477	$	975

The following table summarizes the capital expenditures related to Archrock included in the consolidated statements of cash flows for the periods presented:

	For the years ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Capital expenditures:			
Oil and natural gas properties	$ —	$ —	$ 57
Midstream service assets	$ 20	$ 64	$ 833

The following table summarizes the amounts included in accounts payable from Archrock in the consolidated balance sheets as of the periods presented:

	December 31,	
(in thousands)	**2016**	**2015**
Accounts payable	$ 177	$ 13

c. Helmerich & Payne, Inc.

The Company has had drilling contracts with Helmerich & Payne, Inc. ("H&P"). Laredo's Chairman and Chief Executive Officer is on the board of directors of H&P.

The following table summarizes the capitalized oil and natural gas properties related to H&P and included in the consolidated statements of cash flows for the periods presented:

	For the years ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Capital expenditures:			
Oil and natural gas properties	$ —	$ 2,434	$ 9,518

Note 16—Segments

The Company operates in two business segments: (i) exploration and production and (ii) midstream and marketing. The exploration and production segment is engaged in the acquisition, exploration and development of oil and natural gas properties. The midstream and marketing segment provides Laredo's exploration and production segment and third parties with products and services that need to be delivered by midstream infrastructure, including oil and natural gas gathering services as well as rig fuel, natural gas lift and water delivery and takeaway.

The following table presents selected financial information, for the periods presented, regarding the Company's operating segments on a stand-alone basis and the consolidation and elimination entries necessary to arrive at the information for the Company on a consolidated basis:

(in thousands)	Exploration and production	Midstream and marketing	Eliminations	Consolidated company
Year ended December 31, 2016				
Oil, NGL and natural gas sales	$ 427,231	$ 1,141	$ (1,887)	$ 426,485
Midstream service revenues	—	49,971	(41,629)	8,342
Sales of purchased oil	—	162,551	—	162,551
Total revenues	427,231	213,663	(43,516)	597,378
Lease operating expenses, including production and ad valorem tax	115,496	—	(11,583)	103,913
Midstream service expenses	—	29,693	(25,616)	4,077
Costs of purchased oil	—	169,536	—	169,536
General and administrative(1)	83,901	7,855	—	91,756
Depletion, depreciation and amortization(2)	139,407	8,932	—	148,339
Impairment expense	162,027	—	—	162,027
Other operating costs and expenses(3)	5,483	209	—	5,692
Operating loss	$ (79,083)	$ (2,562)	$ (6,317)	$ (87,962)
Other financial information:				
Income from equity method investee	$ —	$ 9,403	$ —	$ 9,403
Interest expense(4)	$ (87,485)	$ (5,813)	$ —	$ (93,298)
Capital expenditures(5)	$ (368,290)	$ (5,240)	$ —	$ (373,530)
Gross property and equipment(6)	$ 5,780,137	$ 400,127	$ (8,240)	$ 6,172,024
Year ended December 31, 2015				
Oil, NGL and natural gas sales	$ 432,711	$ 1,692	$ (2,669)	$ 431,734
Midstream service revenues	—	27,965	(21,417)	6,548
Sales of purchased oil	—	168,358	—	168,358
Total revenues	432,711	198,015	(24,086)	606,640
Lease operating expenses, including production and ad valorem tax	151,918	—	(10,685)	141,233
Midstream service expenses	—	17,557	(11,711)	5,846
Costs of purchased oil	—	174,338	—	174,338
General and administrative(1)	82,251	8,174	—	90,425
Depletion, depreciation and amortization(2)	269,631	8,093	—	277,724
Impairment expense	2,372,296	2,592	—	2,374,888
Other operating costs and expenses(3)	12,522	1,178	—	13,700
Operating loss	$ (2,455,907)	$ (13,917)	$ (1,690)	$ (2,471,514)
Other financial information:				
Income from equity method investee	$ —	$ 6,799	$ —	$ 6,799
Interest expense(4)	$ (98,040)	$ (5,179)	$ —	$ (103,219)
Loss on early redemption of debt(7)	$ (30,056)	$ (1,481)	$ —	$ (31,537)
Income tax benefit(8)	$ 171,952	$ 4,993	$ —	$ 176,945
Capital expenditures	$ (597,086)	$ (35,515)	$ —	$ (632,601)
Gross property and equipment(6)	$ 5,302,716	$ 345,183	$ (1,923)	$ 5,645,976
Year ended December 31, 2014				
Oil, NGL and natural gas sales	$ 738,455	$ 1,660	$ (2,912)	$ 737,203
Midstream service revenues	—	7,838	(5,593)	2,245
Sales of purchased oil	—	54,437	—	54,437
Total revenues	738,455	63,935	(8,505)	793,885
Lease operating expenses, including production and ad valorem tax	153,427	—	(6,612)	146,815
Midstream service expenses	—	7,089	(1,660)	5,429
Costs of purchased oil	—	53,967	—	53,967
General and administrative(1)	99,075	6,969	—	106,044
Depletion, depreciation and amortization(2)	241,834	4,640	—	246,474
Impairment expense	1,802	2,102	—	3,904
Other operating costs and expenses(3)	2,248	2,618	—	4,866
Operating income (loss)	$ 240,069	$ (13,450)	$ (233)	$ 226,386
Other financial information:				
Loss from equity method investee	$ —	$ (192)	$ —	$ (192)
Interest expense(4)	$ (117,560)	$ (3,613)	$ —	$ (121,173)
Income tax (expense) benefit (8)	$ (170,551)	$ 6,265	$ —	$ (164,286)
Capital expenditures(5)	$ (1,279,142)	$ (60,607)	$ —	$ (1,339,749)

Gross property and equipment[6]	$	4,841,895	$	179,355	$	(233)	$	5,021,017

(1) General and administrative expense was allocated based on the number of employees in the respective segment as of December 31, 2016, 2015 and 2014. Certain components of general and administrative expense, primarily payroll,

deferred compensation and vehicle expenses, were not allocated but were actual expenses for each segment. Land and geology expenses were not allocated to the midstream and marketing segment.

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

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

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

(5) Capital expenditures exclude acquisition of oil and natural gas properties for the years ended December 31, 2016 and 2014 and acquisition of mineral interests for the year ended December 31, 2014.

(6) Gross property and equipment for the midstream and marketing segment includes investment in equity method investee totaling $244.0 million, $192.5 million and $58.3 million as of December 31, 2016, 2015 and 2014, respectively. Other fixed assets were allocated based on the number of employees in the respective segment as of December 31, 2016, 2015 and 2014.

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

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

Note 17—Subsidiary guarantors

The Guarantors have fully and unconditionally guaranteed the January 2022 Notes, the May 2022 Notes, the March 2023 Notes and the Senior Secured Credit Facility (and had guaranteed the January 2019 Notes until the Redemption Date), subject to the Releases. In accordance with practices accepted by the SEC, Laredo has prepared condensed consolidating financial statements to quantify the balance sheets, results of operations and cash flows of such subsidiaries as subsidiary guarantors. The following condensed consolidating balance sheets as of December 31, 2016 and 2015 and condensed consolidating statements of operations and condensed consolidating statements of cash flows each for the years ended December 31, 2016, 2015 and 2014 present financial information for Laredo on a stand-alone basis (carrying any investment in subsidiaries under the equity method), financial information for the subsidiary guarantors on a stand-alone basis (carrying any investment in subsidiaries under the equity method), and the consolidation and elimination entries necessary to arrive at the information for the Company on a condensed consolidated basis. Deferred income taxes for LMS and for GCM are recorded on Laredo's statements of financial position, statements of operations and statements of cash flows as they are disregarded entities for income tax purposes. Laredo and the Guarantors are not restricted from making intercompany distributions to each other. During the year ended December 31, 2016, certain assets were transferred from Laredo to LMS and from LMS to Laredo at historical cost. During the year ended December 31, 2014, certain assets were transferred from Laredo to LMS at historical cost.

Condensed consolidating balance sheet
December 31, 2016

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Accounts receivable, net	$ 70,570	$ 16,297	$ —	$ 86,867
Other current assets	65,884	2,026	—	67,910
Oil and natural gas properties, net	1,194,801	9,293	(8,240)	1,195,854
Midstream service assets, net	—	126,240	—	126,240
Other fixed assets, net	44,221	552	—	44,773
Investment in subsidiaries and equity method investee	376,028	243,953	(376,028)	243,953
Other long-term assets	13,065	3,684	—	16,749
Total assets	$ 1,764,569	$ 402,045	$ (384,268)	$ 1,782,346
Accounts payable	$ 14,427	$ 627	$ —	$ 15,054
Other current liabilities	150,531	22,360	—	172,891
Long-term debt, net	1,353,909	—	—	1,353,909
Other long-term liabilities	56,889	3,030	—	59,919
Stockholders' equity	188,813	376,028	(384,268)	180,573
Total liabilities and stockholders' equity	$ 1,764,569	$ 402,045	$ (384,268)	$ 1,782,346

Condensed consolidating balance sheet
December 31, 2015

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Accounts receivable, net	$ 74,613	$ 13,086	$ —	$ 87,699
Other current assets	244,477	56	—	244,533
Oil and natural gas properties, net	1,017,565	9,350	(1,923)	1,024,992
Midstream service assets, net	—	131,725	—	131,725
Other fixed assets, net	43,210	328	—	43,538
Investment in subsidiaries and equity method investee	301,891	192,524	(301,891)	192,524
Other long-term assets	84,360	3,916	—	88,276
Total assets	$ 1,766,116	$ 350,985	$ (303,814)	$ 1,813,287
Accounts payable	$ 12,203	$ 1,978	$ —	$ 14,181
Other current liabilities	158,283	44,351	—	202,634
Long-term debt, net	1,416,226	—	—	1,416,226
Other long-term liabilities	46,034	2,765	—	48,799
Stockholders' equity	133,370	301,891	(303,814)	131,447
Total liabilities and stockholders' equity	$ 1,766,116	$ 350,985	$ (303,814)	$ 1,813,287

Condensed consolidating statement of operations
For the year ended December 31, 2016

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total revenues	$ 427,028	$ 213,866	$ (43,516)	$ 597,378
Total costs and expenses	514,483	208,056	(37,199)	685,340
Operating income (loss)	(87,455)	5,810	(6,317)	(87,962)
Interest expense & other, net	(93,123)	—	—	(93,123)
Other non-operating income (expense)	(73,844)	9,381	(15,191)	(79,654)
Income (loss) before income tax	(254,422)	15,191	(21,508)	(260,739)
Income tax	—	—	—	—
Net income (loss)	$ (254,422)	$ 15,191	$ (21,508)	$ (260,739)

Condensed consolidating statement of operations
For the year ended December 31, 2015

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total revenues	$ 432,478	$ 198,248	$ (24,086)	$ 606,640
Total costs and expenses	2,897,272	203,278	(22,396)	3,078,154
Operating loss	(2,464,794)	(5,030)	(1,690)	(2,471,514)
Interest expense & other, net	(102,793)	—	—	(102,793)
Other non-operating income	182,396	6,708	(1,678)	187,426
Income (loss) before income tax	(2,385,191)	1,678	(3,368)	(2,386,881)
Income tax benefit	176,945	—	—	176,945
Net income (loss)	$ (2,208,246)	$ 1,678	$ (3,368)	$ (2,209,936)

Condensed consolidating statement of operations
For the year ended December 31, 2014

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total revenues	$ 738,446	$ 63,944	$ (8,505)	$ 793,885
Total costs and expenses	505,455	70,316	(8,272)	567,499
Operating income (loss)	232,991	(6,372)	(233)	226,386
Interest expense & other, net	(120,879)	—	—	(120,879)
Other non-operating income (expense)	317,980	(339)	6,711	324,352
Income (loss) before income tax	430,092	(6,711)	6,478	429,859
Income tax expense	(164,286)	—	—	(164,286)
Net income (loss)	$ 265,806	$ (6,711)	$ 6,478	$ 265,573

Condensed consolidating statement of cash flows
For the year ended December 31, 2016

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Net cash flows provided by operating activities	$ 355,458	$ 16,028	$ (15,191)	$ 356,295
Change in investments between affiliates	(73,988)	58,797	15,191	—
Capital expenditures and other	(489,577)	(74,825)	—	(564,402)
Net cash flows provided by financing activities	209,625	—	—	209,625
Net increase in cash and cash equivalents	1,518	—	—	1,518
Cash and cash equivalents, beginning of period	31,153	1	—	31,154
Cash and cash equivalents, end of period	$ 32,671	$ 1	$ —	$ 32,672

Condensed consolidating statement of cash flows
For the year ended December 31, 2015

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Net cash flows provided by operating activities	$ 316,838	$ 787	$ (1,678)	$ 315,947
Change in investments between affiliates	(136,252)	134,574	1,678	—
Capital expenditures and other	(532,146)	(135,361)	—	(667,507)
Net cash flows provided by financing activities	353,393	—	—	353,393
Net increase in cash and cash equivalents	1,833	—	—	1,833
Cash and cash equivalents, beginning of period	29,320	1	—	29,321
Cash and cash equivalents, end of period	$ 31,153	$ 1	$ —	$ 31,154

Condensed consolidating statement of cash flows
For the year ended December 31, 2014

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Net cash flows provided by (used in) operating activities	$ 496,955	$ (5,389)	$ 6,711	$ 498,277
Change in investments between affiliates	(113,449)	120,160	(6,711)	—
Capital expenditures and other	(1,292,191)	(114,770)	—	(1,406,961)
Net cash flows provided by financing activities	739,852	—	—	739,852
Net (decrease) increase in cash and cash equivalents	(168,833)	1	—	(168,832)
Cash and cash equivalents, beginning of period	198,153	—	—	198,153
Cash and cash equivalents, end of period	$ 29,320	$ 1	$ —	$ 29,321

Note 18—Recently issued or adopted accounting pronouncements

The Company considers the applicability and impact of all accounting standard updates ("ASU") issued by the Financial Accounting Standards Board ("FASB"). The ASUs listed below were either adopted during the year ended December 31, 2016 or the discussion of the ASU was determined to be meaningful to the Company's consolidated financial statements.

In August 2016, the FASB issued new guidance in Topic 230, *Classification of Certain Cash Receipts and Cash Payments*, to address the following cash flow issues: (i) debt prepayment or debt extinguishment costs; (ii) settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; (iii) contingent consideration payments made after a business combination; (iv) proceeds from the settlement of insurance claims; (v) proceeds from the settlement of corporate-owned life insurance policies; (vi) distributions received from equity method investees; (vii) beneficial interests in securitization transactions and (viii) separately identifiable cash flows and application of the predominance principle. The amendments in this update are effective for fiscal years beginning after December 15, 2017 and interim periods within those fiscal years. Early adoption is permitted, including adoption in an interim period. If an entity early adopts the amendments in an interim period, any adjustments should be reflected as of the beginning of the fiscal year that includes that interim period. An entity that elects early adoption must adopt all of the amendments in the same period. If practical, the amendments in this ASU should be applied using a retrospective transition method to each period presented. The Company elected to early-adopt this guidance in the third quarter of 2016 on a retrospective basis, and the adoption did not have an effect on its consolidated financial statements.

In March 2016, the FASB issued new guidance in Topic 718, *Compensation—Stock Compensation*, which seeks to simplify the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. The amendments in this update are effective for annual periods beginning after December 15, 2016 and interim periods within those annual periods. Early adoption is permitted for any entity in any interim or annual period. If an entity early adopts the amendments in an interim period, any adjustments should be reflected as of the beginning of the fiscal year that includes that interim period. An entity that elects early adoption must adopt all of the applicable amendments in the same period. The Company elected to early-adopt this guidance in the third quarter of 2016 utilizing the adoption methods required by the ASU. The Company will continue its current accounting policy of estimating forfeitures. See Note 7 for discussion of additional accounting consequences related to the adoption of this ASU.

In February 2016, the FASB issued new guidance in Topic 842, *Leases*. The core principle of the new guidance is that a lessee should recognize the assets and liabilities that arise from leases in the statement of financial position. A lessee should recognize in the statement of financial position a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. When measuring assets and liabilities arising from a lease, a lessee (and a lessor) should include payments to be made in optional periods only if the lessee is reasonably certain to exercise an option to extend the lease or not to exercise an option to terminate the lease. Similarly, optional payments to purchase the underlying asset should be included in the measurement of lease assets and lease liabilities only if the lessee is reasonably certain to exercise that purchase option. Reasonably certain is a high threshold that is consistent with and intended to be applied in the same way as the reasonably assured threshold in the previous leases guidance. In addition, also consistent with the previous leases guidance, a lessee (and a lessor) should exclude most variable lease payments in measuring lease assets and lease liabilities, other than those that depend on an index or a rate or are in substance fixed payments. For leases with a term of 12 months or less, a lessee is permitted to make an accounting policy election by class of underlying asset not to recognize lease assets and lease liabilities. If a lessee makes this election, it should recognize lease expense for such leases generally on a straight-line basis over the lease term. The recognition, measurement and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from previous GAAP. There continues to be a differentiation between finance leases and operating leases. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The modified retrospective approach includes a number of optional practical expedients that entities may elect to apply. These practical expedients relate to the identification and classification of leases that commenced before the effective date, initial direct costs for leases that commenced before the effective date and the ability to use hindsight in evaluating lessee options to extend or terminate a lease or to purchase the underlying asset. An entity that elects to apply the practical expedients will, in effect, continue to account for leases that commence before the effective date in accordance with previous GAAP unless the lease is modified, except that lessees are required to recognize a right-of-use asset and a lease liability for all operating leases at each reporting date based on the present value of the remaining minimum rental payments that were tracked and disclosed under previous GAAP. The amendments in this update are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application of the amendments in this update is permitted. The Company expects to provide insight regarding the impact the adoption of this standard will have on its consolidated financial statements in third-quarter 2017.

In July 2015, the FASB issued new guidance in Topic 330, *Inventory*, which seeks to simplify the measurement of inventory. The amendments in this update apply to inventory that is measured using all methods excluding last-in, first-out and the retail inventory method. The main substantive provision of this guidance is for an entity to change the subsequent measurement of inventory, within the scope of this guidance, from LCM to the lower of cost and NRV. NRV is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. The amendments in this ASU are effective for annual reporting periods beginning after December 15, 2016, including interim periods within those fiscal years and should be applied prospectively with earlier application permitted as of the beginning of an interim or annual reporting period. The Company early-adopted this ASU in the fourth quarter of 2016 on a prospective basis, and the adoption did not have an effect on its consolidated financial statements. See Note 2.j for additional discussion of the Company's inventory.

In April 2015, the FASB issued new guidance in Subtopic 350-40, *Intangibles—Goodwill and Other—Internal-Use Software*. The amendments in this update provide guidance to customers about whether a cloud computing arrangement includes a software license. If a cloud computing arrangement includes a software license, then the customer should account for the software license element of the arrangement consistent with the acquisition of other software licenses. If a cloud computing arrangement does not include a software license, the customer should account for the arrangement as a service contract. The guidance will not change GAAP for a customer's accounting for service contracts. In addition, the guidance in this update supersedes paragraph 350-40-25-16. The amendments in this update are effective for annual periods beginning after December 15, 2015, including interim periods within those annual periods and should be applied prospectively to all arrangements entered into or materially modified after the effective date or retrospectively. The Company adopted this ASU in the first quarter of 2016 on a prospective basis, and the adoption did not have an effect on its consolidated financial statements.

In May 2014, the FASB issued a comprehensive new revenue recognition standard that supersedes the revenue recognition requirements in Topic 605, *Revenue Recognition*, and industry-specific guidance in Subtopic 932-605, *Extractive Activities—Oil and Gas—Revenue Recognition*. The core principle of the new guidance is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for transferring those goods or services. The new standard also requires significantly expanded disclosure regarding the qualitative and quantitative information of an entity's nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The standard creates a five-step model that requires companies to exercise judgment when considering the terms of a contract and all relevant facts and circumstances. The standard allows for several transition methods: (a) a full retrospective adoption in which the standard is applied to all of the periods presented, or (b) a modified retrospective adoption in which the standard is applied only to the most current period presented in the financial statements, including additional disclosures of the standard's application impact to individual financial statement line items. In March, April, May and December 2016, the FASB, issued new guidance in Topic 606, *Revenue from Contracts with Customers*, to address the following potential implementation issues of the new revenue standard: (a) to clarify the implementation guidance on principal versus agent considerations, (b) to clarify the identification of performance obligations and the licensing implementation guidance and (c) to address certain issues in the guidance on assessing collectibility, presentation of sales taxes, noncash consideration, and completed contracts and contract modifications at transition. This new guidance is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. The Company is currently evaluating the impact the adoption of this standard will have on its consolidated financial statements.

Note 19—Subsequent events

a. Divestiture of oil and natural gas properties

On January 17, 2017, the Company completed the sale of 2,900 net acres and working interests in 16 producing vertical wells in the Midland Basin to a third-party buyer for a purchase price of $59.6 million. After transaction costs reflecting an economic effective date of October 1, 2016, the proceeds were $59.4 million net of working capital and closing adjustments and subject to final closing adjustments. A portion of these proceeds were used to pay down $55.0 million on the Senior Secured Credit Facility. The outstanding balance under the Senior Secured Credit Facility was $15.0 million as of the filing of this Annual Report.

Note 20—Supplemental oil, NGL and natural gas disclosures (unaudited)

a. Costs incurred in oil and natural gas property acquisition, exploration and development activities

Costs incurred in the acquisition, exploration and development of oil, NGL and natural gas assets are presented below:

	For the years ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Property acquisition costs:			
Evaluated[(1)]	$ 5,905	$ —	$ 3,873
Unevaluated	119,923	—	9,925
Exploration costs[(2)]	41,333	20,697	242,284
Development costs[(3)]	298,942	500,577	1,049,317
Total costs incurred	$ 466,103	$ 521,274	$ 1,305,399

(1) Evaluated property acquisition costs include $1.1 million in asset retirement obligations for the year ended December 31, 2016. See Note 4.a for additional discussion.

(2) The Company acquired significant leasehold interests during the year ended December 31, 2014. See Note 4.c for additional discussion.

(3) Development costs include $2.5 million, $13.4 million and $6.9 million in asset retirement obligations for the years ended December 31, 2016, 2015 and 2014, respectively.

b. *Capitalized oil, NGL and natural gas costs*

Aggregate capitalized costs related to oil, NGL and natural gas production activities with applicable accumulated depletion and impairment are presented below:

	For the years ended December 31,		
(in thousands)	2016	2015	2014
Capitalized costs:			
Evaluated properties	$ 5,488,756	$ 5,103,635	$ 4,446,781
Unevaluated properties not being depleted	221,281	140,299	342,731
	5,710,037	5,243,934	4,789,512
Less accumulated depletion and impairment	(4,514,183)	(4,218,942)	(1,586,237)
Net capitalized costs	$ 1,195,854	$ 1,024,992	$ 3,203,275

The following table shows a summary of the unevaluated property costs not being depleted as of December 31, 2016, by year in which such costs were incurred:

(in thousands)	2016	2015	2014	2013 and prior	Total
Unevaluated properties not being depleted[(1)]	$ 148,647	$ 1,839	$ 67,467	$ 3,328	$ 221,281

(1) Acquisition costs comprise 95% of the $221.3 million in unevaluated properties not being depleted.

Unevaluated properties, which are not subject to depletion, are not individually significant and consist of costs for acquiring oil, NGL and natural gas leaseholds where no evaluated reserves have been identified, including costs of wells being evaluated. The evaluation process associated with these properties has not been completed and therefore, the Company is unable to estimate when these costs will be included in the depletion calculation.

c. *Results of oil, NGL and natural gas producing activities*

The results of operations of oil, NGL and natural gas producing activities (excluding corporate overhead and interest costs) are presented below:

	For the years ended December 31,		
(in thousands)	2016	2015	2014
Revenues:			
Oil, NGL and natural gas sales	$ 426,485	$ 431,734	$ 737,203
Production costs:			
Lease operating expenses	75,327	108,341	96,503
Production and ad valorem taxes	28,586	32,892	50,312
	103,913	141,233	146,815
Other costs:			
Depletion	134,105	263,666	237,067
Accretion of asset retirement obligations	3,274	2,236	1,721
Impairment expense	161,064	2,369,477	—
Income tax (benefit) expense[(1)]	—	(164,141)	126,576
Results of operations	$ 24,129	$ (2,180,737)	$ 225,024

(1) During the years ended December 31, 2016 and 2015, the Company recorded valuation allowances against its deferred tax assets related to its oil, NGL and natural gas producing activities. Accordingly, for the years ended December 31, 2016 and 2015, income tax benefit is computed utilizing the Company's effective rates of 0% and 7%, respectively, which reflects tax deductions and tax credits and allowances relating to the oil, NGL and natural gas producing activities that are reflected in the Company's consolidated income tax benefit for the period. For the year ended December 31, 2014, income tax expense is computed utilizing the statutory rate.

d. Net proved oil, NGL and natural gas reserves

Ryder Scott Company, L.P. ("Ryder Scott"), the Company's independent reserve engineers, estimated 100% of the Company's proved reserves as of December 31, 2016, 2015 and 2014. In accordance with SEC regulations, reserves as of December 31, 2016, 2015 and 2014 were estimated using the Realized Prices (which are the Benchmark Prices adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead), see Note 2.g. The Company's reserves as of December 31, 2016 and 2015 are reported in three streams: oil, NGL and natural gas. The Company's reserves as of December 31, 2014 are reported in two streams: oil and liquids-rich natural gas with the economic value of the NGLs in the Company's natural gas included in the wellhead natural gas price. This change impacts the comparability of 2016 and 2015 with 2014. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil, NGL and natural gas properties. Accordingly, the estimates may change as future information becomes available.

The following tables provide an analysis of the changes in estimated reserve quantities of oil, NGL and natural gas for the years ended December 31, 2016 and 2015 and of oil and liquids-rich natural gas for the year ended December 31, 2014, all of which are located within the U.S.

	Year ended December 31, 2016			
	Oil (MBbl)	NGL (MBbl)	Gas (MMcf)	MBOE
Proved developed and undeveloped reserves:				
Beginning of year	52,639	36,067	221,952	125,698
Revisions of previous estimates	8,726	12,021	80,004	34,082
Extensions, discoveries and other additions	10,741	6,930	43,614	24,940
Purchases of reserves in place	276	116	822	529
Production	(8,442)	(4,784)	(29,535)	(18,149)
End of year	63,940	50,350	316,857	167,100
Proved developed reserves:				
Beginning of year	40,944	29,349	180,613	100,395
End of year	53,156	42,950	270,291	141,155
Proved undeveloped reserves:				
Beginning of year	11,695	6,718	41,339	25,303
End of year	10,784	7,400	46,566	25,945

	Year ended December 31, 2015			
	Oil (MBbl)	NGL (MBbl)	Gas (MMcf)	MBOE
Proved developed and undeveloped reserves:				
Beginning of year	140,190	—	642,794	247,322
Revisions of previous estimates(1)	(88,900)	35,477	(424,546)	(124,180)
Extensions, discoveries and other additions	10,511	5,865	36,074	22,388
Sales of reserves in place	(1,552)	(1,008)	(5,554)	(3,486)
Production	(7,610)	(4,267)	(26,816)	(16,346)
End of year	52,639	36,067	221,952	125,698
Proved developed reserves:				
Beginning of year	56,975	—	291,493	105,557
End of year	40,944	29,349	180,613	100,395
Proved undeveloped reserves:				
Beginning of year	83,215	—	351,301	141,765
End of year	11,695	6,718	41,339	25,303

(1) The positive NGL revisions of previous estimates and the negative natural gas revisions of previous estimates include the impact of the Company's conversion to three-stream reporting. For period prior to January 1, 2015, the Company presented its reserves 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.

	Year ended December 31, 2014		
	Oil (MBbl)	Gas (MMcf)	MBOE
Proved developed and undeveloped reserves:			
Beginning of year	111,498	552,702	203,615
Revisions of previous estimates	(10,134)	(67,350)	(21,359)
Extensions, discoveries and other additions	45,554	185,909	76,539
Purchases of reserves in place	173	498	256
Production	(6,901)	(28,965)	(11,729)
End of year	140,190	642,794	247,322
Proved developed reserves:			
Beginning of year	37,878	203,082	71,725
End of year	56,975	291,493	105,557
Proved undeveloped reserves:			
Beginning of year	73,620	349,620	131,890
End of year	83,215	351,301	141,765

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. 26,049 MBOE is due to a combination of positive performance, reduction in operating costs and other factors. Previously estimated quantities of 2,292 MBOE were removed due to derecognizing certain proved undeveloped locations and proved developed non-producing targets due to changes in development and drilling plans. In addition, 10,325 MBOE of revisions is due to proved undeveloped locations that were removed from the development plan in prior years, four of these locations were drilled in 2016 and seven are scheduled to be drilled in 2017. Extensions, discoveries and other additions of 24,940 MBOE during the year ended December 31, 2016 consisted of 13,302 MBOE that resulted from new wells drilled during the year and 11,638 MBOE that resulted from new horizontal proved undeveloped locations added during the year.

For the year ended December 31, 2015, the Company's negative revision of 124,180 MBOE of previously estimated quantities is primarily attributable to the removal of 106,883 MBOE due to the combined effect of the removal of 378 proved undeveloped locations and the net effect of reinterpreting 34 undeveloped locations. The 378 locations that were removed were comprised of 182 vertical Wolfberry wells due to lower commodity prices and 196 horizontal wells to better align the timing of their development with the Company's future drilling plans. The remaining 17,297 MBOE of negative revisions is due to a combination of pricing, performance and other changes to the proved developed producing and proved developed non-producing wells. Extensions, discoveries and other additions of 22,388 MBOE during the year ended December 31, 2015, consisted of 19,719 MBOE primarily from the drilling of new wells during the year and 2,669 MBOE from four new horizontal Middle Wolfcamp proved undeveloped locations added during the year.

For the year ended December 31, 2014, the Company's negative revision of 21,359 MBOE of previously estimated quantities is primarily attributable to the removal of 26,017 MBOE due to the combined effect of the removal of 226 proved undeveloped locations and the net effect of reinterpreting 345 undeveloped locations. The 226 locations that were removed were comprised of vertical Wolfberry and horizontal laterals to better align with the proved developed producing wells. The increase of 4,658 MBOE, which offsets the overall negative revision, is due to a combination of pricing, performance and other changes. Extensions, discoveries and other additions of 76,539 MBOE during the year ended December 31, 2014, consisted of 34,782 MBOE primarily from the drilling of new wells during the year and 41,757 MBOE from 113 new horizontal proved undeveloped locations added during the year. Purchases of minerals in place added 256 MBOE from acquisition of proved reserves in the Permian Basin.

e. Standardized measure of discounted future net cash flows

The standardized measure of discounted future net cash flows does not purport to be, nor should it be interpreted to present, the fair value of the oil, NGL and natural gas reserves of the property. An estimate of fair value would take into account, among other things, the recovery of reserves not presently classified as proved, the value of proved properties and consideration of expected future economic and operating conditions.

The estimates of future cash flows and future production and development costs as of December 31, 2016, 2015 and 2014 are based on the Realized Prices, which reflect adjustments to the Benchmark Prices for gravity, quality, local conditions, fuel and shrinkage and/or distance from market. All Realized Prices are held flat over the forecast period for all reserve categories in calculating the discounted future net revenues. Any effect from the Company's commodity hedges is excluded. In accordance with SEC regulations, the proved reserves were anticipated to be economically producible from the "as of date" forward based on existing economic conditions, including prices and costs at which economic producibility from a reservoir was determined. These costs, held flat over the forecast period, include development costs, operating costs, ad valorem and production taxes and abandonment costs after salvage. Future income tax expenses are computed using the appropriate year-end statutory tax rates applied to the future pretax net cash flows from proved oil, NGL and natural gas reserves, less the tax basis of the Company's oil, NGL and natural gas properties. The estimated future net cash flows are then discounted at a rate of 10%. The Company's net book value of evaluated oil, NGL and natural gas properties exceeded the full cost ceiling amount as of March 31, 2016 and each of the quarterly periods in 2015. See Note 2.g for discussion of the Benchmark Prices, Realized Prices and the corresponding non-cash full cost ceiling impairments recorded.

The standardized measure of discounted future net cash flows relating to proved oil, NGL and natural gas reserves is as follows:

	For the years ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Future cash inflows	$ 3,548,567	$ 3,269,184	$ 16,663,685
Future production costs	(1,238,369)	(1,321,471)	(3,616,775)
Future development costs	(290,505)	(376,701)	(2,471,985)
Future income tax expenses	—	—	(2,827,763)
Future net cash flows	2,019,693	1,571,012	7,747,162
10% discount for estimated timing of cash flows	(1,041,199)	(740,265)	(4,500,434)
Standardized measure of discounted future net cash flows	$ 978,494	$ 830,747	$ 3,246,728

It is not intended that the FASB's standardized measure of discounted future net cash flows represent the fair market value of the Company's proved reserves. The Company cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision, and the 10% discount rate is arbitrary. In addition, prices and costs as of the measurement date are used in the determinations, and no value may be assigned to probable or possible reserves.

Changes in the standardized measure of discounted future net cash flows relating to proved oil, NGL and natural gas reserves are as follows:

(in thousands)	For the years ended December 31, 2016	2015	2014
Standardized measure of discounted future net cash flows, beginning of year	$ 830,747	$ 3,246,728	$ 2,322,204
Changes in the year resulting from:			
Sales, less production costs	(322,573)	(290,501)	(590,388)
Revisions of previous quantity estimates	179,297	(2,444,322)	(320,275)
Extensions, discoveries and other additions	133,472	192,979	1,340,022
Net change in prices and production costs	(80,102)	(1,495,144)	145,740
Changes in estimated future development costs	22,153	(2,974)	(22,961)
Previously estimated development costs incurred during the period	189,085	162,237	92,135
Purchases of reserves in place	3,422	—	6,100
Divestitures of reserves in place	—	(29,149)	—
Accretion of discount	83,075	424,453	305,325
Net change in income taxes	—	997,805	(266,757)
Timing differences and other	(60,082)	68,635	235,583
Standardized measure of discounted future net cash flows, end of year	$ 978,494	$ 830,747	$ 3,246,728

Estimates of economically recoverable oil, NGL and natural gas reserves and of future net revenues are based upon a number of variable factors and assumptions, all of which are, to some degree, subjective and may vary considerably from actual results. Therefore, actual production, revenues, development and operating expenditures may not occur as estimated. The reserve data are estimates only, are subject to many uncertainties and are based on data gained from production histories and on assumptions as to geologic formations and other matters. Actual quantities of oil, NGL and natural gas may differ materially from the amounts estimated.

Note 21—Supplemental quarterly financial data (unaudited)

The Company's results by quarter for the periods presented are as follows:

(in thousands, except per share data)	Year ended December 31, 2016 First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$ 106,557	$ 146,773	$ 159,734	$ 184,314
Operating income (loss)	(176,788)	17,874	25,492	45,460
Net income (loss)	(180,371)	(71,432)	9,485	(18,421)
Net income (loss) per common share:				
Basic	$ (0.85)	$ (0.33)	$ 0.04	$ (0.08)
Diluted	$ (0.85)	$ (0.33)	$ 0.04	$ (0.08)

(in thousands, except per share data)	Year ended December 31, 2015 First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$ 150,694	$ 182,331	$ 150,340	$ 123,275
Operating loss	(26,498)	(501,480)	(927,859)	(1,015,677)
Net loss	(472)	(397,034)	(847,783)	(964,647)
Net loss per common share:				
Basic	$ —	$ (1.88)	$ (4.01)	$ (4.57)
Diluted	$ —	$ (1.88)	$ (4.01)	$ (4.57)

LAREDO PETROLEUM, INC.
CHANGE IN CONTROL
EXECUTIVE SEVERANCE PLAN

Effective November 9, 2011
As Amended June 21, 2015, December 14, 2015and
September 9, 2016

INTRODUCTION

The purpose of the Plan is to enable Laredo Petroleum, Inc. (the "**Company**," together with its subsidiaries, the "**Employer**") to offer certain protections to employees if their employment with the Employer is terminated by the Employer without Cause or by the Participant for Good Reason in connection with a Change in Control. Accordingly, to accomplish this purpose, the Board has adopted the Plan, effective as of November 9, 2011 (the "**Effective Date**").

Unless otherwise expressly provided in Section 2.3 or unless otherwise agreed to between the Employer and a Participant on or after the date hereof, Participants covered by the Plan shall not be eligible to participate in any other severance or termination plan, policy or practice of the Employer that would otherwise apply under the circumstances described herein. The Plan is intended to constitute a "top hat" plan under ERISA for the benefit of a select group of highly compensated or management employees. Capitalized terms and phrases used herein shall have the meanings ascribed thereto in Article I.

ARTICLE I
DEFINITIONS

For purposes of the Plan, capitalized terms and phrases used herein shall have the meanings ascribed in this Article.

"Accounting Firm" shall have the meaning set forth in Section 2.6 below.

"**Applicable Percentage**" shall mean (i) for the Company's Chief Executive Officer, 300%, (ii) for the Company's other executive officers as determined by the Board, other than the Chief Executive Officer, 200%, and (iii) for any employee who has a title of "Vice President" or as determined by the Board that is not otherwise described in clauses (i) or (ii) of this definition, 100%.

"Base Salary" shall mean a Participant's annual base compensation rate for services paid by the Employer to the Participant at the time immediately prior to the Participant's termination of employment, as reflected in the Employer's payroll records. Base Salary shall not include commissions, bonuses, overtime pay, incentive compensation, benefits paid under any qualified or non-qualified plan, any group medical, dental or other welfare benefit plan, non-cash compensation or any other additional compensation.

“Board” shall mean the Board of Directors of the Company.

“Bonus Target” shall mean (i) for the Company’s Chief Executive Officer, the sum of 300% of such officer’s target annual bonus plus the prorated amount of such target annual bonus for the fiscal year in which either the Change in Control occurs or the Participant’s termination of employment occurs, whichever is greater, (ii) for the Company’s Executive Vice Presidents or Senior Vice Presidents, the sum of 200% of such officer’s target annual bonus plus the prorated amount of such target annual bonus for the fiscal year in which either the Change in Control occurs or the Participant’s termination of employment occurs, whichever is greater, and (iii) for the Company’s other officers with a title of “Vice President” and not otherwise described in clauses (i) or (ii) of this definition, the sum of 200% of such officer’s target annual bonus plus the prorated amount of such target annual bonus for the fiscal year in which either the Change in Control occurs or the Participant’s termination of employment occurs, whichever is greater, as set forth under the Participant’s individual employment agreement with the Employer or in any written bonus plan, program or arrangement approved by the Board or the Compensation Committee of the Board.

“Cause” shall have the meaning in a Participant’s employment or similar services agreement, or if none (or in the absence of any definition of “Cause” contained in such an agreement), (i) the Participant’s commission of, conviction for, plea of guilty or nolo contendere to a felony or a crime involving moral turpitude, or other material act or omission involving dishonesty or fraud, (ii) the Participant’s conduct that results in or is reasonably likely to result in harm to the reputation or business of the Employer or any of its affiliates in any material way, (iii) the Participant’s failure to perform duties as reasonably directed by the Employer or the Participant’s material violation of any rule, regulation, policy or plan for the conduct of any service provider to the Employer or its affiliates or its or their business (which, if curable, is not cured within 5 days after notice thereof is provided to the Participant) or (iv) the Participant’s gross negligence, willful malfeasance or material act of disloyalty with respect to the Employer or its affiliates (which, if curable, is not cured within 5 days after notice thereof is provided to the Participant). Any determination of whether Cause exists shall be made by the Committee in its sole discretion.

“Change in Control” shall have the meaning set forth in the Laredo Petroleum Holdings, Inc. 2011 Omnibus Equity Incentive Plan, as amended from time to time.

“**COBRA**” shall mean the Consolidated Omnibus Budget Reconciliation Act of 1985, as amended.

“Code” shall mean the Internal Revenue Code of 1986, as amended.

"Code Section 409A" shall mean Section 409A of the Code together with the treasury regulations and other official published guidance promulgated thereunder.

"Committee" shall mean the Compensation Committee of the Board or such other committee appointed by the Board from time to time to administer the Plan.

"Company" shall have the meaning set forth in the Introduction above.

"**Continuation Period"** shall mean a period commencing on the date of a Participant's termination of employment until the earliest of: (A) eighteen (18) months following the date of termination; (B) the date the Participant becomes eligible for coverage under the health insurance plan of a subsequent employer; or (C) the date the Participant or the Participant's eligible dependents, as the case may be, cease to be eligible under COBRA.

"**Continued Health Coverage**" shall mean the benefit set forth in Section 2.2(b) below.

"Delay Period" shall mean the period commencing on the date the Participant incurs a Separation from Service from the Employer until the earlier of (A) the six (6)-month anniversary of the date of such Separation from Service and (B) the date of the Participant's death.

"Disability" shall mean a Participant's disability that would qualify as such under the Employer's long-term disability plan without regard to any waiting periods set forth in such plan.

"Effective Date" shall have the meaning set forth in the Introduction above.

"Employer" shall have the meaning set forth in the Introduction above.

"ERISA" shall mean the Employee Retirement Income Security Act of 1974, as amended.

"Exchange Act" shall mean the Securities Exchange Act of 1934, as amended.

"**Good Reason**" shall have the meaning in a Participant's employment or similar services agreement, or if none (or in the absence of any definition of "Good Reason" contained in such an agreement), shall mean the occurrence of any of the following events on or following a Change in Control without the Participant's express written consent, provided, that, the Participant gives notice to the Employer of the Good Reason event within ninety (90) days after the initial occurrence of the Good Reason event and such event is not fully corrected in all material respects by the Employer within thirty (30) days following receipt of the Participant's written notification: (a) a material diminution in the Participant's (i) title, (ii) authority, (iii) duties or responsibilities, or (iv) Base Salary (other than in connection with a diminution of base salaries to similarly situated employees), (b) a relocation of the Participant's principal business location to an area outside a 50 mile radius of the Participant's principal business location immediately prior to the Change in Control, or (c) the Employer's failure to pay amounts to the Participant when due.

"Net After Tax Benefit" shall have the meaning set forth in Section 2.6 below.

“Participant” shall mean any individual with the title of Vice President or above and any individual that is designated in writing by the Board or the Committee for participation in the Plan.

“Plan” shall mean the Laredo Petroleum, Inc. Change in Control Executive Severance Plan.

“Plan Administrator” shall have the meaning set forth in Section 4.1 below.

“Qualifying Event” shall have the meaning set forth in Section 2.1 below.

“Release” shall mean the general release of claims contemplated by Section 2.5 below.

“Separation from Service” shall mean termination of a Participant’s employment with the Employer, provided, that, such termination constitutes a separation from service within the meaning of Code Section 409A and the default presumptions set forth in the Treasury Regulations promulgated under Code Section 409A. All references in the Plan to a “resignation,” “termination,” “termination of employment” or like terms shall mean Separation from Service.

“Severance Benefits” shall mean collectively, the Severance Payments and the Continued Health Coverage.

“Severance Payments” shall mean the payments set forth in Section 2.2(a) below.

“Specified Employee” shall mean a Participant who, as of the date of his or her Separation from Service, is deemed to be a “specified employee” within the meaning of that term under Section 409A(a)(2)(B) of the Code and using the identification methodology selected by the Employer from time to time in accordance therewith, or if none, the default methodology set forth therein.

“**Underpayment**” shall have the meaning set forth in Section 2.6 below.

ARTICLE II
SEVERANCE BENEFITS

2.1 **Eligibility for Severance Benefits.**

(a) Qualifying Event for Participants. In the event that during the period commencing on the date of the consummation of a Change in Control and ending eighteen (18) months thereafter, the employment of a Participant is terminated by the Employer without Cause or by the Participant for Good Reason (each a “**Qualifying Event**”), then the Employer shall pay or provide the Participant with the Severance Benefits.

(b) Non-Qualifying Events. A Participant shall not be entitled to Severance Benefits under the Plan if the Participant’s employment is terminated for any reason other than a

Qualifying Event, including, without limitation, (i) by the Employer for Cause, (ii) by the Participant for any reason other than for Good Reason, or (iii) on account of the Participant's death or Disability.

2.2 **Amount of Severance Benefits.** Unless otherwise determined by the Committee at the time of termination, in the event that a Participant becomes entitled to benefits pursuant to Section 2.1 hereof, the Employer shall pay or provide the Participant with the Severance Benefits as follows:

(a) Severance Payment. Subject to the provisions of Sections 2.3 through 2.7, the Employer shall pay to the Participant the sum of (x) the product of the Applicable Percentage multiplied by the Participant's Base Salary and (y) the Participant's Bonus Target, if any. Any such Severance Payment shall be payable in a lump sum on the first payroll after the sixtieth (60^{th}) day following a Qualifying Event, so long as the conditions therefor have been fully satisfied.

(b) Continued Health Coverage. Subject to the provisions of Sections 2.3 through 2.7, and subject to a timely election pursuant to COBRA by a Participant, during the applicable Continuation Period the Company shall pay the full cost for continued coverage pursuant to COBRA, for the Participant and the Participant's eligible dependents, under the Employer's group health plans in which the Participant participated immediately prior to the date of termination of the Participant's employment. Following the applicable Continuation Period, the Participant shall be entitled to such continued coverage for the remainder of the COBRA period on a full self-pay basis to the extent eligible under COBRA. For the avoidance of doubt, nothing in this Plan shall prohibit the Employer from amending or terminating any group health plan. Notwithstanding anything in this Plan to the contrary, in the event that the payment of amounts payable hereunder this clause (b) shall result in adverse tax consequences under Chapter 100 of the Code, Code Section 4980D or otherwise to the Employer, the parties shall undertake commercially reasonable efforts to restructure such benefit in an economically equivalent manner to avoid the imposition of such taxes on the Employer, provided, however, that, should the Employer's auditors determine in good faith that no such alternative arrangement is achievable, the Participant shall not be entitled to his rights to payment under this clause (b). Further, the Employer's and the Participant shall undertake commercially reasonable efforts to structure the benefits under this clause (b) in a manner that is most tax efficient for the parties (i.e., on an after-tax basis), although neither the Employer nor any of its employees, directors, managers, board members, affiliates, parents, stakeholders, equityholders, agents, successors, predecessors or related parties guarantees the tax treatment of any benefit under this clause (b) and no such party shall have liability to the Participant or his beneficiaries with respect to the taxation of such benefits or amounts payable in respect thereof.

2.3 **No Other Entitlements.** Participants hereunder shall not be entitled to severance amounts under any other plan, program or policy of the Employer and any amounts required to be paid to Participant as a matter of law or contract shall offset amounts payable hereunder in a manner that does not result in adverse tax consequences to the Participant under Code Section 409A as determined by the Plan Administrator.

2.4 **No Duty to Mitigate/Set-off.** No Participant entitled to receive Severance Benefits hereunder shall be required to seek other employment or to attempt in any way to reduce any amounts payable to the Participant by the Employer pursuant to the Plan and, except as provided in Sections 2.2(b) hereof, there shall be no offset against any amounts due to the Participant under the Plan on account of any remuneration attributable to any subsequent employment that the Participant may obtain or otherwise. The amounts payable hereunder may be subject to setoff, counterclaim, recoupment, defense or other right which the Employer may have against the Participant, except as the Plan Administrator determines would result in adverse tax consequences to the Participant under Code Section 409A.

2.5 **Release Required.** Any amounts payable pursuant to the Plan shall be conditioned upon the Participant's execution and non-revocation, within sixty (60) days following the effective date of termination, of a general release of claims against the Employer, its affiliates, and related parties thereto, in a form reasonably satisfactory to the Employer. The Employer shall provide the release to the Participant within five (5) calendar days following the Participant's date of termination. The Release will contain customary carveouts for the payment of consideration payable hereunder (which shall serve as consideration for such Release), vested benefits under the Employer's qualified plans, directors' and officers' insurance and indemnification and such other carveouts as the Plan Administrator determines in its sole and absolute discretion. In the event that the Release is not executed or is revoked by the Participant in accordance with its terms, and benefits have been provided by the Employer to the Participant (including, without limitation, benefits under Section 2.2(b), the Participant shall be required (and the Employer will be entitled to setoff amounts owed to Participant) to immediately reimburse the Employer for the cost of benefits provided to Participant and his/her beneficiaries thereunder as reasonably determined by the Plan Administrator.

2.6 **Code Section 280G.** Notwithstanding any other provision of this Plan or any other agreement to which the Participant is a party to the contrary, if payments made pursuant to this Plan (when taken together with other payments to such Participant) are considered "excess parachute payments" under Section 280G of the Code, then such excess parachute payments plus any other payments made by the Employer and its affiliates to such Participant which are considered excess parachute payments shall be limited (cash first then stock compensation) to the greatest amount which may be paid to such Participant under Section 280G of the Code without causing any loss of deduction to the Employer under such Code Section, but only if, by reason of such reduction, the "Net After Tax Benefit" (as defined below) to the Participant shall exceed the net after tax benefit if such reduction was not made. "**Net After Tax Benefit**" for purposes of this Plan shall mean the sum of (i) the total amounts payable to the Participant under this Plan, plus

(ii) all other payments and benefits which the Executive receives or then is entitled to receive from the Employer and its affiliates that would constitute an “excess parachute payment” within the meaning of Section 280G of the Code, less (iii) the amount of federal and state income taxes payable with respect to the foregoing calculated at the maximum marginal income tax rate for each year in which the foregoing shall be paid to the Participant (based upon the rate in effect for such year as set forth in the Code at the time of termination of the Participant’s employment), less (iv) the amount of excise taxes imposed with respect to the payments and benefits described in (i) and (ii) above by Section 4999 of the Code. The determination of whether payments would be considered excess parachute payments and the calculation of all the amounts referred to in this Plan shall be made by the Employer’s regular independent accounting firm at the expense of the Employer (the “**Accounting Firm**”), which shall provide detailed supporting calculations. Any determination by the Accounting Firm shall be binding upon the Employer and the Participants. As a result of the uncertainty in the application of Section 4999 of the Code at the time of the initial determination by the Accounting Firm hereunder, it is possible that payments to which Participant was entitled, but that he or she did not receive pursuant to this Section, could have been made without the imposition of the excise tax imposed by Section 4999 of the Code (“**Underpayment**”). In such event, the Accounting Firm shall determine the amount of the Underpayment that has occurred and any such Underpayment shall be promptly paid by the Employer to or for the benefit of the Participant.

2.7 **Restrictive Covenants.** As a condition for the eligibility for the Severance Benefits hereunder, to the extent not already done, each Participant hereby agrees to execute the Laredo Petroleum, Inc. Confidentiality, Non-Disparagement and Non-Solicitation Agreement, substantially in the form attached hereto as Annex A.

ARTICLE III
UNFUNDED PLAN; ERISA

3.1 **Unfunded Status.** The Plan shall be “unfunded” for the purposes of ERISA and the Code and Severance Payments shall be paid out of the general assets of the Employer as and when Severance Payments are payable under the Plan. All Participants shall be solely unsecured general creditors of the Employer. If the Employer decides in its sole discretion to establish any advance accrued reserve on its books against the future expense of the Severance Payments payable hereunder, or if the Employer decides in its sole discretion to fund a trust under the Plan, such reserve or trust shall not under any circumstances be deemed to be an asset of the Plan.

3.2 **ERISA**. The Plan is intended to constitute a “top hat” plan under ERISA for the benefit of a select group of highly compensated or management employees.

ARTICLE IV
ADMINISTRATION OF THE PLAN

4.1 **Plan Administrator.** The general administration of the Plan on behalf of the Employer shall be placed with the Committee, or if none the Board (the "**Plan Administrator**").

4.2 **Reimbursement of Expenses of Plan Administrator.** The Employer may, in its sole discretion, pay or reimburse the members of the Plan Administrator for all reasonable expenses incurred in connection with their duties hereunder, including, without limitation, expenses of outside legal counsel.

4.3 **Retention of Professional Assistance.** The Plan Administrator may employ such legal counsel, accountants and other persons as may be reasonably required in carrying out its work in connection with the Plan.

4.4 **Books and Records.** The Plan Administrator shall maintain such books and records regarding the fiscal and other transactions of the Plan and such other data as may be required to carry out its functions under the Plan and to comply with all applicable laws.

4.5 **Indemnification.** The Plan Administrator and its members shall not be liable for any action or determination made in good faith with respect to the Plan. The Employer shall, to the fullest extent permitted by law, indemnify and hold harmless each member of the Plan Administrator for liabilities or expenses they and each of them incur in carrying out their respective duties under the Plan, other than for any liabilities or expenses arising out of such individual's willful misconduct or fraud.

ARTICLE V
AMENDMENT AND TERMINATION

The Employer reserves the right to amend or terminate, in whole or in part, any or all of the provisions of the Plan by action of the Board (or a duly authorized committee thereof) at any time. The Plan shall automatically terminate on the eighteen month anniversary following the first Change in Control to occur hereunder, provided, that, in no event shall any amendment reducing the Severance Benefits provided hereunder or any Plan termination be effective prior to the twelve (12) month anniversary of the Effective Date, and further provided that the Employer shall not amend or terminate the Plan at any time after (i) the occurrence of a Change in Control or (ii) the date the Employer enters into a definitive agreement which, if consummated, would result in a Change in Control, unless the potential Change in Control is abandoned (as publicly announced by the Employer), and in either case until eighteen (18) months after the occurrence of a Change in Control, provided, that, all Severance Benefits under the Plan have been paid.

ARTICLE VI
SUCCESSORS

For purposes of the Plan, the Employer shall include any and all successors or assignees, whether direct or indirect, by purchase, merger, consolidation or otherwise, to all or substantially all the business or assets of the Employer (or its members, as the case may be) and such successors and assignees shall perform the Employer's obligations under the Plan, in the same manner and to the same extent that the Employer would be required to perform if no such succession or assignment had taken place. In the event the surviving corporation in any transaction to which the Employer is a party is a subsidiary of another corporation, then the ultimate parent corporation of such surviving corporation shall cause the surviving corporation to perform the Plan in the same manner and to the same extent that the Employer would be required to perform if no such succession or assignment had taken place. In such event, the term "Employer," as used in the Plan, shall mean the Employer, as hereinbefore defined and any successor or assignee (including the ultimate parent corporation) to the business or assets which by reason hereof becomes bound by the terms and provisions of the Plan.

ARTICLE VII
MISCELLANEOUS

7.1 **Minors and Incompetents**. If the Plan Administrator shall find that any person to whom Severance Benefits are payable under the Plan is unable to care for his or her affairs because of illness or accident, or is a minor, any Severance Benefits due (unless a prior claim therefore shall have been made by a duly appointed guardian, committee or other legal representative) may be paid to the spouse, child, parent, or brother or sister, or to any person deemed by the Plan Administrator to have incurred expense for such person otherwise entitled to the Benefits, in such manner and proportions as the Plan Administrator may determine in its sole discretion. Any such Severance Benefits shall be a complete discharge of the liabilities of the Employer, the Plan Administrator and the Board under the Plan.

7.2 **Limitation of Rights.** Nothing contained herein shall be construed as conferring upon a Participant the right to continue in the employ of the Employer as an employee in any other capacity or to interfere with the Employer's right to discharge him or her at any time for any reason whatsoever.

7.3 **Payment Not Salary.** Any Severance Benefits payable under the Plan shall not be deemed salary or other compensation to the Participant for the purposes of computing benefits to which he or she may be entitled under any pension plan or other arrangement of the Employer maintained for the benefit of its employees, unless such plan or arrangement provides otherwise.

7.4 **Severability.** In case any provision of the Plan shall be illegal or invalid for any reason, said illegality or invalidity shall not affect the remaining parts hereof, but the Plan shall be construed and enforced as if such illegal and invalid provision never existed.

7.5 **Withholding.** The Employer shall have the right to make such provisions as it deems necessary or appropriate to satisfy any obligations it may have to withhold federal, state or local income or other taxes incurred by reason of payments pursuant to the Plan. In lieu thereof, the Company and/or the Employer shall have the right to withhold the amounts of such taxes from any other sums due or to become due from the Company and/or the Employer to the Participant upon such terms and conditions as the Plan Administrator may prescribe.

7.6 **Non-Alienation of Benefits.** The Severance Benefits payable under the Plan shall not be subject to alienation, transfer, assignment, garnishment, execution or levy of any kind, and any attempt to cause any Severance Benefits to be so subjected shall not be recognized.

7.7 **Governing Law.** To the extent legally required, the Code and ERISA shall govern the Plan and, if any provision hereof is in violation of any applicable requirement thereof, the Employer reserves the right to retroactively amend the Plan to comply therewith. To the extent not governed by the Code and ERISA, the Plan shall be governed by the laws of the State of Oklahoma without reference to rules relating to conflicts of law.

7.8 **Code Section 409A.**

(a) General. Neither the Employer nor any employee, director, manager, board member, affiliate, parent, stakeholder, equityholder, agent, successor, predecessor or related party makes a guarantee with respect to the tax treatment of payments hereunder and no such party shall be responsible in any event with regard to non-compliance with or failure to be exempt from Code Section 409A. The Plan is intended to either comply with, or be exempt from, the requirements of Code Section 409A. To the extent that the Plan is not exempt from the requirements of Code Section 409A, the Plan is intended to comply with the requirements of Code Section 409A and shall be limited, construed and interpreted in accordance with such intent. Notwithstanding the foregoing, in no event whatsoever shall the Employer be liable for any additional tax, interest or penalty that may be imposed on a Participant by Code Section 409A or any damages for failing to comply with Code Section 409A.

(b) Separation from Service; Specified Employees. A termination of employment shall not be deemed to have occurred for purposes of any provision of the Plan providing for the payment of any amounts or benefits upon or following a termination of employment unless such termination is also a Separation from Service. If a Participant is deemed on the date of termination to be a Specified Employee, then with regard to any payment hereunder that is nonqualified deferred compensation subject to Section 409A and that is specified as subject to this Section, such payment shall be delayed and not be made prior to the expiration of the Delay

Period. All payments delayed pursuant to this Section 7.8(b) (whether they would have otherwise been payable in a single lump sum or in installments in the absence of such delay) shall be paid to the Participant in a single lump sum on the first payroll date on or following the first day following the expiration of the Delay Period, and any remaining payments and benefits due under the Plan shall be paid or provided in accordance with the normal payment dates specified for them herein.

7.9 **Non-Exclusivity.** The adoption of the Plan shall not be construed as creating any limitations on the power of the Employer to adopt such other termination or benefits arrangements as it deems desirable, and such arrangements may be either generally applicable or limited in application.

7.10 **Headings and Captions**. The headings and captions herein are provided for reference and convenience only. They shall not be considered part of the Plan and shall not be employed in the construction of the Plan.

7.11 **Gender and Number.** Whenever used in the Plan, the masculine shall be deemed to include the feminine and the singular shall be deemed to include the plural, unless the context clearly indicates otherwise.

7.12 **Communications.** All announcements, notices and other communications regarding the Plan will be made by the Employer in writing.

The Plan Administrator keeps records of the Plan and is responsible for the administration of the Plan. The Plan Administrator will also answer any questions a Participant may have about the Plan. Service of legal process may be made upon the Plan Administrator (at the address above) or the Company's General Counsel.

No individual may, in any case, become entitled to additional benefits or other rights under the Plan after the Plan is terminated. Under no circumstances, will any benefit under the Plan ever vest or become nonforfeitable.

Adopted by the Board: November 9, 2011

Amended by the Board: June 21, 2015

Amended by the Board: November 14, 2015

Amended by the Board: September 9, 2016

ANNEX A

LAREDO PETROLEUM, INC.

Confidentiality, Non-Disparagement and Non-Solicitation Agreement

As an employee ("***Employee***") of **Laredo Petroleum, Inc**. or any of its subsidiaries or affiliates (collectively the "***Company***"), you acknowledge that the Company's business and services are highly specialized and that in the course of your employment you will be privy to certain business opportunities, geological and geophysical data, well and lease files, economic projections, and other documents and information regarding the Company's methods of operation, oil and gas exploration, production and prospects, and financial matters, all of which are highly confidential and constitute proprietary confidential information and trade secrets ("***Confidential Information***"). You further acknowledge that you have had or will have access to Confidential Information belonging to the Company, the loss of which by the Company cannot be adequately compensated by damages in an action at law. For purposes of this Agreement, "Confidential Information" includes both information disclosed to Employee by the Company and information developed by Employee in the course employment with the Company. In consideration of these premises, Employee agrees:

1. **Use or Disclosure Prohibited**. During the term of Employee's employment with the Company and following the voluntary or involuntary termination of Employee's employment with the Company for any reason, Employee shall not use for any purpose or disclose, directly or indirectly, to any person or entity, all or any part of the Confidential Information acquired by Employee during the course of employment with the Company.

2. **Company Records**. Employee shall not, directly or indirectly, copy, take, or remove from the Company's premises, any of the Company's books, records, geological or geophysical data, or other documents or materials (collectively "***Company Records***") and Employee agrees, upon request by the Company, to promptly return all Company Records which may be in his or her possession. "Company Records" shall include all geological and geophysical reports and related data such as maps, charts, logs, seismographs, seismic records, calculations, summaries, memoranda or opinions relating to such geophysical or geological data, production records, electric logs, core data, pressure data, lease files, well files and records, land files, abstracts, title opinions, title or curative matters, contract files, notes, records, drawings, manuals, correspondence, financial and accounting information, statistical data and compilations, patents, copyrights, trademarks, trade names, inventions, formulae, methods, processes, agreements, contracts, manuals or any other documents relating to the business of the Company, and all copies thereof.

3. **Non-Disparagement**. During Employee's employment with the Company and following any termination of employment with the Company for any reason whatsoever, the Employee agrees not to disparage, either orally or in writing, any of the Company or any of alliliates, business, services or practices, or its directors, managers, officers, stockholders, members, or employees.

4. **<u>Non-Solicitation.</u>** During the period ending one (1) year from termination of Employee’s employment for any reason, Employee shall not recruit, directly solicit the employment or services of, or induce employees of the Company to terminate their employment with the Company; provided, that nothing herein shall prohibit a general solicitation through the use of written or electronic media so long as any such solicitation is not structured to specifically target a Company employee.

5. **<u>Company Opportunities</u>**. Employee acknowledges that Employee owes a duty of loyalty to Company with respect to business opportunities of which Employee becomes aware while employed by Employer.

6. **<u>Employee Representation and Future Notification</u>**. Employee represents that his or her employment with the Company will not require the use of confidential or proprietary information in violation of any confidentiality, non-competition or similar agreement Employee may have entered into with a previous employer or other party or otherwise violate the provisions of any such agreement(s) in any manner. Should Employee no longer be employed by the Company, Employee agrees to advise his or her future employers of the restrictions contained in this Agreement and authorizes the Company to notify others, including Employee's future employers, of Employee’s obligations under this Agreement.

7. **<u>Remedies</u>**. The Employee acknowledges that money damages would not be sufficient remedy for Employee’s breach of this Agreement and the Company shall be entitled to specific performance and injunctive relief as remedies for such breach or any threatened breach. Such remedies shall not be deemed the exclusive remedies for a breach of this Agreement, but shall be in addition to all remedies available to the Company at law or in equity, including the recovery of money damages from the Employee.

8. **<u>Not an Employment Contract</u>**. This Agreement is not a contract of employment. Unless Employee has a separate written employment contract, Employee shall be deemed an employee-at-will.

9. **<u>Severability</u>**. The provisions of this Agreement shall be deemed to be severable, and the invalidity or unenforceability of any one or more of the provisions hereof shall not affect the validity or enforceability of any other provision.

DATED as of this day of , 201_.

LAREDO PETROLEUM, INC.	**EMPLOYEE**
/s/ Randy A. Foutch	
Randy A. Foutch	Name:
Chairman & CEO	

EXHIBIT 21.1

List of Subsidiaries of Laredo Petroleum, Inc.

Name of Subsidiary	Jurisdiction of Organization
Laredo Midstream Services, LLC	Delaware
Garden City Minerals, LLC	Delaware

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated February 16, 2017, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Laredo Petroleum, Inc. on Form 10-K for the year ended December 31, 2016. We consent to the incorporation by reference of said reports in the Registration Statements of Laredo Petroleum, Inc. on Form S-3 (File No. 333-209887, effective March 2, 2016) and on Form S-8 (File No. 333-178828, effective December 30, 2011 and File No. 333-211610, effective May 25, 2016).

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 16, 2017

EXHIBIT 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

Ryder Scott Company, L.P. hereby consents to the references to its firm in the form and context in which they appear in this Annual Report on Form 10-K filed by Laredo Petroleum, Inc. (the “Annual Report”). Ryder Scott Company, L.P. hereby further consents to the use and incorporation by reference of information from its reports regarding those quantities estimated by Ryder Scott of proved reserves of Laredo Petroleum, Inc. and its subsidiaries, the future net revenues from those reserves and their present value for the years ended December 31, 2016, 2015 and 2014, and to the inclusion of its summary report dated January 13, 2017 as an exhibit to the Annual Report. We hereby further consent to the incorporation by reference thereof into Laredo Petroleum, Inc.'s Registration Statements on Form S-8 (File No. 333-178828, effective December 30, 2011 and File No. 333-211610, effective May 25, 2016) and the Registration Statement of Laredo Petroleum, Inc. on Form S-3 (File No. 333-209887, effective March 2, 2016).

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas
February 16, 2017

EXHIBIT 31.1

CERTIFICATION

I, Randy A. Foutch, certify that:

1. I have reviewed this Annual Report on Form 10-K of Laredo Petroleum, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 16, 2017

/s/ Randy A. Foutch

Randy A. Foutch

Chairman and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Richard C. Buterbaugh, certify that:

1. I have reviewed this Annual Report on Form 10-K of Laredo Petroleum, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 16, 2017

/s/ Richard C. Buterbaugh

Richard C. Buterbaugh

Executive Vice President and Chief Financial Officer

EXHIBIT 32.1

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, Randy A. Foutch, Chairman and Chief Executive Officer of Laredo Petroleum, Inc. (the "Company"), and Richard C. Buterbaugh, Executive Vice President and Chief Financial Officer of the Company, certify that, to their knowledge:

(1) the Annual Report on Form 10-K of the Company for the period ending December 31, 2016, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

February 16, 2017

/s/ Randy A. Foutch

Randy A. Foutch

Chairman and Chief Executive Officer

February 16, 2017

/s/ Richard C. Buterbaugh

Richard C. Buterbaugh

Executive Vice President and Chief Financial officer

LAREDO PETROLEUM, INC.

SUMMARY REPORT

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

SEC PARAMETERS

As of

December 31, 2016

/s/ Val Rick Robinson

Val Rick Robinson, P.E.
TBPE License No. 105137
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

[SEAL]

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA STREET SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

January 13, 2017

Laredo Petroleum, Inc.
15 West 6th Street, Suite 900
Tulsa, Oklahoma 74119

Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of Laredo Petroleum, Inc. (Laredo) as of December 31, 2016. The subject properties are located in the state of Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 11, 2017 and presented herein, was prepared for public disclosure by Laredo in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Laredo as of December 31, 2016.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2016, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SUITE 600, 1015 4TH STREET, S.W. CALGARY, ALBERTA T2R 1J4 TEL (403) 262-2799 FAX (403) 262-2790
621 17TH STREET, SUITE 1550 DENVER, COLORADO 80293-1501 TEL (303) 623-9147 FAX (303) 623-4258

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
Laredo Petroleum, Inc.
As of December 31, 2016

	Proved		
	Developed Producing	Undeveloped	Total Proved
Net Remaining Reserves			
Oil/Condensate - MBBL	53,156	10,784	63,940
Plant Products - MBBL	42,950	7,400	50,350
Gas - MMCF	270,291	46,566	316,857
MBOE*	141,155	25,945	167,100
Income Data (M$)			
Future Gross Revenue	$ 2,809,714	$ 542,138	$ 3,351,852
Deductions	1,029,758	302,401	1,332,159
Future Net Income (FNI)	$ 1,779,956	$ 239,737	$ 2,019,693
Discounted FNI @ 10%	$ 925,922	$ 52,572	$ 978,494

** 6 MCF gas = 1 barrel of oil equivalent*

Liquid hydrocarbons are expressed in standard 42 gallon barrels and shown herein as thousands of barrels (MBBL). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. The net remaining reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MBOE means thousand barrels of oil equivalent. In this report, the revenues, deductions, and income data are expressed in thousands of U.S. dollars (M$).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package Aries™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of Laredo. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion costs, development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income. Liquid hydrocarbon reserves account for approximately 84 percent and gas reserves account for the remaining 16 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income (M$) As of December 31, 2016
Discount Rate Percent	Total Proved
5	$ 1,313,418
9	$ 1,030,175
15	$ 786,305
20	$ 661,475

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various proved reserve status categories are defined under the attachment entitled "Petroleum Reserves Status Definitions and Guidelines" in this report.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes included herein do not attribute gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Laredo's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease."

Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Laredo's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Laredo owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used individually or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods, analogy, and/or a combination of methods. Approximately 83 percent of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods include decline curve analysis which utilized extrapolations of historical production and pressure data available through December 2016, in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Laredo or obtained from public data sources and were considered sufficient for the purpose thereof. The remaining 17 percent of the proved producing reserves was estimated by analogy. This method was used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate.

All proved undeveloped reserves included herein were estimated by analogy to the historical performance of offset wells producing from the same reservoir. The data utilized from the analogues incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data that cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Laredo has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Laredo with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Laredo. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC Regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were projected to decline similarly to historical offset wells producing from the same reservoir. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Laredo. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

Laredo furnished us with the above mentioned average prices in effect on December 31, 2016. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic areas included in the report.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, fuel and shrinkage and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by Laredo. The differentials furnished by Laredo were reviewed by us for their reasonableness using information furnished by Laredo for this purpose.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Plains Pipeline	$39.25/Bbl	$37.44/Bbl
	NGLs	Mont Belvieu	$18.24/Bbl	$11.72/Bbl
	Gas	El Paso Permian	$2.33/MMBTU	$1.78/MCF

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by Laredo and are based on the operating expense reports of Laredo and include only those costs directly applicable to the leases or wells. When applicable for operated properties, an appropriate level of costs associated with regional administration and overhead was included in the operating costs assigned to leases and wells. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Laredo. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Laredo and are based on authorizations for expenditure for the proposed work and actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included. The estimates of the net abandonment costs furnished by Laredo were accepted without independent verification.

The proved undeveloped reserves in this report have been incorporated herein in accordance with Laredo's plans to develop these reserves as of December 31, 2016. The implementation of Laredo's development plans as presented to us and incorporated herein is subject to the approval process adopted by Laredo's management. As the result of our inquiries during the course of preparing this report, Laredo has informed us that the development activities included herein have been subjected to and received the internal approvals required by Laredo's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Laredo. Additionally, Laredo has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change or evolve from those under existing economic conditions as of December 31, 2016, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Laredo were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to Laredo. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing, and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Laredo.

Laredo makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Laredo has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in registration statements on Form S-3 and Form S-8 of Laredo of the references to our name as well as to the references to our third party report for Laredo, which appears in the December 31, 2016 annual report on Form 10-K of Laredo. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Laredo.

We have provided Laredo with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Laredo and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

\s\ Val Rick Robinson

Val Rick Robinson, P.E.
TBPE License No. 105137
Managing Senior Vice President

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Professional Qualifications of Primary Technical Engineer

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Val Rick Robinson was the primary technical person responsible for the estimate of the reserves, future production and income presented herein.

Mr. Robinson, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Robinson served in a number of engineering positions with ExxonMobil Corporation. For more information regarding Mr. Robinson's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Mr. Robinson earned a Bachelor of Science degree in Chemical Engineering from Brigham Young University in 2003 and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Robinson fulfills. As part of his 2016 continuing education hours, Mr. Robinson attended 23 hours of formalized training including the 2016 RSC Reserves Conference and various professional society presentations covering such topics as the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register, the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, overviews of the various productive basins of North America, computer software, and professional ethics.

Based on his educational background, professional training and more than 13 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Robinson has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the “Modernization of Oil and Gas Reporting; Final Rule” in the Federal Register of National Archives and Records Administration (NARA). The “Modernization of Oil and Gas Reporting; Final Rule” includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The “Modernization of Oil and Gas Reporting; Final Rule”, including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the “SEC regulations”. The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1) *completion intervals which are open at the time of the estimate, but which have not started producing;*
(2) *wells which were shut-in for market conditions or pipeline connections; or*
(3) *wells not capable of production for mechanical reasons.*

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) *Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.*

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.