LAREDO PETROLEUM

LAREDO PETROLEUM | 2017 ANNUAL REPORT

CORPORATE PROFILE

Laredo Petroleum is an independent energy company with headquarters in Tulsa, Oklahoma. Laredo's business strategy is focused on the acquisition, exploration and development of oil and natural gas properties and transportation of oil and natural gas from such properties, primarily in the Permian Basin in West Texas.

AREAS OF OPERATION

Our activities are focused on the multi-target stacked horizontal development of our Permian Basin acreage position located in West Texas. These plays are characterized by high oil and liquids-rich natural gas content, multiple target horizons, extensive production histories, long-lived reserves, high drilling success rate and significant resource potential.

PERMIAN BASIN

Oil and liquids-rich natural gas

Multiple target horizons

Extensive horizontal drilling program

Dear Stockholders:


RANDY A. FOUTCH | CHAIRMAN & CHIEF EXECUTIVE OFFICER

In 2017, Laredo continued to capitalize and expand upon strategies that have driven the Company's results since inception and are expected to underpin future development that maximizes the value of our leasehold. Our contiguous acreage base in the Permian Basin, investments in field infrastructure, support of the Medallion-Midland Basin pipeline system through both investment and volume commitments and collection of the data necessary to understand the subsurface characteristics of our leasehold all positively impacted 2017. As oil prices remained volatile and the cost of well stimulation services rose substantially, our focus on the measured, value-enhancing development of our acreage produced well-level returns on invested capital of more than 30%. We also believe completion design and spacing tests conducted in 2017 have positioned the Company for future high-density development in our Upper and Middle Wolfcamp formations and have the potential to enhance productivity in our Lower Wolfcamp and Cline formations.

The Company's contiguous leasehold enables the drilling of longer laterals, which lowers our drilling cost per foot and enhances returns. In 2017, our average lateral length was approximately two miles and we continued to expand technological capabilities by drilling three laterals of approximately three miles in length. We expect to continue to enhance well returns by increasing the average lateral length of our horizontal wells in 2018 and have identified approximately 500 locations on our leasehold in the Upper and Middle Wolfcamp formations that support laterals of at least 15,000 feet.

Our field infrastructure investments have contributed operational cost savings that have resulted in some of the lowest unit lease operating expenses in the Permian Basin. The main infrastructure to support thousands of horizontal wells has been built and savings are expected to increase as the number of our wells supported by these facilities increases. At the end of 2017, our water systems were gathering almost 80% of our produced water and recycling approximately 45% of that produced water. The Company's crude oil gathering system gathered approximately 80% of Laredo's gross operated crude production on pipe instead of trucking it to market, increasing our oil price realizations and shortening the time from production to sales. The combined financial benefits of our field infrastructure investments were approximately $28 million in 2017. The benefits extend to the environment as well. In 2017, our water and crude gathering infrastructure removed approximately 185,000 truckloads from the road by transporting crude and water by pipe.

We are intensely focused on controlling our costs. In addition to reducing our unit lease operating expenses by 15% in 2017, we reduced unit cash general and administrative costs by 17% and total unit cash costs by 11%, enabling the Company to more fully benefit from an increase in commodity prices. In 2017, our average unhedged realized price increased 24% while, due to our aggressive cost reduction initiatives, our cash margin increased by 48%.

Laredo has always been managed to balance short-term returns and long-term value. In addition to producing impressive well-level returns on invested capital in 2017, we applied our extensive technical database to increasing inventory in our Upper and Middle Wolfcamp formations. Using our physics-based workflows and high-resolution 3D reservoir geomodels, we conducted multiple tests of completion and spacing design needed to collect the production data to verify the potential for higher-density

development. Initial data is confirming our belief that we can drill more wells closer together in the Upper and Middle Wolfcamp formations that produce consistent with our 1.3 million BOE Upper/Middle Wolfcamp type curve and, over the long term, substantially increase the value of our leasehold with a higher-density development plan.

In 2017, the Company's focus on long-term investments produced a substantial benefit when we monetized our 49% interest in the Medallion-Midland Basin pipeline system. Our initial investment was utilized to fund a pipeline to transport our oil to Colorado City, Texas, and increase our exposure to better pricing in the Gulf Coast market. As other operators recognized the value of being able to access multiple sales points for their produced oil, the system expanded dramatically. In the fourth quarter of 2017, we closed on the sale of our interest in the system for net proceeds of approximately $830 million, representing three times our invested capital, while retaining all operational benefits of the system

We applied a substantial portion of the proceeds from the Medallion sale to debt reduction, eliminating approximately half of our debt and dramatically reducing the amount of interest we expect to pay on an annual basis. To further maintain our financial flexibility, we employ a disciplined hedging program designed to mitigate the impacts of commodity price swings on anticipated cash flows. For 2018, we have approximately 90% of our anticipated oil production and approximately 60% of our anticipated natural gas production hedged. We retain substantial upside benefit from increased oil prices as the majority of our oil hedges are structured as puts.

For 2018, the Company announced a capital budget of $555 million, representing a reduction in capital expenditures from 2017. The 2018 capital budget is more focused on development drilling and completion activities and has a significantly reduced testing component. We expect to grow production greater than 10% in 2018 while aligning capital expenditures with operating cash flow by the end of the year. Additionally, our Board of Directors has approved a program to repurchase up to $200 million of our common stock. Given our view of the Company's current fundamentals and future prospects, we believe this repurchase program is a compelling avenue for recognizing value for our current stockholders.

The Company achieved impressive operational results in 2017. We realized production growth of 17%, proved developed reserve growth of 36% and well-level returns on invested capital of 33%. These accomplishments could not have been achieved without the dedication of our employees. They displayed a strong commitment to creating value for our stockholders through our guiding principles of integrity, stewardship, respect, teamwork and success. Our Board of Directors has provided tremendous leadership and guidance throughout the year as we have transformed our balance sheet and made significant progress in enhancing our development plan. We also thank our stockholders for their support as we manage the Company to maximize the long-term value of our asset and generate sustainable returns.

Randy A Foutch

Randy A. Foutch
Chairman & Chief Executive Officer

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, 2017
or
☐ **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	**45-3007926**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
15 W. Sixth Street, Suite 900 Tulsa, Oklahoma	**74119**
(Address of principal executive offices)	(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 ☐

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate 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 ☐

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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates was approximately $1.3 billion on June 30, 2017, based on $10.52 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 12, 2018: 242,534,843

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2018 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2017, are incorporated by reference into Part III of this report for the year ended December 31, 2017.

LAREDO PETROLEUM, INC.

TABLE OF CONTENTS

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.

"*AFE*"—Authorization for expenditure.

"*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.

"*Benchmark prices*"—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, as required by SEC guidelines.

"*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.

"*HRGM*"—High-resolution geocellular models.

"*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.

"*Realized prices*"—Prices which reflect adjustments to the Benchmark prices for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

"*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.

"*Standardized measure*"—Discounted future net cash flows estimated by applying Realized 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.

"*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;
- 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;
- 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;
- 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 recruit and retain the qualified personnel necessary to operate our business;
- our ability to generate sufficient cash to service our indebtedness, fund our capital requirements and generate future profits;
- the potential impact on production of oil, NGL and natural gas from our wells due to tighter spacing of our wells;
- our ability to hedge and regulations that affect our ability to hedge;
- 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;
- 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;
- risks related to the geographic concentration of our assets;
- changes in the regulatory environment and changes in U.S. or international legal, political, administrative or economic conditions including 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;
- drilling and operating risks, including risks related to hydraulic fracturing activities;
- our 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
- the impact of the new tax laws enacted on December 22, 2017.

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 currently 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, 2017, we had assembled 124,843 net acres in the Permian Basin and had total proved reserves, presented on a three-stream basis, of 215,883 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. Prior to October 30, 2017, LMS also owned a 49% interest in Medallion Gathering & Processing, LLC ("Medallion"), which owns and operates more than 650 miles of pipeline in the Permian Basin ("Medallion-Midland Basin"). On October 30, 2017, LMS sold its entire 49% interest in Medallion to an unrelated third party (the "Medallion Sale" as more fully described below).

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 15 to our consolidated financial statements included elsewhere in this Annual Report).

2017 segment operation highlights

<u>Exploration and production</u>

- Produced a Company record 61,922 BOE/D in the fourth quarter of 2017, resulting in full-year 2017 production growth of 17% from full-year 2016;
- Grew proved developed reserves organically by 36% in 2017;
- Converted all 31 PUD locations booked at December 31, 2016 into proved producing locations in 2017;
- Completed 62 horizontal wells in 2017;
- Received $16.0 million of net cash settlements on maturing and early terminated derivatives, net of premiums paid, during 2017, increasing the average sales price for oil by $3.48 per Bbl and for natural gas by $0.06 per Mcf compared to pre-hedged average sales prices; and
- Reduced unit lease operating expenses to $3.22 per BOE in the fourth quarter of 2017, resulting in $3.53 per BOE for full-year 2017, a reduction of 15% from full-year 2016.

<u>Midstream and marketing</u>

- Recognized $27.9 million of net cash benefits from LMS field infrastructure investments through reduced capital and operating costs and increased revenue; and

- Sold LMS' 49% interest in Medallion for $831.3 million, net of estimated expenses and closing costs; estimated to be approximately three times our aggregate investment.

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, 2017, we held 124,843 net acres in the Permian Basin, all of which were held in 266 sections in the Permian-Garden City area, with an average working interest of 97% 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 two horizontal drilling targets (Upper and Middle Wolfcamp formations) that have multiple landing points within each target. In addition, we have also established the existence of additional producing formations, including the Lower Wolfcamp, Cline, Spraberry and Canyon. From our inception in 2006 through December 31, 2017, we have drilled and completed (i.e., the particular well is flowing) 240 horizontal wells in the Upper and Middle Wolfcamp and 967 vertical wells in the Wolfberry interval. Of these 240 horizontal wells, 151 were horizontal Upper Wolfcamp wells and 89 were horizontal Middle Wolfcamp wells. We have also drilled and completed 33 horizontal Lower Wolfcamp wells and 64 horizontal Cline wells. We anticipate focusing our 2018 drilling program on the Upper and Middle Wolfcamp formations due to their lower development cost and superior production expectations.

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.

As oil, NGL and natural gas prices and related margins have somewhat stabilized (although they are still at reduced levels from highs seen in 2013 and early 2014), we have approved a 2018 capital budget of $555 million, excluding acquisitions. Of this budget, $470 million is allocated to drilling and completion activities and $85 million is allocated to production facilities, land and other capitalized costs. Substantially all of the planned capital budget is anticipated to be invested in the Permian-Garden City area. Our strategy is to continue to concentrate our drilling activities on 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. We continue to use our existing data (and acquire new data) to optimize completion designs and well spacing within the development plan to enhance inventory and net asset value. We will also continue to pursue cost saving measures as we seek to continue to improve our capital efficiency; however, as commodity prices have increased, service costs have also risen. We are uncertain if this upward trend on service costs will continue.

On December 31, 2017, we had a total of four drilling rigs drilling horizontal wells. Our current drilling schedule anticipates that we will utilize three horizontal rigs during the first half of 2018 and add a fourth horizontal rig during the second half of the year. We do not anticipate utilizing any vertical rigs throughout 2018.

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 215,883 MBOE on a three-stream basis as of December 31, 2017, of which 89% are classified as proved developed reserves and 37% are attributed to oil reserves. We report 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, 2017, and average daily production presented on a three-stream basis for the year ended December 31, 2017. Based on estimates in the report prepared by Ryder Scott, we operated wells that represent 99.6% of the economic value of our proved developed oil, NGL and natural gas reserves as of December 31, 2017.

	As of December 31, 2017						
	Estimated net proved reserves[1]				Producing wells		
	MBOE	% of total reserves	% Oil	Net acreage	Gross	Net	Year ended December 31, 2017 average daily production (BOE/D)
Permian Basin	215,883	100%	37%	124,843	1,226	1,136	58,273
Other properties	—	—%	—%	4,292	—	—	—
Total	215,883	100%	37%	129,135	1,226	1,136	58,273

(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, 2017 was 58,273 BOE/D, 45% of which was oil, 27% of which was NGL and 28% of which was natural gas.

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 through 2017, commodity prices increased and stabilized at relatively higher prices but at significantly lower levels than the first half of 2014. Prices continue to remain volatile. Our capital budget for 2018 is $555 million, representing an 11% decrease from 2017 capital expenditures, excluding acquisitions. This budget is based on benchmark pricing of $55 per Bbl of oil and $3 per Mcf of natural gas.

Beginning in 2016, we purposely and significantly reduced the portion of our reserves that had historically been categorized as "proved undeveloped" or "PUD." We adjusted our 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 the geology of 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 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 insight gained as we drill and collect data across our acreage, regardless of SEC reserve-booking status. We converted all 31 PUD locations we booked at December 31, 2016 into proved producing locations in 2017. 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 2018, we have continued to limit our booked PUD locations to those locations that we have a high degree of certainty that we will develop and have made a specific capital commitment to drill within the first six months of 2018. This strategy maintains our flexibility to add new PUD locations and convert other locations to proved developed reserves as we deem appropriate and opportunistic.

We have built an extensive proprietary technical database that includes 597 in-house, core-calibrated petrophysical logs, 1,133 square miles of 3D seismic, 59 microseismic surveys, 1,278 open and cased-hole logging suites, including 148 dipole sonic logs, 6,032 feet of proprietary whole cores in 16 wells, 1,032 sidewall cores in 25 wells, 40 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 four fundamental areas: (i) high-resolution geocellular modeling, (ii) well spacing and completions optimization, (iii) reservoir engineering studies and (iv) predictive analytics.

HRGMs incorporate and integrate the above-described data to provide some of the highest quality three-dimensional characterizations of reservoir, mechanical and natural fracturing properties available with today's technology. Vertical resolution has increased approximately six-fold from our previously described Earth Model following comprehensive improvements in seismic reprocessing, acoustic impedance inversion and depth refinement workflows. Integrating these newly revised data sets with recent advances in sequence stratigraphic correlations and core-calibrated geological facies studies has resulted in an improved technical understanding and depiction of subsurface development potential at a much higher resolution. Improved depth accuracy of HRGM of 10 feet or less has been achieved, facilitating a transition during 2017 to a new "drill to plan" technical workflow. The drill to plan workflow optimally targets geological landing points within the inferred highest quality reservoir during pre-drill drilling engineering horizontal well-planning activities. This minimizes "on-the-fly" directional target changes during operations, increasing accuracy of well positioning within the perceived best reservoir, reducing time and costs associated with target changes and enhancing operational efficiencies. All of the 2018 planned wells are anticipated to adopt the drill to plan workflow.

Utilizing the HRGM developed across large portions of Laredo's acreage position, hydraulic fracture and proppant transport models have been utilized to explicitly describe fracture networks. These fracture networks have then been used in conjunction with reservoir simulators to match specific packages of wells with unique landing points and completion designs. These models are then used to assess possible differences in fracture geometry and well productivity due to a multitude of variables, which include but are not limited to, the landing point, well path, proppant loading, fluid loading, proppant concentration, pump rate and perforation design. Additionally, these models can be used for simulation of multi-well packages to assess potential interactions during the completion operation and total recovery factor of the resource in place.

Expanded regional sequence stratigraphic correlations within Laredo's previous scheme facilitates an enhanced framework for co-development of multiple landing points within individual formations. This ability provides the potential for increasing premium inventory within the Upper and Middle Wolfcamp formations. Microseismic analysis advanced our knowledge across various well spacing combinations and individual completion design field trials, improving our understanding of fracture geometry, cluster efficiency and proppant distribution associated with both well spacing and individual completion design. We consider our database a fundamental technical advantage, enabling the above-described workflows to yield critical insights into improved development decision making**.**

Predictive analytical modeling includes non-linear multivariate regression and machine learning algorithms facilitating the detection and assessment of the impact of individual parameters on fundamental value drivers. Proprietary software and workflows quantify the effects of individual parameters within completion designs, well spacing and rock properties on production. This knowledge can be leveraged to generate optimized, capital-efficient development plans.

We consider the above technical workflows to be potentially significant tools in optimizing multi-well co-development well packages. We anticipate that 100% of our horizontal wells to be drilled in 2018 will utilize at least some aspects of the above workflows. If our preliminary applications of these workflows are replicated in forward-looking well planning, we anticipate this will positively impact our ability to select optimal multi-well development plans.

Midstream and marketing

Capitalizing on our large contiguous acreage blocks, we have built crude oil, natural gas and/or water systems in five 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 2017, we commenced operations at two additional water recycle facilities, increasing our recycling capacity to more than 54,000 Bbls of water per day. Combined, our three water recycling facilities have a storage capacity of 3.6 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 2018 drilling program.

Additionally, we have built and maintain more than 59 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. Combined, our oil and gas gathering assets provided transportation for 66% of our production in 2017.

On October 30, 2017, LMS, together with Medallion Midstream Holdings, LLC ("MMH"), which is owned and controlled by an affiliate of The Energy & Minerals Group ("EMG"), completed the sale of 100% of the ownership interests in Medallion to an affiliate of Global Infrastructure Partners ("GIP"), for cash consideration of $1.825 billion, subject to customary post-closing adjustments (the "Medallion Sale"). LMS' net cash proceeds for its 49% ownership interest in Medallion in 2017 were $829.6 million, before post-closing adjustments and taxes, but after deduction of its proportionate share of fees and other expenses associated with the Medallion Sale. On February 1, 2018, closing adjustments were finalized and LMS received additional net cash of $1.7 million, for total net cash proceeds before taxes of $831.3 million. The proceeds were used to pay in-full borrowings on our Senior Secured Credit Facility, to redeem our May 2022 Notes (as defined below) and for working capital purposes. The Medallion Sale closed pursuant to the membership interest purchase and sale agreement, which provides for potential post-closing additional cash consideration that is structured based on GIP's realized profit at exit. There can be no assurance as to when and whether the additional consideration will be paid.

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 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. See Notes 4.a and 13.d to our consolidated financial statements included elsewhere in this Annual Report for a further discussion of our firm transportation agreement with Medallion.

As of December 31, 2017, 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	2018	2019	2020	2021 and after
Crude oil (MBbl):					
Sales commitments	17,328	6,935	6,935	3,458	—
Transportation commitments:					
Field	80,261	13,384	12,067	10,980	43,830
To U.S. gulf coast	26,160	3,650	3,650	3,660	15,200
Natural gas (MMcf):					
Sales commitments	75,011	8,701	8,701	8,459	49,150
Total commitments (MBOE)(1)	136,251	25,419	24,102	19,508	67,222

(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. One of these agreements is with Medallion and it remains in place and unchanged following the Medallion Sale. Effective as of June 1, 2017, we signed a Dedication and Connection Agreement with Medallion whereby we dedicated to Medallion for transportation the oil from a significant portion of our acreage, subject to certain exceptions. 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 substantially equivalent to 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 12 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, 2017, affiliates of Warburg Pincus LLC ("Warburg Pincus"), our founding member, owned 32.0% of our common stock.

Debt

Laredo Petroleum, Inc. is the borrower under our Fifth 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") and our $450 million of 5 5/8% senior unsecured notes due 2022 (the "January 2022 Notes"). We refer to the March 2023 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. The maturity date of our Senior Secured Credit Facility is May 2, 2022, provided that if the January 2022 Notes have not been redeemed or refinanced on or prior to October 17, 2021 (the "Early Maturity Date"), the Senior Secured Credit Facility will mature on such Early Maturity Date.

On April 6, 2015 (the "January 2019 Notes 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 up to, but not including, the January 2019 Notes Redemption Date. On November 29, 2017 (the "May 2022 Notes Redemption Date"), following the Medallion Sale, we redeemed our $500 million of 7 3/8% senior unsecured notes due 2022 (the "May 2022 Notes") at a redemption price of 103.688% of the principal amount of the May 2022 Notes, plus accrued and unpaid interest up to, but not including, the May 2022 Notes Redemption Date.

Our business strategy

Our goal is to enhance shareholder value by executing the following strategy:

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 in identifying the optimal landing point, well spacing 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 larger 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.
- In order to increase our operational flexibility, in the past three 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 more cost-efficient and 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 strategic manner while considering value-enhancing acquisitions, divestitures, mergers, redemptions, delevering and similar transactions

- We believe that maintaining a strong liquidity position is critical. Therefore, we will be highly selective in the projects that we consider and as we did with the Medallion Sale, we will continue to monitor the market for strategic opportunities that we believe could be accretive and enhance shareholder value. These opportunities may take the form of acquisitions, divestitures, mergers, redemptions, delevering or other similar transactions, any of which could result in the utilization of 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 2017, we realized a significant benefit through our hedging program and the certainty that it provided to our cash flow. In the future, we will continue to seek hedging opportunities on a multi-year basis to further protect our cash flows from commodity price fluctuations while maintaining upside exposure if commodity prices increase.

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.

Our competitive strengths

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

Exploration and production

Our extensive Permian technical database

- We have made a substantial upfront investment in technical data in order to accurately assess reservoir and production characteristics of our largely contiguous acreage. Our extensive proprietary technical data set, in combination with industry-leading technologies and in-house workflows, enables a comprehensive characterization and visualization of the total subsurface resource potential. This in turn facilitates a development planning workflow that seeks to maximize resource recovery and achieve a significant return on capital employed with respect to each discrete development package of wells.

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 124,843 net acres in the Permian-Garden City area that are largely contiguous with a high average working interest percentage (average working interest of 97% in all Laredo-operated producing wells), are 86% 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 enables 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 99.6% of the economic value of our proved developed reserves as of December 31, 2017, 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 recycle facilities 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 248 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, 2017. 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.

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 capacity for oil and access to four points of delivery. This capacity was not affected by the Medallion Sale. We also have 10,000 Bbls per day of firm transportation capacity 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, 2017, we held 4,292 net acres in the Palo Duro Basin. Approximately 96% of this acreage will expire in 2018, absent drilling or renegotiation of the applicable leases. We anticipate little or no activity on these properties in 2018.

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 discounted future cash flows. The following table presents the Benchmark Prices and Realized Prices for the periods presented:

	As of December 31,	
	2017	2016
Benchmark Prices:		
Oil ($/Bbl)	$ 47.79	$ 39.25
NGL ($/Bbl)[(1)]	$ 26.13	$ 18.24
Natural gas ($/MMBtu)	$ 2.63	$ 2.33
Realized Prices:		
Oil ($/Bbl)	$ 46.34	$ 37.44
NGL ($/Bbl)	$ 18.45	$ 11.72
Natural gas ($/Mcf)	$ 2.06	$ 1.78

(1) Based on the Company's average composite NGL Bbl.

Our net proved reserves were estimated at 215,883 MBOE on a three-stream basis as of December 31, 2017, of which 89% were classified as proved developed reserves and 37% are attributable to oil reserves. The following table presents summary data for our operating areas as of December 31, 2017.

	As of December 31, 2017	
	Proved reserves	% of total
Area:	(MBOE)	
Permian Basin	215,883	100%
Other properties	—	—%
Total	215,883	100%

Our estimated proved reserves as of December 31, 2017 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 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 following table sets forth additional information regarding our estimated proved reserves as of December 31, 2017 and 2016. Ryder Scott estimated 100% of our proved reserves as of December 31, 2017 and 2016. The reserve estimates as of December 31, 2017 and 2016 were prepared in accordance with the applicable SEC rules regarding oil, NGL and natural gas reserve reporting.

	As of December 31,	
	2017	2016
Proved developed producing:		
Oil (MBbl)	68,877	53,156
NGL (MBbl)	60,441	42,950
Natural gas (MMcf)	371,946	270,291
Total proved developed producing (MBOE)	191,309	141,155
Proved undeveloped:		
Oil (MBbl)	10,536	10,784
NGL (MBbl)	6,930	7,400
Natural gas (MMcf)	42,646	46,566
Total proved undeveloped (MBOE)	24,574	25,945
Estimated proved reserves:		
Oil (MBbl)	79,413	63,940
NGL (MBbl)	67,371	50,350
Natural gas (MMcf)	414,592	316,857
Total estimated proved reserves (MBOE)	215,883	167,100
Percent developed	89%	84%

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.

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 through 2017 commodity prices increased and stabilized at relatively higher prices but significantly lower than prices in the first half of 2014. However, prices continue to remain volatile and below 2014 highs. Our capital budget for 2018, excluding acquisitions, is $555 million, representing an 11% decrease from 2017 capital expenditures, excluding acquisitions. This budget is based on benchmark pricing of $55 per Bbl of oil and $3 per Mcf of natural gas.

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 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 the geology of 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. We converted all 31 PUD locations booked at December 31, 2016 into proved producing locations in 2017. 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 2018, we have continued to limit our booked PUD locations to those we have a high degree of certainty to believe that we will develop and have made a specific capital commitment to drill within the first six months of 2018. 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, 2017 and 2016 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 18 years of practical experience, with nine 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 decreased from 25,945 MBOE as of December 31, 2016 to 24,574 MBOE as of December 31, 2017. We estimate that we incurred $223.8 million of costs to convert 25,945 MBOE of proved undeveloped reserves from 31 locations into proved developed reserves in 2017. New proved undeveloped reserves of 15,936 MBOE were added during the year from 18 new horizontal Wolfcamp locations. Positive revisions to proved undeveloped reserves of 8,638 MBOE were due to adding eight undeveloped locations that were removed from reserves in a previous year. A final investment decision has been made on these 26 locations and they are scheduled to be drilled and completed in 2018.

Estimated total future development and abandonment costs related to the development of proved undeveloped reserves as shown in our December 31, 2017 reserve report are $212.0 million. Based on this report and our PUD booking methodology, the capital estimated to be spent in 2018 to develop the proved undeveloped reserves is $210.0 million and $0 for each of 2019, 2020, 2021 and 2022. 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 the first six months of 2018. 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, 2017, 2016 and 2015. Our reserves and production are 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)	**2017**	**2016**	**2015**
Sales volumes:			
Oil (MBbl)	9,475	8,442	7,610
NGL (MBbl)	5,800	4,784	4,267
Natural gas (MMcf)	35,972	29,535	26,816
Oil equivalents (MBOE)(1)(2)	21,270	18,149	16,346
Average daily sales volumes (BOE/D)(2)	58,273	49,586	44,782
Oil, NGL and natural gas sales (in thousands):			
Oil	$ 445,012	$ 318,466	$ 329,301
NGL	$ 101,438	$ 56,982	$ 50,604
Natural gas	$ 75,057	$ 51,037	$ 51,829
Average sales prices without hedges:			
Index oil ($/Bbl)(3)	$ 50.95	$ 43.32	$ 48.80
Oil, realized ($/Bbl)(4)	$ 46.97	$ 37.73	$ 43.27
Index NGL ($/Bbl)(3)	$ 26.36	$ 18.97	$ 18.81
NGL, realized ($/Bbl)(4)	$ 17.49	$ 11.91	$ 11.86
Index natural gas ($/MMBtu)(3)	$ 3.08	$ 2.46	$ 2.66
Natural gas, realized ($/Mcf)(4)	$ 2.09	$ 1.73	$ 1.93
Average price, realized ($/BOE)(4)	$ 29.22	$ 23.50	$ 26.41
Average sales prices with hedges(5):			
Oil, hedged ($/Bbl)	$ 50.45	$ 58.07	$ 74.41
NGL, hedged ($/Bbl)	$ 16.91	$ 11.91	$ 11.86
Natural gas, hedged ($/Mcf)	$ 2.15	$ 2.20	$ 2.42
Average price, hedged ($/BOE)	$ 30.71	$ 33.73	$ 41.71
Average costs per BOE sold(1):			
Lease operating expenses	$ 3.53	$ 4.15	$ 6.63
Production and ad valorem taxes	$ 1.78	$ 1.58	$ 2.01
Midstream service expenses	$ 0.19	$ 0.22	$ 0.36
General and administrative:			
Cash	$ 2.85	$ 3.45	$ 4.03
Non-cash stock-based compensation, net of amounts capitalized	$ 1.68	$ 1.61	$ 1.50
Depletion, depreciation and amortization	$ 7.45	$ 8.17	$ 16.99

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

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

(3) 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 Bbl. 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.

(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.

(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.

Productive wells

The following table sets forth certain information regarding productive wells in each of our core areas as of December 31, 2017. 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	816	342	1,158	1,122	97%
Non-operated Permian-Garden City	61	7	68	14	21%
Other properties	—	—	—	—	—%
Total	877	349	1,226	1,136	93%

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own an interest as of December 31, 2017 for each of our core operating areas, including acreage 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	123,424	106,883	21,114	17,960	144,538	124,843	86%
Other properties	—	—	7,772	4,292	7,772	4,292	—%
Total	123,424	106,883	28,886	22,252	152,310	129,135	83%

Undeveloped acreage expirations

The following table sets forth the gross and net undeveloped acreage in our core operating areas as of December 31, 2017 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.

	2018		2019		2020		2021	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian Basin	11,846	10,461	521	260	5,577	4,095	—	—
Other properties	7,252	4,122	520	170	—	—	—	—
Total	19,098	14,583	1,041	430	5,577	4,095	—	—

Of the total undeveloped acreage identified as expiring over the next four years, 0 net acres have associated PUD reserves as of December 31, 2017.

At December 31, 2016, 357 net acres of potentially expiring leasehold were identified as attributable to PUD reserves. All of the PUD reserves on those acres were drilled and completed in 2017.

At December 31, 2015, 40 net acres of potentially expiring leasehold were identified as attributable to PUD reserves. 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, 2017, 2016 and 2015. 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.

	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	62	60.7	45	44.5	93	80.4
Dry	—	—	—	—	—	—
Total development wells	62	60.7	45	44.5	93	80.4
Exploratory wells:						
Productive	—	—	—	—	2	2
Dry	—	—	1	0.5	—	—
Total exploratory wells	—	—	1	0.5	2	2

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, 2017, 83% of all of our net leasehold acreage was HBP and 86% of our Permian-Garden City acreage was HBP.

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 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. This well design is intended to eliminate 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 the approved disposal wells. 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, we have constructed and currently operate three water recycle facilities on our production corridors providing a recycling capacity of more than 54,000 Bbls of water per day, and a storage capacity of more than 3.6 million Bbls.

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-Hydraulic fracturing." 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, NGL 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, NGL 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 current 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 tended to increase over time. 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 ("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 December 2016, 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 ("Corps"). On June 29, 2015, the EPA and the Corps jointly promulgated final rules redefining the scope of waters protected under the Clean Water Act. To the extent the rule expands the range of properties subject to the Clean Water Act's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. Following its promulgation, numerous states and industry groups challenged the rule and, on October 9, 2015, a federal court stayed the rule's implementation nationwide, pending further action in court. In response to this decision, the EPA and the Corps have resumed nationwide use of the agencies' prior regulations defining the term "waters of the United States." Further, on February 28, 2017, President Trump signed an executive order directing the relevant executive agencies to review the rules and to initiate rulemaking to rescind or revise them, as appropriate under the stated policies of protecting navigable waters from pollution while promoting economic growth, reducing uncertainty, and showing due regard for Congress and the states. On July 27, 2017, the EPA and the Corps published a proposed rule to rescind the 2015 rules, and, on November 22, 2017, the agencies published a proposed rule to maintain the status quo pending the agencies review of the 2015 rules.

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 previously announced its 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 actions may have on our business at this time, but further regulation of hydraulic fracturing activities 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. On March 28, 2017, President Trump signed an executive order directing the BLM to review the rule, and, if appropriate, to initiate a rulemaking to rescind or revise it. Accordingly, on December 29, 2017, the BLM published a final rule to rescind the 2015 hydraulic fracturing rule. Further legal challenges are expected. At this time, it is uncertain when, or if, the rule will be implemented, and what impact it would have on our operations.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. 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.

<u>*Air emissions*</u>

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. Also, on May 12, 2016, the EPA issued a final rule regarding the criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements. 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 rules include NSPS for completions of hydraulically fractured gas wells and establish specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rules seek 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. However, in a March 28, 2017 executive order, President Trump directed the EPA to review the 2016 regulations and, if appropriate, to initiate a rulemaking to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation's energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. On June 16, 2017, the EPA published a proposed rule to stay for two years certain requirements of the 2016 regulations, including fugitive emission requirements.

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. On March 28, 2017, President Trump signed an executive order directing the BLM to review the above rule and, if appropriate, to initiate a rulemaking to rescind or revise it. Accordingly, on December 8, 2017, the BLM published a final rule to suspend or delay certain requirements of the 2016 methane rule until January 17, 2019. Further legal challenges are expected. At this time, it is uncertain when, or if, the rule will be implemented, and what impact it would have on our operations.

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 mandate the use of 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 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 the 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, 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. For a more complete description of potential risks that such regulations may impose on our operations, see, "Item 1A. Risk Factors—Risks related to our business—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."

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, though, in December 2017, the U.S. Fish and Wildlife Service ("USFWS") provided guidance limiting the reach of the Act. The USFWS 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 2017, 2016 or 2015.

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 was withdrawn by the PHMSA in January 2017, and it is unclear whether and to what extent the PHMSA will move forward with its regulatory reforms.

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, 2017 were negligible relative to the overall revenues and profits of Banco Santander SA.

(b) 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, 2017. The accounts are in arrears (£1,844.73 in debit combined) and are currently being managed by Santander UK Collections & Recoveries department. No revenues or profits were generated by Santander UK on these accounts in the year ended December 31, 2017."

Employees

As of December 31, 2017, we had 361 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 and Dallas, Texas.

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 beginning in the second half of 2014. While prices have increased from recent lows, they are still significantly below previous highs and 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, production and 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 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 in the past and may in the future 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 further 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, in recent years, 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 scheduled 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 would likely cause a decline in our stock price.

The potential drilling locations that we have tentatively internally identified for our future wells 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.

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, our ability to leverage our data and development experience to drill wells in multi-well packages with tighter spacing, including the impact on longer laterals, the availability of drilling services and equipment, 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. As such, it is likely that our actual drilling activities, especially in the long term, could materially differ from those presently anticipated.

There is no guarantee that we will be successful in optimizing our spacing, drilling and completions techniques in order to maximize our inventory and net asset value.

As we accumulate and process geological and production data, we attempt to create a development plan, including well spacing and completion design, that maximizes our inventory and other factors such as oil as a percentage of overall production, which impact net asset value. However, due to many factors, including some beyond our control, there is no guarantee that we will be able to find the optimal plan or one that provides continuous improvement. If we are unable to design and implement an effective spacing, drilling and completions strategy, it may have a material adverse effect on our production results, financial performance, stock price and net asset value.

The unavailability or high cost of additional oilfield services, including personnel, drilling rigs, equipment and supplies, 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 and complete wells and conduct field operations (including, but not limited to, frac crews), 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 also been shortages of drilling and workover rigs, pipe, sand, water and equipment as demand for rigs, crews, supplies and equipment has increased along with the number of wells being drilled. In particular, in recent months, the high level of drilling activity in the Permian Basin has resulted in equipment and crew shortages in completions. 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, shortages in completions equipment and crews as well as 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.

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 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, rates of return and other projected capital efficiencies.

Currently, we receive a level of cash flow stability 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 and, in the past, call spreads. In accordance with applicable accounting principles, we are required to record our derivatives at fair market value, and they are included in 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. As our current hedges expire, there is a significant uncertainty that we will be able to put new hedges in place that satisfy our hedge philosophy.

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.

In addition, recent government regulation may adversely impact our ability to hedge these risks.

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

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.

We may incur significant additional amounts of debt.

As of February 13, 2018, we had total long-term indebtedness of $800.0 million. 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.

Our use of 2D and 3D seismic, analytics and other data 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, analytics and other data 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.

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 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 (i) the sale of our oil, NGL and natural gas production ($67.1 million in receivables as of December 31, 2017), which we market to energy marketing companies, refineries and affiliates, (ii) the sale of purchased oil and other products ($19.5 million in receivables as of December 31, 2017) and (iii) net joint operations receivables ($8.8 million as of December 31, 2017). 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 four largest purchasers of our oil, NGL and natural gas production accounted for 39.3%, 26.1%, 17.4% and 12.6%, respectively, of our total oil, NGL and natural gas revenues for the year ended December 31, 2017. We had one customer that accounted for 97.5% of our sales of purchased oil for the year ended December 31, 2017. See Note 12 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 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 that 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 oil 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 business could be negatively impacted by disruption of electronic systems, security threats, including cyber-security threats, and other disruptions.

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.

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. In particular, cyber-security attacks 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.

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 13, 2018 we had a $1.0 billion borrowing base with no amounts 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 $1.0 billion would result in increased annual interest expense of $10.0 million and a decrease in our income before income taxes. 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 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.

We may be unable to quickly adapt to changes in market/investor priorities.

Historically, one of the key drivers in the unconventional resource industry has been growth in production and reserves. With the continued downturn and volatility in oil and natural gas prices, and the possibility that interest rates will rise in the near term, increasing the cost of borrowing, the market and investor emphasis has elevated capital efficiency and free cash flow from earnings as potentially the key drivers for energy companies, especially those primarily focused in the shale play arena. Shifts in focus such as these sometimes require changes in planning and resource management, which cannot necessarily occur instantaneously. Any delay in responding to such changes in market sentiment or perception can result in the investment community in general having a negative sentiment regarding our business plan, potential profitability and our ability to operate in a manner deemed "efficient," which can have a negative impact on the price of our common stock.

The loss of senior management or technical personnel and the failure to attract, train and retain qualified personnel could adversely affect our operations.

We have historically depended on our senior management for the general supervision of the Company. As senior management has aged, we have attempted to hire, train and retain younger management personnel, including technical personnel, with the view toward business growth and succession planning. Effective succession planning, which we have recently become more focused on, is important to our long-term success. Failure to ensure effective transfer of knowledge and smooth transitions involving senior management and technical personnel could hinder our strategic planning and execution and could have a material adverse impact on our operations. We do not maintain any key-man or similar insurance for any officer or other employee.

We may not always foresee new operational/technical issues as new technology enables greater operational capabilities.

The unconventional oil and natural gas industry has seen a large increase in new technologies to enhance all aspects of operations. This boon has arguably accelerated as a result of the recent and extended downturn in commodity prices, forcing companies to find new ways to efficiently produce oil and natural gas. While such technologies can and often ultimately enhance operations, production and profitability, the utilization of such technologies, especially in their early phases, may result in unforeseen consequences and operational issues, resulting in negative consequences. As an example, new technologies have resulted in the ability to drill longer horizontal laterals than previously envisioned; however, in certain instances such longer laterals may initially take a longer than projected time to begin flow-back of production, thereby causing us to fail to meet short-term projections, with a resulting negative impact on our stock price.

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 oil pipelines that transport our oil to market have quality specifications, including a Reid Vapor Pressure ("RVP") specification. While our tank batteries and equipment are designed to deliver oil that meets all pipeline specifications, including RVP, there is a risk that our 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 oil that does not meet their quality specifications, including RVP, be shut in until such oil 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.

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. Texas has previously experienced, and may experience again, low inflows of water. 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, the Safe Drinking Water Act, the Oil Pollution Act, 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. The RRC adopted new regulations effective in November 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 environmental and occupational health and safety matters" for a further description of the laws and regulations that affect us.

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 $1.0 billion. 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 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 13, 2018, we had no borrowings outstanding under our Senior Secured Credit Facility. We anticipate borrowing 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.

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 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 twelve 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 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."

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;
- 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 current ratio and maximum leverage 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. Our Senior Secured Credit Facility terminates in May 2022, provided that if the January 2022 Notes have not been redeemed or refinanced on or prior to the Early Maturity Date, the Senior Secured Credit Facility will terminate on the Early Maturity Date.

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 operator. 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, 2017, the Company's positive revision of 35,351 MBOE of previously estimated quantities is primarily attributable to the combination of positive performance, price increases 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 positive revisions in 2016 and 2017, 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 18.d to our consolidated financial statements included elsewhere in this Annual Report.

As a result of the volatility 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.h to our consolidated financial statements included elsewhere in this Annual Report for additional information.

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, 2017, 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, interruption of the processing or transportation of oil or natural gas, as well as impacts from extreme weather or other natural disasters impacting the Permian Basin.

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 could be impacted by the outcome of pending litigation as well as unexpected litigation or proceedings. Certain litigation claims may not be covered under our insurance policies, or our insurance carriers may seek to deny coverage. Because we cannot accurately predict the outcome of any action, it is possible that, as a result of pending and/or unexpected litigation, we will be subject to adverse judgments or settlements that could significantly reduce our earnings or result in losses. See "Item 3. Legal Proceedings" for a description of our pending litigation.

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 impact of litigation as well as 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.

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, which involves the injection of water, proppants and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production, is typically regulated by state oil and natural gas commissions. However, legislation has been proposed in recent sessions of Congress to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of "underground injection," to require federal permitting and regulatory control of hydraulic fracturing, and to require disclosure of the chemical constituents of the fluids used in the fracturing process. Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the Underground Injection Control program, specifically as "Class II" Underground Injection Control wells under the Safe Drinking Water Act. The EPA has also published air emission standards for certain equipment, processes and activities across the oil and natural gas sector. In addition, the BLM previously published final rules governing hydraulic fracturing on federal and Indian lands, which rules have been rescinded or suspended, but litigation is ongoing regarding the rules. See "Item 1. Business—Regulation of environmental and occupational health and safety matters—Hydraulic fracturing" for a further description of federal and state regulations addressing hydraulic fracturing.

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, in 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 in November 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.

Legislation or regulatory initiatives intended to address seismic activity could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could have a material adverse effect on our business.

State and federal regulatory agencies have recently focused on a possible connection between hydraulic fracturing-related activities, particularly the underground injection of wastewater into disposal wells, and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. In addition, a number of lawsuits have been filed in some states, most recently in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements regarding the permitting of produced water disposal wells or otherwise to assess the relationship between seismicity and the use of such wells. See "Item 1. Business—Regulation of environmental and occupational health and safety matters—Hydraulic fracturing" for a further description of local regulations addressing seismic activity.

We dispose of large volumes of produced water gathered from our drilling and production operations by injecting it into wells pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities. The adoption and implementation of any new laws or regulations that restrict our ability to use hydraulic fracturing or dispose of produced water gathered from our drilling and production activities by owned disposal wells could have a material adverse effect on our business, financial condition and results of operations.

We are subject to other 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.

In addition to the specific laws and regulations discussed elsewhere herein, our oil, NGL and natural gas exploration, production and gathering operations are subject to numerous other 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.

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.

In recent years, federal, state and local governments have taken steps to reduce emissions of greenhouse gases. The EPA has finalized a series of greenhouse gas monitoring, reporting and emission control rules for the oil and natural gas industry, and Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of the states have already taken measures to reduce emissions of greenhouse gases primarily through the development of greenhouse gas emission inventories and/or regional greenhouse gas cap-and-trade programs. See "Item 1. Business—Regulation of environmental and occupational health and safety matters—Regulation of 'greenhouse gas' emissions" for a further description of federal and state regulations addressing greenhouse gases.

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. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement, and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. It is not clear what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

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.

In addition, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Furthermore, 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 or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other liabilities. 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 hotter or 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 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, the 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 tended to increase over time. The trend of more expansive and stringent environmental legislation and regulations applied to the 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 actions are 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.

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.

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.

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, 2017, Warburg Pincus owned 32.0% 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 and disposition of assets.

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 successful disposition of assets requires an assessment of several factors, including historical operations, potential environmental and other liabilities and impact on our business, such as the Medallion Sale. 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 or buyer 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 or sell assets 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 or buyer will not be able to fulfill its contractual obligations. Problems with assets we acquire or dispose of could have a material adverse effect on our business, financial condition and results of operations.

Tax laws and regulations may change over time, and the recently passed comprehensive tax reform bill could adversely affect our business and financial condition.

On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act") that significantly reforms the Internal Revenue Code of 1986, as amended (the "Code"). The Tax Act, among other things, (i) permanently reduces the U.S. corporate income tax rate, (ii) repeals the corporate alternative minimum tax, (iii) eliminates the deduction for certain domestic production activities, (iv) imposes new limitations on the utilization of net operating losses, and (v) provides for more general changes to the taxation of corporations, including changes to cost recovery rules and to the deductibility of interest expense, which may impact the taxation of oil and gas companies. The Tax Act is complex and far-reaching and we cannot predict with certainty the resulting impact its enactment has on us. The ultimate impact of the Tax Act may differ from our estimates due to changes in interpretations and assumptions made by us as well as additional regulatory guidance that may be issued and any such changes in interpretations or assumptions could adversely affect our business and financial condition. See Note 11 to our consolidated financial statements included elsewhere in this Annual Report for additional information.

In addition, from time to time, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal and state income tax laws, including (i) the elimination of the immediate deduction for intangible drilling and development costs, (ii) the repeal of the percentage depletion allowance for oil and natural gas properties and (iii) an extension of the amortization period for certain geological and geophysical expenditures. While these specific changes are not included in the Tax Act, no accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. The elimination of such U.S. federal tax deductions, as well as any other changes to or the imposition of new federal, state, local or non-U.S. taxes (including the imposition of, or increases in production, severance or similar taxes) could adversely affect our business and financial condition.

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, 2017, we had a Federal net operating loss ("NOL") carryforward of $1.7 billion. If we were to experience an "ownership change," as determined under Section 382 of 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, 2017, based on evidence available to us, and our estimates on the impact of the Tax Act, 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, 2017, a valuation allowance has been recorded against our NOL tax assets. See Note 11 to our consolidated financial statements included elsewhere in this Annual Report for additional information.

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.

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, 2017, Warburg Pincus owned 32.0% 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. Provisions such as these are also not favored by various institutional investor services, which may periodically "grade" us on various factors, including stockholder rights and corporate governance policies. Certain institutional investors may have internal policies that prohibit investments in companies receiving a certain grade level from such services, and if we fail to meet such criteria, it could limit the number or type of certain investors which might otherwise be attracted to an investment in the Company, potentially negatively impacting the public float and/or market price of our common stock.

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 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.

We cannot guarantee that our recently announced share repurchase program will be fully consummated or that it will enhance long-term stockholder value. Share repurchases could also increase the volatility of the trading price of our common stock and could diminish our cash reserves.

In February 2018, our board of directors authorized the repurchase of up to $200 million of our common stock commencing in February 2018 and expiring in February 2020. Share repurchases under the share repurchase program may be made through a variety of methods, which may include open market purchases, privately negotiated transactions and block trades. Although our board of directors has authorized this share repurchase program, the program does not obligate us to repurchase any specific dollar amount or to acquire any specific number of shares. The timing and amount of repurchases, if any, will depend upon several factors, including market conditions, business conditions, the trading price of our common stock and the nature of other investment opportunities available to us. The share repurchase program may be limited, suspended or discontinued at any time without prior notice. The share repurchase program could affect the trading price of our common stock and increase volatility, and any announcement of a termination of this program may result in a decrease in the trading price of our common stock. In addition, the share repurchase program could diminish our cash reserves.

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, except with regard to the specific litigation noted below, we do not believe that the ultimate resolution of any such pending litigation or pending claims will be material or have a material adverse effect on our business, financial position, results of operations or liquidity.

On May 3, 2017, Shell Trading (US) Company ("Shell") filed an Original Petition and Request for Disclosure in the District Court of Harris County, Texas, alleging that the crude oil purchase agreement entered into between Shell and Laredo effective October 1, 2016 does not accurately reflect the compensation to be paid to Shell under certain circumstances due to a drafting mistake. Shell seeks reformation of one clause of the crude oil purchase agreement on the grounds of alleged mutual mistake or, in the alternative, unilateral mistake, an award of the amounts Shell alleges it should have been or should be paid under the agreement, court costs and attorneys' fees. The Company does not believe there was a drafting mistake made in the crude oil purchase agreement. On December 11, 2017, Shell filed its First Amended Petition, in which it asserted nine causes of action including multiple new claims for breach of contract and fraud. The Company believes it has substantive defenses and intends to vigorously defend its position. The Company is unable to determine a probability of the outcome of this litigation at this time. As of December 31, 2017, the Company has estimated an amount of $17.1 million related to this litigation that is not recorded in the accompanying unaudited consolidated balance sheets. Under the current pricing election, which elections are made for six-month periods, this estimate of the unrecorded amount will increase through the life of the contract. The Company has accounted for the costs (and resulting increased crude oil price realization) as reflected in the terms of the crude oil purchase agreement.

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 presents the range of high and low sales prices of our common stock as reported by the NYSE:

	Price per share	
	High	Low
2017:		
Fourth Quarter	$ 13.01	$ 9.46
Third Quarter	$ 13.46	$ 10.06
Second Quarter	$ 15.15	$ 9.57
First Quarter	$ 15.55	$ 12.35
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

On February 14, 2018, the last sale price of our common stock, as reported on the NYSE, was $7.93 per share.

Holders. As of February 12, 2018, 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, 2017 - October 31, 2017	1,582	$ 12.93	—	—
November 1, 2017 - November 30, 2017	133	$ 12.18	—	—
December 1, 2017 - December 31, 2017	182	$ 10.67	—	—
Total	1,897			

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

In February 2018, our board of directors authorized a $200 million share repurchase program commencing in February 2018. The repurchase program expires in February 2020. Share repurchases under the share repurchase program may be made through a variety of methods, which may include open market purchases, privately negotiated transactions and block trades. The timing and actual number of shares repurchased, if any, will depend upon several factors, including market conditions, business conditions, the trading price of our common stock and the nature of other investment opportunities available to us.

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

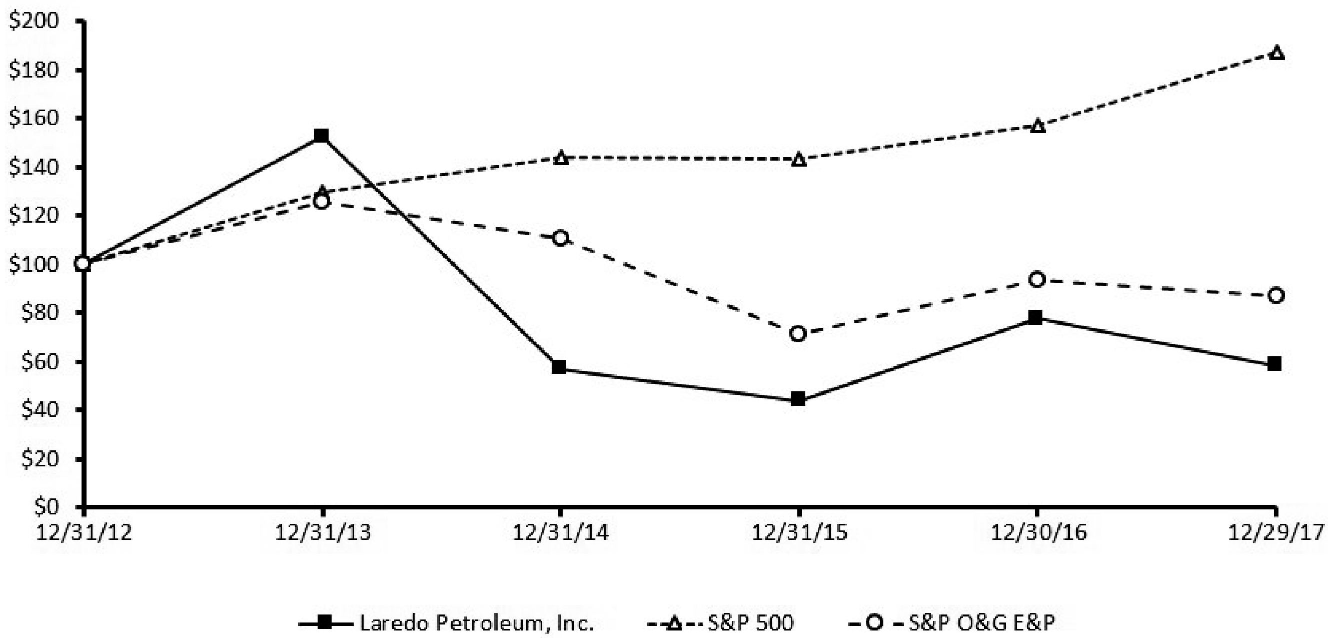
Stock Performance Graph. The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the

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 31, 2012 to December 29, 2017; 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, 2017, 2016 and 2015 and the balance sheet data as of December 31, 2017 and 2016 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, 2014 and 2013 and the balance sheet data as of December 31, 2015, 2014 and 2013 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)	2017	2016	2015	2014	2013[2]
Statement of operations data:					
Total revenues	$ 822,162	$ 597,378	$ 606,640	$ 793,885	$ 665,257
Total costs and expenses[1]	572,490	685,340	3,078,154	567,499	450,906
Operating income (loss)	249,672	(87,962)	(2,471,514)	226,386	214,351
Non-operating income (expense), net	301,102	(172,777)	84,633	203,473	(23,267)
Income (loss) from continuing operations before income taxes	550,774	(260,739)	(2,386,881)	429,859	191,084
Income tax (expense) benefit	(1,800)	—	176,945	(164,286)	(74,507)
Income (loss) from continuing operations	548,974	(260,739)	(2,209,936)	265,573	116,577
Income from discontinued operations, net of tax	—	—	—	—	1,423
Net income (loss)	$ 548,974	$ (260,739)	$ (2,209,936)	$ 265,573	$ 118,000
Net income (loss) per common share:					
Basic:					
Income (loss) from continuing operations	$ 2.30	$ (1.16)	$ (11.10)	$ 1.88	$ 0.88
Income from discontinued operations, net of tax	—	—	—	—	0.01
Net income (loss) per share	$ 2.30	$ (1.16)	$ (11.10)	$ 1.88	$ 0.89
Diluted:					
Income (loss) from continuing operations	$ 2.29	$ (1.16)	$ (11.10)	$ 1.85	$ 0.87
Income from discontinued operations, net of tax	—	—	—	—	0.01
Net income (loss) per share	$ 2.29	$ (1.16)	$ (11.10)	$ 1.85	$ 0.88

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

(2) The oil and natural gas properties that were a component of the sale of assets in the Anadarko Basin in 2013 (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.

(in thousands)	As of December 31, 2017	2016	2015	2014	2013
Balance sheet data[(1)]:					
Cash and cash equivalents	$ 112,159	$ 32,672	$ 31,154	$ 29,321	$ 198,153
Property and equipment, net	$ 1,768,385	$ 1,366,867	$ 1,200,255	$ 3,354,082	$ 2,204,324
Total assets	$ 2,023,289	$ 1,782,346	$ 1,813,287	$ 3,910,701	$ 2,606,610
Total current liabilities	$ 277,419	$ 187,945	$ 216,815	$ 353,834	$ 253,969
Long-term debt, net	$ 791,855	$ 1,353,909	$ 1,416,226	$ 1,779,447	$ 1,038,022
Stockholders' equity	$ 765,579	$ 180,573	$ 131,447	$ 1,563,201	$ 1,272,256

(in thousands)	For the years ended December 31, 2017	2016	2015	2014	2013[(2)]
Other financial data:					
Net cash provided by operating activities	$ 384,914	$ 356,295	$ 315,947	$ 498,277	$ 364,729
Net cash provided by (used in) investing activities	$ 295,050	$ (564,402)	$ (667,507)	$(1,406,961)	$ (329,884)
Net cash (used in) provided by financing activities	$ (600,477)	$ 209,625	$ 353,393	$ 739,852	$ 130,084

(1) Prior period amounts have been reclassified to conform to the current-year presentation.

(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

The non-GAAP financial measure of Adjusted EBITDA, as defined by us, may not be comparable to similarly titled measures used by other companies. Therefore, this non-GAAP measure should be considered in conjunction with net income or loss and other performance measures prepared in accordance with GAAP, such as operating income or loss or cash flow from operating activities. Adjusted EBITDA should not be considered in isolation or as a substitute for GAAP measures, such as net income or loss, operating income or loss or any other GAAP measure of liquidity or financial performance.

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for income tax expense or benefit, depletion, depreciation and amortization, bad debt expense, impairment expense, non-cash stock-based compensation, net of amounts capitalized, accretion expense, mark-to-market on derivatives, cash premiums paid for derivatives, interest expense, write-off of debt issuance costs, gains or losses on disposal of assets, income or loss from equity method investee, proportionate Adjusted EBITDA of our equity method investee and other non-recurring income and expenses. 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, 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, the 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.

For the year ended December 31, 2016, we changed the methodology for calculating Adjusted EBITDA by including adjustments for both accretion expense 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) from continuing and discontinued operations to Adjusted EBITDA (non-GAAP):

	For the years ended December 31,				
(in thousands, unaudited)	**2017**	**2016**	**2015**	**2014**	**2013**
Net income (loss)	$ 548,974	$ (260,739)	$ (2,209,936)	$ 265,573	$ 118,000
Plus:					
Income tax expense (benefit)	1,800	—	(176,945)	164,286	75,288
Depletion, depreciation and amortization	158,389	148,339	277,724	246,474	234,571
Bad debt expense	—	—	255	342	653
Impairment expense	—	162,027	2,374,888	3,904	—
Non-cash stock-based compensation, net of amounts capitalized	35,734	29,229	24,509	23,079	21,433
Accretion expense	3,791	3,483	2,423	1,787	1,475
Restructuring expenses	—	—	6,042	—	—
Mark-to-market on derivatives:					
(Gain) loss on derivatives, net	(350)	87,425	(214,291)	(327,920)	(79,878)
Cash settlements received for matured derivatives, net	37,583	195,281	255,281	28,241	4,046
Cash settlements received for early terminations and modifications of derivatives, net	4,234	80,000	—	76,660	6,008
Cash premiums paid for derivatives	(25,853)	(89,669)	(5,167)	(7,419)	(11,292)
Interest expense	89,377	93,298	103,219	121,173	100,327
Write-off of debt issuance costs	—	842	—	124	1,502
Gain on sale of investment in equity method investee	(405,906)	—	—	—	—
Loss on disposal of assets, net	1,306	790	2,127	3,252	1,508
Loss on early redemption of debt	23,761	—	31,537	—	—
Buyout of minimum volume commitment	—	—	3,014	—	—
(Income) loss from equity method investee	(8,485)	(9,403)	(6,799)	192	(29)
Proportionate Adjusted EBITDA of equity method investee[(1)]	22,081	20,367	9,383	462	29
Adjusted EBITDA	$ 486,436	$ 461,270	$ 477,264	$ 600,210	$ 473,641

(1) Proportionate Adjusted EBITDA of Medallion, our equity method investee through October 30, 2017, is calculated as follows:

	For the years ended December 31,				
(in thousands, unaudited)	**2017**	**2016**	**2015**	**2014**	**2013**
Income (loss) from equity method investee	$ 8,485	$ 9,403	$ 6,799	$ (192)	$ 29
Adjusted for proportionate share of:					
Depreciation and amortization	13,596	10,964	4,061	654	—
Buyout of minimum volume commitment	—	—	(1,477)	—	—
Proportionate Adjusted EBITDA of equity method investee	$ 22,081	$ 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, 2017 included the following:

- Oil, NGL and natural gas sales of $621.5 million, compared to $426.5 million for the year ended December 31, 2016;
- Average daily sales volumes of 58,273 BOE/D, compared to 49,586 BOE/D for the year ended December 31, 2016;
- Net income of $549.0 million, compared to a net loss of $260.7 million, including a non-cash full cost ceiling impairment of $161.1 million, for the year ended December 31, 2016;
- Adjusted EBITDA (a non-GAAP financial measure) of $486.4 million, compared to $461.3 million for the year ended December 31, 2016. See "Item 6. Selected Historical Financial Data" for a reconciliation of Adjusted EBITDA; and
- Proved developed and undeveloped reserves of 215,883 MBOE, compared to 167,100 MBOE for the year ended December 31, 2016. See Note 18.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

Early redemption of May 2022 Notes

On the May 2022 Notes Redemption Date, utilizing a significant portion of our proceeds from the Medallion Sale, we redeemed the entire $500.0 million outstanding principal amount of our May 2022 Notes at a redemption price of 103.688% of the principal amount, plus accrued and unpaid interest up to, but not including, the May 2022 Notes Redemption Date. We recognized a loss on extinguishment of $23.8 million related to the difference between the redemption price and the net carrying amount of our May 2022 Notes. For further discussion of the redemption of our May 2022 Notes, see Note 5.d to our consolidated financial statements included elsewhere in this Annual Report.

Medallion Sale

On October 30, 2017, LMS, together with MMH, which is owned and controlled by an affiliate of EMG, completed the Medallion Sale to an affiliate of GIP, for cash consideration of $1.825 billion, subject to customary post-closing adjustments. LMS' net cash proceeds for its 49% ownership interest in Medallion in 2017 were $829.6 million, before post-closing adjustments and taxes, but after deduction of its proportionate share of fees and other expenses associated with the Medallion Sale. On February 1, 2018, closing adjustments were finalized and LMS received additional net cash of $1.7 million for total net cash proceeds before taxes of $831.3 million. Proceeds of $690.0 million were used to repay in-full borrowings on our Senior Secured Credit Facility and to redeem our May 2022 Notes, with the remainder applied for working capital purposes. The Medallion Sale closed pursuant to the membership interest purchase and sale agreement, which provides for potential post-closing additional cash consideration that is structured based on GIP's realized profit at exit. There can be no assurance as to when and whether any such additional consideration will be paid. The Medallion Sale is not expected to have a major effect on the Company's future operations or financial results. For further discussion of the Medallion Sale, see Notes 4.a and 17.a to our consolidated financial statements included elsewhere in this Annual Report. As a result of the Medallion Sale, we currently anticipate that we will no longer present more than one reportable segment in 2018 and thereafter.

Senior Secured Credit Facility borrowing base reaffirmation

On October 20, 2017, pursuant to a regular semi-annual redetermination, our lenders reaffirmed the $1.0 billion borrowing base under our Senior Secured Credit Facility. Our aggregate elected commitment of $1.0 billion remained unchanged.

Share repurchase program

In February 2018, our board of directors authorized a $200 million share repurchase program commencing in February 2018 and expiring in February 2020. Share repurchases under the share repurchase program may be made through a variety of methods, which may include open market purchases, privately negotiated transactions and block trades. The timing and actual number of shares repurchased, if any, will depend upon several factors, including market conditions, business conditions, the trading price of our common stock and the nature of other investment opportunities available to us.

On February 14, 2018, we entered into the Second Amendment to the Senior Secured Credit Facility pursuant to which we amended such agreement to allow our share repurchase program in accordance with the terms described above.

Pricing and reserves

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.

The Realized Prices utilized to value our reserves as of December 31, 2017 and 2016 were $46.34 per Bbl for oil, $18.45 per Bbl for NGL and $2.06 per Mcf for natural gas and $37.44 per Bbl for oil, $11.72 per Bbl for NGL and $1.78 per Mcf for natural gas, respectively. The Realized Prices used to estimate proved reserves do not include derivative transactions. The unamortized cost of our evaluated oil and natural gas properties did not exceed the full cost ceiling amount for 2017. See Note 2.h to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our 2016 first-quarter and prior period full cost ceiling impairments.

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."

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, 2017, we had assembled 124,843 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, 2017, our revenues were comprised of: 54% sales of produced oil, 13% sales of produced NGL, 9% sales of produced natural gas, 23% sales of 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 amount of volumes purchased. 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.

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

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.

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 unit-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 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. See Note 2.h to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding full cost accounting.

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, 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 from equity method investee. We owned 49% of the ownership units in Medallion which was sold on October 30, 2017. Prior to the Medallion Sale, we accounted for this investment under the equity method of accounting with our proportionate share of net income reflected in the consolidated statements of operations as "Income from equity method investee" and the carrying amount reflected in the consolidated balance sheets as "Investment in equity method investee."

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 May 2022 Notes and January 2019 Notes in November 2017 and in April 2015, respectively, and both 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.

Gain on sale of investment in equity method investee. This represents the difference between the net proceeds received from the Medallion Sale and the book value of Medallion as of October 30, 2017. A portion of this gain was deferred in the amount of our maximum exposure to loss associated with future commitments under the Transportation Services Agreement with a wholly-owned subsidiary of Medallion. See Notes 4.a and 17.a to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding the Medallion Sale.

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 (expense) benefit. Income taxes in our financial statements are generally presented on a consolidated basis. We are subject to federal and state corporate income taxes and the 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 consider all available evidence, both positive and negative, in determining whether, based on the weight of that evidence, a valuation allowance is needed on either the federal or Oklahoma net operating loss carry-forwards. Such consideration includes estimated future projected earnings based on existing reserves and projected future cash flows from our oil, NGL and natural gas reserves (including the timing of those cash flows), the reversal of deferred tax liabilities, 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.

On December 22, 2017, the Tax Act was signed into law. See Note 11 to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our income taxes.

Results of operations consolidated

For the year ended December 31, 2017 as compared to the year ended December 31, 2016, and for the year ended December 31, 2016 as compared to the year ended December 31, 2015

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

The following table presents information regarding oil, NGL and natural gas sales volumes, revenues and average sales prices:

	For the years ended December 31,		
	2017	2016	2015
Sales volumes:			
Oil (MBbl)	9,475	8,442	7,610
NGL (MBbl)	5,800	4,784	4,267
Natural gas (MMcf)	35,972	29,535	26,816
Oil equivalents (MBOE)(1)(2)	21,270	18,149	16,346
Average daily sales volumes (BOE/D)(2)	58,273	49,586	44,782
% Oil	45%	47%	47%
Oil, NGL and natural gas sales (in thousands):			
Oil	$ 445,012	$ 318,466	$ 329,301
NGL	101,438	56,982	50,604
Natural gas	75,057	51,037	51,829
Total oil, NGL and natural gas sales	$ 621,507	$ 426,485	$ 431,734
Average sales prices(2):			
Oil, realized ($/Bbl)(3)	$ 46.97	$ 37.73	$ 43.27
NGL, realized ($/Bbl)(3)	$ 17.49	$ 11.91	$ 11.86
Natural gas, realized ($/Mcf)(3)	$ 2.09	$ 1.73	$ 1.93
Average price, realized ($/BOE)(3)	$ 29.22	$ 23.50	$ 26.41
Oil, hedged ($/Bbl)(4)	$ 50.45	$ 58.07	$ 74.41
NGL, hedged ($/Bbl)(4)	$ 16.91	$ 11.91	$ 11.86
Natural gas, hedged ($/Mcf)(4)	$ 2.15	$ 2.20	$ 2.42
Average price, hedged ($/BOE)(4)	$ 30.71	$ 33.73	$ 41.71

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

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

(3) 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.

(4) 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 following table presents cash settlements received (paid) 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)	2017	2016	2015
Cash settlements received (paid) for matured derivatives:			
Oil	$ 35,724	$ 181,401	$ 241,391
NGL	(3,368)	—	—
Natural gas	5,227	13,880	13,890
Total	$ 37,583	$ 195,281	$ 255,281
Premiums paid attributable to contracts that matured during the respective period:			
Oil	$ (2,738)	$ (9,669)	$ (4,464)
Natural gas	(3,070)	—	(703)
Total	$ (5,808)	$ (9,669)	$ (5,167)

The following table presents 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, 2017, 2016 and 2015:

(in thousands)	Oil	NGL	Natural gas	Total net effect of change
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
Effect of changes in average realized sales prices	87,572	32,363	12,897	132,832
Effect of changes in sales volumes	38,974	12,093	11,123	62,190
2017 Revenue	$ 445,012	$ 101,438	$ 75,057	$ 621,507

Oil revenue. Our oil revenue is a function of oil production volumes sold and average sales prices received for those volumes. The increase in oil revenue of $126.5 million, or 40%, for the year ended December 31, 2017 as compared to 2016, is due to a 24% increase in average oil prices realized and a 12% increase in oil sales volumes. The decrease in oil revenue of $10.8 million, or 3%, for the year ended December 31, 2016 as compared to the year ended 2015, is due to a 13% decrease in average oil prices realized, partially offset by an 11% increase in oil sales volumes.

NGL revenue. Our NGL revenue is a function of NGL production volumes sold and average sales prices received for those volumes. The increase in NGL revenue of $44.5 million, or 78%, for the year ended December 31, 2017 as compared to 2016, is due to a 47% increase in average NGL prices realized and a 21% increase in NGL sales volumes. The increase in NGL revenue of $6.4 million, or 13%, for the year ended December 31, 2016 as compared to 2015, is due to a 12% increase in NGL sales volumes.

Natural gas revenue. Our natural gas revenue is a function of natural gas production volumes sold and average sales prices received for those volumes. The increase in natural gas revenue of $24.0 million, or 47%, for the year ended December 31, 2017 as compared to 2016, is due to a 22% increase in natural gas sales volumes and a 21% increase in average natural gas prices realized. The decrease in natural gas revenue of $0.8 million, or 2%, for the year ended December 31, 2016 as compared to 2015, is due to an 11% decrease in average natural gas prices realized, partially offset by a 10% increase in natural gas sales volumes.

Costs and expenses

The following table presents information regarding costs and expenses and average costs per BOE sold:

	For the years ended December 31,		
(in thousands except for per BOE sold data)	**2017**	**2016**	**2015**
Costs and expenses:			
Lease operating expenses	$ 75,049	$ 75,327	$ 108,341
Production and ad valorem taxes	37,802	28,586	32,892
Midstream service expenses	4,099	4,077	5,846
Costs of purchased oil	195,908	169,536	174,338
General and administrative:			
Cash	60,578	62,527	65,916
Non-cash stock-based compensation, net of amounts capitalized	35,734	29,229	24,509
Restructuring expenses	—	—	6,042
Depletion, depreciation and amortization	158,389	148,339	277,724
Impairment expense	—	162,027	2,374,888
Other operating expenses	4,931	5,692	7,658
Total costs and expenses	$ 572,490	$ 685,340	$ 3,078,154
Average costs per BOE sold[1]:			
Lease operating expenses	$ 3.53	$ 4.15	$ 6.63
Production and ad valorem taxes	1.78	1.58	2.01
Midstream service expenses	0.19	0.22	0.36
General and administrative:			
Cash	2.85	3.45	4.03
Non-cash stock-based compensation, net of amounts capitalized	1.68	1.61	1.50
Depletion, depreciation and amortization	7.45	8.17	16.99
Total costs and expenses	$ 17.48	$ 19.18	$ 31.52

(1) Average costs per BOE sold are based on actual amounts and are not calculated using the rounded numbers presented in the tables.

Lease operating expenses. Lease operating expenses, which include workover expenses, decreased by $0.3 million for the year ended December 31, 2017 compared to 2016 and decreased by $33.0 million, or 30%, for the year ended December 31, 2016 compared to 2015. On a per BOE sold basis, lease operating expenses decreased 15% for the year ended December 31, 2017 compared to 2016. These decreases are due to previous investments in field infrastructure, primarily in four of our production corridors, including water recycling facilities and centralized compression, that 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.

Production and ad valorem taxes. Production and ad valorem taxes increased by $9.2 million, or 32%, for the year ended December 31, 2017 compared to 2016. This change is due to an $8.5 million increase in production taxes and a $0.7 million increase in ad valorem taxes for the year ended December 31, 2017 compared to 2016. Production taxes are based on and fluctuate in proportion to our oil, NGL and natural gas sales. Ad valorem taxes are based on and fluctuate in proportion to the taxable value assessed by the various counties where our oil and natural gas properties are located.

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.

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

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

General and administrative ("G&A"). The following table presents the changes in the significant components of G&A expense:

(in thousands)	Year ended December 31, 2017 compared to 2016	Year ended December 31, 2016 compared to 2015
Stock-based compensation, net of amounts capitalized	$ 6,506	$ 4,720
Salaries, benefits and bonuses, net of amounts capitalized	(3,710)	3,578
Professional fees	1,504	(2,200)
Performance unit awards	—	(4,081)
Other	256	(686)
Total changes in G&A	$ 4,556	$ 1,331

Cash G&A decreased by $1.9 million, or 3%, for the year ended December 31, 2017 compared to 2016. This decrease is largely due to a decrease in salaries, benefits and bonuses, net of amounts capitalized compared to 2016, that is partially offset by an increase in professional fees.

Cash G&A decreased by $3.4 million, or 5%, for the year ended December 31, 2016 compared to 2015. This change is mainly 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 were no comparable expenses in 2017 and 2016 as these types of awards are no longer a part of our compensation. 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 $6.5 million, or 22%, for the year ended December 31, 2017 compared to 2016, resulting from a greater number of performance share awards granted to a larger base of management and employees during the year ended December 31, 2017 compared to 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.

The fair values for 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 our restricted 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 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 settled performance unit awards were accounted for as liability awards and settled in cash at the end of their requisite service periods. The 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 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.

See Notes 2.r and 7 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 reduction in force, which was undertaken to reduce expenses and better position ourselves for future operations in a low commodity price environment. No comparable expenses were recorded in 2017 and 2016. See Note 2.s to our consolidated financial statements included elsewhere in this Annual Report for further discussion of the reduction in force.

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

(in thousands)	For the years ended December 31, 2017	2016	2015
Depletion of evaluated oil and natural gas properties	$ 143,592	$ 134,105	$ 263,666
Depreciation of midstream service assets	8,939	8,331	7,529
Depreciation and amortization of other fixed assets	5,858	5,903	6,529
Total DD&A	$ 158,389	$ 148,339	$ 277,724

DD&A increased by $10.1 million, or 7%, for the year ended December 31, 2017 as compared to 2016 mainly due to an increase in production volumes sold for the year ended December 31, 2017 compared to 2016. On a per BOE sold basis, DD&A decreased 9% for the year ended December 31, 2017 compared to 2016, mainly due to positive well results and the impact of our full cost ceiling impairment of $161.1 million recorded as of March 31, 2016.

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.

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 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 was no comparable full cost ceiling impairment recorded in 2017. For further discussion of our non-cash full cost ceiling impairment accounting policy, see Note 2.h to our consolidated financial statements included elsewhere in this Annual Report.

During the years ended December 31, 2016 and 2015, we reduced materials and supplies inventory by $1.0 million and $2.8 million, respectively, in order to reflect the balance at lower of cost or market. There was no comparable materials and supplies inventory impairment in 2017. For the year ended December 31, 2015, we recorded a lower of cost or market adjustment of $1.3 million related to our line-fill inventory. There were no comparable line-fill inventory impairments in 2017 and 2016. For further discussion of long-lived assets and inventory impairment accounting policies, see Note 2.k to our consolidated financial statements included elsewhere in this Annual Report.

Non-operating income (expense). The following table presents the components of non-operating income (expense):

(in thousands)	For the years ended December 31, 2017	2016	2015
Gain (loss) on derivatives, net	$ 350	$ (87,425)	$ 214,291
Income from equity method investee	8,485	9,403	6,799
Interest expense	(89,377)	(93,298)	(103,219)
Interest and other income	805	175	426
Loss on early redemption of debt	(23,761)	—	(31,537)
Write-off of debt issuance costs	—	(842)	—
Gain on sale of investment in equity method investee (see Note 4.a)	405,906	—	—
Loss on disposal of assets, net	(1,306)	(790)	(2,127)
Total non-operating income (expense), net	$ 301,102	$ (172,777)	$ 84,633

Gain (loss) on derivatives, net. The following table presents the changes in the components of gain (loss) on derivatives, net:

(in thousands)	Year ended December 31, 2017 compared to 2016	Year ended December 31, 2016 compared to 2015
Fair value of derivatives outstanding	$ 321,239	$ (321,716)
Cash settlements received for matured derivatives, net	(157,698)	(60,000)
Cash settlements received for early terminations of derivatives, net	(75,766)	80,000
Total changes in gain (loss) on derivatives, net	$ 87,775	$ (301,716)

The changes in fair value of derivatives outstanding are the result of new, early-terminated 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, terminated or modified, we experience gains during periods of decreasing market prices and losses during periods of increasing market prices. Net 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, 2017, we received proceeds from a hedge restructuring in which we early terminated a derivative contract swap, resulting in a termination amount received of $4.2 million. The $4.2 million was settled in full by applying the proceeds to pay the premium on one new derivative contract collar entered into during the hedge restructuring.

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 received 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. There was no comparable early termination amount in 2015.

See Notes 2.f, 9 and 10.a 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 from equity method investee. See "—Results of operations - midstream and marketing" for a discussion of this income.

Interest expense. The following table presents the changes in the significant components of interest expense:

(in thousands)	**Year ended December 31, 2017 compared to 2016**	**Year ended December 31, 2016 compared to 2015**
May 2022 Notes	$ (3,278)	$ —
Senior Secured Credit Facility, net of capitalized interest	(613)	(615)
January 2019 Notes	—	(13,865)
March 2023 Notes	—	4,740
Other	(30)	(181)
Total changes in interest expense	$ (3,921)	$ (9,921)

Interest expense decreased by $3.9 million, or 4%, for the year ended December 31, 2017 compared to 2016 mainly due to the early redemption of the May 2022 Notes on November 29, 2017. Interest expense decreased by $9.9 million, or 10%, for the year ended December 31, 2016 compared to 2015 mainly 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, 2017, we redeemed the entire $500.0 million outstanding principal amount of the May 2022 Notes at a redemption price of 103.688% of the principal amount of the May 2022 Notes, plus accrued and unpaid interest up to, but not including, the May 2022 Notes Redemption Date. We recognized a loss on extinguishment of $23.8 million related to the difference between the redemption price and the net carrying amount of the extinguished May 2022 Notes.

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 of the January 2019 Notes, plus accrued and unpaid interest up to, but not including, the January 2019 Notes 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 extinguished January 2019 Notes. There was no comparable early redemption of debt amount in 2016.

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. See Note 2.l for further discussion of our debt issuance costs written-off during the years ended December 31, 2017 and 2015 as a result of our early redemptions of debt, which are included in the "Loss on early redemption of debt" line item in the consolidated statements of operations.

Gain on sale of investment in equity method investee. See "—Results of operations - midstream and marketing" for a discussion of this gain.

Loss on disposal of assets, net. Loss on disposal of assets, net, increased by $0.5 million for the year ended December 31, 2017 compared to 2016, and decreased by $1.3 million for the year ended December 31, 2016 compared to 2015. 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 (expense) benefit. The following table presents income tax (expense) benefit:

	For the years ended December 31,		
(in thousands)	**2017**	**2016**	**2015**
Current	$ (1,800)	$ —	$ —
Deferred	—	—	176,945
Total income tax (expense) benefit	$ (1,800)	$ —	$ 176,945

On December 22, 2017, the Tax Act was signed into law. The Tax Act, among other things, reduces the corporate tax rate to 21% from 35% and made changes to exclusions, deductions and credits. For further discussion of the estimated effect of the Tax Act, see Note 11 to our consolidated financial statements located elsewhere in this Annual Report.

Current tax expense recorded of $1.8 million for the year ended December 31, 2017, is comprised of Texas franchise tax, mainly as a result of the Medallion Sale. During the year ended December 31, 2017, due to the revaluation of our deferred tax assets at the new 21% federal corporate tax rate and the reduction of net deferred tax assets in the normal course of business, we recorded a total adjustment to the valuation allowance of $423.4 million. 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. Since September 30, 2015, we have recorded a full valuation allowance against our net deferred tax position. As such, our effective tax rate was 0% for each of the years ended December 31, 2017 and 2016. The effective tax rate for our operations was 7% for the year ended December 31, 2015. 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. For further discussion of our valuation allowance, see Note 11 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 years ended December 31,		
(in thousands)	2017	2016	2015
Revenues:			
Natural gas sales	$ 3,301	$ 1,141	$ 1,692
Midstream service revenues	72,643	49,971	27,965
Sales of purchased oil	190,138	162,551	168,358
Total revenues	$ 266,082	$ 213,663	$ 198,015
Costs and expenses:			
Midstream service expenses	$ 49,017	$ 29,693	$ 17,557
Costs of purchased oil	195,908	169,536	174,338
General and administrative[1]	8,199	7,855	8,174
Depreciation and amortization[2]	9,561	8,932	8,093
Impairment expense	—	—	2,592
Other operating expenses[3]	224	209	1,178
Operating income (loss)	$ 3,173	$ (2,562)	$ (13,917)
Other financial information:			
Income from equity method investee[4]	$ 8,485	$ 9,403	$ 6,799
Interest expense[5]	$ (5,619)	$ (5,813)	$ (5,179)
Loss on early redemption of debt[6]	$ (1,536)	$ —	$ (1,481)
Gain on sale of investment in equity method investee[4]	$ 405,906	$ —	$ —

(1) G&A expenses were allocated based on the number of employees in the midstream and marketing segment during the years ended December 31, 2017, 2016 and 2015. Certain components of G&A expenses, primarily payroll, deferred compensation and vehicle expenses, were not allocated but were actual expenses for the midstream and marketing 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 during the years ended December 31, 2017, 2016 and 2015. Certain components of depreciation and amortization of other fixed assets, primarily vehicles, were not allocated but were actual expenses for each segment.

(3) Other operating expenses consist of (i) accretion expense for the years ended December 31, 2017 and 2016, and (ii) minimum volume commitments, restructuring expense and accretion expense for the year ended December 31, 2015. These are actual costs and expenses and were not allocated.

(4) See Note 4.a for additional discussion of the Medallion Sale.

(5) Interest expense was allocated to the midstream and marketing segment based on gross property and equipment and life-to-date contributions to our equity method investee during the years ended December 31, 2017, 2016 and 2015.

(6) 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, 2017 and 2015.

See Note 15 to our consolidated financial statements included elsewhere in this Annual Report for additional information on our operating segments.

Natural gas sales. Our revenues from natural gas sales increased by $2.2 million, or 189%, for the year ended December 31, 2017 compared to 2016. 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."

Midstream service revenues. Our midstream service revenues increased by $22.7 million, or 45%, for the year ended December 31, 2017 compared to 2016, and $22.0 million, or 79%, for the year ended December 31, 2016 compared to 2015. These increases are mainly due to increased volume of water services provided.

Sales of purchased oil. Sales of purchased oil increased by $27.6 million, or 17%, for the year ended December 31, 2017 compared to 2016, and decreased $5.8 million, or 3%, for the year ended December 31, 2016 compared to 2015. For these sales of purchased oil, we purchase oil from third parties in West Texas, transport it on the Bridgetex Pipeline and sell it to a third party in the Houston market. Sales of purchased oil fluctuate due to changes in oil prices.

Midstream service expenses. Midstream service expenses increased by $19.3 million, or 65%, for the year ended December 31, 2017 compared to 2016, and $12.1 million, or 69%, for the year ended December 31, 2016 compared to 2015. 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 increased by $26.4 million, or 16%, for the year ended December 31, 2017 compared to 2016, and decreased $4.8 million, or 3%, for the year ended December 31, 2016 compared to 2015. These costs include purchasing oil from third parties and transporting it on the Bridgetex Pipeline. Costs of purchased oil fluctuate due to changes in oil prices.

Income from equity method investee. Prior to the Medallion Sale, we owned 49% of the ownership units of Medallion. As such, we previously accounted for this investment under the equity method of accounting with our proportionate share of Medallion's net income reflected in the consolidated statements of operations as "Income from equity method investee" and the carrying amount reflected in the consolidated balance sheets as "Investment in equity method investee." For further discussion of the Medallion Sale, see Notes 4.a and 17.a to our consolidated financial statements included elsewhere in this Annual Report.

Gain on sale of investment in equity method investee. On October 30, 2017, LMS, together with MMH, which is owned and controlled by an affiliate of EMG, completed the Medallion Sale to an affiliate of GIP, for cash consideration of $1.825 billion. LMS' net cash proceeds for its 49% ownership interest in Medallion in 2017 were $829.6 million, before post-closing adjustments and taxes, but after deduction of its proportionate share of fees and other expenses associated with the Medallion Sale. On February 1, 2018, closing adjustments were finalized and LMS received additional net cash of $1.7 million for total net cash proceeds before taxes of $831.3 million. The Medallion Sale closed pursuant to the membership interest purchase and sale agreement, which provides for potential post-closing additional cash consideration that is structured based on GIP's realized profit at exit. There can be no assurance as to when and whether the additional consideration will be paid. The Medallion Sale will not have a major effect on the Company's future operations or future financial results. For further discussion of the Medallion Sale, see Notes 4.a and 17.a to our consolidated financial statements included elsewhere in this Annual Report. As a result of the Medallion Sale, we currently anticipate that in 2018 and thereafter we will no longer present more than one reportable segment.

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 May 2022 Notes during the year ended December 31, 2017 and the extinguished January 2019 Notes during the year ended 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, until October 30, 2017, investments in Medallion.

On October 30, 2017, LMS, together with MMH, which is owned and controlled by an affiliate of EMG, completed the Medallion Sale to an affiliate of GIP, for cash consideration of $1.825 billion. LMS' net cash proceeds for its 49% ownership interest in Medallion in 2017 were $829.6 million, before post-closing adjustments and taxes, but after deduction of its proportionate share of fees and other expenses associated with the Medallion Sale. On February 1, 2018, closing adjustments were finalized and LMS received additional net cash of $1.7 million, for total net cash proceeds before taxes of $831.3 million. Of the net proceeds, $690.0 million were used to early redeem the May 2022 Notes and to repay borrowings outstanding on our

Senior Secured Credit Facility. For further discussion of the Medallion Sale, see Notes 4.a and 17.a to our consolidated financial statements included elsewhere in this Annual Report.

On the January 2019 Notes 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 January 2019 Notes at a redemption price of 104.75% of the principal amount of such notes, plus accrued and unpaid interest up to, but not including, the January 2019 Notes Redemption Date. On November 29, 2017, following the Medallion Sale, we redeemed our May 2022 Notes at a redemption price of 103.688% of the principal amount of the May 2022 Notes, plus accrued and unpaid interest up to, but not including the May 2022 Note Redemption Date.

In January 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 $59.7 million. After transaction costs reflecting an economic effective date of October 1, 2016, the proceeds were $59.5 million, net of working capital and post-closing adjustments. We completed the post-closing for this divestiture in May 2017. A significant portion of these proceeds was used to pay down borrowings on our Senior Secured Credit Facility. For further discussion of our 2017 divestiture of oil and natural gas properties, see Note 4.b to our consolidated financial statements included elsewhere in this Annual Report.

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 4.d, 5 and 6 to our consolidated financial statements included elsewhere in this Annual Report for further discussion regarding our divestitures of oil and natural gas properties and the Medallion Sale, equity offerings and debt, respectively.

We continually seek to maintain a financial profile that provides operational flexibility. As of December 31, 2017, we had the full $1.0 billion borrowing capacity available under our Senior Secured Credit Facility and $112.2 million in cash on hand for total available liquidity of $1.1 billion. As of February 13, 2018, we had the full $1.0 billion borrowing capacity available under our Senior Secured Credit Facility and $46.0 million in cash on hand for total available liquidity of $1.05 billion. 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 and to fund the recently announced share repurchase program.

We use 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, 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 prices of oil, NGL and natural gas. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" below.

The following table summarizes our hedge positions that were in place as of February 13, 2018 for the calender years presented:

	Year 2018	Year 2019	Year 2020
Oil positions[1]:			
Total volume hedged with floor price (Bbl)	9,515,375	6,606,500	1,061,400
Weighted-average floor price ($/Bbl)	$ 47.42	$ 48.82	$ 49.70
Total volume hedged with ceiling price (Bbl)	4,088,000	657,000	695,400
Weighted-average ceiling price ($/Bbl)	$ 60.00	$ 53.45	$ 52.18
Basis swaps:			
Total volume hedged (Bbl)	3,650,000	—	—
Weighted-average price ($/Bbl)	$ (0.56)	$ —	$ —
NGL swap positions[1]:			
Purity Ethane:			
Total volume hedged (Bbl)	567,800	—	—
Weighted-average price ($/Bbl)	$ 11.66	$ —	$ —
Propane (Non-TET):			
Total volume hedged (Bbl)	467,600	—	—
Weighted-average price ($/Bbl)	$ 33.92	$ —	$ —
Normal Butane (Non-TET):			
Total volume hedged (Bbl)	167,000	—	—
Weighted-average price ($/Bbl)	$ 38.22	$ —	$ —
Isobutane (Non-TET):			
Total volume hedged (Bbl)	66,800	—	—
Weighted-average price ($/Bbl)	$ 38.33	$ —	$ —
Natural Gasoline (Non-TET):			
Total volume hedged (Bbl)	167,000	—	—
Weighted-average price ($/Bbl)	$ 57.02	$ —	$ —
Natural gas positions:			
Total volume hedged with floor price (MMBtu)	23,805,500	—	—
Weighted-average floor price ($/MMBtu)	$ 2.50	$ —	$ —
Total volume hedged with ceiling price (MMBtu)	15,585,500	—	—
Weighted-average ceiling price ($/MMBtu)	$ 3.35	$ —	$ —
Basis swaps:			
Total volume hedged (MMBtu)	9,125,000	9,125,000	—
Weighted-average price ($/MMBtu)	$ (0.62)	$ (0.70)	$ —

(1) See Notes 9.a and 17.d to our consolidated financial statements included elsewhere in this Annual Report for information regarding our derivative settlement indices for the derivatives entered into subsequent to December 31, 2017.

See Note 9.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, 2017.

Cash flows

Our cash flows for the periods presented are summarized in the table below:

	For the years ended December 31,		
(in thousands)	**2017**	**2016**	**2015**
Net cash provided by operating activities	$ 384,914	$ 356,295	$ 315,947
Net cash provided by (used in) investing activities	295,050	(564,402)	(667,507)
Net cash (used in) provided by financing activities	(600,477)	209,625	353,393
Net increase in cash and cash equivalents	$ 79,487	$ 1,518	$ 1,833

Cash flows from operating activities

Net cash from operating activities increased by $28.6 million from 2016 to 2017 mainly due to the price-related increase in oil, NGL and natural gas revenues; however, other notable cash changes included (i) a decrease of $169.6 million in cash settlements received for matured and early terminations of derivatives, net of premiums paid, (ii) an increase in working capital cash inflows of $8.1 million and (iii) a cash outflow of $6.4 million related to the settlement of our last tranche of performance unit awards in first-quarter 2016 with no comparable amount incurred in 2017.

Net cash from operating activities increased by $40.3 million from 2015 to 2016 and 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.

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" below.

Cash flows from investing activities

Net cash from investing activities increased by $859.5 million from 2016 to 2017 and is mainly attributable to (i) proceeds we received from the Medallion Sale, (ii) proceeds we received from a divestiture of oil and natural gas properties and (iii) decreased contributions to Medallion. These increases in cash flows were partially offset by an increase in capital expenditures due to our increased capital budget.

Net cash used in investing activities decreased by $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.

For additional discussion of the Medallion Sale, current and prior period divestitures of oil and natural gas properties and prior period acquisition of oil and natural gas properties, see Note 4 to our consolidated financial statements included elsewhere in this Annual Report.

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

(in thousands)	For the years ended December 31, 2017	2016	2015
Deposit received for potential sale of oil and natural gas properties	$ —	$ 3,000	$ —
Deposit utilized for sale of oil and natural gas properties	(3,000)	—	—
Capital expenditures:			
Acquisitions of oil and natural gas properties	—	(124,660)	—
Oil and natural gas properties	(538,122)	(360,679)	(588,017)
Midstream service assets	(20,887)	(5,240)	(35,459)
Other fixed assets	(4,905)	(7,611)	(9,125)
Investment in equity method investee (see Note 4.a)	(31,808)	(69,609)	(99,855)
Proceeds from disposition of equity method investee, net of selling costs (see Note 4.a)	829,615	—	—
Proceeds from dispositions of capital assets, net of selling costs	64,157	397	64,949
Net cash provided by (used in) investing activities	$ 295,050	$ (564,402)	$ (667,507)

Capital budget

Our board of directors approved a capital budget of approximately $555.0 million for calendar year 2018, excluding acquisitions. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted.

The amount, timing and allocation of capital expenditures 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, 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 from financing activities

For the year ended December 31, 2017, our net cash flows from financing activities were the result of (i) the early redemption of our May 2022 Notes, (ii) payments on our Senior Secured Credit Facility, partially offset by borrowings, (iii) the purchase of treasury stock to satisfy employees' tax withholding upon vesting of their stock-based compensation awards and (iv) payments for debt issuance costs as a result of entering into the Fifth Amended and Restated Credit Agreement. The aforementioned increase in the purchase of treasury stock is mainly due to the increase of our stock price at the stock awards' vest dates, which is utilized to determine the taxable compensation, compared to our stock price at the stock awards' grant dates, which is utilized to determine the number of shares of restricted stock awards to be granted.

For the year ended December 31, 2016, our net cash flows from financing activities were mainly the result of (i) the combined proceeds from our equity offerings in May and July 2016 and (ii) borrowings on our Senior Secured Credit Facility offset by payments.

For the year ended December 31, 2015, our net cash flows from financing activities were mainly the result of (i) proceeds from our March 2015 equity offering, (ii) the issuance of our March 2023 Notes and (iii) borrowings on our Senior Secured Credit Facility offset by payments. The cash inflows were offset by (i) the redemption of our January 2019 Notes and (ii) payments for debt issuance costs.

Our cash flows from financing activities for the periods presented are summarized in the table below:

(in thousands)	For the years ended December 31, 2017	2016	2015
Borrowings on Senior Secured Credit Facility	$ 190,000	$ 239,682	$ 310,000
Payments on Senior Secured Credit Facility	(260,000)	(304,682)	(475,000)
Issuance of March 2023 Notes	—	—	350,000
Early redemption of debt	(518,480)	—	(576,200)
Proceeds from issuance of common stock, net of offering costs	—	276,052	754,163
Purchase of treasury stock	(7,662)	(1,635)	(2,811)
Proceeds from exercise of stock options	397	208	—
Payments for debt issuance costs	(4,732)	—	(6,759)
Net cash (used in) provided by financing activities	$ (600,477)	$ 209,625	$ 353,393

Debt

As of December 31, 2017, we were a party only to our Senior Secured Credit Facility and the indentures governing our Senior Unsecured Notes.

Senior Secured Credit Facility. As of December 31, 2017, our Senior Secured Credit Facility had a maximum credit amount of $2.0 billion and a borrowing base and aggregate elected commitment of $1.0 billion each with no amounts outstanding. As of December 31, 2016 and 2015, borrowings outstanding under our Senior Secured Credit Facility totaled $70.0 million and $135.0 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. The maturity date of the Senior Secured Credit Facility is May 2, 2022, provided that if the January 2022 Notes have not been redeemed or refinanced on or prior to the Early Maturity Date, the Senior Secured Credit Facility will mature on such Early Maturity Date.

On October 20, 2017, pursuant to a regular semi-annual redetermination, the lenders reaffirmed the $1.0 billion borrowing base under our Senior Secured Credit Facility. Our aggregate elected commitment of $1.0 billion remained unchanged. The next semi-annual redetermination will occur by May 1, 2018.

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," as defined in our Senior Secured Credit Facility, 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," as defined in our Senior Secured Credit Facility, in each case, plus an applicable margin, which ranges from 1.0% to 2.0% for Adjusted Base Rate loans and from 2.0% to 3.0% 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 85% 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, 2017, 2016 and 2015.

As of December 31, 2017, 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
- a leverage ratio at the end of each fiscal quarter for the twelve-month period ending on such day of (x) total debt (excluding reimbursement obligations in respect of undrawn letters of credit, if no loans are outstanding under the Senior Secured Credit Facility) minus a maximum of $50 million of unrestricted and unencumbered cash and cash equivalents, to (y) earnings for such period before interest, taxes, depletion, depreciation, amortization and exploration expenses and other non-cash charges ("Consolidated EBITDAX"), as defined by the agreement, that is not permitted to be greater than 4.25 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;
- enter into transactions with affiliates;
- engage in certain transactions that violate the Employment Retirement Income Security Act of 1974 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.

We have amended our Senior Secured Credit Facility to allow us to execute our stock repurchase plan whereby we can pay up to $200 million to repurchase our common stock within the next two years.

As of December 31, 2017, 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, 2017, 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 in our Senior Secured Credit Facility is incorrect in any material respect when deemed made or confirmed;
- failure to make any payment in respect of any other indebtedness in excess of $50.0 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 $50.0 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 $50.0 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 $50.0 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, 2017. 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, 2017:

(in millions, except for interest rates)	Principal	Interest rate
January 2022 Notes	$ 450.0	5.625%
March 2023 Notes	350.0	6.250%
Total Senior Unsecured Notes	$ 800.0	

Utilizing a significant portion of the proceeds from the Medallion Sale, we redeemed the May 2022 Notes in full on November 29, 2017. See Note 5.d to our consolidated financial statements included elsewhere in this Annual Report for information regarding the early redemption of the May 2022 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 and redemption, January 2019 Notes and redemption and our Senior Secured Credit Facility.

Obligations and commitments

The following table presents significant contractual obligations and commitments as of December 31, 2017:

(in thousands)	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
Senior Secured Credit Facility[1]	$ —	$ —	$ —	$ —	$ —
Senior Unsecured Notes[2]	47,188	94,375	531,719	360,937	1,034,219
Drilling contracts[3]	3,459	—	—	—	3,459
Firm sale and transportation commitments[4]	60,409	109,160	80,050	107,339	356,958
Derivatives[5]	20,335	9,009	—	—	29,344
Asset retirement obligations[6]	1,544	10,755	10,625	32,582	55,506
Lease commitments[7]	3,177	5,286	3,046	5,802	17,311
Total	$ 136,112	$ 228,585	$ 625,440	$ 506,660	$ 1,496,797

(1) At December 31, 2017, there were no amounts outstanding under our Senior Secured Credit Facility. 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, 2017, the principal on our Senior Secured Credit Facility is due on May 2, 2022.

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

(3) As of December 31, 2017, we had drilling rig term contracts with a third party which expire during 2018. 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 13.c to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our drilling contracts.

(4) As of December 31, 2017, 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 13.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 10.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 13.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) estimation of depletion, depreciation and amortization, (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, (ix) fair value of assets acquired and liabilities assumed in an acquisition, (x) deferred gain on sale of equity method investment and (xi) contingent liabilities. 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, 2017. 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. See Note 2.h to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our full cost method of accounting for oil and natural gas properties.

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. See Notes 18.d and 18.e to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our oil, NGL and natural gas reserves and standardized measure of discounted future net cash flows, respectively.

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. 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.h to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our prior period impairments 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.

See Note 3.a to our consolidated financial statements included elsewhere in this Annual Report for discussion of the expected effects on our consolidated financial statements upon the adoption of new revenue recognition guidance subsequent to December 31, 2017.

Income taxes

As of December 31, 2017 and 2016, 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 and our estimate of the impact of the Tax Act, 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;
- 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; and
- current market prices for oil, NGL and natural gas.

During 2017, 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. We will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods. See Note 11 to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our income taxes.

Variable interest entities ("VIE")

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. See Notes 4.a, 14.a and 17.a to our consolidated financial statements included elsewhere in this Annual Report for a discussion of our previously unconsolidated VIE, Medallion, which was sold on October 30, 2017.

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. See Note 2.m to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our asset retirement obligations.

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 reflected in "Non-operating income (expense)" in our consolidated statements of operations. See Notes 9 and 10.a to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our derivatives.

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 values of the awards are 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 7 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 2017, 2016 and 2015 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 7.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 were classified as liability awards as they had 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 7.e of our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our prior period performance unit awards.

Recent accounting pronouncements

For discussion of recent accounting pronouncements, see Note 3 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, 2015 through the year ended December 31, 2017. 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 Note 13 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, basis swaps and, in the past, call spreads 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, 2017, 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	$ (48,019)	$ 20,478

As of December 31, 2017 and 2016, the net fair values of our open derivative contracts were a liability of $13.0 million and an asset of $3.0 million, respectively. Refer to Notes 2.f, 9 and 10.a of our consolidated financial statements included elsewhere in this Annual Report for additional disclosures regarding our derivatives.

Interest rate risk

The expected maturity years, carrying amounts and fixed interest rates on our long-term debt as of December 31, 2017 and the Senior Secured Credit Facility's average floating interest rate for the year ended December 31, 2017 were as follows:

	Expected maturity year	
(in millions except for interest rates)	2022	2023
Senior Secured Credit Facility - floating rate	$ —	$ —
Average interest rate	2.372%	—%
January 2022 Notes - fixed rate	$ 450.0	$ —
Interest rate	5.625%	—%
March 2023 Notes - fixed rate	$ —	$ 350.0
Interest rate	—%	6.250%

Counterparty and customer credit risk

As of December 31, 2017, our principal exposure to credit risk was through receivables of (i) $67.1 million from the sales of our oil, NGL and natural gas production that we market to energy marketing companies and refineries, (ii) $19.5 million from sales of purchased oil and other products, (iii) $10.3 million from the fair values of our open derivative contracts, (iv) $8.8 million from joint-interest partners and (v) $0.6 million from matured derivatives.

We are subject to credit risk due to the concentration of (i) our oil, NGL and natural gas receivables with four significant customers and (ii) our sales of 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 12 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, 2017, 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, 2017.

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, 2017. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2017, 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.

Opinion on internal control over financial reporting
We have audited the internal control over financial reporting of Laredo Petroleum, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in the 2013 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, 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) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2017, and our report dated February 15, 2018 expressed an unqualified opinion on those financial statements.

Basis for opinion
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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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.

Definition and limitations of internal control over financial reporting
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.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 15, 2018

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, 2017 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, 2017. 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***

Item 1.01 Entry into a Material Definitive Agreement.

On February 14, 2018, the Company entered into the Second Amendment (the "Second Amendment") to the Senior Secured Credit Facility. The Second Amendment, allows the Company, on or prior to February 14, 2020, to repurchase its common stock provided that (i) no Default or Event of Default exists or results therefrom, (ii) immediately after giving effect to any such repurchase, undrawn Commitments are greater than or equal to 20% of the Borrowing Base in effect at such time, (iii) immediately after giving effect to any such repurchase, the Company will be in pro forma compliance with all financial covenants, determined as if such repurchase and any related borrowings or issuance of Debt occurred on the last day of the Fiscal Quarter then most recently ended, (iv) the amount of aggregate consideration paid in respect of any such repurchases shall not exceed $200,000,000 in the aggregate, and (v) the Consolidated Total Leverage Ratio on a pro forma basis (determined as if such repurchase and any related borrowing or issuance of Debt occurred on the last day of the Fiscal Quarter then most recently ended) is less than 2.75 to 1.00. All capitalized terms above have the meanings ascribed to them in the Second Amendment.

The foregoing description of the Second Amendment is a summary only and is qualified in its entirety by reference to the complete text of the Second Amendment, a copy of which is filed as Exhibit 10.3 to this Annual Report.

Item 8.01 Other Events.

In February 2018, the Company's board of directors authorized a $200 million share repurchase program commencing in February 2018 and expiring in February 2020. Share repurchases under the share repurchase program may be made through a variety of methods, which may include open market purchases, privately negotiated transactions and block trades. The timing and actual number of shares repurchased, if any, will depend upon several factors, including market conditions, business conditions, the trading price of our common stock and the nature of other investment opportunities available to the Company.

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, 2017.

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, 2017.

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, 2017.

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, 2017.

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, 2017.

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).
2.2	Membership Interest Purchase and Sale Agreement, dated as of October 1, 2017, by and among Medallion Midland Acquisition, LLC, Medallion Gathering & Processing, LLC, Laredo Midstream Services, LLC, and Medallion Midstream Holdings, LLC (incorporated by reference to Exhibit 2.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on October 30, 2017).
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	Fifth Amended and Restated Credit Agreement, dated as of May 2, 2017, 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 Quarterly Report on Form 10-Q (File No. 001-35380) filed on May 4, 2017).
10.2	First Amendment to Fifth Amended and Restated Credit Agreement, dated as of October 24, 2017, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors 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 October 30, 2017).
10.3*	Second Amendment to Fifth Amended and Restated Credit Agreement, dated as of February 14, 2018, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto.
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 (incorporated by reference to Exhibit 10.18 of Laredo's Annual Report on Form 10-K (File No. 001-35380) filed on February 16, 2017).
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 15, 2018

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)	2/15/2018
/s/ Richard C. Buterbaugh Richard C. Buterbaugh	Executive Vice President and Chief Financial Officer (principal financial officer)	2/15/2018
/s/ Michael T. Beyer Michael T. Beyer	Vice President - Controller and Chief Accounting Officer (principal accounting officer)	2/15/2018
/s/ Peter R. Kagan Peter R. Kagan	Director	2/15/2018
/s/ James R. Levy James R. Levy	Director	2/15/2018
/s/ B.Z. (Bill) Parker B.Z. (Bill) Parker	Director	2/15/2018
/s/ Pamela S. Pierce Pamela S. Pierce	Director	2/15/2018
/s/ Dr. Myles W. Scoggins Dr. Myles W. Scoggins	Director	2/15/2018
/s/ Edmund P. Segner, III Edmund P. Segner, III	Director	2/15/2018
/s/ Donald D. Wolf Donald D. Wolf	Director	2/15/2018

LAREDO PETROLEUM, INC.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Laredo Petroleum, Inc.

Opinion on the financial statements
We have audited the accompanying consolidated balance sheets of Laredo Petroleum, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2017 and 2016, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, 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) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2017, 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 15, 2018 expressed an unqualified opinion.

Basis for opinion
These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2007.

Tulsa, Oklahoma
February 15, 2018

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

	December 31, 2017	December 31, 2016
Assets		
Current assets:		
Cash and cash equivalents	$ 112,159	$ 32,672
Accounts receivable, net	100,645	86,867
Derivatives	6,892	20,947
Other current assets	15,686	14,291
Total current assets	235,382	154,777
Property and equipment:		
Oil and natural gas properties, full cost method:		
Evaluated properties	6,070,940	5,488,756
Unevaluated properties not being depleted	175,865	221,281
Less accumulated depletion and impairment	(4,657,466)	(4,514,183)
Oil and natural gas properties, net	1,589,339	1,195,854
Midstream service assets, net	138,325	126,240
Other fixed assets, net	40,721	44,773
Property and equipment, net	1,768,385	1,366,867
Derivatives	3,413	8,718
Investment in equity method investee (see Note 4.a)	—	243,953
Other noncurrent assets, net	16,109	8,031
Total assets	$ 2,023,289	$ 1,782,346
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 58,341	$ 52,204
Accrued capital expenditures	82,721	30,845
Undistributed revenue and royalties	37,852	26,838
Derivatives	22,950	20,993
Other current liabilities	75,555	57,065
Total current liabilities	277,419	187,945
Long-term debt, net	791,855	1,353,909
Derivatives	384	5,694
Asset retirement obligations	53,962	50,604
Other noncurrent liabilities	134,090	3,621
Total liabilities	1,257,710	1,601,773
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $0.01 par value, 50,000,000 shares authorized and zero issued as of December 31, 2017 and 2016	—	—
Common stock, $0.01 par value, 450,000,000 shares authorized and 242,521,143 and 241,929,070 issued and outstanding as of December 31, 2017 and 2016, respectively	2,425	2,419
Additional paid-in capital	2,432,262	2,396,236
Accumulated deficit	(1,669,108)	(2,218,082)
Total stockholders' equity	765,579	180,573
Total liabilities and stockholders' equity	$ 2,023,289	$ 1,782,346

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,		
	2017	2016	2015
Revenues:			
Oil, NGL and natural gas sales	$ 621,507	$ 426,485	$ 431,734
Midstream service revenues	10,517	8,342	6,548
Sales of purchased oil	190,138	162,551	168,358
Total revenues	822,162	597,378	606,640
Costs and expenses:			
Lease operating expenses	75,049	75,327	108,341
Production and ad valorem taxes	37,802	28,586	32,892
Midstream service expenses	4,099	4,077	5,846
Costs of purchased oil	195,908	169,536	174,338
General and administrative	96,312	91,756	90,425
Restructuring expenses	—	—	6,042
Depletion, depreciation and amortization	158,389	148,339	277,724
Impairment expense	—	162,027	2,374,888
Other operating expenses	4,931	5,692	7,658
Total costs and expenses	572,490	685,340	3,078,154
Operating income (loss)	249,672	(87,962)	(2,471,514)
Non-operating income (expense):			
Gain (loss) on derivatives, net	350	(87,425)	214,291
Income from equity method investee (see Note 4.a)	8,485	9,403	6,799
Interest expense	(89,377)	(93,298)	(103,219)
Interest and other income	805	175	426
Loss on early redemption of debt	(23,761)	—	(31,537)
Write-off of debt issuance costs	—	(842)	—
Gain on sale of investment in equity method investee (see Note 4.a)	405,906	—	—
Loss on disposal of assets, net	(1,306)	(790)	(2,127)
Non-operating income (expense), net	301,102	(172,777)	84,633
Income (loss) before income taxes	550,774	(260,739)	(2,386,881)
Income tax (expense) benefit:			
Current	(1,800)	—	—
Deferred	—	—	176,945
Total income tax (expense) benefit	(1,800)	—	176,945
Net income (loss)	$ 548,974	$ (260,739)	$ (2,209,936)
Net income (loss) per common share:			
Basic	$ 2.30	$ (1.16)	$ (11.10)
Diluted	$ 2.29	$ (1.16)	$ (11.10)
Weighted-average common shares outstanding:			
Basic	239,096	225,512	199,158
Diluted	240,122	225,512	199,158

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, 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 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 stock exchanged for tax withholding	—	—	—	296	(1,635)	—	(1,635)
Retirement of treasury stock	(296)	(3)	(1,632)	(296)	1,635	—	—
Exercise of 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
Restricted stock awards	1,237	12	(12)	—	—	—	—
Restricted stock forfeitures	(302)	(3)	3	—	—	—	—
Performance share conversion	150	2	(2)	—	—	—	—
Vested stock exchanged for tax withholding	—	—	—	547	(7,662)	—	(7,662)
Retirement of treasury stock	(547)	(5)	(7,657)	(547)	7,662	—	—
Exercise of stock options	54	—	397	—	—	—	397
Stock-based compensation	—	—	43,297	—	—	—	43,297
Net income	—	—	—	—	—	548,974	548,974
Balance, December 31, 2017	242,521	$ 2,425	$ 2,432,262	—	$ —	$ (1,669,108)	$ 765,579

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, 2017	2016	2015
Cash flows from operating activities:			
Net income (loss)	$ 548,974	$ (260,739)	$ (2,209,936)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred income tax benefit	—	—	(176,945)
Depletion, depreciation and amortization	158,389	148,339	277,724
Impairment expense	—	162,027	2,374,888
Gain on sale of investment in equity method investee (see Note 4.a)	(405,906)	—	—
Loss on early redemption of debt	23,761	—	31,537
Bad debt expense	—	—	255
Non-cash stock-based compensation, net of amounts capitalized	35,734	29,229	24,509
Mark-to-market on derivatives:			
(Gain) loss on derivatives, net	(350)	87,425	(214,291)
Cash settlements received for matured derivatives, net	37,583	195,281	255,281
Cash settlements received for early terminations of derivatives, net	4,234	80,000	—
Change in net present value of derivative deferred premiums	394	232	203
Cash premiums paid for derivatives	(25,853)	(89,669)	(5,167)
Amortization of debt issuance costs	4,086	4,279	4,727
Write-off of debt issuance costs	—	842	—
Income from equity method investee (see Note 4.a)	(8,485)	(9,403)	(6,799)
Cash settlement of performance unit awards	—	(6,394)	(2,738)
Other, net	6,067	4,596	4,554
(Increase) decrease in accounts receivable	(12,124)	832	38,975
Increase in other current assets	(3,132)	(1,013)	(2,309)
Increase in other noncurrent assets	(5,103)	—	—
Increase (decrease) in accounts payable and accrued liabilities	9,137	5,432	(38,881)
Increase (decrease) in undistributed revenues and royalties	11,014	(7,735)	(30,898)
(Decrease) increase in other current liabilities	(2,327)	13,153	(12,942)
Increase (decrease) in other noncurrent liabilities	8,821	(419)	119
Increase in fair value of performance unit awards	—	—	4,081
Net cash provided by operating activities	384,914	356,295	315,947
Cash flows from investing activities:			
Deposit received for potential sale of oil and natural gas properties	—	3,000	—
Deposit utilized for sale of oil and natural gas properties	(3,000)	—	—
Capital expenditures:			
Acquisitions of oil and natural gas properties	—	(124,660)	—
Oil and natural gas properties	(538,122)	(360,679)	(588,017)
Midstream service assets	(20,887)	(5,240)	(35,459)
Other fixed assets	(4,905)	(7,611)	(9,125)
Investment in equity method investee (see Note 4.a)	(31,808)	(69,609)	(99,855)
Proceeds from disposition of equity method investee, net of selling costs (see Note 4.a)	829,615	—	—
Proceeds from dispositions of capital assets, net of selling costs	64,157	397	64,949
Net cash provided by (used in) investing activities	295,050	(564,402)	(667,507)
Cash flows from financing activities:			
Borrowings on Senior Secured Credit Facility	190,000	239,682	310,000
Payments on Senior Secured Credit Facility	(260,000)	(304,682)	(475,000)
Issuance of March 2023 Notes	—	—	350,000
Early redemption of debt	(518,480)	—	(576,200)
Proceeds from issuance of common stock, net of offering costs	—	276,052	754,163
Purchase of treasury stock	(7,662)	(1,635)	(2,811)
Proceeds from exercise of stock options	397	208	—
Payments for debt issuance costs	(4,732)	—	(6,759)
Net cash (used in) provided by financing activities	(600,477)	209,625	353,393
Net increase in cash and cash equivalents	79,487	1,518	1,833
Cash and cash equivalents, beginning of period	32,672	31,154	29,321
Cash and cash equivalents, end of period	$ 112,159	$ 32,672	$ 31,154

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 liquids-rich 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. 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 4.a, 14.a and 17.a 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) volumes 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) deferred gain on sale of equity method investment, (ix) fair value of assets acquired and liabilities assumed in an acquisition, (x) fair values of derivatives and deferred premiums and (xi) contingent liabilities. 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 2017 presentation. These reclassifications had no impact on previously reported total assets, total liabilities, net income (loss), stockholders' equity or total operating, investing or financing cash flows.

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 12 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 majority of the Company's accounts receivable are 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 greater than 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 the dates presented:

(in thousands)	December 31, 2017	December 31, 2016
Oil, NGL and natural gas sales	$ 67,116	$ 46,999
Sales of purchased oil and other products	19,504	16,213
Joint operations, net[(1)]	8,780	12,175
Matured derivatives	641	11,059
Other	4,604	421
Total accounts receivable	$ 100,645	$ 86,867

(1) Accounts receivable for joint operations are presented net of an allowance for doubtful accounts of $0.1 million and $0.2 million as of December 31, 2017 and 2016, respectively. 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 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, basis swaps and, in the past, call spreads.

Derivatives are recorded at fair value and are presented on a net basis on the consolidated balance sheets as assets and/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 10.a 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 9, 10.a and 17.d for discussion regarding the Company's derivatives.

g. Other current assets, current liabilities and noncurrent liabilities

Other current assets consisted of the following components as of the dates presented:

(in thousands)	December 31, 2017	December 31, 2016
Inventory[(1)]	$ 9,148	$ 8,063
Prepaid expenses and other	6,538	6,228
Total other current assets	$ 15,686	$ 14,291

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

Accounts payable and accrued liabilities consisted of the following components as of the dates presented:

(in thousands)	December 31, 2017	December 31, 2016
Purchased oil payable	$ 19,084	$ 17,213
Lease operating expense payable	9,034	10,572
Trade accounts payable	5,730	15,054
Other accrued liabilities	24,493	9,365
Total accounts payable and accrued liabilities	$ 58,341	$ 52,204

Other current liabilities consisted of the following components as of the dates presented:

(in thousands)	December 31, 2017	December 31, 2016
Accrued compensation and benefits	$ 21,287	$ 25,947
Deferred gain on sale of equity method investment(1)	20,144	—
Accrued interest payable	18,013	24,152
Other accrued liabilities	16,111	6,966
Total other current liabilities	$ 75,555	$ 57,065

(1) See Notes 4.a, 14.a and 17.a for additional discussion regarding the Company's equity method investee.

Other noncurrent liabilities consisted of the following components as of the dates presented:

(in thousands)	December 31, 2017	December 31, 2016
Deferred gain on sale of equity method investment(1)	$ 120,974	$ —
Other accrued liabilities	13,116	3,621
Total other noncurrent liabilities	$ 134,090	$ 3,621

(1) See Notes 4.a, 14.a and 17.a for additional discussion regarding the Company's equity method investee.

h. 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 depleted 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 unit-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 $175.9 million and $221.3 million of such costs were excluded from the depletion base as of December 31, 2017 and 2016, 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 $4.7 billion and $4.5 billion for the years ended December 31, 2017 and 2016, respectively. Depletion expense for oil and natural gas properties was $143.6 million, $134.1 million, and $263.7 million for the years ended December 31, 2017, 2016 and 2015, respectively. Depletion per barrel of oil equivalent for the Company's oil and natural gas properties was $6.75, $7.39 and $16.13 for the years ended December 31, 2017, 2016 and 2015, respectively.

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

	For the years ended December 31,		
(in thousands)	2017	2016	2015
Capitalized employee-related costs	$ 25,553	$ 19,222	$ 10,688

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 18.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, 2017	December 31, 2016	December 31, 2015
Benchmark Prices:			
Oil ($/Bbl)	$ 47.79	$ 39.25	$ 46.79
NGL ($/Bbl)(1)	$ 26.13	$ 18.24	$ 18.75
Natural gas ($/MMBtu)	$ 2.63	$ 2.33	$ 2.47
Realized Prices:			
Oil ($/Bbl)	$ 46.34	$ 37.44	$ 45.58
NGL ($/Bbl)	$ 18.45	$ 11.72	$ 12.50
Natural gas ($/Mcf)	$ 2.06	$ 1.78	$ 1.89

(1) Based on the Company's average composite NGL barrel.

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, 2017. 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 15.

i. 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 $8.9 million, $8.3 million and $7.5 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Midstream service assets consisted of the following components as of the dates presented:

(in thousands)	December 31, 2017	December 31, 2016
Midstream service assets	$ 171,427	$ 150,629
Less accumulated depreciation and impairment	(33,102)	(24,389)
Total midstream service assets, net	$ 138,325	$ 126,240

Impairment losses are recorded on midstream service 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. 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 the "Impairment expense" line item in the consolidated statements of operations and as "Impairment expense" for the Company's midstream and marketing segment presented in Note 15. There were no comparable midstream service asset impairments recorded during the years ended December 31, 2017 or 2016.

j. 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, $5.9 million, and $6.5 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Other fixed assets consisted of the following components as of the dates presented:

(in thousands)	December 31, 2017	December 31, 2016
Computer hardware and software	$ 11,696	$ 12,710
Vehicles	9,661	7,413
Real estate and buildings	7,618	7,618
Leasehold improvements	7,590	7,549
Aircraft	6,402	11,352
Other	5,990	5,849
Depreciable total	48,957	52,491
Less accumulated depreciation and amortization	(23,150)	(22,632)
Depreciable total, net	25,807	29,859
Land	14,914	14,914
Total other fixed assets, net	$ 40,721	$ 44,773

k. Inventory

The Company has the following types of inventory: (i) materials and supplies inventory used in production activities of oil and natural gas properties and midstream service assets, (ii) frac pit water inventory used in developing oil and natural gas properties and (iii) line-fill in third-party pipelines, which is the minimum volume of product in a pipeline system that enables the system to operate, and is generally not available to be withdrawn from the pipeline until the expiration of the transportation contract. All inventory is carried at the lower of cost or net realizable value ("NRV"), with cost determined using the weighted-average cost method, and is included in each of the "Other current assets" and "Other noncurrent assets, net" line items on the consolidated balance sheets. The NRV for materials and supplies inventory and frac pit water inventory is determined utilizing a replacement cost approach (Level 2). The NRV for line-fill in third-party pipelines is determined utilizing a quoted market price adjusted for regional price differentials (Level 2).

The following table presents inventory impairments recorded:

(in thousands)	For the years ended December 31, 2017	2016	2015
Materials and supplies[1]	$ —	$ 963	$ 2,819
Line-fill[2]	—	—	1,314
Total inventory impairments	$ —	$ 963	$ 4,133

(1) Included in the "Impairment expense" line item in the consolidated statements of operations and in "Impairment expense" for the Company's exploration and production segment presented in Note 15.

(2) Included in the "Impairment expense" line item in the consolidated statements of operations and in "Impairment expense" for the Company's midstream and marketing segment presented in Note 15.

l. 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 $4.7 million of debt issuance costs during the year ended December 31, 2017 as a result of entering into the Fifth Amended and Restated Credit Agreement (as amended, the "Senior Secured Credit Facility"). 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). No debt issuance costs were capitalized during the year ended December 31, 2016.

The Company wrote-off $5.3 million of debt issuance costs during the year ended December 31, 2017 as a result of the early redemption of the May 2022 Notes (as defined below), which are included in the "Loss on early redemption of debt" line item in the consolidated statements of operations. 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, which are included in the "Write-off of debt issuance costs" line item in the consolidated statements of operations. The Company wrote-off $6.6 million 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 "Loss on early redemption of debt" line item in the consolidated statements of operations.

The Company had total debt issuance costs of $14.2 million and $18.8 million, net of accumulated amortization of $20.8 million and $21.3 million, as of December 31, 2017 and 2016, respectively. Debt issuance costs related to the Company's senior unsecured notes are included in the "Long-term debt, net" line item on the consolidated balance sheets. Debt issuance costs related to the Senior Secured Credit Facility are included in the "Other noncurrent assets, net" line item on the consolidated balance sheets. See Note 5.h for additional discussion of debt issuance costs.

The following table presents future amortization expense of debt issuance costs:

(in thousands)	December 31, 2017
2018	$ 3,173
2019	3,173
2020	3,173
2021	3,173
2022	1,350
Thereafter	134
Total	$ 14,176

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 table reconciles the asset retirement obligation liability:

	For the years ended December 31,	
(in thousands)	**2017**	**2016**
Liability at beginning of year	$ 52,207	$ 46,306
Liabilities added due to acquisitions, drilling, midstream service asset construction and other	616	1,528
Accretion expense	3,791	3,483
Liabilities settled upon plugging and abandonment	(408)	(1,242)
Liabilities removed due to sale of property	(871)	—
Revision of estimates	171	2,132
Liability at end of year	$ 55,506	$ 52,207

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 10.a 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, 2017 or 2016.

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.

See Note 3.a for discussion of the expected effects on the Company's consolidated financial statements upon the adoption of new revenue recognition guidance subsequent to December 31, 2017.

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 table presents the fees received for the operation of jointly-owned oil and natural gas properties:

	For the years ended December 31,		
(in thousands)	**2017**	**2016**	**2015**
Fees received for the operation of jointly-owned oil and natural gas properties	$ 2,549	$ 2,477	$ 3,125

r. Compensation awards

Stock-based compensation expense, net of amounts capitalized, is included in the "General and administrative" line item 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, the 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 in the "Oil and natural gas properties" line item on the consolidated balance sheets. See Note 7 for further discussion regarding the restricted stock awards, stock option awards, performance share awards and performance unit awards.

s. 2015 restructuring

On January 20, 2015, following the fourth-quarter 2014 drop in oil prices and, in an effort to reduce costs and to better position the Company for ongoing efficient growth, 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 packages. 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, 2017 or 2016.

t. 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, 2017 or 2016. See Note 11 for additional information regarding the Company's income taxes.

u. 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, 2017 or 2016.

v. Non-cash investing and supplemental cash flow information

The following table presents the non-cash investing and supplemental cash flow information:

(in thousands)	For the years ended December 31, 2017	2016	2015
Non-cash investing information:			
Change in accrued capital expenditures	$ 51,876	$ (31,027)	$ (86,369)
Change in accrued capital contribution to equity method investee(1)	$ —	$ (27,583)	$ 27,583
Capitalized asset retirement cost	$ 787	$ 3,660	$ 13,836
Supplemental cash flow information:			
Cash paid for interest, net of $1,152, $294 and $236 of capitalized interest, respectively(2)	$ 91,548	$ 89,432	$ 112,457
Cash paid for income taxes(3)	$ 5,500	$ —	$ —

(1) See Notes 4.a, 14.a and 17.a for additional discussion of the Company's equity method investee.

(2) See Note 5.a for additional discussion of the Company's interest expense.

(3) See Note 11 for additional discussion of the Company's income taxes.

Note 3—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 discussion of the ASUs listed below were determined to be meaningful to the Company's consolidated financial statements and/or footnotes during the year ended December 31, 2017.

a. Revenue recognition

In May 2014, the FASB issued a comprehensive new revenue recognition standard in Topic 606, *Revenue from Contracts with Customers,* 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: (i) a full retrospective adoption in which the standard is applied to all of the periods presented, or (ii) 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: (i) to clarify the implementation guidance on principal versus agent considerations, (ii) to clarify the identification of performance obligations and the licensing implementation guidance and (iii) to address certain issues in the guidance on assessing collectability, presentation of sales taxes, noncash consideration and completed contracts and contract modifications at transition.

The Company has substantially completed its evaluation of the impact of the new standard. This process included a review of significant and representative contracts across both its exploration and production and midstream and marketing segments, application of the accounting standards codification ("ASC") 606 framework and documentation of conclusions thereof. The Company is currently evaluating disclosure requirements, finalizing accounting policies and implementing changes to the relevant business processes and the control activities as a result of this standard. The Company follows the sales method of accounting for oil, NGL and natural gas production, which is generally consistent with the revenue recognition provision of the new standard. Based upon its evaluation to date, the Company anticipates no impact to the timing or amounts of revenue recognition for its existing contracts upon implementation in 2018 of the new standard. The Company expects to present enhanced disclosures upon implementation and will reclassify deficiency payments, which were $1.1 million, $2.2 million and $5.2 million for the years ended December 31, 2017, 2016 and 2015, respectively, that are currently included in the "other operating expenses" line item in the consolidated statement of operations, to net with the revenue stream from which they derive. The Company adopted this standard on January 1, 2018 and will apply this guidance on a modified retrospective approach to adoption in its quarterly report on Form 10-Q for the three-month period ended March 31, 2018.

On October 30, 2017, the Company sold its interest in Medallion (defined in Note 4.a below). At December 31, 2017, the transaction was accounted for under the real estate guidance in ASC 360-20, *Property, Plant, and Equipment* and a portion of the gain on the sale had been deferred and would have been amortized over the TA's (defined in Note 4.a below) firm commitment transportation term through 2024 had the Company not adopted ASC 606 on January 1, 2018. Upon the adoption of ASC 606, the guidance in ASC 360-20 was superseded by ASC 860, *Transfers and Servicing.* Therefore utilizing the modified retrospective approach of adoption, this deferred gain of $141.1 million will be recognized in the beginning balance of retained earnings.

b. Leases

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 lease guidance. In addition, also consistent with the previous lease 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 ASU are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application of the amendments in this ASU is permitted. The Company does not expect to early-adopt this guidance and is in the process of evaluating the potential impact upon adoption. The primary effect will be to record assets and obligations for contracts currently recognized as operating leases with a term greater than 12 months and evaluate operating leases with a term less than or equal to 12 months for election.

c. Business combinations

In January 2017, the FASB issued new guidance in Topic 805, *Business Combinations*, to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. Under the current implementation guidance in Topic 805, there are three elements of a business—inputs, processes and outputs. While an integrated set of assets and activities (collectively referred to as a "set") that is a business usually has outputs, outputs are not required to be present. In addition, all the inputs and processes that a seller uses in operating a set are not required if market participants can acquire the set and continue to produce outputs, for example, by integrating the acquired set with their own inputs and processes. The amendments in this ASU provide a screen to determine when a set is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired (or disposed of) is concentrated in a single identifiable asset or a group of similar identifiable assets, the set is not a business. This screen reduces the number of transactions that need to be further evaluated. If the screen is not met, the amendments in this ASU (i) require that to be considered a business, a set must include, at a minimum, an input and a substantive process that together significantly contribute to the ability to create an output and (ii) remove the evaluation of whether a market participant could replace missing elements. The amendments provide a framework to assist entities in evaluating whether both an input and a substantive process are present. The framework includes two sets of criteria to consider that depend on whether a set has outputs. Although outputs are not required for a set to be a business, outputs generally are a key element of a business; therefore, the FASB has developed more stringent criteria for sets without outputs. Lastly, the amendments in this ASU narrow the definition of the term output so that the term is consistent with how outputs are described in Topic 606. The amendments in this ASU are effective for annual periods beginning after December 15, 2017, including interim periods within those periods. The amendments in this ASU should be applied prospectively on or after the effective date. The Company adopted this standard on January 1, 2018 and will apply this guidance to its next business combination.

Note 4—Divestitures and acquisitions

a. 2017 Medallion sale

Medallion Gathering & Processing, LLC, a Texas limited liability company formed on October 12, 2012, which, together with its wholly-owned subsidiaries (collectively, "Medallion"), was established for the purpose of developing midstream solutions and providing midstream infrastructure to bring oil to market in the Midland Basin. Prior to the Medallion Sale (defined below), LMS held 49% of Medallion's ownership units. LMS and the third-party 51% interest-holder agreed that the voting rights of Medallion, the profit and loss sharing and the additional capital contribution requirements would be equal to the ownership unit percentage held. Additionally, Medallion required a super-majority vote of 75% for many key operating and business decisions. The Company determined that Medallion was a variable interest entity ("VIE"). However, LMS was not considered to be the primary beneficiary of the VIE because LMS did not have the power to direct the activities that most significantly affected Medallion's economic performance. As such, prior to the Medallion Sale, Medallion was accounted for under the equity method of accounting. The Company's proportionate share of Medallion's net income is reflected in the consolidated statements of operations on the "Income from equity method investee" line item and the carrying amount is reflected in the consolidated balance sheets on the "Investment in equity method investee" line item. The Company elected to classify distributions received from Medallion using the cumulative earnings approach. No such distributions were received through December 31, 2017.

LMS contributed $31.8 million and $69.6 million to Medallion during the years ended December 31, 2017 and 2016, respectively. Medallion continued expansion activities on existing portions of its pipeline infrastructure in order to gather and transport additional third-party oil production during each of the years ended December 31, 2017 and 2016. 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 "Other operating expenses" for the period in which the buyout was settled. See Note 14.a for discussion of items included in the Company's consolidated financial statements related to Medallion.

On October 30, 2017, LMS, together with Medallion Midstream Holdings, LLC ("MMH"), which is owned and controlled by an affiliate of the third-party interest-holder, The Energy & Minerals Group ("EMG"), completed the sale of 100% of the ownership interests in Medallion to an affiliate of Global Infrastructure Partners ("GIP"), for cash consideration of $1.825 billion (the "Medallion Sale"). LMS' net cash proceeds for its 49% ownership interest in Medallion in 2017 were $829.6 million, before post-closing adjustments and taxes, but after deduction of its proportionate share of fees and other expenses associated with the Medallion Sale. On February 1, 2018, closing adjustments were finalized and LMS received additional net cash of $1.7 million for total net cash proceeds before taxes of $831.3 million. The proceeds were used to pay in-full borrowings on the Senior Secured Credit Facility, to redeem the May 2022 Notes (defined below) and for working capital purposes. The Medallion Sale closed pursuant to the membership interest purchase and sale agreement, which provides for potential post-closing additional cash consideration that is structured based on GIP's realized profit at exit. There can be no assurance as to when and whether the additional consideration will be paid. The Company recorded an estimated post-closing final adjustment receivable amount of $1.7 million as of December 31, 2017, which is included in the consolidated balance sheets in the "Accounts Receivable, net" line item and is included in the consolidated statements of operations in the "Gain on sale of investment in equity method investee" line item. See Note 17.a for additional discussion of the Medallion Sale post-closing subsequent to December 31, 2017. The Medallion Sale does not represent a strategic shift and will not have a major effect on the Company's future operations or financial results.

LMS has a Transportation Services Agreement (the "TA") with a wholly-owned subsidiary of Medallion, under which LMS receives firm transportation of the Company's crude oil production from Reagan and Glasscock County, Texas to Colorado City, Texas that continues to be in effect after the Medallion Sale. Historically, the Company's crude oil purchasers have fulfilled the commitment by transporting crude oil, purchased from the Company, under the TA, as agent. As of December 31, 2017, the Company's maximum exposure to loss associated with future commitments under the TA is $141.1 million that is not recorded in the Company's consolidated balance sheets. As a result of the Company's continuing involvement with Medallion by guaranteeing cash flows under the TA, the Company recorded a deferred gain in the amount of its maximum exposure to loss related to such guarantees that would have been amortized over the TA's firm commitment transportation term through 2024 had the Company not adopted new revenue recognition guidance on January 1, 2018. Upon adoption of the new revenue recognition guidance, utilizing the modified retrospective approach, this deferred gain will be recognized into the beginning balance of retained earnings. See Note 3.a for further discussion of the future impact to the Company upon the adoption of the new revenue recognition rules. See Note 2.g for the amounts of deferred gain on sale of equity method investment that is included in the consolidated balance sheets in each of the "Other current liabilities" and "Other noncurrent liabilities" line items.

b. 2017 divestiture of evaluated and unevaluated oil and natural gas properties

In January 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 $59.7 million. After transaction costs reflecting an economic effective date of October 1, 2016, the proceeds were $59.5 million, net of working capital and post-closing adjustments. The Company completed the post-closing for this divestiture in May 2017. A significant portion of these proceeds was used to pay down borrowings on the Senior Secured Credit Facility. The purchase price was recorded as an adjustment 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 future operations or financial results.

c. 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 10.

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

d. 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 year ended December 31:

(in thousands)	2015
Oil, NGL and natural gas sales	$ 5,138
Expenses(1)	$ 5,791

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

e. Exchange of unevaluated oil and natural gas properties

From time to time, the Company exchanges undeveloped acreage with third parties, with no gain or loss recognized pursuant to the rules governing full cost accounting.

Note 5—Debt

a. Interest expense

The following table presents amounts that have been incurred and charged to interest expense:

	For the years ended December 31,		
(in thousands)	2017	2016	2015
Cash payments for interest	$ 92,700	$ 89,726	$ 112,693
Amortization of debt issuance costs and other adjustments	3,968	3,922	4,243
Change in accrued interest	(6,139)	(56)	(13,481)
Interest costs incurred	90,529	93,592	103,455
Less capitalized interest	(1,152)	(294)	(236)
Total interest expense	$ 89,377	$ 93,298	$ 103,219

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 and bear an interest rate of 6 1/4% per annum, 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 a price of 104.688% of face value with call premiums declining annually to 100% of face value on March 15, 2021 and thereafter 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 and bear an interest rate of 5 5/8% per annum, 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.

The January 2022 Notes became callable by the Company on January 15, 2017. The Company may redeem, at its option, all or part of the January 2022 Notes at any time on and after January 15, 2018, at a price of 102.813% of face value with call premiums declining annually to 100% of face value on January 15, 2020 and thereafter 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 were due to mature on May 1, 2022 and bore 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 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 May 2022 Notes were issued under and were 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 contained 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.

On November 29, 2017 (the "May 2022 Notes Redemption Date"), utilizing a portion of the proceeds from the Medallion Sale, the entire $500.0 million outstanding principal amount of the May 2022 Notes was redeemed at a redemption price of 103.688% of the principal amount of the May 2022 Notes, plus accrued and unpaid interest up to, but not including, the May 2022 Notes Redemption Date. The Company recognized a loss on extinguishment of $23.8 million related to the difference between the redemption price and the net carrying amount of the extinguished May 2022 Notes.

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 the 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 dividends or similar restricted payments, the undertaking of transactions with Laredo's unrestricted affiliates and limitations on asset sales.

On April 6, 2015 (the "January 2019 Notes 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, but not including, the January 2019 Notes 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, 2017, the Senior Secured Credit Facility, which matures on May 2, 2022 or October 17, 2021, if the January 2022 Notes have not been redeemed or refinanced by such date, had a maximum credit amount of $2.0 billion, a borrowing base and an aggregate elected commitment of $1.0 billion each, with no amounts outstanding. 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 1.0% to 2.0%, 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 2.0% to 3.0%, based on the ratio of outstanding revolving credit to the total commitment under the Senior Secured Credit Facility. Laredo is 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 and stock, including oil, NGL and natural gas properties, constituting at least 85% of the present value of the Company's proved 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, commencing with the calendar quarter ended March 31, 2017, the Company must maintain as of the last day of each calendar quarter a ratio of (a) its total debt (excluding reimbursement obligations in respect of undrawn letters of credit, if no loans are outstanding under the Senior Secured Credit Facility) minus a maximum of $50 million of unrestricted and unencumbered cash and cash equivalents, to (b) "Consolidated EBITDAX," as defined in the Senior Secured Credit Facility, for, prior to December 31, 2017, the period commencing on January 1, 2017 and ending on the last day of such applicable calendar quarter, and commencing on December 31, 2017, any period of four consecutive calendar quarters ending on the last day of such applicable calendar quarter of not greater than 4.25 to 1.00. Prior to the Company entering into the Fifth Amended and Restated Credit Agreement as of May 2, 2017, at the end of each calendar quarter, the Company was required to 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, 2017 or 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:

	December 31, 2017		December 31, 2016	
(in thousands)	**Long-term debt**	**Fair value**	**Long-term debt**	**Fair value**
January 2022 Notes	$ 450,000	$ 454,500	$ 450,000	$ 456,382
May 2022 Notes	—	—	500,000	521,413
March 2023 Notes	350,000	364,105	350,000	365,649
Senior Secured Credit Facility	—	—	70,000	69,975
Total	$ 800,000	$ 818,605	$ 1,370,000	$ 1,413,419

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, 2017 and 2016 quoted market price (Level 1) for each respective instrument. The fair value of the outstanding debt on the Senior Secured Credit Facility as of December 31, 2016 was estimated utilizing pricing models for similar instruments (Level 2). See Note 10.a 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:

	December 31, 2017			December 31, 2016		
(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	$ (3,987)	$ 446,013	$ 450,000	$ (4,963)	$ 445,037
May 2022 Notes	—	—	—	500,000	(6,164)	493,836
March 2023 Notes	350,000	(4,158)	345,842	350,000	(4,964)	345,036
Senior Secured Credit Facility[(1)]	—	—	—	70,000	—	70,000
Total	$ 800,000	$ (8,145)	$ 791,855	$ 1,370,000	$ (16,091)	$ 1,353,909

(1) Debt issuance costs, net related to our Senior Secured Credit Facility of $6.0 million and $2.7 million as of December 31, 2017 and 2016, respectively, are included in "Other noncurrent assets, net" in the consolidated balance sheets.

Note 6—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 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, 2017.

Note 7—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. The LTIP provides for the issuance of up 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 and (iii) fully on the third anniversary of the grant date. Beginning August 2017, stock awards granted to non-employee directors vest immediately upon the grant date. Restricted stock awards granted to non-employee directors prior to August 2017 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, 2015, 2016 and 2017:

(in thousands, except for weighted-average grant date fair value)	Restricted stock awards	Weighted-average grant date fair value (per award)
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	(1,186)	$ 16.07
Outstanding as of December 31, 2016	3,878	$ 12.88
Granted	1,237	$ 13.87
Forfeited	(302)	$ 12.87
Vested(1)	(1,644)	$ 13.75
Outstanding as of December 31, 2017	3,169	$ 12.81

(1) The total intrinsic value of vested restricted stock awards for the year ended December 31, 2017 was $22.8 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, 2017, unrecognized stock-based compensation related to the restricted stock awards expected to vest was $21.6 million. Such cost is expected to be recognized over a weighted-average period of 1.58 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, 2015, 2016 and 2017:

(in thousands, except for weighted-average exercise price and weighted-average remaining contractual term)	Stock option awards	Weighted-average exercise price (per award)	Weighted-average remaining contractual term (years)
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
Granted	391	$ 14.12	
Exercised(1)	(54)	$ 7.43	
Expired or canceled	(60)	$ 20.41	
Outstanding as of December 31, 2017	2,647	$ 12.70	7.12
Vested and exercisable as of December 31, 2017(2)	1,260	$ 16.47	5.97
Expected to vest as of December 31, 2017(3)	1,387	$ 9.27	8.17

(1) The total intrinsic value of exercised stock option awards for the year ended December 31, 2017 was $0.3 million.

(2) The vested and exercisable stock option awards as of December 31, 2017 had an aggregate intrinsic value of $1.3 million.

(3) The stock option awards expected to vest as of December 31, 2017 had an aggregate intrinsic value of $4.5 million.

The Company utilizes the Black-Scholes option pricing model to determine the fair value of stock option awards and recognizes 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, 2017, unrecognized stock-based compensation related to stock option awards expected to vest was $8.3 million. Such cost is expected to be recognized over a weighted-average period of 2.34 years.

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

	February 17, 2017	May 25, 2016	April 1, 2016	February 27, 2015
Risk-free interest rate(1)	2.14%	1.58%	1.44%	1.70%
Expected option life(2)	6.25 years	6.25 years	6.25 years	6.25 years
Expected volatility(3)	60.84%	61.94%	61.34%	52.59%
Fair value per stock option award	$ 8.22	$ 9.75	$ 4.44	$ 6.15

(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.

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

Performance share awards granted to management are subject to a combination of market and service vesting criteria. A Monte Carlo simulation prepared by an independent third party is 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. Any shares earned under such awards are expected to be issued in the first quarter following the completion of the requisite service period based on the achievement of certain performance criteria. The 454,164 outstanding 2015 performance share awards had a performance period of January 1, 2015 to December 31, 2017 and, as their performance criteria were not satisfied, these awards will not be converted into shares of common stock during the first quarter of 2018.

The following table reflects the performance share award activity for the years ended December 31, 2015, 2016 and 2017:

(in thousands, except for weighted-average grant date fair value)	Performance share awards	Weighted-average grant date fair value (per award)
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
Granted	696	$ 18.96
Forfeited	(76)	$ 18.12
Vested[(1)]	(200)	$ 28.56
Outstanding as of December 31, 2017	2,745	$ 17.77

(1) These performance share awards had a performance period of January 1, 2014 to December 31, 2016 and, as their vesting and performance criteria were satisfied, each award converted into 0.75 shares representing 150,388 shares of common stock issued during the first quarter of 2017.

As of December 31, 2017, unrecognized stock-based compensation related to the performance share awards expected to vest was $20.9 million. Such cost is expected to be recognized over a weighted-average period of 1.57 years.

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

	February 17, 2017	May 25, 2016	April 1, 2016	February 27, 2015
Risk-free interest rate[(1)]	1.44%	1.02%	0.87%	0.95%
Dividend yield	—%	—%	—%	—%
Expected volatility[(2)]	74.00%	74.73%	71.54%	53.78%
Laredo stock closing price on grant date	$ 14.12	$ 12.36	$ 7.71	$ 11.93
Fair value per performance share award	$ 18.96	$ 17.86	$ 9.83	$ 16.23

(1) The risk-free interest 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 in order to develop the expected volatility.

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)	2017	2016	2015
Restricted stock award compensation	$ 22,223	$ 21,609	$ 17,534
Stock option award compensation	4,762	4,519	4,074
Performance share award compensation	16,312	9,112	5,222
Total stock-based compensation, gross	43,297	35,240	26,830
Less amounts capitalized in oil and natural gas properties	(7,563)	(6,011)	(2,321)
Total stock-based compensation, net of amounts capitalized	$ 35,734	$ 29,229	$ 24,509

e. Performance unit awards

The performance unit awards issued to management in prior years 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.

For the year ended December 31, 2015, compensation expense for the performance unit awards of $4.1 million is included in "General and administrative" line item in the Company's consolidated statements of operations.

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)	**2017**	**2016**	**2015**
Contributions	$ 1,929	$ 1,789	$ 1,847

Note 8—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, outstanding stock option awards and non-vested performance share awards. 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, excluded from the calculation of diluted net loss per common share.

The following table reflects 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)	**2017**	**2016**	**2015**
Net income (loss) (numerator):			
Net income (loss)—basic and diluted	$ 548,974	$ (260,739)	$ (2,209,936)
Weighted-average common shares outstanding (denominator):			
Basic(1)	239,096	225,512	199,158
Non-vested restricted stock awards(2)	880	—	—
Outstanding stock option awards(3)	122	—	—
Non-vested performance share awards(4)	24	—	—
Diluted	240,122	225,512	199,158
Net income (loss) per common share:			
Basic	$ 2.30	$ (1.16)	$ (11.10)
Diluted	$ 2.29	$ (1.16)	$ (11.10)

(1) Weighted-average common shares outstanding used in the computation of basic and diluted net income (loss) per common share 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, 2017. See Note 6 for additional discussion of the Company's equity offerings.

(2) The dilutive effect of the non-vested restricted stock awards was calculated utilizing the treasury stock method. See Note 7.a for additional discussion of the Company's restricted stock awards.

(3) The dilutive effect of the outstanding stock option awards was calculated utilizing the treasury stock method. The effect of the outstanding stock option awards, with the exception of the options granted in 2016, was excluded from the calculation of diluted net income per common share for the year ended December 31, 2017. The inclusion of these outstanding stock option awards 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 options granted in 2015 and (ii) the exercise prices were greater than the average stock prices during the period for the options granted in 2012, 2013, 2014 and 2017. See Note 7.b for additional discussion of the Company's stock option awards.

(4) The dilutive effect of the non-vested performance share awards was calculated utilizing the Company's total shareholder return ("TSR") from the beginning of each performance share awards' respective performance period to the end of the respective period presented in comparison to the TSR of the peers specified in each performance share award's respective agreement. For the year ended December 31, 2017, the TSRs for the performance share awards granted in 2015, 2016 and 2017 were below their agreement's payout threshold and, therefore, these awards were excluded from the calculation of diluted net income per share. See Note 7.c for additional discussion of the Company's performance share awards.

Note 9—Derivatives

a. Derivatives

The Company engages in derivative transactions such as puts, swaps, collars, basis swaps and, in the past, call spreads to hedge price risks due to unfavorable changes in oil, NGL and natural gas prices related to its production. As of December 31, 2017, the Company had 39 open derivative contracts with financial institutions that extend from January 2018 to December 2020. 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 in the consolidated statements of operations in the "Gain (loss) on derivatives, net" line item.

Each put transaction has an established floor price. The Company pays its counterparty a premium, which can be paid at inception or 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 floor price multiplied by the hedged contract volume. When the settlement price is at or above the floor price in an individual month in the contract period, the put option expires with no settlement for that particular month, except with regard to the deferred premium, if any.

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. Depending on the terms, the Company may pay its counterparty a premium, which can be paid at inception or deferred until settlement. When the settlement price is below the price floor established by these collars, the counterparty pays the Company an amount 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. When the settlement price is between the price floor and price ceiling established by these collars in an individual month in the contract period, the collar expires with no settlement paid by either the Company or the counterparty for that particular month, except with regard to the deferred premium, if any.

Each basis swap transaction has an established fixed basis differential corresponding to two floating index prices. Depending on the difference of the two floating index prices in relationship to the fixed basis differential, the Company either receives an amount from its counterparty, or pays an amount to its counterparty, equal to the difference multiplied by the hedged contract volume.

Each call spread transaction has an established short call price and long call price. Depending on the terms, the counterparty may pay a premium to the Company to enter into the transaction. When the settlement price is above the short call price up to the long call price, the Company pays its counterparty an amount equal to the difference between the settlement price and the short call price multiplied by the hedged contract volume. When the settlement price is above the long call price, the Company pays the counterparty an amount equal to the difference between the long call price and the short call price multiplied by the hedged contract volume. When the settlement price is at or below the short call price in an individual month in the contract period, the call option expires with no settlement paid by either the Company or the counterparty for that particular month, except with regard to the deferred premium, if any.

Other than the oil basis swaps, 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 oil basis swaps are settled based on the swaps' differential between the Argus Americas Crude West Texas Intermediate ("WTI") index prices for WTI Midland-weighted average and WTI Cushing-WTI formula basis price less the differential price for the trade month. 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. Other than the natural gas basis swaps, the Company's natural gas derivatives are settled based on the Inside FERC index price for West Texas WAHA for the calculation period. The natural gas basis swaps are settled based on the swaps' differential between the Inside FERC index price for West Texas WAHA and the NYMEX Henry Hub index price less the differential price for the calculation period.

During the year ended December 31, 2017, the Company completed a hedge restructuring by early terminating a swap that resulted in a termination amount to the Company of $4.2 million that was settled in full by applying the proceeds to pay the premium on one new collar entered into during the hedge restructuring. The following details the derivative that was terminated:

	Aggregate volumes (Bbl)	Floor price ($/Bbl)	Ceiling price ($/Bbl)	Contract period
Oil swap	1,095,000	$ 52.12	$ 52.12	January 2018 - December 2018

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

During the year ended December 31, 2017, the following derivatives were entered into:

	Aggregate volumes[(1)]	Floor price[(2)]	Ceiling price[(2)]	Short call price[(2)]	Long call price[(2)]	Differential price[(2)]	Contract period
Oil[(3)]:							
Call spread[(4)]	1,140,800	$ —	$ —	$ 60.00	$ 100.00	$ —	July 2017 - December 2017
Call spread[(5)]	184,000	$ —	$ —	$ 60.00	$ 80.00	$ —	July 2017 - December 2017
Put[(6)]	4,378,000	$50.00	$ —	$ —	$ —	$ —	January 2018 - December 2018
Collar[(7)]	3,504,000	$40.00	$60.00	$ —	$ —	$ —	January 2018 - December 2018
Collar	584,000	$50.00	$60.00	$ —	$ —	$ —	January 2018 - December 2018
Basis swap	1,825,000	$ —	$ —	$ —	$ —	$ (0.59)	January 2018 - December 2018
Basis swap	730,000	$ —	$ —	$ —	$ —	$ (0.52)	January 2018 - December 2018
Basis swap	730,000	$ —	$ —	$ —	$ —	$ (0.49)	January 2018 - December 2018
Basis swap	365,000	$ —	$ —	$ —	$ —	$ (0.58)	January 2018 - December 2018
Put[(8)]	3,285,000	$45.00	$ —	$ —	$ —	$ —	January 2019 - December 2019
Put	1,387,000	$50.00	$ —	$ —	$ —	$ —	January 2019 - December 2019
Swap	365,000	$53.45	$53.45	$ —	$ —	$ —	January 2019 - December 2019
Swap	292,000	$53.46	$53.46	$ —	$ —	$ —	January 2019 - December 2019
Put[(9)]	366,000	$45.00	$ —	$ —	$ —	$ —	January 2020 - December 2020
Swap	695,400	$52.18	$52.18	$ —	$ —	$ —	January 2020 - December 2020
Natural gas:							
Collar[(10)]	10,950,000	$ 2.50	$ 3.25	$ —	$ —	$ —	January 2018 - December 2018
Basis swap	9,125,000	$ —	$ —	$ —	$ —	$ (0.62)	January 2018 - December 2018
Basis swap	9,125,000	$ —	$ —	$ —	$ —	$ (0.70)	January 2019 - December 2019

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

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

(3) There are $25.7 million in deferred premiums associated with these contracts.

(4) A premium of $0.5 million was settled in full at inception and the proceeds were applied to pay the premiums on a put entered into simultaneously.

(5) A premium of $0.1 million was settled in full at inception and the proceeds were applied to pay the premiums on a put entered into simultaneously.

(6) Premiums of $4.9 million were paid at inception, of which $0.6 million were settled in full at inception by applying the proceeds of the call spreads entered into simultaneously.

(7) A premium of $4.2 million was settled in full at inception as part of the Company's 2017 hedge restructuring by applying the proceeds of the terminated swap.

(8) Premiums of $9.3 million were paid at inception.

(9) A premium of $1.6 million was paid at inception.

(10) There are $0.9 million in deferred premiums associated with these contracts.

See Note 17.d for discussion of additional hedges entered into subsequent to December 31, 2017.

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

	For the years ended December 31,		
(in thousands)	**2017**	**2016**	**2015**
Cash settlements received for matured derivatives, net[1]	$ 37,583	$ 195,281	$ 255,281
Cash settlements received for early terminations of derivatives, net[2]	4,234	80,000	—
Cash settlements received for derivatives, net	$ 41,817	$ 275,281	$ 255,281

(1) The settlement amounts do 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 originated.

The following table summarizes open positions as of December 31, 2017, and represents, as of such date, derivatives in place through December 2020 on annual production volumes:

	Year 2018	Year 2019	Year 2020
Oil positions:			
Puts:			
Hedged volume (Bbl)	5,427,375	4,672,000	366,000
Weighted-average floor price ($/Bbl)	$ 51.93	$ 46.48	$ 45.00
Swaps:			
Hedged volume (Bbl)	—	657,000	695,400
Weighted-average price ($/Bbl)	$ —	$ 53.45	$ 52.18
Collars:			
Hedged volume (Bbl)	4,088,000	—	—
Weighted-average floor price ($/Bbl)	$ 41.43	$ —	$ —
Weighted-average ceiling price ($/Bbl)	$ 60.00	$ —	$ —
Totals:			
Total volume hedged with floor price (Bbl)	9,515,375	5,329,000	1,061,400
Weighted-average floor price ($/Bbl)	$ 47.42	$ 47.34	$ 49.70
Total volume hedged with ceiling price (Bbl)	4,088,000	657,000	695,400
Weighted-average ceiling price ($/Bbl)	$ 60.00	$ 53.45	$ 52.18
Basis Swaps:			
Hedged volume (Bbl)	3,650,000	—	—
Weighted-average price ($/Bbl)	$ (0.56)	$ —	$ —
Natural gas positions:			
Puts:			
Hedged volume (MMBtu)	8,220,000	—	—
Weighted-average floor price ($/MMBtu)	$ 2.50	$ —	$ —
Collars:			
Hedged volume (MMBtu)	15,585,500	—	—
Weighted-average floor price ($/MMBtu)	$ 2.50	$ —	$ —
Weighted-average ceiling price ($/MMBtu)	$ 3.35	$ —	$ —
Totals:			
Total volumed hedged with floor price (MMBtu)	23,805,500	—	—
Weighted-average floor price ($/MMBtu)	$ 2.50	$ —	$ —
Total volume hedged with ceiling price (MMBtu)	15,585,500	—	—
Weighted-average ceiling price ($/MMBtu)	$ 3.35	$ —	$ —
Basis Swaps:			
Hedged volume (MMBtu)	9,125,000	9,125,000	—
Weighted-average price ($/MMBtu)	$ (0.62)	$ (0.70)	$ —

b. Balance sheet presentation

In accordance with the Company's standard practice, its derivatives are subject to counterparty netting under their governing agreements. The Company's oil, NGL and natural gas derivatives are presented on a net basis as "Derivatives" on the consolidated balance sheets. See Note 10.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 10—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, 2017, 2016 or 2015.

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 dates 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, 2017:						
Assets						
Current:						
Oil derivatives	$ —	$ 7,427	$ —	$ 7,427	$ (3,721)	$ 3,706
NGL derivatives	—	—	—	—	—	—
Natural gas derivatives	—	10,546	—	10,546	(4,817)	5,729
Oil deferred premiums	—	—	—	—	(87)	(87)
Natural gas deferred premiums	—	—	—	—	(2,456)	(2,456)
Noncurrent:						
Oil derivatives	$ —	$ 11,613	$ —	$ 11,613	$ (6,087)	$ 5,526
NGL derivatives	—	—	—	—	—	—
Natural gas derivatives	—	934	—	934	(934)	—
Oil deferred premiums	—	—	—	—	(2,113)	(2,113)
Natural gas deferred premiums	—	—	—	—	—	—
Liabilities						
Current:						
Oil derivatives	$ —	$ (12,477)	$ —	$ (12,477)	$ 3,721	$ (8,756)
NGL derivatives	—	—	—	—	—	—
Natural gas derivatives	—	—	—	—	4,817	4,817
Oil deferred premiums	—	—	(18,202)	(18,202)	87	(18,115)
Natural gas deferred premiums	—	—	(3,352)	(3,352)	2,456	(896)
Noncurrent:						
Oil derivatives	$ —	$ (2,389)	$ —	$ (2,389)	$ 6,087	$ 3,698
NGL derivatives	—	—	—	—	—	—
Natural gas derivatives	—	—	—	—	934	934
Oil deferred premiums	—	—	(7,129)	(7,129)	2,113	(5,016)
Natural gas deferred premiums	—	—	—	—	—	—
Net derivative position	$ —	$ 15,654	$ (28,683)	$ (13,029)	$ —	$ (13,029)

(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

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 cash payments required for deferred premiums as of December 31, 2017 for the calendar years presented:

(in thousands)	December 31, 2017
2018	$ 20,335
2019	8,376
2020	633
Total	$ 29,344

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

	For the years ended December 31,		
(in thousands)	2017	2016	2015
Balance of Level 3 at beginning of year	$ (8,998)	$ (14,619)	$ (9,285)
Change in net present value of derivative deferred premiums	(394)	(232)	(203)
Total purchases and settlements:			
Purchases	(25,733)	(7,715)	(10,298)
Settlements[(1)]	6,442	13,568	5,167
Balance of Level 3 at end of year	$ (28,683)	$ (8,998)	$ (14,619)

(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 hedge 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. No impairments of long-lived assets were recorded during the year ended December 31, 2017 or 2016. See Note 2.k for discussion regarding the Company's impairment of long-lived assets for the year ended December 31, 2015.

The Company accounts for the impairment of inventory, if any, at lower of cost or NRV on a nonrecurring basis. For purposes of fair value 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.k for discussion of the Company's inventory impairments recorded during the years ended December 31, 2016 and 2015. No impairment of inventory was recorded during the year ended December 31, 2017.

The accounting policies for impairment of oil and natural gas properties and the prices used in the calculation of discounted cash flows are discussed in Note 2.h. 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.h for discussion of the Company's full cost ceiling impairments recorded during the years ended December 31, 2016 and 2015. There was no full cost ceiling impairment recorded during the year ended December 31, 2017.

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 is measured using a discounted cash flow model that converts future cash flows to a single discounted amount. These assumptions represent Level 3 inputs under the fair value hierarchy. See Note 4.c for additional discussion of the Company's acquisitions of evaluated and unevaluated oil and natural gas properties during the year ended December 31, 2016 and discussion of the significant inputs to the valuations. There were no acquisitions during the years ended December 31, 2017 or 2015.

Note 11—Income taxes

On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act"). The Tax Act, among other things, (i) permanently reduces the U.S. corporate income tax rate, (ii) repeals the corporate alternative minimum tax, (iii) imposes new limitations on the utilization of net operating losses and (iv) provides for more general changes to the taxation of corporations, including changes to cost recovery rules and to the deductibility of interest expense. The Company recognizes the effects of changes in tax laws and rates on deferred tax assets and liabilities and the retroactive effects of changes in tax laws in the period in which the new legislation is enacted. The enactment date in the U.S. is the date the bill becomes law, which is when the President signs the bill. Specific effects of the Tax Act are discussed below.

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

	For the years ended December 31,		
(in thousands)	**2017**	**2016**	**2015**
Current taxes:			
Federal	$ —	$ —	$ —
State	(1,800)	—	—
Deferred taxes:			
Federal	—	—	152,590
State	—	—	24,355
Income tax (expense) benefit	$ (1,800)	$ —	$ 176,945

Current tax expense recorded of $1.8 million is comprised of Texas franchise tax, mainly as a result of the Medallion Sale. Additionally, the Company paid Alternative Minimum Tax ("AMT") related to the Medallion Sale. The payment of AMT creates an AMT credit carryforward. Due to changes in the Tax Act, AMT credit carryforwards do not expire and are now refundable over the next five years, and therefore, a receivable has been recorded in the amount of $5.0 million which is included in the "Other noncurrent assets, net" line item on the consolidated balance sheets. If the actual amount of tax due and paid on the 2017 tax return differs, the associated AMT credit carryforward receivable will also change.

The following table presents the expected years in which the Company's AMT credit carryforward will be refunded:

(in thousands)	**December 31, 2017**
2019	$ 2,513
2020	1,257
2021	628
2022	628
AMT credit carryforward	$ 5,026

Income tax (expense) benefit differed from amounts computed by applying the applicable federal income tax rate of 35% for the years ended December 31, 2017, 2016 and 2015 to pre-tax earnings as a result of the following:

	For the years ended December 31,		
(in thousands)	**2017**	**2016**	**2015**
Income tax (expense) benefit computed by applying the statutory rate	$ (192,141)	$ 91,259	$ 835,408
Decrease (increase) in deferred tax valuation allowance	417,518	(86,569)	(668,702)
Change in tax rate applicable to net deferred tax assets	(226,263)	—	—
State income tax and change in valuation allowance	696	(370)	13,975
Stock-based compensation tax deficiency	(64)	(4,144)	(3,274)
Non-deductible stock-based compensation	—	—	(256)
Other items	(1,546)	(176)	(206)
Income tax (expense) benefit	$ (1,800)	$ —	$ 176,945

The effective tax rates for the Company's operations were 0% for each of the years ended December 31, 2017 and 2016, and 7% for the year ended December 31, 2015. The Company's effective tax rate is affected by changes in tax rates, valuation allowances, recurring permanent differences and by discrete items that may occur in any given year, but are not consistent from year to year. Based on the reduction in the federal corporate tax rate from 35% to 21% effective on January 1, 2018, the Company currently expects that its effective tax rate will not be impacted because of the valuation allowance against its net deferred tax assets. The Company's effective tax rate is expected to remain at 0%.

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, 2017, 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, 2017, management determined it was more likely than not that the net deferred tax assets were not realizable. 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 had been recorded against the deferred tax asset. The Company revalued its deferred tax assets and liabilities as of December 31, 2017, at the new rate of 21%. Based upon preliminary analysis of the changes in the Tax Act, the Company decreased its net deferred tax assets by approximately $226.0 million in the fourth quarter of 2017. A corresponding adjustment to the Company's valuation allowance was also recorded of approximately $226.0 million. Due to the full valuation allowance, no related deferred income tax expense was recorded. The Company's actual write-down may vary materially from the estimated amount due to a number of uncertainties and factors, including the completion of the analysis of all impacts of the Tax Act. An additional adjustment of $197.4 million was made to the valuation allowance due to the reduction of net deferred tax assets in the normal course of business, resulting in a total adjustment to the valuation allowance of $423.4 million during the year ended December 31, 2017.

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

(in thousands)	2017	2016
Net operating loss carryforward	$ 355,100	$ 573,521
Oil and natural gas properties, midstream service assets and other fixed assets	(80,153)	186,473
Gain on sale of assets	40,177	—
Equity method investee	—	(24,293)
Stock-based compensation	14,025	15,639
Accrued bonus	4,343	8,834
Derivatives	3,788	150
Materials and supplies impairment	1,206	1,982
Capitalized interest	721	1,767
Other	2,195	743
Net deferred tax asset before valuation allowance[1]	341,402	764,816
Valuation allowance	(341,402)	(764,816)
Net deferred tax asset	$ —	$ —

(1) The SEC has issued rules that would allow for a measurement period of up to one year after the enactment date of the Tax Act to finalize the impact of the Tax Act on a company's financial statements. The Company has substantially completed the analysis of the Tax Act and does not expect a material change due to the transition impacts. Any changes that do arise due to changes in interpretations of the Tax Act, legislative action to address questions that arise because of the Tax Act, changes in accounting standards for income taxes or related interpretations in response to the Tax Act, or any updates or changes to estimates the Company has utilized to calculate the transition impacts will be disclosed in future periods as they arise.

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

(in thousands)	December 31, 2017
2026	$ 2,741
2027	38,651
2028	228,661
2029	101,932
2030	80,963
Thereafter	1,228,819
Total	$ 1,681,767

The Company had federal net operating loss carry-forwards totaling $1.7 billion and state of Oklahoma net operating loss carryforwards totaling $40.7 million as of December 31, 2017, which begin expiring in 2026 and 2032, respectively. As of December 31, 2017, 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, 2017, 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 2014 through 2017 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 carryforwards typically does not begin to run until the year the attribute is utilized in a tax return. See Note 2.t for further discussion of accounting policies regarding income taxes.

Note 12—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 generally 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, 9, 10.a and 17.d for additional information regarding the Company's derivatives.

The Company had four customers that accounted for (i) 39.3%, 26.1%, 17.4% and 12.6% of total oil, NGL and natural gas sales for the year ended December 31, 2017, and (ii) 34.6%, 27.3%, 15.6% and 15.4% of oil, NGL and natural gas sales accounts receivable as of December 31, 2017. The Company had three customers that accounted for (i) 48.5%, 23.0% and 17.0% of total oil, NGL and natural gas sales for the year ended December 31, 2016, and (ii) 45.7%, 24.7% and 22.6% of oil, NGL and natural gas sales accounts receivable as of December 31, 2016. The Company had two customers that accounted for 37.5% and 20.3% of total oil, NGL and natural gas sales for the year ended December 31, 2015. These customers and percentages reported are related to the Company's exploration and production segment, see Note 15.

The Company had one partner whose joint operations accounts receivable accounted for 21.4% of the Company's total joint operations accounts receivable as of December 31, 2017. 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, 2016. These partners and percentages reported are related to the Company's exploration and production segment, see Note 15.

The Company had one customer that accounted for 97.5% of total sales of purchased oil for the year ended December 31, 2017, with the same customer accounting for 99.7% of purchased oil and other product sales receivable as of

December 31, 2017. The Company had one customer that accounted for 100.0% of total sales of purchased oil for the year ended December 31, 2016, with the same customer accounting for 99.7% of purchased oil and other product sales receivable as of December 31, 2016. The Company had one customer that accounted for 100.0% of total sales of purchased oil for the year ended December 31, 2015. The customer and percentages reported relate to the Company's midstream and marketing segment, see Note 15.

The Company's cash balances that are insured by the FDIC up to $250,000 per bank did not exceed this amount as of December 31, 2017. The Company had $117.8 million in cash balances on deposit with two banks as of December 31, 2017 that were not insured by the FDIC. Management believes that the risk of loss is mitigated by the banks' reputation and financial position.

Note 13—Commitments and contingencies

a. Lease commitments

The Company leases office space under operating leases expiring on various dates through 2027. The following table presents future minimum rental payments required:

(in thousands)	December 31, 2017
2018	$ 3,177
2019	3,255
2020	2,031
2021	1,826
2022	1,220
Thereafter	5,802
Total future minimum rental payments required	$ 17,311

The Company subleases office space under an operating lease with $2.4 million total future minimum rentals to be received as of December 31, 2017.

The following table presents rent expense:

	For the years ended December 31,		
(in thousands)	2017	2016	2015
Rent expense	$ 2,696	$ 2,664	$ 2,880

Rent income for the year ended December 31, 2017 totaled a de minimis amount. No such amounts were included for the years ended December 31, 2016 and December 31, 2015.

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 and rent income on a straight-line basis and a deferred lease liability and deferred lease asset, respectively, for the difference between the straight-line amount and the actual amounts of the lease payments and lease receipts. Deferred lease liability, net is included in the "Other noncurrent liabilities" line item on the consolidated balance sheets. Rent expense and rent income are included in the "General and administrative" line item and "Interest and other income" line item, respectively, in the consolidated statements of operations.

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. In the case of a known contingency, the Company accrues a liability when the loss is probable and the amount is reasonably estimable. Except with regard to the specific litigation noted below, the Company has concluded that the likelihood is remote that the ultimate resolution of any such 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.

On May 3, 2017, Shell Trading (US) Company ("Shell") filed an Original Petition and Request for Disclosure in the District Court of Harris County, Texas, alleging that the crude oil purchase agreement entered into between Shell and Laredo effective October 1, 2016 does not accurately reflect the compensation to be paid to Shell under certain circumstances due to a drafting mistake. Shell seeks reformation of one clause of the crude oil purchase agreement on the grounds of alleged mutual mistake or, in the alternative, unilateral mistake, an award of the amounts Shell alleges it should have been or should be paid under the agreement, court costs and attorneys' fees. The Company does not believe there was a drafting mistake made in the crude oil purchase agreement. On December 11, 2017, Shell filed its First Amended Petition, in which it asserted nine causes of action including multiple new claims for breach of contract and fraud. The Company believes it has substantive defenses and intends to vigorously defend its position. The Company is unable to determine a probability of the outcome of this litigation at this time. As of December 31, 2017, the Company has estimated an amount of $17.1 million related to this litigation that is not recorded in the accompanying consolidated balance sheets. Under the current pricing election, which elections are made for six-month periods, this estimate of the unrecorded amount will increase through the life of the contract. The Company has accounted for the costs (and resulting increased crude oil price realization) as reflected in the terms of the crude oil purchase agreement.

c. Drilling contracts

The Company has committed to several drilling contracts with a third party to facilitate the Company's drilling plans. Two of these contracts are for a term of multiple months and contain an early termination clause that requires the Company to potentially pay a penalty to the third party should the Company cease drilling efforts. This penalty would negatively impact the Company's financial statements upon early contract termination. There were no penalties incurred for early contract termination for the years ended December 31, 2017, 2016 or 2015. Future commitments of $3.5 million as of December 31, 2017 are not recorded in the accompanying consolidated balance sheets. Management does not currently anticipate the early termination of the Company's two contracts in 2018.

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. The Company incurred deficiency payments of $1.1 million, $2.2 million and $5.2 million during the years ended December 31, 2017, 2016 and 2015, respectively, which are included in the "Other operating expenses" line item in the consolidated statements of operations. 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. See Notes 4.a, 14.a and 17.a for additional discussion regarding Medallion, the Company's equity method investment. Future commitments of $357.0 million as of December 31, 2017 are not recorded in the accompanying consolidated balance sheets. For information regarding the TA related to Medallion, see Note 4.a.

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.

Note 14—Related parties

a. Medallion

Medallion was a related party until the Medallion Sale in October 2017. The following table presents items included in the consolidated balance sheets related to Medallion:

(in thousands)	December 31, 2016
Accounts payable and accrued liabilities	$ 118
Accrued capital expenditures	$ 586

The following table presents items included in the consolidated statements of operations related to Medallion:

(in thousands)	For the years ended December 31, 2017	2016	2015
Midstream service revenues	$ —	$ —	$ 487
Other operating expenses(1)	$ —	$ —	$ 5,235
Interest and other income	$ —	$ —	$ 158
Loss on disposal of assets, net	$ (70)	$ —	$ —

(1) Amounts included in "Other operating expenses" above represent minimum volume commitments for the year ended December 31, 2015.

See Note 4.a for discussion of the Medallion Sale and the TA between LMS and a wholly-owned subsidiary of Medallion.

See Notes 4.a and 17.a for additional discussion regarding the Company's equity method investee.

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.

As of December 31, 2016, amounts included in accounts payable from Archrock in the consolidated balance sheets totaled $0.2 million. A de minimis amount was included as of December 31, 2017.

The following table presents the lease operating expenses related to Archrock included in the consolidated statements of operations:

(in thousands)	For the years ended December 31, 2017	2016	2015
Lease operating expenses	$ 826	$ 1,975	$ 1,477

For the year ended December 31, 2015, amounts included in capital expenditures for midstream service assets from Archrock in the consolidated statements of cash flows totaled $0.1 million. For the year ended December 31, 2016, amounts included in capital expenditures for midstream service assets from Archrock in the consolidated statements of cash flows totaled a de minimis amount. No such amounts were included for the year ended December 31, 2017.

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 presents the capitalized oil and natural gas properties related to H&P and included in the consolidated statements of cash flows:

(in thousands)	For the years ended December 31, 2017	2016	2015
Capital expenditures:			
Oil and natural gas properties	$ —	$ —	$ 2,434

Note 15—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 liquids-rich natural gas gathering services as well as rig fuel, natural gas lift and water delivery and takeaway. As a result of the Medallion Sale, we currently anticipate that in 2018 and thereafter we will no longer present more than one reportable segment.

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, 2017				
Revenues:				
Oil, NGL and natural gas sales	$ 623,401	$ 3,301	$ (5,195)	$ 621,507
Midstream service revenues	—	72,643	(62,126)	10,517
Sales of purchased oil	—	190,138	—	190,138
Total revenues	623,401	266,082	(67,321)	822,162
Costs and expenses:				
Lease operating expenses, including production and ad valorem tax	126,779	—	(13,928)	112,851
Midstream service expenses	—	49,017	(44,918)	4,099
Costs of purchased oil	—	195,908	—	195,908
General and administrative[1]	88,113	8,199	—	96,312
Depletion, depreciation and amortization[2]	148,828	9,561	—	158,389
Other operating expenses[3]	4,707	224	—	4,931
Operating income	$ 254,974	$ 3,173	$ (8,475)	$ 249,672
Other financial information:				
Income from equity method investee[4]	$ —	$ 8,485	$ —	$ 8,485
Interest expense[5]	$ (83,758)	$ (5,619)	$ —	$ (89,377)
Loss on early redemption of debt[6]	$ (22,225)	$ (1,536)	$ —	$ (23,761)
Gain on sale of investment in equity method investee[4]	$ —	$ 405,906	$ —	$ 405,906
Capital expenditures	$ (543,027)	$ (20,887)	$ —	$ (563,914)
Gross property and equipment[7]	$ 6,321,725	$ 177,093	$ (16,715)	$ 6,482,103
Year ended December 31, 2016				
Revenues:				
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
Costs and expenses:				
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 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[4]	$ —	$ 9,403	$ —	$ 9,403
Interest expense[5]	$ (87,485)	$ (5,813)	$ —	$ (93,298)
Capital expenditures[8]	$ (368,290)	$ (5,240)	$ —	$ (373,530)
Gross property and equipment[7]	$ 5,780,137	$ 400,127	$ (8,240)	$ 6,172,024
Year ended December 31, 2015				
Revenues:				
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
Costs and expenses:				
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 expenses[3]	12,522	1,178	—	13,700
Operating loss	$ (2,455,907)	$ (13,917)	$ (1,690)	$ (2,471,514)

TABLE CONTINUES ON NEXT PAGE

Other financial information:								
Income from equity method investee[4]	$	—	$	6,799	$	—	$	6,799
Interest expense[5]	$	(98,040)	$	(5,179)	$	—	$	(103,219)
Loss on early redemption of debt[6]	$	(30,056)	$	(1,481)	$	—	$	(31,537)
Capital expenditures	$	(597,086)	$	(35,515)	$	—	$	(632,601)
Gross property and equipment[7]	$	5,302,716	$	345,183	$	(1,923)	$	5,645,976

(1) General and administrative expenses were allocated based on the number of employees in the respective segment during the years ended December 31, 2017, 2016 and 2015. Certain components of general and administrative expenses, 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 during the years ended December 31, 2017, 2016 and 2015. Certain components of depreciation and amortization of other fixed assets, primarily vehicles, were not allocated but were actual expenses for each segment.

(3) Other operating expenses consist of (i) minimum volume commitments and accretion expense for the years ended December 31, 2017 and 2016, and (ii) minimum volume commitments, restructuring expense and accretion expense for the year ended December 31, 2015. These are actual costs and expenses and were not allocated.

(4) See Note 4.a for additional discussion of the Medallion Sale.

(5) Interest expense was allocated to the exploration and production segment based on gross property and equipment during the years ended December 31, 2017, 2016 and 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 during the years ended December 31, 2017, 2016 and 2015. Certain components of other fixed assets, primarily vehicles, were not allocated but were actual assets for each segment.

(6) Loss on early redemption of debt was allocated to the exploration and production segment based on gross property and equipment as of December 31, 2017 and 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, 2017 and 2015. Certain components of other fixed assets, primarily vehicles, were not allocated but were actual assets for each segment.

(7) Gross property and equipment for the midstream and marketing segment includes investment in equity method investee totaling $244.0 million and $192.5 million as of December 31, 2016 and 2015, respectively. Other fixed assets were allocated based on the number of employees in the respective segment as of December 31, 2017, 2016 and 2015. Certain components of other fixed assets, primarily vehicles, were not allocated but were actual assets for each segment.

(8) Capital expenditures exclude acquisition of oil and natural gas properties for the years ended December 31, 2016.

Note 16—Subsidiary guarantors

The Guarantors have fully and unconditionally guaranteed the January 2022 Notes, the March 2023 Notes and the Senior Secured Credit Facility (and had guaranteed the January 2019 Notes until the January 2019 Notes Redemption Date and the May 2022 Notes until the May 2022 Notes 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, 2017 and 2016 and condensed consolidating statements of operations and condensed consolidating statements of cash flows each for the years ended December 31, 2017, 2016 and 2015 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. Income taxes for LMS and for GCM are recorded on Laredo's balance sheets, 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. No such transfers occurred during the years ended December 31, 2017 and 2015.

Condensed consolidating balance sheet
December 31, 2017

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Accounts receivable, net	$ 79,413	$ 21,232	$ —	$ 100,645
Other current assets	132,219	2,518	—	134,737
Oil and natural gas properties, net	1,596,834	9,220	(16,715)	1,589,339
Midstream service assets, net	—	138,325	—	138,325
Other fixed assets, net	40,344	377	—	40,721
Investment in subsidiaries	(7,566)	—	7,566	—
Other noncurrent assets	15,526	3,996	—	19,522
Total assets	$ 1,856,770	$ 175,668	$ (9,149)	$ 2,023,289
Accounts payable and accrued liabilities	$ 34,550	$ 23,791	$ —	$ 58,341
Other current liabilities	193,104	25,974	—	219,078
Long-term debt, net	791,855	—	—	791,855
Other noncurrent liabilities	54,967	133,469	—	188,436
Stockholders' equity	782,294	(7,566)	(9,149)	765,579
Total liabilities and stockholders' equity	$ 1,856,770	$ 175,668	$ (9,149)	$ 2,023,289

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	376,028	243,953	(376,028)	243,953
Other noncurrent assets	13,065	3,684	—	16,749
Total assets	$ 1,764,569	$ 402,045	$ (384,268)	$ 1,782,346
Accounts payable and accrued liabilities	$ 30,903	$ 21,301	$ —	$ 52,204
Other current liabilities	134,055	1,686	—	135,741
Long-term debt, net	1,353,909	—	—	1,353,909
Other noncurrent 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 statement of operations
For the year ended December 31, 2017

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total revenues	$ 623,028	$ 266,455	$ (67,321)	$ 822,162
Total costs and expenses	376,938	254,398	(58,846)	572,490
Operating income	246,090	12,057	(8,475)	249,672
Interest expense	(89,377)	—	—	(89,377)
Gain on sale of investment in equity method investee (see Note 4.a)	—	405,906	—	405,906
Other non-operating income (expense), net	402,536	8,083	(426,046)	(15,427)
Income before income tax	559,249	426,046	(434,521)	550,774
Current income tax expense	(1,800)	—	—	(1,800)
Net income	$ 557,449	$ 426,046	$ (434,521)	$ 548,974

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	(93,298)	—	—	(93,298)
Other non-operating income (expense), net	(73,669)	9,381	(15,191)	(79,479)
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	(103,219)	—	—	(103,219)
Other non-operating income, net	182,822	6,708	(1,678)	187,852
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 cash flows
For the year ended December 31, 2017

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Net cash flows provided by operating activities	$ 778,851	$ 32,109	$ (426,046)	$ 384,914
Change in investments between affiliates	383,613	(809,659)	426,046	—
Capital expenditures and other	(482,500)	(52,065)	—	(534,565)
Proceeds from disposition of equity method investee, net of selling costs (see Note 4.a)	—	829,615	—	829,615
Net cash flows used in financing activities	(600,477)	—	—	(600,477)
Net increase in cash and cash equivalents	79,487	—	—	79,487
Cash and cash equivalents, beginning of period	32,671	1	—	32,672
Cash and cash equivalents, end of period	$ 112,158	$ 1	$ —	$ 112,159

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

Note 17—Subsequent events

a. Medallion Sale post-close

On February 1, 2018, the Medallion Sale closing adjustments were finalized and LMS received additional net cash of $1.7 million for total net cash proceeds before taxes of $831.3 million.

b. Share repurchase program

In February 2018, the Company's board of directors authorized a $200 million share repurchase program commencing in February 2018. The repurchase program expires in February 2020. Share repurchases under the share repurchase program may be made through a variety of methods, which may include open market purchases, privately negotiated transactions and block trades. The timing and actual number of shares repurchased, if any, will depend upon several factors, including market conditions, business conditions, the trading price of our common stock and the nature of other investment opportunities available to the Company.

c. Senior Secured Credit Facility

On February 14, 2018, the Company entered into the Second Amendment (the "Second Amendment") to the Senior Secured Credit Facility. The Second Amendment, allows the Company, on or prior to February 14, 2020, to pay up to $200 million to repurchase its common stock provided that (i) no Default or Event of Default exists or results therefrom, (ii) immediately after giving effect to any such repurchase, undrawn Commitments are greater than or equal to 20% of the Borrowing Base in effect at such time, (iii) immediately after giving effect to any such repurchase, (a) the Company will be in pro forma compliance with all financial covenants (current ratio and Consolidated Total Leverage Ratio) in the Senior Secured Credit Facility, and (b) the Consolidated Total Leverage Ratio on a pro forma basis is not greater than 2.75 to 1.00, in the case of both (a) and (b), for purposes of determining the Consolidated Total Leverage Ratio, Net Debt or Total Debt, as applicable, shall be as of the date of determination, and Consolidated EBTIDAX shall be determined as of the last day of the most recent calendar quarter for which financial statements have been provided to the Administrative Agent; and provided further that any such Equity so repurchased shall be contemporaneously canceled by the Company. All capitalized terms in this Note 17.c., other than "Company" and "Senior Secured Credit Facility," have the meanings ascribed to them in the Second Amendment.

d. New derivative contracts

The following table presents new derivatives that were entered into subsequent to December 31, 2017:

	Aggregate volumes (Bbl)	Floor price ($/Bbl)	Ceiling price ($/Bbl)	Contract period
Oil[(1)]:				
Put[(2)]	1,277,500	$ 55.00	$ —	January 2019 - December 2019
NGL:				
Swap - Purity Ethane[(1)]	567,800	$ 11.66	$ 11.66	February 2018 - December 2018
Swap - Propane (Non-TET)[(3)]	467,600	$ 33.92	$ 33.92	February 2018 - December 2018
Swap - Normal Butane (Non-TET)[(3)]	167,000	$ 38.22	$ 38.22	February 2018 - December 2018
Swap - Isobutane (Non-TET)[(3)]	66,800	$ 38.33	$ 38.33	February 2018 - December 2018
Swap - Natural Gasoline (Non-TET)[(3)]	167,000	$ 57.02	$ 57.02	February 2018 - December 2018

(1) See Note 9.a for information regarding the Company's derivative settlement indices for oil and purity ethane.

(2) There are $5.6 million in deferred premiums associated with these contracts.

(3) These NGL derivatives are settled based on the month's average daily OPIS index price for each Mont Belvieu Non-TET Propane, Non-TET N. Butane, Non-TET Isobutane and Non-TET N. Gasoline.

Note 18—Supplemental oil, NGL and natural gas disclosures (unaudited)

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

The following table presents the costs incurred in the acquisition, exploration and development of oil, NGL and natural gas assets:

	For the years ended December 31,		
(in thousands)	**2017**	**2016**	**2015**
Property acquisition costs:			
Evaluated[(1)]	$ —	$ 5,905	$ —
Unevaluated	—	119,923	—
Exploration costs	36,257	41,333	20,697
Development costs[(2)]	560,919	298,942	500,577
Total costs incurred	$ 597,176	$ 466,103	$ 521,274

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

(2) Development costs include $0.7 million, $2.5 million and $13.4 million in asset retirement obligations for the years ended December 31, 2017, 2016 and 2015, respectively.

b. *Aggregate capitalized oil, NGL and natural gas costs*

The following table presents the aggregate capitalized costs related to oil, NGL and natural gas production activities with applicable accumulated depletion and impairment:

	For the years ended December 31,		
(in thousands)	2017	2016	2015
Gross capitalized costs:			
Evaluated properties	$ 6,070,940	$ 5,488,756	$ 5,103,635
Unevaluated properties not being depleted	175,865	221,281	140,299
Total gross capitalized costs	6,246,805	5,710,037	5,243,934
Less accumulated depletion and impairment	(4,657,466)	(4,514,183)	(4,218,942)
Net capitalized costs	$ 1,589,339	$ 1,195,854	$ 1,024,992

The following table presents a summary of the unevaluated property costs not being depleted as of December 31, 2017, by year in which such costs were incurred:

(in thousands)	2017	2016	2015	2014 and prior	Total
Unevaluated properties not being depleted	$ 31,259	$ 93,099	$ 324	$ 51,183	$ 175,865

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 operations of oil, NGL and natural gas producing activities*

The following table presents the results of operations of oil, NGL and natural gas producing activities (excluding corporate overhead and interest costs):

	For the years ended December 31,		
(in thousands)	2017	2016	2015
Revenues:			
Oil, NGL and natural gas sales	$ 621,507	$ 426,485	$ 431,734
Production costs:			
Lease operating expenses	75,049	75,327	108,341
Production and ad valorem taxes	37,802	28,586	32,892
Total production costs	112,851	103,913	141,233
Other costs:			
Depletion	143,592	134,105	263,666
Accretion of asset retirement obligations	3,567	3,274	2,236
Impairment expense	—	161,064	2,369,477
Income tax benefit(1)	—	—	(164,141)
Total other costs	147,159	298,443	2,471,238
Results of operations	$ 361,497	$ 24,129	$(2,180,737)

(1) During each of the years ended December 31, 2017, 2016 and 2015, the Company recorded valuation allowances against its deferred tax assets related to its oil, NGL and natural gas producing activities. Accordingly, the income tax benefit was computed utilizing the Company's effective rate of 0% for each of the years ended December 31, 2017 and 2016 and 7% for the year ended December 31, 2015, 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.

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, 2017, 2016 and 2015. In accordance with SEC regulations, reserves as of December 31, 2017, 2016 and 2015 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.h for additional discussion. The Company's reserves as of December 31, 2017, 2016 and 2015 are reported in three streams: oil, NGL and natural gas. 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, 2017, 2016 and 2015, all of which are located within the U.S.

	Year ended December 31, 2017			
	Oil (MBbl)	NGL (MBbl)	Gas (MMcf)	MBOE
Proved developed and undeveloped reserves:				
Beginning of year	63,940	50,350	316,857	167,100
Revisions of previous estimates	9,818	13,158	74,247	35,351
Extensions, discoveries and other additions	15,250	9,711	59,759	34,921
Sales of reserves in place	(120)	(48)	(299)	(218)
Production	(9,475)	(5,800)	(35,972)	(21,270)
End of year	79,413	67,371	414,592	215,883
Proved developed reserves:				
Beginning of year	53,156	42,950	270,291	141,155
End of year	68,877	60,441	371,946	191,309
Proved undeveloped reserves:				
Beginning of year	10,784	7,400	46,566	25,945
End of year	10,536	6,930	42,646	24,574

	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 as of January 1, 2015.

For the year ended December 31, 2017, the Company's positive revision of 35,351 MBOE of previously estimated quantities consisted of (i) 16,916 MBOE from positive performance, price increases and other changes to proved developed producing wells and (ii) 18,435 MBOE of revisions due to proved undeveloped locations that were removed from the development plan in prior years, 10 of these locations were drilled in 2017 and eight are scheduled to be drilled in 2018. Extensions, discoveries and other additions of 34,921 MBOE during the year ended December 31, 2017 consisted of (i) 18,985 MBOE that resulted from new wells drilled during the year and (ii) 15,936 MBOE that resulted from new horizontal proved undeveloped locations added during the year.

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.

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, 2017, 2016 and 2015 are based on the Realized Prices, which reflect adjustments to the Benchmark Prices for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. 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, but did not for the year ended December 31, 2017. See Note 2.h for discussion of the Benchmark Prices, Realized Prices and the corresponding non-cash full cost ceiling impairments recorded.

The following table presents the standardized measure of discounted future net cash flows relating to proved oil, NGL and natural gas reserves:

	For the years ended December 31,		
(in thousands)	**2017**	**2016**	**2015**
Future cash inflows	$ 5,777,533	$ 3,548,567	$ 3,269,184
Future production costs	(1,675,837)	(1,238,369)	(1,321,471)
Future development costs	(307,689)	(290,505)	(376,701)
Future income tax expenses	(237,153)	—	—
Future net cash flows	3,556,854	2,019,693	1,571,012
10% discount for estimated timing of cash flows	(1,786,533)	(1,041,199)	(740,265)
Standardized measure of discounted future net cash flows	$ 1,770,321	$ 978,494	$ 830,747

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.

The following table presents the changes in the standardized measure of discounted future net cash flows relating to proved oil, NGL and natural gas reserves:

	For the years ended December 31,		
(in thousands)	**2017**	**2016**	**2015**
Standardized measure of discounted future net cash flows, beginning of year	$ 978,494	$ 830,747	$ 3,246,728
Changes in the year resulting from:			
Sales, less production costs	(508,656)	(322,573)	(290,501)
Revisions of previous quantity estimates	289,150	179,297	(2,444,322)
Extensions, discoveries and other additions	296,129	133,472	192,979
Net change in prices and production costs	474,831	(80,102)	(1,495,144)
Changes in estimated future development costs	10,989	22,153	(2,974)
Previously estimated development costs incurred during the period	192,332	189,085	162,237
Purchases of reserves in place	—	3,422	—
Divestitures of reserves in place	(793)	—	(29,149)
Accretion of discount	97,849	83,075	424,453
Net change in income taxes	(46,610)	—	997,805
Timing differences and other	(13,394)	(60,082)	68,635
Standardized measure of discounted future net cash flows, end of year	$ 1,770,321	$ 978,494	$ 830,747

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 19—Supplemental quarterly financial data (unaudited)

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

	Year ended December 31, 2017			
(in thousands, except per share data)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
Revenues	$ 189,006	$ 187,001	$ 205,818	$ 240,337
Operating income	51,326	52,061	60,452	85,833
Net income	68,276	61,110	11,027	408,561
Net income per common share:				
Basic	$ 0.29	$ 0.26	$ 0.05	$ 1.71
Diluted	$ 0.28	$ 0.25	$ 0.05	$ 1.70

	Year ended December 31, 2016			
(in thousands, except per share data)	**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)

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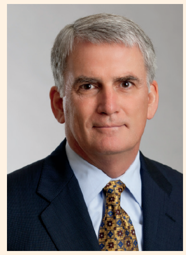

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