

Edgar Filing: Laredo Petroleum, Inc. - Form 10-K

Laredo Petroleum, Inc.

Form 10-K

February 14, 2019

false--12-31FY20182018-12-3110-K0001528129YesfalseLarge Accelerated Filer1500000000Laredo Petroleum, Inc.falsefalseNoYes33110.250.250.50.5P1YP90DP30D0010000000000000.010.0145000000045000000024252114323393635
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**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, 2018

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 (I.R.S. Employer
incorporation or organization) Identification No.)

15 W. Sixth Street, Suite 900 74119
Tulsa, Oklahoma (Zip code)

(Address of principal executive offices)

(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 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 \$1.5 billion on June 30, 2018, based on \$9.62 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 11, 2019: 233,924,462

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2019 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2018, are incorporated by reference into Part III of this report for the year ended December 31, 2018.

LAREDO PETROLEUM, INC.
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GLOSSARY OF OIL AND NATURAL GAS TERMS

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

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

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

"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.

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"*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 in 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.

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"*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.

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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, NGL 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;
- revisions to our reserve estimates as a result of changes in commodity prices, decline curves and other uncertainties;
- 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;
- the potential impact on production of oil, NGL and natural gas from our wells resulting from tighter spacing of our wells;
- capital requirements for our operations and projects;
- impacts to our financial statements as a result of impairment write-downs;
- 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;
- 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 generate sufficient cash to service our indebtedness, fund our capital requirements and generate future profits;
- 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;
- the potentially insufficient refining capacity in the U.S. 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;
- our ability to hedge and regulations that affect our ability to hedge;
- changes in the regulatory environment and changes in U.S. or international legal, tax, political, administrative or economic conditions including regulations that prohibit or restrict our ability to

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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; and
our ability to comply with federal, state and local regulatory requirements.

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

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Part I

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

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

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

Item 1. Business

Overview

Laredo is an independent energy company focused on the acquisition, exploration and development of oil and natural gas properties, and midstream and marketing services, primarily in the Permian Basin of 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. As of December 31, 2018, we had assembled 120,617 net acres in the Permian Basin and had total proved reserves, presented on a three-stream basis, of 238,167 MBOE. Our wholly-owned subsidiary, LMS buys, sells, gathers and transports oil, natural gas and water primarily for the account of Laredo.

We have identified one operating segment: exploration and production. Our midstream and marketing functions are integral to our exploration and production activities. We have a single company-wide management team that administers all properties as a whole rather than discrete operating segments and we allocate capital resources on a project-by-project basis across our asset base without regard to individual areas.

2018 operation highlights

Produced a Company record average of 68,168 BOE per day in full-year 2018, resulting in production growth of 17% from full-year 2017

Grew the value of our proved reserves by 19% from year-end 2017

Reduced unit cash general and administrative ("G&A") expense by 16% in full-year 2018

Recognized \$31.9 million of net cash benefits from LMS field infrastructure investments through reduced capital and operating costs and increased revenue

Our core assets

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, 2018, we held 120,617 net acres in the Permian Basin, all of which were held in 248 sections in the Permian-Garden City area, with an average working interest of 97% in all Laredo-operated currently 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, 2018, we have drilled and completed (i.e., the particular well is flowing) 314 horizontal wells in the Upper and Middle Wolfcamp and 967 vertical wells in the Wolfberry interval. Of these 314 horizontal wells, 189 were horizontal Upper Wolfcamp wells and 125 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 2019 drilling program on the Upper and Middle Wolfcamp formations due to their lower development cost and superior

production expectations.

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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. In 2019, we plan to widen the spacing between our wells and focus on achieving cash flow neutrality.

Because oil, NGL and natural gas prices and related margins continue to remain volatile, our board of directors approved a capital expenditures budget of approximately \$365 million, based on annual benchmark averages of a \$53.60 per barrel WTI NYMEX strip price and a \$2.90 per MMBtu Henry Hub NYMEX strip price, for calendar year 2019, excluding non-budgeted acquisitions. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted. Our goal is to achieve cash flow neutrality, and therefore, our capital spending in 2019 will ultimately be influenced by commodity price changes, as well as any changes in service costs and drilling and completions efficiencies. Of this budget, approximately \$300 million is allocated to drilling and completion activities and approximately \$65 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, primarily in the Upper and Middle Wolfcamp formations.

Our near-term 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. In the later part of the second quarter of 2019, we plan to widen the spacing between our wells as we seek to increase capital efficiency. In addition, in response to the continued volatile commodity price environment and our stated goal of achieving cash flow neutrality, we anticipate decreasing the number of drilling rigs and/or completions crews that we use. We continue to use our existing data (and acquire new data) to optimize completion designs and well spacing within the development plan in order to enhance inventory and net asset value. We will also continue to pursue cost saving measures, but given the volatile commodity price environment, we are unsure what, if any, changes there will be to service costs.

On December 31, 2018, we had a total of three drilling rigs drilling horizontal wells. Our current drilling schedule anticipates that we will utilize three horizontal rigs during the first part of 2019 and decrease our drilling rig count thereafter. We do not anticipate utilizing any vertical rigs throughout 2019. If we decrease our drilling rig count and/or completion crews, it will have a negative impact on our production, especially oil production, and reserves, as well as potentially result in contract termination penalties. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Obligations and commitments" and Note 14.c to our consolidated financial statements included elsewhere in this Annual Report for additional information.

In addition to the impact of commodity prices, the timing of drilling our potential locations is also influenced by several factors, including capital requirements and availability, the Texas Railroad Commission ("RRC") well-spacing requirements and 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 238,167 MBOE on a three-stream basis as of December 31, 2018, of which 91% are classified as proved developed reserves and 26% 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. As part of our on-going reserves estimation process, for our year-end 2018 reserves estimation, we incorporated additional production data to reflect (i) the higher gas content and steeper oil declines on our historical wells and (ii) the negative effects on oil production from tighter spacing on our recent wells. This additional production history has led to more specific forecasts, including specific b-factors, for both developed and undeveloped locations as we take into account additional production data. There is inherent uncertainty in the reserves estimation process and therefore we will continue to monitor the future production of these wells as well as other available data. 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, 2018, and average daily production presented on a three-stream basis for the

year ended December 31, 2018. Based on estimates in the report prepared by Ryder Scott, we operated wells that represent 99.7% of the economic value of our proved developed oil, NGL and natural gas reserves as of December 31, 2018.

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	As of December 31, 2018				Producing wells		Year ended December 31, 2018 average daily production (BOE/D)
	Estimated net proved reserves ⁽¹⁾	% of total reserves	% Oil	Net acreage	Gross	Net	
Permian Basin	238,167	100 %	26 %	120,617	1,246	1,155	68,168
Other properties	—	— %	— %	170	—	—	—
Total	238,167	100 %	26 %	120,787	1,246	1,155	68,168

(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, 2018 was 68,168 BOE/D, 41% of which was oil, 29% of which was NGL and 30% 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 their lowest level in February 2016 since 2003. 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. In 2018, commodity prices continued to remain volatile with significantly lower prices in the last quarter of the year. Our capital expenditures budget for 2019 is approximately \$365 million, based on annual benchmark averages of a \$53.60 per barrel WTI NYMEX strip price and a \$2.90 per MMBtu Henry Hub NYMEX strip price, excluding non-budgeted acquisitions. Our goal is to achieve cash flow neutrality, and therefore, our capital spending in 2019 will ultimately be influenced by commodity price changes, as well as any changes in service costs and drilling and completions efficiencies.

Beginning in 2016, we deliberately 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 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 greatest 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 reserves-booking status. We converted all 26 PUD locations we booked at December 31, 2017 into proved producing locations in 2018. 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 2019, 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 2019. This strategy maintains our flexibility to add new PUD locations and convert other locations to proved developed reserves as we deem appropriate and opportunistic. See "—Proved undeveloped reserves" for additional information on our PUD reserves.

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 which may include 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. We have built and maintain 60 miles of crude oil gathering pipelines to connect Laredo-operated wells in our Permian-Garden City acreage, providing a safer and more economic transportation alternative than trucking. We have also installed and maintain 159 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. Our crude oil and natural gas gathering assets provided transportation for 55% of our production in

2018. Combined, our three water recycling facilities provide a recycling capacity of more than 54,000 Bbls of water per day, and a storage capacity of more than 3.6 million Bbls. Having these production corridors and associated facilities and infrastructure already in place is expected to enhance the value of our 2019 drilling program.

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

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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 (through the use of our water recycling facilities).

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 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. This commitment will enhance our ability to move our crude oil out of the Permian Basin and give us access to potentially more favorable U.S. Gulf Coast pricing. See Note 4.c to our consolidated financial statements included elsewhere in this Annual Report for a further discussion of our firm transportation agreement with Medallion.

On October 30, 2017, LMS, together with Medallion Midstream Holdings, LLC ("MMH"), which was 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.

As of December 31, 2018, 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	2019	2020	2021	2022 and after
Crude oil (MBbl):					
Sales commitments	730	730	—	—	—
Transportation commitments:					
Field	68,224	13,414	10,980	10,950	32,880
To U.S. Gulf Coast	98,910	7,475	13,730	16,425	61,280
Natural gas (MMcf):					
Sales commitments	69,109	10,339	9,578	5,620	43,572
Total commitments (MBOE) ⁽¹⁾	179,382	23,342	26,306	28,312	101,422

(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 major market hubs, including Colorado City, Texas, Midland, Texas and Crane, 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. In 2018, we signed an agreement with Gray Oak Pipeline, LLC to initially transport 25,000 barrels of oil per day going to 35,000 barrels of oil per day of our production from Crane, Texas to the U.S. Gulf Coast. Our shipments under this contract will begin when the pipeline commences operations which is anticipated in the second half of 2019.

Our production has been substantially equivalent to or greater than our delivery commitments during the three most recent years, and we expect such production to meet our 2019 commitments. We are subject to firm transportation payments on excess pipeline capacity and other contractual penalties. In certain instances, we have used spot market purchases to meet commitments in certain locations or due to favorable pricing. We anticipate continuing this practice in the future. We incurred

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firm transportation payments on excess pipeline capacity and other contractual penalties of \$4.7 million, \$1.1 million and \$2.2 million during the years ended December 31, 2018, 2017 and 2016, respectively. 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 the purchase of 10% or more of our oil, NGL and natural gas revenues during the last three calendar years, see Note 13 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."

We have built an extensive proprietary technical database on our properties, including (but not limited to) 1,133 square miles of 3D seismic, 70 wells with microseismic, 7,073 feet of whole core in 18 wells, 958 sidewall cores in 24 wells, over 1,300 open and cased-hole logging suites with over 130 dipole sonic logs, 23 single-zone tests and 40 production logs. Our strategic interest in utilizing this database is directed at characterizing subsurface reservoir properties to gain insight into principles that potentially govern resource recovery, which can be subsequently leveraged during development planning, 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.

HRGM's integrate the above-described data with enhanced interpretations conducted in 2018 to provide 3D reservoir and mechanical property models across the majority of Laredo's acreage. HRGM's provide a sufficiently high resolution and accurate depiction of subsurface development potential to continue executing the "drill to plan" technical workflow, implemented in 2017. Drill to plan targets geological landing points in the perceived highest quality reservoir. This minimizes target changes during operations, increasing the accuracy of well positioning, while reducing time and costs associated with target changes and enhancing operational efficiencies. All of the 2019 planned wells are anticipated to utilize drill to plan.

HRGM's provide the foundation for hydraulic fracture modeling, where 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.

Microseismic analysis continues to advance 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 and workflows advantageous in yielding important insights into subsurface behavior and consequently 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 developments. We anticipate that all of our horizontal wells to be drilled in 2019 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.

Corporate history and structure

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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, 2018, affiliates of Warburg Pincus LLC ("Warburg Pincus"), our founding member, owned 21.9% of our common stock.

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Laredo Petroleum, Inc. is the borrower under our Fifth Amended and Restated Credit Agreement (as amended, the "Senior Secured Credit Facility"), as well as the issuer of our \$350.0 million in aggregate principal amount of 6 1/4% senior unsecured notes due 2023 (the "March 2023 Notes") and our \$450.0 million in aggregate principal amount 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 April 19, 2023, provided that if either the January 2022 Notes or March 2023 Notes have not been refinanced on or prior to the date (as applicable, the "Early Maturity Date") that is 90 days before their respective stated maturity dates, the Senior Secured Credit Facility will mature on such Early Maturity Date. On November 29, 2017 (the "May 2022 Notes Redemption Date"), following the Medallion Sale, we redeemed the entire \$500.0 million outstanding principal amount 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 our capital efficiency by seeking to drill high rate of return wells through wider well spacing, reduced overhead and operational improvements

In 2019, we will seek to reduce overhead costs while increasing operational efficiency and in the later part of the second quarter of 2019, we will widen the spacing between our wells in order to target high rate of return well results. 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 drill our most efficient wells by providing us with crucial flexibility in tailoring our drilling plans in a manner that is more cost-efficient. We converted all 26 PUD locations we booked at December 31, 2017 into proved producing locations in 2018.

Deploy our capital in a strategic manner while considering value-enhancing acquisitions, divestitures, mergers, redemptions, repurchases, delevering and similar transactions

We will be highly selective in the projects that we consider and 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, repurchases, delevering or other similar transactions, any of which could result in the utilization of our Senior Secured Credit Facility and accessing the capital markets.

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.

Seek accretive acquisitions

As we continue to develop our existing Permian-Garden City acreage position, we believe that the acquisition of additional acreage may be beneficial as consolidation and increased scale may lead to increased operational and corporate efficiencies.

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

During 2018, our hedging program provided us with cash flow certainty. 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

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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:

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 120,617 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 88% held by production and have identified up to seven targets to date from which we can produce, resulting in a long-term drilling inventory. Our contiguous acreage position also enables us to drill long laterals (10,000 feet or greater) in many locations, which may 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 facilitates productive new wells.

Significant cash flow from existing operations

Our Permian-Garden City acreage currently has approximately 1,155 net producing wells. That current base provides us with a significant amount of cash flow and such wells require little additional capital to maintain. In addition, we have few on-going drilling requirements to keep our Permian-Garden City acreage from lease expirations which further strengthens our flexibility to use cash flow from operations in a manner we see as most efficient.

Significant operational control

We operated wells that represent 99.7% of the economic value of our proved developed oil, NGL and natural gas reserves as of December 31, 2018, 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 nearly all of our potential drilling locations.

Our production corridors and water recycle facilities enable us to more efficiently develop our acreage and utilize/dispose of water that facilitates development and reduces 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 through increased knowledge thus enabling 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 238 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, 2018. These systems and pipelines provide greater operational efficiency, capital and cost savings 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.

Table of Contents*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. Warburg Pincus has been the lead investor in many such companies, including two previous companies operated by certain members of our management team.

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 an attractive return on capital employed with respect to each discrete development package of wells.

Other properties

In addition to our Permian-Garden City acreage, as of December 31, 2018, we held 170 net acres in the Palo Duro Basin. Essentially all of this acreage will expire in 2019, absent drilling or renegotiation of the applicable leases. We anticipate little or no activity on these properties in 2019.

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 utilized to calculate estimated reserves and the associated discounted future cash flows. The following table presents the Benchmark Prices and Realized Prices as of the dates presented:

	As of December 31,	
	2018	2017
Benchmark Prices:		
Oil (\$/Bbl)	\$62.04	\$47.79
NGL (\$/Bbl) ⁽¹⁾	\$31.46	\$26.13
Natural gas (\$/MMBtu)	\$1.76	\$2.63
Realized Prices:		
Oil (\$/Bbl)	\$59.29	\$46.34
NGL (\$/Bbl)	\$21.42	\$18.45
Natural gas (\$/Mcf)	\$1.38	\$2.06

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

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Our net proved reserves were estimated at 238,167 MBOE on a three-stream basis as of December 31, 2018, of which 91% were classified as proved developed reserves and 26% are attributable to oil reserves. The following table presents summary data for our operating area as of December 31, 2018.

Area:	As of December 31, 2018	
	Proved reserves (MBOE)	% of total
Permian Basin	238,167	100%
Other properties	—	— %
Total	238,167	100%

Our estimated proved reserves as of December 31, 2018 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. Negative revisions to reserve estimates, decreases in oil, NGL and natural gas prices or increases in service costs, may lead to decreased earnings and increased losses or impairment of oil and natural gas properties."

The following table sets forth additional information regarding our estimated proved reserves as of December 31, 2018 and 2017. Ryder Scott estimated 100% of our proved reserves as of December 31, 2018 and 2017. The reserve estimates as of December 31, 2018 and 2017 were prepared in accordance with the applicable SEC rules regarding oil, NGL and natural gas reserves reporting.

	As of December 31,	
	2018	2017
Proved developed producing:		
Oil (MBbl)	55,893	68,877
NGL (MBbl)	79,241	60,441
Natural gas (MMcf)	491,828	371,946
Total proved developed producing (MBOE)	217,105	191,309
Proved undeveloped:		
Oil (MBbl)	6,001	10,536
NGL (MBbl)	7,406	6,930
Natural gas (MMcf)	45,928	42,646
Total proved undeveloped (MBOE)	21,062	24,574
Estimated proved reserves:		
Oil (MBbl)	61,894	79,413
NGL (MBbl)	86,647	67,371
Natural gas (MMcf)	537,756	414,592
Total estimated proved reserves (MBOE)	238,167	215,883
Percent developed	91	% 89 %

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.

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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, including individual b-factors, 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, well spacing 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 their lowest level in February 2016 since 2003. 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. In 2018, commodity prices continued to remain volatile with significantly lower prices in the last quarter of the year. Our capital expenditures budget for 2019 is approximately \$365 million, based on annual benchmark averages of a \$53.60 per barrel WTI NYMEX strip price and a \$2.90 per MMBtu Henry Hub NYMEX strip price, excluding non-budgeted acquisitions. Our goal is to achieve cash flow neutrality, and therefore, our capital spending in 2019 will ultimately be influenced by commodity price changes, as well as any changes in service costs and drilling and completions efficiencies.

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 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 reserves booking status. We converted all 26 PUD locations booked at December 31, 2017 into proved producing locations in 2018. 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 2019, 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 2019. 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 ("SPE Reserves Auditing Standards") and guidelines established by the SEC, Ryder Scott, our independent reserve engineers, estimated 100% of our proved reserve information as of December 31, 2018 and 2017 included in this Annual Report. The technical persons responsible for preparing the reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the SPE Reserves Auditing Standards.

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 reserve 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 reserve estimates. He has more than 19 years of practical experience, with 10 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 - Midstream,

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Marketing & Subsurface. Reserve 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.

Proved undeveloped reserves

Our proved undeveloped reserves decreased from 24,574 MBOE as of December 31, 2017 to 21,062 MBOE as of December 31, 2018. We estimate that we incurred \$215.1 million of costs to convert 24,574 MBOE of proved undeveloped reserves from 26 locations into proved developed reserves in 2018. New proved undeveloped reserves of 18,452 MBOE were added during the year from 18 new horizontal Wolfcamp locations. Positive revisions to proved undeveloped reserves of 2,610 MBOE were due to adding two undeveloped locations that were removed from reserves in a previous year. A final investment decision has been made on these 20 locations and they are scheduled to be drilled and completed in 2019.

Estimated total future development and abandonment costs related to the development of proved undeveloped reserves as shown in our December 31, 2018 reserve report are \$159.0 million. Based on this report and our PUD booking methodology, the capital estimated to be spent in 2019 to develop the proved undeveloped reserves is \$155.0 million and \$0 for each of 2020, 2021, 2022 and 2023. 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 2019. 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.

Table of ContentsSales volumes, revenues and price history

The following table presents information regarding our oil, NGL and natural gas sales volumes, revenues, average sales Realized Prices, and average costs and expenses per BOE sold for the periods presented. 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."

(unaudited)	For the years ended December 31,		
	2018	2017	2016
Sales volumes:			
Oil (MBbl)	10,175	9,475	8,442
NGL (MBbl)	7,259	5,800	4,784
Natural gas (MMcf)	44,680	35,972	29,535
Oil equivalents (MBOE) ⁽¹⁾⁽²⁾	24,881	21,270	18,149
Average daily sales volumes (BOE/D) ⁽²⁾	68,168	58,273	49,586
Sales revenues (in thousands):			
Oil	\$605,197	\$445,012	\$318,466
NGL	\$149,843	\$101,438	\$56,982
Natural gas	\$53,490	\$75,057	\$51,037
Average sales Realized Prices ⁽²⁾ :			
Oil, without derivatives (\$/Bbl) ⁽³⁾	\$59.48	\$46.97	\$37.73
NGL, without derivatives (\$/Bbl) ⁽³⁾	\$20.64	\$17.49	\$11.91
Natural gas, without derivatives (\$/Mcf) ⁽³⁾	\$1.20	\$2.09	\$1.73
Average price, without derivatives (\$/BOE) ⁽³⁾	\$32.50	\$29.22	\$23.50
Oil, with derivatives (\$/Bbl) ⁽⁴⁾	\$55.49	\$50.45	\$58.07
NGL, with derivatives (\$/Bbl) ⁽⁴⁾	\$20.03	\$16.91	\$11.91
Natural gas, with derivatives (\$/Mcf) ⁽⁴⁾	\$1.77	\$2.15	\$2.20
Average price, with derivatives (\$/BOE) ⁽⁴⁾	\$31.72	\$30.71	\$33.73
Average costs and expenses per BOE sold ⁽²⁾ :			
Lease operating expenses	\$3.67	\$3.53	\$4.15
Production and ad valorem taxes	\$1.99	\$1.78	\$1.58
Transportation and marketing expenses	\$0.47	\$—	\$—
Midstream service expenses	\$0.12	\$0.19	\$0.22
General and administrative:			
Cash	\$2.40	\$2.85	\$3.45
Non-cash stock-based compensation, net	\$1.46	\$1.68	\$1.61
Depletion, depreciation and amortization	\$8.55	\$7.45	\$8.17

(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.

Realized oil, NGL and natural gas prices are the actual prices received when control passes to the purchaser/customer adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

(3) Price reflects the after-effects of our derivative transactions on our average sales Realized Prices. Our calculation of such after-effects includes settlements of matured derivatives during the respective periods in accordance with GAAP and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to derivatives that settled during the respective periods.

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The following table sets forth certain information regarding productive wells in our core operating area as of December 31, 2018. 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			Net Total	Average WI %
	Gross		Total		
	Vertical	Horizontal			
Permian Basin:					
Operated Permian-Garden City	766	412	1,178	1,141	97 %
Non-operated Permian-Garden City	61	7	68	14	21 %
Other properties	—	—	—	—	— %
Total	827	419	1,246	1,155	93 %

Acres

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own an interest as of December 31, 2018 for our core operating area and other properties, 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		% HBP
	Gross	Net	Gross	Net	Gross	Net	
Permian Basin	119,433	105,998	16,082	14,619	135,515	120,617	88 %
Other properties	—	—	520	170	520	170	— %
Total	119,433	105,998	16,602	14,789	136,035	120,787	88 %

Undeveloped acreage expirations

The following table sets forth the gross and net undeveloped acreage in our core operating area and other properties as of December 31, 2018 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.

	2019		2020		2021		2022	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian Basin	161	180	5,652	4,576	566	159	—	—
Other properties	520	170	—	—	—	—	—	—
Total	681	350	5,652	4,576	566	159	—	—

Of the total undeveloped acreage identified as expiring over the next four years, 690 net acres have associated PUD reserves as of December 31, 2018. All of those PUD reserves are scheduled to be drilled and completed in the first half of 2019.

At December 31, 2017, 0 net acres of potentially expiring leasehold were identified as attributable to PUD reserves.

Table of ContentsDrilling activity

The following table summarizes our drilling activity for the years ended December 31, 2018, 2017 and 2016. 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.

	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	74	71.2	62	60.7	45	44.5
Dry	—	—	—	—	—	—
Total development wells	74	71.2	62	60.7	45	44.5
Exploratory wells:						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	1	0.5
Total exploratory wells	—	—	—	—	1	0.5

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, 2018, 88% 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 conduct 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.

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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 fracturing 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,

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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

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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. The rules are subject to ongoing litigation and have been stayed in more than half the States, including Texas. Also, on December 11, 2018, the EPA and the Corps released a proposed rule that would replace the 2015 rule, and significantly reduce the waters subject to federal regulation under the Clean Water Act. The proposal is currently subject to public review and comment, after which additional legal challenges are anticipated. As a result of such recent developments, substantial uncertainty exists regarding the scope of waters protected under the Clean Water Act. To the extent the rules expand 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.

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.

Table of ContentsHydraulic 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. 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, 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 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; however, a coalition of environmentalists, tribal advocates and the State of California filed lawsuits challenging the rule rescission. At this time, it is uncertain when, or if, the hydraulic fracturing 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

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wells. In addition to state law, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular.

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

Air emissions

The federal Clean Air Act, as amended, and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations, through the issuance of permits and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. 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. Also, on October 15, 2018, the EPA published a proposed rule to significantly reduce regulatory burdens imposed by the 2016 regulations, including, for example, reducing the monitoring frequency for fugitive emissions and revising the requirements for pneumatic pumps at well sites. In addition, on November 15, 2016, the BLM finalized a waste prevention 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. 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. On April 4, 2018, a federal district court stayed certain provisions of the rule pending the BLM's reconsideration and, on September 28, 2018, the BLM finalized revisions to the waste prevention rule to reduce "unnecessary compliance burdens." The States of California and New Mexico have challenged the scaled-back rule. At this time, it is uncertain when, and to what extent, the waste prevention rule will be implemented, and what impact it will have on our operations.

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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

In recent years, federal, state and local governments have taken steps to reduce emissions of greenhouse gases ("GHGs"). The EPA has finalized a series of GHG 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 GHG emissions primarily through the development of GHG emission inventories and/or regional GHG cap-and-trade programs. Also, some states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources.

At the international level, 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.

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.

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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 during the years ended December 31, 2018, 2017 or 2016.

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 outstanding common stock of and are members of the board of directors of Endurance International Group Holdings, Inc. (together with its subsidiaries, "EIGI"). EIGI 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 EIGI. 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

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Warburg Pincus had any involvement in or control over the disclosed activities of EIGI, 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 EIGI intends to disclose in its next annual or quarterly SEC report that:

"On July 25, 2018, the Office of Foreign Assets Control ("OFAC") designated Electronics Katrangi Trading ("Katrangi") as a Specially Designated National ("SDN") pursuant to the Weapons of Mass Destruction Proliferators Sanctions Regulations, 31 C.F.R. Part 544. On July 30, 2018, during a regular compliance scan of EIGI's user base, EIGI identified the domain SGP-FRANCE.COM (the "Domain Name") which was listed as a website associated with Katrangi, on one of EIGI's platforms. The Domain Name was managed using one of EIGI's platforms by one of its reseller customers. Accordingly, there was no direct financial transaction between EIGI and the registered owner of the Domain Name and EIGI did not generate any revenue in connection with the Domain Name since Katrangi was added to the SDN list on July 25, 2018. Upon discovering the Domain Name on its platform, EIGI promptly suspended the Domain Name and removed it from its platform. EIGI reported the Domain Name to OFAC on August 7, 2018.

On November 6, 2018, EIGI terminated an end customer account (the "End Customer Account") that EIGI believed to be associated with Arian Bank, which was identified by OFAC as an SDN on November 5, 2018, pursuant to 31 C.F.R. Part 594. EIGI initially acquired the End Customer Account on January 23, 2014 as part of EIGI's acquisition of P.D.R Solutions FZC. EIGI reported the End Customer Account to OFAC as potentially the property of an SDN subject to blocking pursuant to Executive Order 13224. As of February 1, 2019, EIGI had not received any correspondence from OFAC regarding this matter."

Employees

As of December 31, 2018, we had 340 full-time employees. We also employed a total of 20 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, which are 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."

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. 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.

Table of Contents**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;
- the pricing disparity between oil and natural gas and the negative effect it may have on our cash flow from operations;
- political conditions in or affecting other oil, NGL and natural gas-producing countries;
- 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 reduced, and may in the future continue to reduce, our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our oil, NGL and natural gas reserves as existing reserves are depleted. A 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 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 by May 1 and November 1 of each year, 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.

Table of Contents***Insufficient transportation capacity in the Permian Basin, and the challenges to alleviating such transportation constraints, could cause significant fluctuations in our realized oil prices and our results of operations.***

In our area of operation, the Permian Basin has been characterized by periods when oil and/or natural gas production has surpassed local transportation capacity, resulting in substantial discounts to the price received for crude oil prices quoted for WTI oil and Henry Hub natural gas. During a significant portion of 2018, Midland market crude oil prices experienced an increased discount to WTI Cushing and WTI Houston prices and the West Texas WAHA market natural gas prices experienced an increased discount to Henry Hub NYMEX prices. The discounts are primarily due to limited pipeline capacity constraining transportation of crude oil and natural gas out of the Permian Basin to major market hubs including, but not limited to, Cushing, Oklahoma and the United States Gulf Coast. Recently, each of these three basin differentials have narrowed; however, they remain volatile. These pipeline constraints may continue to affect Midland market crude oil prices and West Texas WAHA market natural gas prices until further transportation capacity becomes operational or until basin-wide crude oil and natural gas production decreases from its current levels. We will continue to pursue avenues to attempt to protect our oil and natural gas value from basin differentials by securing crude oil transportation capacity, which enables us to sell oil in multiple markets, and entering into basis-swap derivatives, which provides pricing protection. The expansion and construction of pipeline facilities are affected by the availability and costs of necessary equipment, supplies, labor and other services, as well as the length of time to complete such projects. In addition, these projects can be affected by changes in international trade relationships, including the imposition of trade restrictions or tariffs relating to crude oil and natural gas and any materials or products used to expand or construct pipeline facilities, such as certain imported steel mill products that are currently subject to a 25% global tariff on certain imported steel mill products. All of these factors could negatively impact our realized oil prices, as well as actual results of our operations.

There is no guarantee that we will be successful in optimizing our spacing, drilling and completions techniques in order to maximize our rate of return, cash flow from operations and shareholder 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 rate of return, cash flow from operations and shareholder 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.

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.

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, proceeds from equity offerings, proceeds from senior unsecured note offerings, borrowings under our Senior Secured Credit Facility and proceeds from the Medallion Sale and other asset dispositions. 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, 2019, we had total long-term indebtedness of \$1.04 billion. We may be able to incur substantial

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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.

Estimating reserves and future net revenues involves uncertainties. Negative revisions to reserve estimates, decreases in oil, NGL and natural gas prices or increases in service costs, may lead to decreased earnings and increased losses or impairment of oil and natural gas properties.

The reserves 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 more rapid production declines than previously expected and many other factors beyond the control of the operator. Further, initial production rates reported by us or other operators may not be indicative of future or long-term production rates. Production declines may be rapid and irregular when compared to a well's initial production or initial estimates. 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.

For the year ended December 31, 2018, our positive revision of 2,173 MBOE of previously estimated quantities consisted of (i) 11,364 MBOE of negative revisions from performance driven mainly by steeper oil decline curves and tighter well spacing, and a decrease in the Realized Price for natural gas, (ii) 7,045 MBOE of positive revisions from increases in the Realized Prices for oil and NGL and other changes to proved developed producing wells and (iii) 6,492 MBOE of positive revisions due to proved undeveloped locations that were removed from the development plan in prior years. However, in both 2014 and 2015, the Company had negative revisions of estimated quantities, primarily due to a sharp decline in commodity prices. It is possible that the Company will have negative revisions of its reserves 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.

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 rapidly declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploration, development and exploitation activities and/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. ***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

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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.

Our unamortized cost of evaluated oil and natural gas properties being depleted exceeded the full cost ceiling as of March 31, 2016 and as a result, we recorded a non-cash full cost ceiling impairment of \$161.1 million for the year ended December 31, 2016, but did not record any similar impairments for the years ended December 31, 2018 or 2017. If prices remain at or below the current low levels, subject to numerous factors and inherent limitations, and all other factors remain constant, it is possible we would incur a non-cash full cost impairment in 2019, which would have an adverse effect on our results of operations. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations-Recent developments" and Note 6.a to our consolidated financial statements included elsewhere in this Annual Report for additional information.

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, 2019 we had an aggregate elected commitment of \$1.2 billion with \$240.0 million outstanding on our Senior Secured Credit Facility, subject to compliance with financial covenants. The impact of a 1.0% increase in interest rates on an assumed borrowing of the full aggregate elected commitment of \$1.2 billion would result in increased annual interest expense of \$12.0 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.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

We receive debt credit ratings from Standard & Poor's Ratings Group, Inc. ("S&P") and Moody's Investors Service, Inc. ("Moody's"), which are subject to regular reviews. S&P and Moody's consider many factors in determining our ratings including: production growth opportunities, liquidity, debt levels and asset and reserves mix.

A downgrade in our credit ratings could negatively impact our cost of capital and our ability to effectively execute aspects of our strategy. Further, a downgrade in our credit ratings could affect our ability to raise debt in the public debt markets, and the cost of any new debt could be much higher than our outstanding debt. These and other impacts of a downgrade in our credit ratings could have a material adverse effect on our business, financial condition and results of operations.

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.

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, compression, natural gas processing, fractionation and storage facilities owned by us or third parties. We do not control many of the trucks and other third-party facilities necessary for the transportation to market of the products originating at our leases. Our failure to provide or obtain such services on acceptable terms could materially harm our business. In recent years there has been a capacity constraint to move oil, natural gas and NGL out of the Permian Basin. If this constraint continues or gets

worse in the future, it could have a negative impact on the price that we get for our oil, natural gas and NGL. 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

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Vapor Pressure ("RVP") specification and oxygen content. 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.

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 \$1.3 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 reserves 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, 2019, we had \$945.3 million in available capacity 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.

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.

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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. 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.

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.

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 beneficial 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 puts, swaps, collars, 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.

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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" and Notes 9 and 10 to our consolidated financial statements included elsewhere in this Annual Report.

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.

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 on 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 the fair values of open derivative contracts of \$50.9 million, our principal exposure to credit risk is through (i) the sale of our oil, NGL and natural gas production (\$45.0 million in receivables as of December 31, 2018), which we market to energy marketing companies, refineries and affiliates, (ii) the sale of purchased oil and other products (\$10.2 million in receivables as of December 31, 2018) and (iii) net joint operations receivables (\$16.8 million as of December 31, 2018). 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 sales receivables and our sales of purchased oil receivables with several significant customers. The four largest purchasers of our oil, NGL and natural gas production accounted for 29.5%, 24.2%, 16.2% and 16.0% of our total oil, NGL and natural gas sales for the year ended December 31, 2018. We had two customers that accounted for 63.9% and 36.1% of our total sales of purchased oil for the year ended December 31, 2018. See Note 13 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. See "Item 3. Legal Proceedings" for a discussion of Shell's breach and wrongful termination of the crude oil purchase agreement entered into between Shell and Laredo effective October 1, 2016 through June 30, 2020.

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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. 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.

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.

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

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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 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.

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 operational and production 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 operational 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.

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

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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 matures on April 19, 2023, provided that if either the January 2022 Notes or March 2023 Notes have not been refinanced on or prior to the Early Maturity Date that is 90 days before their respective stated maturity dates, the Senior Secured Credit Facility will mature on such Early Maturity Date.

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, 2018, 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 transportation constraints, supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing 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.

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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;
- disagreements regarding the royalty due to our royalty owners
- 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 published rules governing hydraulic fracturing on federal and Indian lands, but it subsequently rescinded or revised those rules and litigation is ongoing. 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

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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 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.

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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. 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

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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

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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.

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, 2018, Warburg Pincus owned 21.9% 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.

Tax laws and regulations may change over time, and the 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 reformed the Internal Revenue

Code of 1986, as amended (the "Code"). The Tax Act, among other things, (i) 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 12 to our consolidated financial statements included elsewhere in this Annual Report for additional information.

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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 carryforwards to reduce future tax payments may be limited if our taxable income does not reach sufficient levels.

As of December 31, 2018, we had federal net operating loss ("NOL") carry-forwards totaling \$1.9 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, as a result of the Tax Act, NOL arising before January 1, 2018, and NOL arising on or after January 1, 2018, are subject to different rules. NOL arising before January 1, 2018, can generally be carried forward to offset future taxable income for a period of 20 years. Any NOL arising on or after January 1, 2018, while subject to additional limitations, can generally be carried forward indefinitely. 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, 2018, based on evidence available to us, including projected future cash flows from our oil, NGL 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, 2018, a valuation allowance has been recorded against our NOL tax assets. See Note 12 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, 2018, Warburg Pincus owned 21.9% 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

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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.

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We cannot guarantee that our previously 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 a \$200 million share repurchase program commencing in February 2018. The repurchase program expires in February 2020. As of December 31, 2018, we had repurchased 11,048,742 shares of common stock at a weighted-average price of \$8.78 per common share for a total of \$97.1 million under this program. 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 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. 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.

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Item 1B. *Unresolved Staff Comments*

Not applicable.

Item 2. *Properties*

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

Item 3. *Legal Proceedings*

From time to time, we are subject to various legal proceedings arising in the ordinary course of business, including proceedings for which we may not have insurance coverage. While many of these matters involve inherent uncertainty, except with regard to the specific litigation noted below, as of the date hereof, we do not currently believe that any such legal proceedings will 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 through June 30, 2020 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 crude oil purchase agreement, court costs and attorneys' fees. We do not believe there was a drafting mistake made in the crude oil purchase agreement, which covered the sale to Shell of 19,000 barrels of crude oil per day of our gross production, as well as the purchase by us of like-quantity crude oil from Shell. 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.

Effective May 1, 2018, Shell terminated the crude oil purchase agreement and ceased purchasing our crude oil and selling crude oil to us under the terms of such agreement. As a result, we filed our Second Amended Answer and Original Counterclaim against Shell on June 15, 2018, in which we deny all allegations by Shell and seek damages in excess of \$150.0 million resulting from Shell's breach and wrongful termination of the crude oil purchase agreement. Shell filed a Second Amended Petition on June 1, 2018, in which it asserted a new cause of action against us for alleged repudiation of Shell's proposed reformed version of the crude oil purchase agreement, a version never signed or agreed to by us.

Through April 30, 2018, the last day before Shell's wrongful termination of the crude oil purchase agreement, we had accounted for the costs and crude oil price realization as reflected in the terms of the crude oil purchase agreement. The accompanying consolidated balance sheets located elsewhere in this Annual Report do not include any amounts for damage claims or attorneys' fees sought by Shell. As of December 31, 2018, we had estimated an aggregate amount of \$37.4 million that is the subject of Shell's claims, which is generally based on the contractual amount in dispute under the pricing election that is the subject of Shell's claims applied to the barrels of crude oil purchased and sold through the date on which Shell wrongfully terminated the crude oil purchase agreement. As a result of such termination, our estimate of this unrecorded amount is not anticipated to materially increase in the future. This estimate does not include damages sought by Shell pursuant to its latest repudiation claim asserted in its Second Amended Petition or amounts sought by Shell for recovery of attorneys' fees incurred for the prosecution of its claims. We are unable to determine a probability of the outcome of this litigation at this time. We believe Shell's claims are meritless and the termination by Shell is improper and a breach of the crude oil purchase agreement. We therefore intend to vigorously defend ourselves against Shell's claims and pursue our rights under the terminated crude oil purchase agreement to seek all appropriate damages from Shell.

Item 4. *Mine Safety Disclosures*

Not applicable.

Table of Contents**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." On February 13, 2019, the last sale price of our common stock, as reported on the NYSE, was \$3.79 per share.

Holders. As of February 11, 2019, 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.

Purchases of Equity Securities.

The following table summarized purchases of common stock by Laredo:

Period	Total number of shares purchased ⁽¹⁾	Weighted-average price paid per share	Total number of shares purchased as part of publicly announced plans ⁽²⁾	Maximum value that may yet be purchased under the program as of the respective period-end date ⁽²⁾
October 1, 2018 - October 31, 2018	960	\$ 7.62	—	\$ 102,945,283
November 1, 2018 - November 30, 2018	—	\$ —	—	\$ 102,945,283
December 1, 2018 - December 31, 2018	—	\$ —	—	\$ 102,945,283
Total	960			

(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.

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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, 2013 to December 31, 2018; and
2. Dividends, if any, are reinvested.

Table of Contents**Item 6. Selected Historical Financial Data**

The selected historical consolidated financial data presented below is not intended to replace our consolidated financial statements. This data should be read 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, 2018, 2017 and 2016 and the balance sheet data as of December 31, 2018 and 2017 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, 2015 and 2014 and the balance sheet data as of December 31, 2016, 2015 and 2014 are derived from our consolidated financial statements not included in this Annual Report.

(in thousands, except per share data)	For the years ended December 31,				
	2018	2017	2016	2015	2014
Statement of operations data:					
Total revenues	\$1,105,775	\$822,162	\$597,378	\$606,640	\$793,885
Total costs and expenses ⁽¹⁾	757,283	572,490	685,340	3,078,154	567,499
Operating income (loss)	348,492	249,672	(87,962)	(2,471,514)	226,386
Non-operating income (expense), net	(19,648)	301,102	(172,777)	84,633	203,473
Income (loss) before income taxes	328,844	550,774	(260,739)	(2,386,881)	429,859
Total income tax (expense) benefit	(4,249)	(1,800)	—	176,945	(164,286)
Net income (loss)	\$324,595	\$548,974	\$(260,739)	\$(2,209,936)	\$265,573
Net income (loss) per common share:					
Basic	\$1.40	\$2.30	\$(1.16)	\$(11.10)	\$1.88
Diluted	\$1.39	\$2.29	\$(1.16)	\$(11.10)	\$1.85

(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.

(in thousands)	As of December 31,				
	2018	2017	2016	2015	2014 ⁽¹⁾
Balance sheet data:					
Cash and cash equivalents	\$45,151	\$112,159	\$32,672	\$31,154	\$29,321
Property and equipment, net	\$2,199,635	\$1,768,385	\$1,366,867	\$1,200,255	\$3,354,082
Total assets	\$2,420,305	\$2,023,289	\$1,782,346	\$1,813,287	\$3,910,701
Total current liabilities	\$200,465	\$277,419	\$187,945	\$216,815	\$353,834
Long-term debt, net	\$983,636	\$791,855	\$1,353,909	\$1,416,226	\$1,779,447
Total stockholders' equity	\$1,174,230	\$765,579	\$180,573	\$131,447	\$1,563,201

(1) Amounts have been reclassified to conform to presentation changes made in 2015.

(in thousands)	For the years ended December 31,					
	2018	2017	2016	2015	2014	
Other financial data:						
Net cash provided by operating activities		\$537,804	\$384,914	\$356,295	\$315,947	\$498,277
Net cash (used in) provided by investing activities		\$(690,956)	\$295,050	\$(564,402)	\$(667,507)	\$(1,406,961)
Net cash provided by (used in) financing activities		\$86,144	\$(600,477)	\$209,625	\$353,393	\$739,852

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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 taxes, depletion, depreciation and amortization, bad debt expense, impairment expense, non-cash stock-based compensation, net, accretion expense, mark-to-market on derivatives, 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.

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The following presents a reconciliation of net income (loss) (GAAP) to Adjusted EBITDA (non-GAAP):

(in thousands, unaudited)	For the years ended December 31,				
	2018	2017	2016	2015	2014
Net income (loss)	\$324,595	\$548,974	\$(260,739)	\$(2,209,936)	\$265,573
Plus:					
Income tax expense (benefit)	4,249	1,800	—	(176,945)	164,286
Depletion, depreciation and amortization	212,677	158,389	148,339	277,724	246,474
Bad debt expense	—	—	—	255	342
Impairment expense	—	—	162,027	2,374,888	3,904
Non-cash stock-based compensation, net	36,396	35,734	29,229	24,509	23,079
Accretion expense	4,472	3,791	3,483	2,423	1,787
Restructuring expenses	—	—	—	6,042	—
Mark-to-market on derivatives:					
(Gain) loss on derivatives, net	(42,984)	(350)	87,425	(214,291)	(327,920)
Settlements received for matured derivatives, net	6,090	37,583	195,281	255,281	28,241
Settlements received for early terminations of derivatives, net	—	4,234	80,000	—	76,660
Premiums paid for derivatives	(20,335)	(25,853)	(89,669)	(5,167)	(7,419)
Interest expense	57,904	89,377	93,298	103,219	121,173
Write-off of debt issuance costs	—	—	842	—	124
Gain on sale of investment in equity method investee	—	(405,906)	—	—	—
Loss on disposal of assets, net	5,798	1,306	790	2,127	3,252
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
Proportionate Adjusted EBITDA of equity method investee ⁽¹⁾	—	22,081	20,367	9,383	462
Adjusted EBITDA	\$588,862	\$486,436	\$461,270	\$477,264	\$600,210

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

(in thousands, unaudited)	For the years ended December 31,				
	2018	2017	2016	2015	2014
Income (loss) from equity method investee	\$-8,485	\$9,403	\$6,799	\$(192)	
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	

Table of Contents**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 included 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. Please 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 midstream and marketing services, primarily in the Permian Basin of 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, 2018 included the following:

- Oil, NGL and natural gas sales of \$808.5 million, compared to \$621.5 million for the year ended December 31, 2017;
- Average daily sales volumes of 68,168 BOE/D, compared to 58,273 BOE/D for the year ended December 31, 2017;
- Net income of \$324.6 million, compared to \$549.0 million for the year ended December 31, 2017;
- Adjusted EBITDA (a non-GAAP financial measure) of \$588.9 million, compared to \$486.4 million for the year ended December 31, 2017. See "Item 6. Selected Historical Financial Data" for a reconciliation of Adjusted EBITDA; and
- Proved developed and undeveloped reserves of 238,167 MBOE, compared to 215,883 MBOE for the year ended December 31, 2017. 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*Potential future low commodity price impact on our quarterly 2019 full cost ceiling impairment tests*

Oil, NGL and natural gas prices decreased in the fourth quarter of 2018 and have remained low in January and February 2019. If prices remain at or below the current low levels, subject to numerous factors and inherent limitations, some of which are discussed below, and all other factors remain constant, it is possible we will incur a non-cash full cost ceiling impairment in 2019, which will have an adverse effect on our results of operations. There are numerous uncertainties inherent in the estimation of proved reserves and accounting for oil and natural gas properties in future periods. In addition to unknown future commodity prices, other uncertainties include (i) changes in drilling and completion costs, (ii) changes in oilfield service costs, (iii) production results, (iv) our ability, in a low price environment, to strategically drill the most economic locations in our multi-stack horizontal targets, (v) income tax impacts, (vi) potential recognition of additional proved undeveloped reserves, (vii) any potential value added to our proved reserves when testing recoverability from drilling unbooked locations, (viii) revising production curves based on additional data and (ix) the inherent significant volatility in the commodity prices for oil, NGL and natural gas recently exemplified by price changes in recent months.

Each of the above factors is evaluated on a quarterly basis and if there is a material change in any factor it is incorporated into our reserves estimation utilized in our quarterly accounting estimates. We use our reserve estimates to evaluate, also on a quarterly basis, the reasonableness of our resource development plans for our reported reserves. Changes in circumstance, including commodity pricing, economic factors and the other uncertainties described above may lead to changes in our development plans.

We have set forth below a calculation of a potential future impairment of our evaluated oil and natural gas properties. Such implied impairment should not be interpreted to be indicative of our development plan or of our actual future results. Each of the uncertainties noted above has been evaluated for material known trends to be potentially included in the estimation of possible first-quarter effects. Based on such review, we determined that the impact of decreased commodity prices is the only significant known variable necessary in calculating the following scenario.

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Our hypothetical first-quarter 2019 full cost ceiling calculation has been prepared by substituting (i) \$57.26 per Bbl for oil, (ii) \$20.67 per Bbl for NGL and (iii) \$1.29 per Mcf for natural gas (the "Pro Forma First-Quarter Prices") for the respective Realized Prices as of December 31, 2018. All other inputs and assumptions have been held constant. Accordingly, this estimation strictly isolates the estimated impact of lower commodity prices on the first-quarter 2019 Realized Prices that will be utilized in our full cost ceiling calculation. The Pro Forma First-Quarter Prices use a slightly modified Realized Price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for oil, NGL and natural gas for the 11 months ended February 1, 2019, with the price for February 1, 2019 held constant for the remaining twelfth month of the calculation. Based solely on the substitution of the Pro Forma First-Quarter Prices into our December 31, 2018 reserve estimates, we would not have a first-quarter 2019 impairment. Under the same assumptions as above, but reducing the oil price to \$50 per Bbl ("Pro Forma Oil Price"), our full cost ceiling would approximately equal our after-tax net book basis to be recovered, implying a potential impairment of our evaluated oil and natural gas properties if the oil Realized Price applied to our reserves decreased below this Pro Forma Oil Price during 2019. We believe that substituting these prices into our December 31, 2018 reserve estimates may help provide users with an understanding of the potential impact on our quarterly 2019 full cost ceiling tests.

See "Item 1A. Risk Factors—Risks related to our business—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." and Note 6.a to our consolidated financial statements included elsewhere in this Annual Report for additional information.

Core area of operations

The oil and liquids-rich Permian Basin is characterized by multiple target horizons, long-lived reserves, high drilling success rates and high initial production rates. As of December 31, 2018, we had assembled 120,617 net acres in the Permian Basin.

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, transportation constraints and a variety of additional factors. Historically, commodity prices have experienced significant fluctuations, and additional changes in commodity prices may affect the economic viability of, and our ability to fund, our drilling projects, as well as the economic valuation and economic recovery of oil, NGL and natural gas reserves.

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

The Realized Prices utilized to value our reserves as of December 31, 2018 and December 31, 2017, were \$59.29 per Bbl for oil, \$21.42 per Bbl for NGL and \$1.38 per Mcf for natural gas, and \$46.34 per Bbl for oil, \$18.45 per Bbl for NGL and \$2.06 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 as of December 31, 2018 or December 31, 2017. As more specifically addressed in "Recent developments" above, if prices remain at or below the current low levels, subject to numerous factors and inherent limitations, and all other factors remain constant, it is possible we would incur a non-cash full cost impairment in 2019, which would have an adverse effect on our results of operations. See Notes 2.h and 6.a to our consolidated financial statements included elsewhere in this Annual Report for discussion of our full cost method of accounting.

Horizontal drilling of unconventional wells using enhanced completions techniques, including, but not limited to, hydraulic fracturing, is a relatively new process and, as such, forecasting the long-term production of such wells is inherently uncertain and subject to varying interpretations. As we receive and process geological and production data from these wells over time, we analyze such data to confirm whether previous assumptions regarding original forecasted production and reserves continue to appear accurate or require modification. While all production forecasts have elements of uncertainty over the life of the related wells, we are seeing indications that the oil portion of such reserves may be less and the decline curves steeper than originally anticipated.

Initial production results, production decline rates, well density, completion design and operating method are examples of the numerous uncertainties and variables inherent in the estimation of proved reserves in future periods. The quantity of proved reserves is one of the many variables inherent in the calculation of depletion. Negative revisions in the estimated quantities of proved reserves have the effect of increasing the rates of depletion on the affected properties, which decreases earnings and increases losses through higher depletion expense. We have experienced increased depletion per BOE sold for each of the quarters of 2018.

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The table below presents our depletion per BOE sold for the periods presented:

For the years ended
December 31,
2018 2017 2016

Depletion per BOE sold \$7.90 \$6.75 \$7.39

Sources of our revenue

Our revenues are derived from the sale of produced oil, NGL and natural gas, the sale of purchased oil and providing midstream services to third parties, all within the continental United States and do not include the effects of derivatives. Our oil, NGL and natural gas revenues may vary significantly from period to period as a result of changes in volumes of production, pricing differentials and/or changes in commodity prices. Our sales of purchased oil revenue may vary due to changes in oil prices, pricing differentials and the 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) oil and natural gas gathering and transportation systems and related facilities, (ii) gas lift, rig fuel and centralized compression infrastructure and (iii) water storage, recycling and transportation infrastructure. See Notes 2.n and 5.b to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our revenue recognition policies.

The following table presents our sources of revenue as a percentage of total revenues:

For the years ended
December 31,
2018 2017 2016

Oil sales	55 %	54 %	53 %
NGL sales	13 %	13 %	10 %
Natural gas sales	5 %	9 %	9 %
Midstream service revenues	1 %	1 %	1 %
Sales of purchased oil	26 %	23 %	27 %
Total	100%	100%	100%

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 based on and fluctuate in proportion to our oil, NGL and natural gas sales revenues, and are established by federal, state or local taxing authorities. We take full advantage of all credits and exemptions in our various taxing jurisdictions. 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.

Transportation and marketing expenses. Transportation and marketing expenses are the costs incurred to transport a portion of our production to the U.S. Gulf Coast market.

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 incurred for obtaining oil from third parties and, in some cases, transporting such oil utilized in our marketing activities. Our costs of purchased oil may vary due to changes in oil prices, pricing differentials, the amount of volumes purchased and fluctuations in transportation fees.

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, option awards and performance share awards with market criteria, which have been recognized on a straight-line basis over the vesting period associated with the award, and performance share awards with performance criteria, which have been recognized based on an estimated probability of how many shares will be earned at the end of the performance period with expense trued-up at each reporting period. The 2013 performance unit awards' fair value was re-measured at the end of each reporting period until settlement in

first-quarter 2016. See Note 8.c to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our stock-based compensation.

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Depletion, depreciation and amortization ("DD&A"). Under the full cost method of accounting for our oil and natural gas properties, we capitalize all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for or developing oil and natural gas properties and then systematically expense those costs on a unit-of-production basis based on proved oil, NGL and natural gas reserve quantities.

Unevaluated costs and related carrying costs are excluded from the depletion base until the properties associated with these costs are evaluated. The depletion base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values. We calculate depreciation on our midstream service assets and other fixed assets utilizing the straight-line method based on estimated useful lives of the assets 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. See Note 6 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding the DD&A of our property and equipment.

Impairment expense. Impairment of our oil and natural gas properties 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 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. With the continuing volatility in commodity prices, we may incur additional write-downs on our oil and natural gas properties. See Note 6.a to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our full cost ceiling calculation.

Impairment losses are recorded on long-lived assets when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying amount. Impairment is measured based on the excess of the carrying amount over the fair value of the asset. Materials and supplies inventory used in production activities of oil and natural gas properties and midstream service assets, frac pit water inventory used in developing oil and natural gas properties and line-fill in third-party pipelines are carried at the lower of cost or net realizable value ("NRV") with costs determined using the weighted-average cost method. See Notes 2.i, 6.b and 10.b to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our inventory and long-lived assets.

Other operating expenses. These costs include accretion expense due to the passage of time on our asset retirement obligations for the years ended December 31, 2018, 2017 and 2016 and firm transportation payments on excess pipeline capacity and other contractual penalties for the years ended December 31, 2017 and 2016. See Notes 2.k and 14.d to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our asset retirement obligations and firm transportation payments on excess pipeline capacity and other contractual penalties, respectively.

Non-operating income (expense)

Gain (loss) on derivatives, net. We utilize derivatives to reduce our exposure to fluctuations in commodity prices, commodity transportation costs and differences in commodity prices between where we produce and where we sell our products. This amount represents (i) the recognition of gains and losses associated with our open derivatives as commodity and location differential prices change and contracts 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. See Notes 9 and 10.a to our consolidated financial statements included elsewhere in this Annual Report for additional information on our derivatives.

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. See Note 7 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our debt and interest expense.

Other income, net. This represents the interest received on our cash and cash equivalents and sublease income as well as other miscellaneous income. See Note 14.a to our consolidated financials statements included elsewhere in this Annual Report for additional information regarding our sublease income.

Income from equity method investee. We owned 49% of the ownership units in Medallion that 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." See

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Note 4.c to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding the Medallion Sale.

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 as of December 31, 2017. In accordance with the modified retrospective approach of adoption to ASC 606, this deferred gain was recognized as an adjustment to the beginning balance of accumulated deficit, presented in the consolidated statements of stockholders' equity for the year ended December 31, 2018. See Notes 4.c and 5.a to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding the Medallion Sale.

Loss on early redemption of debt. This represents the loss on extinguishment recognized in the early redemption of our May 2022 Notes in November 2017 and is the difference between the redemption price and the net carrying amount. See Note 7.c to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding the redemption of our May 2022 Notes.

Loss on disposal of assets, net. This represents losses recorded from selling or disposing of midstream service assets, other fixed assets or inventory. Sale proceeds are compared with the recorded net book value of the asset and the appropriate gain (loss) is recorded and the cost and related accumulated depreciation and amortization are removed from the accounts.

Write-off of debt issuance costs. Debt issuance costs, 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. See Note 7.e to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our debt issuance costs.

Income tax benefit (expense). Income taxes in our financial statements are generally presented on a consolidated basis. We are subject to federal and Oklahoma 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 (i) our earnings history, (ii) our ability to recover net operating loss carry-forwards, (iii) the existence of significant proved oil, NGL and natural gas reserves, (iv) our ability to use tax planning strategies, (v) our current price protection utilizing oil, NGL and natural gas hedges, (vi) our future revenue and operating cost projections and (vii) the current market prices for oil, NGL and natural gas. See Note 12 to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our income taxes.

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For the year ended December 31, 2018 as compared to the year ended December 31, 2017, and for the year ended December 31, 2017 as compared to the year ended December 31, 2016

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

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

	For the years ended December 31,		
	2018	2017	2016
Sales volumes:			
Oil (MBbl)	10,175	9,475	8,442
NGL (MBbl)	7,259	5,800	4,784
Natural gas (MMcf)	44,680	35,972	29,535
Oil equivalents (MBOE) ⁽¹⁾⁽²⁾	24,881	21,270	18,149
Average daily sales volumes (BOE/D) ⁽²⁾	68,168	58,273	49,586
% Oil ⁽²⁾	41	% 45	% 47
%			%
Sales revenues (in thousands):			
Oil	\$605,197	\$445,012	\$318,466
NGL	149,843	101,438	56,982
Natural gas	53,490	75,057	51,037
Total oil, NGL and natural gas sales revenues	\$808,530	\$621,507	\$426,485
Average sales Realized Prices ⁽²⁾ :			
Oil, without derivatives (\$/Bbl) ⁽³⁾	\$59.48	\$46.97	\$37.73
NGL, without derivatives (\$/Bbl) ⁽³⁾	\$20.64	\$17.49	\$11.91
Natural gas, without derivatives (\$/Mcf) ⁽³⁾	\$1.20	\$2.09	\$1.73
Average price, without derivatives (\$/BOE) ⁽³⁾	\$32.50	\$29.22	\$23.50
Oil, with derivatives (\$/Bbl) ⁽⁴⁾	\$55.49	\$50.45	\$58.07
NGL, with derivatives (\$/Bbl) ⁽⁴⁾	\$20.03	\$16.91	\$11.91
Natural gas, with derivatives (\$/Mcf) ⁽⁴⁾	\$1.77	\$2.15	\$2.20
Average price, with derivatives (\$/BOE) ⁽⁴⁾	\$31.72	\$30.71	\$33.73

(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.

Realized oil, NGL and natural gas prices are the actual prices received when control passes to the

(3) purchaser/customer adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

Price reflects the after-effects of our derivative transactions on our average sales Realized Prices. Our calculation of such after-effects includes settlements of matured derivatives during the respective periods in accordance with GAAP and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to derivatives that settled during the respective periods.

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The following table presents settlements (paid) received for matured derivatives and premiums paid previously or upon settlement attributable to derivatives that matured during the periods utilized in our calculation of the average sales Realized Prices with derivatives presented above:

(in thousands)	For the years ended December 31,		
	2018	2017	2016
Settlements (paid) received for matured derivatives:			
Oil	\$(18,631)	\$35,724	\$181,401
NGL	(4,466)	(3,368)	—
Natural gas	29,187	5,227	13,880
Total	\$6,090	\$37,583	\$195,281
Premiums paid previously or upon settlement attributable to derivatives that matured during the respective period:			
Oil	\$(21,890)	\$(2,738)	\$(9,669)
Natural gas	(3,385)	(3,070)	—
Total	\$(25,275)	\$(5,808)	\$(9,669)

Changes in average sales Realized Prices without derivatives and sales volumes caused the following changes to our oil, NGL and natural gas revenues between the years ended December 31, 2018, 2017 and 2016:

(in thousands)	Oil	NGL	Natural gas	Total net effect of change
2016 Revenues	\$318,466	\$56,982	\$51,037	\$426,485
Effect of changes in average sales Realized Prices	87,572	32,363	12,897	132,832
Effect of changes in sales volumes	38,974	12,093	11,123	62,190
2017 Revenues	445,012	101,438	75,057	621,507
Effect of changes in average sales Realized Prices	127,272	22,882	(39,736)	110,418
Effect of changes in sales volumes	32,913	25,523	18,169	76,605
2018 Revenues	\$605,197	\$149,843	\$53,490	\$808,530

Oil sales revenue. Our oil sales revenue is a function of oil production volumes sold and average oil sales Realized Prices received for those volumes. The increase in oil sales revenue of \$160.2 million, or 36%, for the year ended December 31, 2018 as compared to 2017, is due to a 27% increase in average oil sales Realized Prices and a 7% increase in oil sales volumes. The increase in oil sales 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 sales Realized Prices and a 12% increase in oil sales volumes.

NGL sales revenue. Our NGL sales revenue is a function of NGL production volumes sold and average NGL sales Realized Prices received for those volumes. The increase in NGL sales revenue of \$48.4 million, or 48%, for the year ended December 31, 2018 as compared to 2017, is due to a 25% increase in NGL sales volumes and an 18% increase in average NGL sales Realized Prices. The increase in NGL sales 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 sales Realized Prices and a 21% increase in NGL sales volumes.

Natural gas sales revenue. Our natural gas sales revenue is a function of natural gas production volumes sold and average natural gas sales Realized Prices received for those volumes. The decrease in natural gas sales revenue of \$21.6 million, or 29%, for the year ended December 31, 2018 as compared to 2017, is due to a 43% decrease in average natural gas sales Realized Prices, partially offset by a 24% increase in natural gas sales volumes. The increase in natural gas sales 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 sales Realized Prices.

The following table presents midstream service and sales of purchased oil revenues:

(in thousands)	For the years ended December 31,		
	2018	2017	2016
Midstream service revenues	\$8,987	\$10,517	\$8,342
Sales of purchased oil	\$288,258	\$190,138	\$162,551

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Midstream service revenues. Our midstream service revenues decreased by \$1.5 million, or 15%, for the year ended December 31, 2018 as compared to 2017, and increased by \$2.2 million, or 26%, for the year ended December 31, 2017 as compared to 2016. These revenues fluctuate and will vary due to oil throughput fees and the level of services provided to third parties.

Sales of purchased oil. These revenues are a function of the volume and price of purchased oil sold to customers and are offset by the increased costs of purchased oil. Sales of purchased oil increased by \$98.1 million, or 52%, for the year ended December 31, 2018 as compared to 2017, due to an increase in the volume of purchased oil sold during the second quarter of 2018. Sales of purchased oil increased by \$27.6 million, or 17%, for the year ended December 31, 2017 as compared to 2016, mainly due to the increase in oil prices. We enter into purchase transactions with third parties and separate sale transactions with purchasers/customers to diversify a portion of the sales of oil to the U.S. Gulf Coast market. These transactions are presented on a gross basis as we act as the principal in the transaction by assuming control of the commodities purchased and the responsibility to deliver the commodities sold. Revenue is recognized when control transfers to the purchaser/customer at the delivery point based on the price received. The transportation costs associated with these transactions are presented as a component of costs of purchased oil. See "—Costs and expenses - *Costs of purchased oil.*"

Costs and expenses

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

(in thousands except for per BOE sold data)	For the years ended December 31,		
	2018	2017	2016
Costs and expenses:			
Lease operating expenses	\$91,289	\$75,049	\$75,327
Production and ad valorem taxes	49,457	37,802	28,586
Transportation and marketing expenses	11,704	—	—
Midstream service expenses	2,872	4,099	4,077
Costs of purchased oil	288,674	195,908	169,536
General and administrative:			
Cash	59,742	60,578	62,527
Non-cash stock-based compensation, net	36,396	35,734	29,229
Depletion, depreciation and amortization	212,677	158,389	148,339
Impairment expense	—	—	162,027
Other operating expenses	4,472	4,931	5,692
Total costs and expenses	\$757,283	\$572,490	\$685,340
Average costs and expenses per BOE sold ⁽¹⁾ :			
Lease operating expenses	\$3.67	\$3.53	\$4.15
Production and ad valorem taxes	1.99	1.78	1.58
Transportation and marketing expenses	0.47	—	—
Midstream service expenses	0.12	0.19	0.22
General and administrative:			
Cash	2.40	2.85	3.45
Non-cash stock-based compensation, net	1.46	1.68	1.61
Depletion, depreciation and amortization	8.55	7.45	8.17
Total costs and expenses	\$18.66	\$17.48	\$19.18

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

See "— Principal components of our cost structure" for further discussion of the costs and expenses noted below.

Lease operating expenses. Lease operating expenses, which include workover expenses, increased by \$16.2 million, or 22%, for the year ended December 31, 2018 compared to 2017 and decreased by \$0.3 million for the year ended December 31, 2017 compared to 2016. On a per BOE sold basis, lease operating expenses increased 4% for the

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ended December 31, 2018 compared to 2017 due to increased recurring and non-routine workover expenses in 2018. On a per BOE sold basis, lease operating expenses decreased 15% for the year ended December 31, 2017 compared to 2016. The year-over-year 2017 decrease compared to 2016 is 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 \$11.7 million, or 31%, for the year ended December 31, 2018 compared to 2017. This change is comprised of a \$9.0 million, or 28%, increase in production taxes and a \$2.7 million increase in ad valorem taxes for the year ended December 31, 2018 compared to 2017. 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 comprised of an \$8.5 million, or 37%, 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 revenues. 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.

Transportation and marketing expenses. Transportation and marketing expenses were \$11.7 million for the year ended December 31, 2018. In July 2018, we began selling produced oil in the U.S. Gulf Coast market with transportation expenses incurred for the delivery of the oil to the customer recognized as transportation and marketing expense. We did not have any comparable transactions during the years ended December 31, 2017 and 2016.

Midstream service expenses. Midstream service expenses decreased \$1.2 million, or 30%, for the year ended December 31, 2018 compared to 2017 and remained relatively flat for the year ended December 31, 2017 compared to 2016.

Costs of purchased oil. Costs of purchased oil increased \$92.8 million, or 47%, for the year ended December 31, 2018 compared to 2017 due to an increase in the volume of purchased oil during the second quarter of 2018. Costs of purchased oil increased \$26.4 million, or 16%, for the year ended December 31, 2017 compared to 2016 mainly due increases in oil prices.

General and administrative ("G&A"). Total G&A remained relatively flat for year ended December 31, 2018 compared to 2017 and increased \$4.6 million, or 5%, for the year ended December 31, 2017 compared to 2016 mainly due to an increase in stock-based compensation and professional fees, partially offset by a decrease in salaries, benefits and bonuses, net of amounts capitalized. On a per BOE sold basis, G&A decreased 15% for the year ended December 31, 2018 compared to 2017. Stock-based compensation, net remained relatively flat for the year ended December 31, 2018 compared to 2017, and increased \$6.5 million, or 22%, for the year ended December 31, 2017 compared to 2016 as the result of 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. See "— Critical accounting policies and estimates" along with Notes 2.p and 8.c to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our stock and performance-based compensation.

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

(in thousands)	For the years ended December 31,		
	2018	2017	2016
Depletion of evaluated oil and natural gas properties	\$ 196,458	\$ 143,592	\$ 134,105
Depreciation of midstream service assets	10,144	8,939	8,331
Depreciation and amortization of other fixed assets	6,075	5,858	5,903
Total DD&A	\$ 212,677	\$ 158,389	\$ 148,339

DD&A increased by \$54.3 million, or 34%, for the year ended December 31, 2018 as compared to 2017 mainly due to increases in the depletion base and production volumes sold. Depletion per BOE increased 17% for the year ended December 31, 2018 compared to 2017. For further discussion on our depletion per BOE see "—Pricing and reserves." 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 as compared to 2016.

Impairment expense. Our unamortized cost of evaluated oil and natural gas properties being depleted exceeded the full cost ceiling as of March 31, 2016, and, as a result, we recorded a full cost ceiling impairment of \$161.1 million for the year ended December 31, 2016. There were no comparable full cost ceiling impairments recorded during the years ended December 31, 2018 or 2017. For further discussion of our full cost ceiling impairment accounting policy, see Notes 2.h and 6.a to our consolidated financial statements included elsewhere in this Annual Report.

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During the year ended December 31, 2016, we reduced materials and supplies inventory by \$1.0 million in order to reflect the balance at lower of cost or NRV. There were no comparable inventory impairments during the years ended December 31, 2018 and 2017. For further discussion of long-lived assets and inventory impairment accounting policies, see Notes 10.b and 2.i 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,		
	2018	2017	2016
Gain (loss) on derivatives, net	\$42,984	\$350	\$(87,425)
Interest expense	(57,904)	(89,377)	(93,298)
Other income, net	1,070	805	175
Income from equity method investee (see Note 4.c)	—	8,485	9,403
Gain on sale of investment in equity method investee (see Note 4.c)	—	405,906	—
Loss on early redemption of debt	—	(23,761)	—
Loss on disposal of assets, net	(5,798)	(1,306)	(790)
Write-off of debt issuance costs	—	—	(842)
Non-operating income (expense), net	\$(19,648)	\$301,102	\$(172,777)

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

(in thousands)	Year ended	Year ended
	December 31, 2018	December 31, 2017
Increase in fair value of derivatives outstanding	\$78,361	\$321,239
Decrease in settlements received for matured derivatives, net	(31,493)	(157,698)
Decrease in settlements received for early terminations of derivatives, net	(4,234)	(75,766)
Total change in gain (loss) on derivatives, net	\$42,634	\$87,775

The increase in fair value of derivatives outstanding is 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 new contracts are entered into or terminated, we experience gains during periods of decreasing market prices and losses during periods of increasing market prices. Settlements received or paid for matured derivatives are based on the settlement prices of our matured derivatives compared to the prices specified in the derivative contracts.

During the year ended December 31, 2017, we 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. During the year ended December 31, 2016, we 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. There were no comparable hedge restructuring amounts for the year ended December 31, 2018.

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.

Interest expense. Interest expense decreased by \$31.5 million, or 35%, for the year ended December 31, 2018 compared to 2017 and by \$3.9 million, or 4%, for the year ended December 31, 2017 compared to 2016 both mainly due to the early redemption of the May 2022 Notes on November 29, 2017.

Income from equity method investee. For further discussion of the Medallion Sale, see Note 4.c to our consolidated financial statements included elsewhere in this Annual Report.

Gain on sale of investment in equity method investee. For further discussion of the Medallion Sale, see Note 4.c to our consolidated financial statements included elsewhere in this Annual Report.

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Loss on early redemption of debt. For additional discussion of the redemption of our May 2022 Notes, see Note 7.c to our consolidation financial statements included elsewhere in this Annual Report.

Loss on disposal of assets, net. Loss on disposal of assets, net, increased by \$4.5 million for the year ended December 31, 2018 compared to 2017 and increased by \$0.5 million for the year ended December 31, 2017 compared to 2016. 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.

Write-off of debt issuance costs. We wrote-off \$0.8 million of debt issuance costs during the year ended December 31, 2016 as a result of changes in the borrowing base and aggregate elected commitment of the Senior Secured Credit Facility. We wrote-off \$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, which are included in the "Loss on early redemption of debt" line item in the consolidated statements of operations. There were no comparable debt issuance costs written off during the year ended December 31, 2018. See Note 7.e for further discussion of our debt issuance costs.

Income tax benefit (expense). The following table presents income tax benefit (expense):

	For the years ended December 31,		
(in thousands)	2018	2017	2016
Current	\$807	\$(1,800)	\$ —
Deferred	(5,056)	—	—
Total income tax expense	\$(4,249)	\$(1,800)	\$ —

Income tax expense of \$4.2 million for the year ended December 31, 2018 is comprised of deferred Texas franchise tax expense of \$5.1 million offset by a current income tax benefit of \$0.8 million due to a Texas franchise tax refund which is a result of differences in estimated versus actual taxable income from the gain on the Medallion Sale. Income tax expense of \$1.8 million for the year ended December 31, 2017 is comprised of current Texas franchise tax, mainly as a result of the Medallion Sale.

During the years ended December 31, 2018 and 2017, we determined it was more likely than not that our deferred tax assets were not realizable through future net income. We maintain a valuation allowance to reduce certain deferred tax assets to amounts that are more likely than not to be realized, and as of December 31, 2018 we have recorded a total valuation allowance of \$237.3 million against our federal and Oklahoma deferred tax assets. As such, the effective tax rates for our operations were 1% for the year ended December 31, 2018, and 0% for each of the years ended December 31, 2017 and 2016. Our 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. For further discussion of our income taxes, see Note 12 to our consolidated financial statements located elsewhere in this Annual Report.

Liquidity and capital resources

Historically, 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 the Medallion Sale and other asset dispositions. We believe cash flows from operations and availability under our Senior Secured Credit Facility provide sufficient liquidity to manage our cash needs and contractual obligations and to fund our expected capital expenditures. Our primary operational uses of capital have been for the acquisition, exploration and development of oil and natural gas properties, infrastructure development and investments in Medallion until its sale on October 30, 2017.

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 and equity repurchases, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material. See the following Notes to our consolidated financial statements included elsewhere in this Annual Report for further discussion regarding our investing and financing activities (i) Notes 4.a and 4.e for our acquisitions of evaluated and unevaluated

oil and natural gas properties, (ii) Notes 4.b and 4.d for divestitures of oil and natural gas properties and midstream service assets, (iii) Note 4.c for the Medallion Sale, (iv) Note 7 and 7.c for our debt instruments and the redemption of our May 2022 Notes, respectively, (v) Note 8.a and "Part II. Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" above for our \$200.0 million share

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repurchase program authorized by our board of directors and commenced in February 2018 and (vi) Note 8.b for our equity offerings. We also continuously look for other opportunities to maximize shareholder value.

Due to the inherent volatility in oil, NGL and natural gas prices, commodity transportation costs and differences in the prices of oil, NGL and natural gas between where we produce and where we sell such commodities, we engage in derivative transactions, such as puts, swaps, collars, basis swaps and, in the past, call spreads to hedge price risk associated with a portion of our anticipated production. By removing a 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. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" below.

See Note 17.b to our consolidated financial statements included elsewhere in this Annual Report for a summary of open derivative positions as of December 31, 2018 for derivatives that were entered into through February 13, 2019. See Note 9 to our consolidated financial statements included elsewhere in this Annual Report for information regarding our derivative settlement indexes and a summary of open derivative positions as of December 31, 2018 for derivatives that were entered into through December 31, 2018.

We continually seek to maintain a financial profile that provides operational flexibility. As of December 31, 2018, we had cash and cash equivalents of \$45.2 million and available capacity under the Senior Secured Credit Facility of \$995.3 million, resulting in total liquidity of \$1.04 billion. As of February 12, 2019, we had cash and cash equivalents of \$30.0 million and available capacity under the Senior Secured Credit Facility of \$945.3 million, resulting in total liquidity of \$975.3 million. We believe that our operating cash flow and the aforementioned liquidity sources provide us with the financial resources to manage our business needs, to implement our planned capital expenditure budget and, at our discretion, to fund our share repurchase program. We expect 2019 to be a transitional year as we tailor our operational cadence and corporate cost structure, including G&A expense, to balance capital expenditures and cash flow from operations.

Cash flows

The following table presents our cash flows:

(in thousands)	For the years ended December 31,		
	2018	2017	2016
Net cash provided by operating activities	\$537,804	\$384,914	\$356,295
Net cash (used in) provided by investing activities	(690,956)	295,050	(564,402)
Net cash provided by (used in) financing activities	86,144	(600,477)	209,625
Net (decrease) increase in cash and cash equivalents	\$(67,008)	\$79,487	\$1,518

Cash flows from operating activities

Net cash provided by operating activities increased by \$152.9 million, or 40%, from 2017 to 2018, mainly due to increased revenues due to the increase in average sales Realized Prices for oil and NGL and increased sales volumes of all production streams, with additional details included at "—Results of operations," partially offset by a decrease in average sales Realized Prices for natural gas and a decrease of \$30.2 million in settlements received for matured and early terminations of derivatives, net of premiums paid.

Net cash provided by operating activities increased by \$28.6 million, or 8%, from 2016 to 2017, mainly due to the increased revenues due to the increase in average sales Realized Prices for oil, NGL and natural gas; however, other notable cash changes included (i) a decrease of \$169.6 million in 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.

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, mitigated to the extent of our derivatives' exposure, and sales volume levels. Regional and worldwide economic activity, weather, infrastructure, transportation 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 risks related to our business, see "Part I. Item 1A. Risk Factors" included elsewhere in this Annual Report.

Table of Contents***Cash flows from investing activities***

Net cash provided by investing activities decreased by \$986.0 million, or 334%, from 2017 to 2018, and is mainly attributable to (i) proceeds we received from the Medallion Sale in 2017, (ii) an increase in capital expenditures on oil and natural gas properties, (iii) a decrease in proceeds from dispositions of capital assets and (iv) our acquisitions of oil and natural gas properties partially offset by (a) our contributions to Medallion prior to its sale and (b) a decrease in capital expenditures on midstream service assets.

Net cash used in investing activities decreased by \$859.5 million, or 152%, from 2016 to 2017, and is mainly attributable to (i) proceeds we received from the Medallion Sale in 2017, (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.

See the following Notes to our consolidated financial statements included elsewhere in this Annual Report for further discussion regarding our investing activities (i) Notes 4.a and 4.e our acquisitions of evaluated and unevaluated oil and natural gas properties, (ii) Notes 4.b and 4.d our divestitures of evaluated and unevaluated oil and natural gas properties and midstream service assets and (iii) Note 4.c the Medallion Sale.

The following table presents the components of our cash flows from investing activities:

(in thousands)	For the years ended December 31,		
	2018	2017	2016
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)	—
Acquisitions of oil and natural gas properties	(17,538)	—	(124,660)
Capital expenditures:			
Oil and natural gas properties	(673,584)	(538,122)	(360,679)
Midstream service assets	(6,784)	(20,887)	(5,240)
Other fixed assets	(7,308)	(4,905)	(7,611)
Investment in equity method investee (see Note 4.c)	—	(31,808)	(69,609)
Proceeds from disposition of equity method investee, net of selling costs (see Note 4.c)	1,655	829,615	—
Proceeds from dispositions of capital assets, net of selling costs	12,603	64,157	397
Net cash (used in) provided by investing activities	\$(690,956)	\$295,050	\$(564,402)

Capital expenditures budget

Our board of directors approved a capital expenditures budget of approximately \$365.0 million, based on annual benchmark averages of a \$53.60 per barrel WTI NYMEX strip price and a \$2.90 per MMBtu Henry Hub NYMEX strip price, for calendar year 2019, excluding non-budgeted acquisitions. Our goal is to achieve cash flow neutrality, and therefore, our capital spending in 2019 will ultimately be influenced by commodity price changes, as well as any changes in service costs and drilling and completions efficiencies. 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 and supplies, changes in service costs, contractual obligations, internally generated cash flow and other factors both within and outside our control.

Table of Contents**Cash flows from financing activities**

Net cash used in financing activities decreased by \$686.6 million, or 114%, from 2017 to 2018, and is mainly attributable to (i) our early redemption of debt in 2017, (ii) decreased payments on our Senior Secured Credit Facility, and (iii) increased borrowings on our Senior Secured Credit Facility partially offset by share repurchases under our share repurchase program that commenced in February 2018. During the year ended December 31, 2018, we repurchased 11,048,742 shares of common stock at a weighted-average price of \$8.78 per common share for a total of \$97.1 million under this program. All shares were retired upon repurchase. As of December 31, 2018, we had authorization remaining to repurchase until its expiration in February 2020, \$102.9 million of common stock. For the year ended December 31, 2017, our net cash flows used in 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 provided by 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.

See the following Notes to our consolidated financial statements included elsewhere in this Annual Report for further discussion regarding our financing activities (i) Note 7 and 7.c for our debt instruments and the redemption of our May 2022 Notes, respectively, (ii) Note 8.a and "Part II. Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" above for our \$200.0 million share repurchase program authorized by our board of directors and commenced in February 2018 and (iii) Note 8.b for our equity offerings.

The following table presents the components of our cash flows from financing activities:

(in thousands)	For the years ended December 31,		
	2018	2017	2016
Borrowings on Senior Secured Credit Facility	\$210,000	\$190,000	\$239,682
Payments on Senior Secured Credit Facility	(20,000)	(260,000)	(304,682)
Early redemption of debt	—	(518,480)	—
Proceeds from issuance of common stock, net of offering costs	—	—	276,052
Share repurchases	(97,055)	—	—
Vested stock exchanged for tax withholding	(4,418)	(7,662)	(1,635)
Proceeds from exercise of stock options	86	397	208
Payments for debt issuance costs	(2,469)	(4,732)	—
Net cash provided by (used in) financing activities	\$86,144	\$(600,477)	\$209,625

Debt

As of December 31, 2018, 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, 2018, the Senior Secured Credit Facility had a maximum credit amount of \$2.0 billion, a borrowing base of \$1.3 billion and an aggregate elected commitment of \$1.2 billion, with \$190.0 million outstanding and was subject to an interest rate of 3.75%. As of December 31, 2018, we had one letter of credit outstanding of \$14.7 million under the Senior Secured Credit Facility.

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 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 Senior Secured Credit Facility matures on April 19, 2023, provided that if either the January 2022 Notes or March 2023 Notes have not been refinanced on or prior to the applicable Early Maturity Date, the Senior

Secured Credit Facility will mature on such Early Maturity Date.

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On October 23, 2018, pursuant to the regular semi-annual redetermination, the lenders reaffirmed the borrowing base of \$1.3 billion under our Senior Secured Credit Facility. Our aggregate elected commitment of \$1.2 billion remains unchanged.

As defined in the Senior Secured Credit Facility, (i) the Adjusted Base Rate advances under the facility bear interest payable quarterly at an Adjusted Base Rate plus applicable margin, which ranges from 0.25% to 1.25%, based on the ratio of outstanding revolving credit to the borrowing base under the Senior Secured Credit Facility; and (ii) the Eurodollar advances under the facility bear interest, at our election, at the end of one-month, two-month, three-month, six-month or, to the extent available, 12-month interest periods (and in the case of six-month and 12-month interest periods, every three months prior to the end of such interest period) at an Adjusted London Interbank Offered Rate plus an applicable margin, which ranges from 1.25% to 2.25%, based on the ratio of outstanding revolving credit to the borrowing base under the Senior Secured Credit Facility. We are required to pay a quarterly 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 aggregate elected commitment under the Senior Secured Credit Facility.

The Senior Secured Credit Facility is secured by a first-priority lien on our assets and stock, including oil and natural gas properties, constituting at least 85% of the present value of our proved reserves. Further, we are subject to various financial and non-financial covenants. We were in compliance with these covenants for all periods presented.

As of December 31, 2018, we were subject to the following financial ratios on a consolidated basis:

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; and

a leverage ratio as of the last day of each calendar quarter of (a) our 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 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.

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.

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As of December 31, 2018, 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, 2018, 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, the Senior Secured Credit Facility provides for the issuance of letters of credit, limited to the lesser of total capacity or \$80.0 million. See Note 7.d 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, 2018:

(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	

See Notes 7.a and 7.b to our consolidated financial statements included elsewhere in this Annual Report for further discussion of the March 2023 Notes and January 2022 Notes, respectively.

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 7.c to our consolidated financial statements included elsewhere in this Annual Report for information regarding the early redemption of the May 2022 Notes.

Table of Contents**Obligations and commitments**

The following table presents significant contractual obligations and commitments as of December 31, 2018:

(in thousands)	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
Senior Unsecured Notes ⁽¹⁾	\$47,188	\$94,375	\$845,468	\$—	\$987,031
Firm sale and transportation commitments ⁽²⁾	66,102	115,315	87,642	96,881	365,940
Senior Secured Credit Facility ⁽³⁾	—	—	190,000	—	190,000
Asset retirement obligations ⁽⁴⁾	3,495	13,762	8,262	31,363	56,882
Lease commitments ⁽⁵⁾	3,092	6,307	3,918	4,556	17,873
Derivatives ⁽⁶⁾	15,502	1,295	—	—	16,797
Drilling contracts ⁽⁷⁾	15,179	1,322	—	—	16,501
Sand purchase and supply agreement ⁽⁸⁾	3,858	—	—	—	3,858
Total	\$154,416	\$232,376	\$1,135,290	\$132,800	\$1,654,882

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

As of December 31, 2018, 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

(2) are subject to firm transportation payments on excess pipeline capacity and other contractual penalties. See "Part I. Item 1A. Risk Factors" and Note 14.d to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our firm sale and transportation commitments.

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 (3) 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, 2018, the principal on our Senior Secured Credit Facility is due on April 19, 2023.

(4) Amounts represent our asset retirement obligation liabilities. See Note 2.k to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our asset retirement obligations.

(5) See Note 14.a to our consolidated financial statements included elsewhere in this Annual Report for a description of our lease obligations.

Represents payments due for deferred premiums on our commodity hedging contracts. See Note 10.a to our (6) consolidated financial statements included elsewhere in this Annual Report for additional discussion of our deferred premiums.

(7)