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, 2019
or
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number: 001-35380

Laredo Petroleum, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**45-3007926**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

15 W. Sixth Street	**Suite 900**	
Tulsa	**Oklahoma**	**74119**
(Address of principal executive offices)		(Zip code)

(918) 513-4570

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

Title of each class	Trading symbol	Name of each exchange on which registered
Common stock, $0.01 par value per share	LPI	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 every Interactive Data File required to be submitted 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 such files). Yes No

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	Accelerated filer
Non-accelerated filer	Smaller reporting company
Emerging growth company	

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

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates was approximately $526.2 million on June 30, 2019, based on $2.90 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, 2020: 237,207,787

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2020 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2019, are incorporated by reference into Part III of this report for the year ended December 31, 2019.

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Glossary of Oil and Natural Gas Terms

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

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

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

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

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

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

"*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.

"Brent"—A light (low density) and sweet (low sulfur) crude oil sourced from the North Sea, used as a pricing benchmark for ICE oil futures contracts.

"*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.

"*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.

"Henry Hub"—A natural gas pipeline delivery point in south Louisiana that serves as the benchmark natural gas price underlying NYMEX natural gas futures contracts.

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

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

"ICE"—The Intercontinental Exchange.

"*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, 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 Btu.

"*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 without giving effect to our commodity derivative transactions.

"*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.

"*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.

"*WTI*"—West Texas Intermediate grade crude oil. A light (low density) and sweet (low sulfur) crude oil, used as a pricing benchmark for NYMEX oil futures contracts.

Cautionary Statement Regarding Forward-Looking Statements

Various statements contained in or incorporated by reference into this Annual Report are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These forward-looking statements include statements, projections and estimates concerning our operations, performance, business strategy, oil, 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 oil, NGL and natural gas prices, including in our area of operation in the Permian Basin;
- our ability to discover, estimate, develop and replace oil, NGL and natural gas reserves and inventory;
- 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 long-term performance of wells that were completed using different technologies;
- 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 co-development considerations such as horizontal spacing, vertical spacing and parent-child interactions;
- capital requirements for our operations and projects;
- impacts of impairment write-downs on our financial statements;
- the availability and costs of drilling and production equipment, supplies, labor and oil and natural gas processing and other services;
- the availability and costs 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 secure or generate sufficient electricity to produce our wells without limitations;
- 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 apply hydraulic fracturing to our oil and natural gas wells and to access and dispose of water used in these operations and outbreak of disease;
- 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;
- drilling and operating risks, including risks related to inclement weather impacting our ability to produce existing wells and/or drill and complete new wells over an extended period of time; 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.

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, 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, 2019, we had assembled 133,512 net acres in the Permian Basin and had total proved reserves, presented on a three-stream basis, of 293,377 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.

2019 operation highlights

- Generated $475.1 million of net cash provided by operating activities and $59.7 million of Free Cash Flow in 2019 as we reduced capital expenditures by 25% from full-year 2018 (See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP financial measures and other calculations—Free Cash Flow")
- Executed two accretive acquisitions of high-margin, oily inventory at valuations significantly below historic averages while maintaining a competitive leverage ratio
- Produced 28,429 Bbl/D of oil and 80,883 BOE/D, increases of 2% and 19%, respectively, from full-year 2018
- Grew total proved reserves by 55 million BOE and proved oil reserves by 17 million barrels, increases of 23% and 27%, respectively, versus year-end 2018
- Drove well costs down to $6.6 million for a 10,000-foot lateral with our standard completion design, a decrease from $7.7 million at year-end 2018
- Reduced controllable cash costs of combined unit lease operating expenses ("LOE") and unit cash general and administrative ("G&A") to $4.65 per BOE, a 23% decrease from full-year 2018 results of $6.07 per BOE
- Received net cash of $48.7 million on settlements of derivatives, as our hedges mitigated the impact of commodity price declines

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. 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-Midland Basin" area. As of

December 31, 2019, we had assembled 133,512 net acres in the Permian Basin, all of which were held in 294 sections in the Permian-Midland Basin area, with an average working interest of 97% in Laredo-operated active productive wells and 89% in all wells in which Laredo has an interest. This Permian-Midland Basin area includes two acreage blocks in Howard and Glasscock counties, respectively, that we acquired in separate transactions in the fourth quarter of 2019. We anticipate shifting much of our drilling focus to these newly acquired areas during the course of 2020 as we believe that wells in this area will produce with a higher oil content percentage than many of our previously drilled wells. We will continue to look for additional acquisition opportunities in the future.

We believe our acreage in the Permian-Midland Basin area is a resource play for multiple producing formations that make up a significant portion of the entire stratigraphic section. We are currently focusing our development activities on horizontal drilling targets in the Middle Wolfcamp, Upper Wolfcamp and Lower Spraberry formations. Other potential formations for future development are in the Upper Spraberry, Middle Spraberry, Lower Wolfcamp, Cline and Canyon. From our inception in 2006 through December 31, 2019, we have drilled and completed (i.e., the particular well is flowing) 373 horizontal wells in the Upper and Middle Wolfcamp and 967 vertical wells in the Wolfberry interval. Of these 373 horizontal wells, 206 were horizontal Upper Wolfcamp wells and 167 were horizontal Middle Wolfcamp wells. We have also drilled and completed 33 horizontal Lower Wolfcamp wells and 64 horizontal Cline wells.

Beginning in mid-2012, we started focusing our horizontal activity on drilling longer laterals. Since that time, our average lateral length has grown to 10,000 feet and longer in areas where our contiguous acreage position allows. Starting in the second quarter of 2019, we increased the spacing between our wells in an effort to increase capital efficiency. In 2020, we plan to continue to drill wells with wide spacing as we believe that this leads to increased productivity and decreased well-to-well interference; however, we believe that different areas of our acreage support different spacing plans and will drill accordingly. We continue to use our existing data (and newly acquired data from both our ongoing operations and numerous public data sources) to optimize completion designs and well spacing optimization within the development plan. 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.

Despite volatility in the price of oil, NGL and natural gas and their related margins, our goal continues to be to achieve cash flow neutrality or positive free cash flow (excluding acquisitions). We will adjust our 2020 capital spending to attempt to meet this goal and such spending will be influenced by commodity price changes, as well as any changes in individual well performance, service costs and drilling and completions efficiencies and lease operating costs. Our near-term strategy is to concentrate our drilling activities on multi-well packages on our newly acquired acreage in Howard and Glasscock counties and around our previously established production corridors.

On December 31, 2019, we had a total of three drilling rigs drilling horizontal wells. Our current drilling schedule anticipates that we will utilize four horizontal drilling rigs during the first half of 2020 and decrease our drilling count thereafter. We do not anticipate utilizing any vertical drilling rigs in 2020. 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. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Obligations and commitments" and Note 15.b to our consolidated financial statements included elsewhere in this Annual Report for additional information.

While we continue to look at potential acquisitions on a going forward basis, both within our Permian-Midland Basin area and in other locations, we expect our Permian-Midland Basin 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 targeted acquisitions. Our net proved reserves were estimated at 293,377 MBOE on a three-stream basis as of December 31, 2019, of which 83% are classified as proved developed reserves and 27% are attributable to oil reserves. We report our production volumes on a three-stream basis, which separately reports NGL from crude oil and natural gas.

In this Annual Report, the information 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 reporting dates presented.

The following table summarizes our total estimated net proved reserves presented on a three-stream basis, net acreage and producing wells as of the date presented, and net average daily production presented on a three-stream basis for the period presented. Based on estimates in the report prepared by Ryder Scott, we operated wells that represent 99.8% of the economic value of our proved developed oil, NGL and natural gas reserves as of December 31, 2019.

	December 31, 2019					Year ended December 31, 2019			
	Estimated proved reserves(1)			Producing wells		Average daily production			
	MBOE	% Oil	Net acreage	Gross	Net	(BOE/D)	% Oil	% NGL	% Natural gas
Permian-Midland Basin	293,377	27%	133,512	1,337	1,251	80,883	35%	31%	34%

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

In the second half of 2017 and through the majority of 2018, crude oil, NGL and natural gas prices gradually and continually increased to levels greater than what was experienced in 2015, 2016 and the first half of 2017 with crude oil, NGL and natural gas prices reaching their highest level in the last four months of 2018 since 2014. However, in the last quarter of 2018 for crude oil and NGL, and in the first quarter of 2019 for natural gas, commodity prices significantly decreased. Throughout the majority of 2019, crude oil, NGL and natural gas prices continued to remain volatile.

In order to maximize operational flexibility through the commodity price declines experienced during 2014 through 2016, we reduced the portion of reserves categorized as "proved undeveloped" or "PUD." Beginning in 2016, we adjusted our five-year SEC PUD booking methodology to approximately one year of activity. This allowed us to emphasize operations on our most economic investments and maintain conservative assurance that all PUD locations would be converted despite commodity price volatility. In light of commodity price volatility, we have hedged the majority of our oil for 2020, we have increased our PUD reserves to approximately two years of drilling inventory. In 2019, we acquired two new development areas, and in order to align with our commitment to develop this acreage, the majority of our added proved undeveloped reserves are in these areas.

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 our insight gained as we drill and collect data across our acreage. We converted all 20 PUD locations we booked as of December 31, 2018 into proved producing locations in 2019. For 2020, we have increased our PUD count to 109 locations, which represent those that we have a high degree of confidence will be developed and have made a specific capital commitment to drill within a two year time frame. 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 in our Glasscock and Reagan County areas, we have built crude oil, natural gas and water pipeline systems and facilities. These pipeline systems and facilities are designed to provide a combination of services to certain portions of our acreage which may include high-pressure centralized natural gas lift systems and facilities, crude oil, natural gas and produced water gathering, fresh and recycled frac water distribution and produced water recycling. We have built and maintain 61 miles of crude oil gathering pipelines and 109 miles of produced water gathering pipelines connected to our operated wells in our Glasscock and Reagan County acreage, providing a safer, more economic and lower emission transportation alternative than trucking. We have also installed and maintain 141 miles of natural gas gathering pipelines, providing us with takeaway optionality that enables us to maintain lower operating pressures, decreased non-productive time and more consistent well performance. Our crude oil and natural gas gathering assets provided transportation for 72% and 43% of our production in 2019, respectively. Combined, our three water recycling facilities provide 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 pipeline systems and associated facilities in place is expected to enhance the value of our 2020 drilling program for the portion of our acreage in this area.

The leaseholds we recently acquired in central Howard County, Texas and western Glasscock County, Texas are situated on or near previously existing third-party oil, gas and water gathering infrastructure. As such, we plan to leverage this third-party infrastructure through market-based midstream and marketing contractual arrangements, allowing for our 2020 drilling program and recently commenced operations in said regions to experience economic, environmental and operating benefits. We anticipate conducting produced water recycling on our central Howard County and western Glasscock County acreage through the relocation and construction of our existing recycling facilities.

Our midstream and marketing infrastructure activities continue to focus on achieving increased efficiencies, cost reductions, safe operating practices and reducing emissions for (i) the transportation and marketing of our oil and natural gas, (ii) the centralization and operation of natural gas lift facilities and (iii) the handling of fresh, recycled and produced water (through the use of our integrated water pipelines and 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 multiple years in length of term, all at monthly calculated market prices. We typically 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.

On October 30, 2017, our subsidiary LMS, together with Medallion Midstream Holdings, LLC , which is owned and controlled by an affiliate of the third-party interest-holder, The Energy & Minerals Group, completed the sale of 100% of the ownership interests in Medallion to an affiliate of Global Infrastructure Partners ("GIP"), for cash consideration of $1.825 billion (the "Medallion Sale"). LMS' total net cash proceeds before taxes for its 49% ownership interest in Medallion in 2017 were $831.3 million.

As of December 31, 2019, we were 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:

	Total	2020	2021	2022	2023 and after
Crude oil (MBbl):					
Sales commitments	31,110	12,875	9,125	8,210	900
Transportation commitments:					
Field	54,810	10,980	10,950	10,950	21,930
To U.S. Gulf Coast	95,985	12,810	15,525	13,365	54,285
Natural gas (MMcf):					
Sales commitments	64,215	14,215	5,712	5,712	38,576
Total commitments (MBOE)(1)	192,608	39,034	36,552	33,477	83,545

(1) BOE is 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 increasing 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 began in the fourth quarter of 2019. We believe these commitments will enhance our ability to move our crude oil out of the Permian Basin and give us access to U.S. Gulf Coast pricing. See Note 4.d to our consolidated financial statements included elsewhere in this Annual Report for a further discussion of our firm transportation agreement with Medallion.

We have committed to deliver, for sale or transportation, fixed volumes of product under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. If not fulfilled, we are subject to firm transportation payments on excess pipeline capacity and other contractual penalties. These commitments are normal and customary for our business. In certain instances, we have used spot market purchases to meet our commitments in certain locations or due to favorable pricing. We anticipate continuing this practice in the future. We incurred firm transportation payments on excess pipeline capacity and other contractual penalties of $0.9 million, $4.7 million and $1.1 million during the years ended December 31, 2019, 2018 and 2017, respectively.

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 discussion on purchasers that individually accounted for 10% or more of each (i) oil, NGL and natural gas sales and (ii) sales of purchased oil in at least one of the years ended December 31, 2019, 2018 and 2017, see Note 14 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 assembled a multidisciplinary technical database that characterizes subsurface reservoir properties with the goal of maximizing value. 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. This process along with applicable data and our talented workforce across various disciplines are key to operational results, identification of additional resources and evaluation of strategic acquisitions.

Geocellular models integrate the above-described data with enhanced interpretations conducted in 2019 to provide 3D reservoir and mechanical property models across the majority of our acreage. These models are relied on in well planning, allowing us to optimize landing targets and geosteering in the highest quality reservoir. This minimizes target changes during operations which enhances operational efficiencies.

Hydraulic fracture modeling, integrated with microseismic data is used to estimate fracture geometries in an effort to optimize well spacing and completion design for multiple reservoir targets. This work assists in predicting key drivers that affect fracture geometry such as landing point, proppant and fluid loading, pump rate, perforation design and cluster efficiency. This analysis yields important insights into subsurface behavior and improves development planning.

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 as tools in optimizing multi-well developments. We anticipate that all of our horizontal wells to be drilled in 2020 will utilize at least some aspects of the above workflows which we believe will positively impact results. The workflows are also used in our basin-wide geocellular models, creating a competitive edge for our future acquisition analysis.

Corporate history and structure

Laredo Petroleum, Inc. is a Delaware corporation formed in 2011 for the purpose of merging with Laredo Petroleum, LLC (a Delaware limited liability company formed in 2007) to consummate an IPO in December 2011. Laredo Petroleum, Inc. was the survivor of such merger and currently has two wholly-owned subsidiaries, LMS and GCM. As of December 31, 2019, affiliates of Warburg Pincus LLC ("Warburg Pincus"), our founding member, owned 21.6% of our common stock.

Our business strategy

Maximize our capital efficiency by seeking to drill high rate of return wells with continued low overhead and operational productivity

- In 2019, we undertook an effort to increase our capital efficiency by (i) acquiring acreage that we believe will result in higher rate of return wells, (ii) reducing our overhead costs and (iii) increasing operational productivity through, among other things, spacing and completions design. We plan to continue to focus on maximizing capital efficiency in 2020.

Continue to grow our Permian-Midland Basin position

- As we continue to grow while focusing on areas with higher oil content and develop our existing Permian-Midland Basin acreage position, we believe that additional acreage may be beneficial as consolidation and increased scale may lead to increased operational and corporate efficiencies along with increased inventory of wells that we expect to produce a higher percentage of oil than our established acreage.

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/or further accessing the capital markets.

Proactively manage risk to limit downside

- We actively attempt to limit our business and operating risks by focusing on safe and environmentally sound work practices, meeting all regulatory requirements, reliable operations execution and contingency planning, rigorous supply chain management and cost control processes, flexibility in our financial profile, operational efficiencies, hedging, controlling costs and developing oil and natural gas takeaway capacity with multiple delivery points.

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

- During 2019, 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.

Use our existing 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 established Permian-Midland Basin acreage position. Because of the value we ascribe to this infrastructure, we will continue to utilize it to supplement 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

- As of December 31, 2019, we have 133,512 net acres in the Permian-Midland Basin area that are largely contiguous with a high average working interest percentage (average working interest of 97% in Laredo-operated active productive wells and 89% in all wells in which Laredo has an interest), are 85% 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.

Significant cash flow from existing operations with no near-term debt maturities

- Our Permian-Midland Basin acreage has 1,251 net producing wells as of December 31, 2019. That current base provides us with a significant amount of cash flow and such wells require less additional capital to maintain. With such cash flow we can fund drilling on acreage that we believe will result in higher oil producing wells. In addition, we have few on-going drilling requirements to keep our Permian-Midland Basin acreage from lease expirations, which further strengthens our flexibility to use cash flow from operations in a manner we see as most efficient.

- We recently issued two series of senior unsecured notes and used the proceeds therefrom to, among other things, repay our then outstanding senior unsecured notes, which we expect to be completed on March 15, 2020, all as described below. As a result, the maturity dates on our new senior unsecured notes were extended to 2025 and 2028. We believe that this extension in the date of maturity provides us with financial flexibility to execute on our strategy.

Significant operational control

- We operated wells that represent 99.8% of the economic value of our proved developed oil, NGL and natural gas reserves as of December 31, 2019, 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.

Low cost drilling & completions and operating expenses

- We have successfully operated in the Permian-Midland Basin for over a decade. We have very experienced and capable employees in all areas of our operations, including environmental & safety, drilling, completions, facilities, production, mid-stream and supply chain management. In 2019, we delivered low well costs and operating costs as well as delivered production above guidance for all four quarters as a result of significant operational efficiencies.

Our production corridors, owned oil, gas and water pipeline infrastructure and facilities and contracted third-party oil, gas and water infrastructure enable us to more efficiently, safely and economically develop our acreage

- 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 reuse and disposal of produced water is one of the most challenging aspects of horizontal drilling in the Permian Basin. Our water recycle facilities, together with our integrated owned water pipeline infrastructure and contracted third-party water pipeline infrastructure 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 our flowback and produced water.

Extensive infrastructure in place

- We own and operate more than 340 miles of pipeline in our crude oil gathering, natural gas gathering, fuel gas and natural gas lift distribution systems and produced water gathering and fresh and recycled water distribution systems in the Permian Basin as of December 31, 2019. These systems and pipelines, in conjunction with contracted third-party pipelines, provide safe operational practices, greater operational efficiency including minimizing natural gas disruptions and fluid spills, capital and cost savings and potentially better market pricing for our production and enable us to coordinate our activities to connect our wells to market upon completion with minimal delays.

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, our founder and former Chief Executive Officer 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.

Our extensive Permian technical database

- Our multidisciplinary 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

We do not have any other properties in addition to our Permian-Midland Basin acreage.

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 has been prepared by Ryder Scott, our independent reserve engineers, in accordance with the rules and regulations of the SEC applicable to the reporting dates presented.

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") without giving effect to our commodity derivative transactions. 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:

	December 31, 2019	December 31, 2018
Benchmark Prices:		
Oil ($/Bbl)	$ 52.19	$ 62.04
NGL ($/Bbl)(1)	$ 21.14	$ 31.46
Natural gas ($/MMBtu)	$ 0.87	$ 1.76
Realized Prices:		
Oil ($/Bbl)	$ 52.12	$ 59.29
NGL ($/Bbl)	$ 12.21	$ 21.42
Natural gas ($/Mcf)	$ 0.53	$ 1.38

(1) Based on our average composite NGL barrel.

Our net proved reserves were estimated at 293,377 MBOE on a three-stream basis as of December 31, 2019, of which 83% are classified as proved developed reserves and 27% are attributable to oil reserves.

Our estimated proved reserves as of December 31, 2019 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 the dates presented.

	December 31, 2019	December 31, 2018
Proved developed producing:		
Oil (MBbl)	52,711	55,893
NGL (MBbl)	90,861	79,241
Natural gas (MMcf)	600,334	491,828
Total proved developed producing (MBOE)	243,628	217,105
Proved undeveloped:		
Oil (MBbl)	25,928	6,001
NGL (MBbl)	11,337	7,406
Natural gas (MMcf)	74,903	45,928
Total proved undeveloped (MBOE)	49,749	21,062
Estimated proved reserves:		
Oil (MBbl)	78,639	61,894
NGL (MBbl)	102,198	86,647
Natural gas (MMcf)	675,237	537,756
Total estimated proved reserves (MBOE)	293,377	238,167
Percent developed	83%	91%

Technology used to establish proved reserves

Under SEC rules, proved reserves are those quantities of oil, NGL and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible within five years from a given date forward from known reservoirs, and under existing economic conditions, operating methods and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil, NGL and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

To establish reasonable certainty with respect to our estimated proved reserves, our internal reserve engineers and Ryder Scott, our independent reserve engineers, employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, open-hole logs, core analyses, geologic maps, available downhole and production data and seismic data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves, 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.

In order to maximize operational flexibility through the commodity price declines experienced during 2014 through 2016, we reduced the portion of reserves categorized as "proved undeveloped" or "PUD." Beginning in 2016, we adjusted our five-year SEC PUD booking methodology to approximately one year of activity. This allowed us to emphasize operations on our most economic investments and maintain conservative assurance that all PUD locations would be converted despite commodity price volatility. In light of commodity price volatility, we have hedged the majority of our oil for 2020, we have increased our PUD reserves to approximately two years of drilling inventory. In 2019, we acquired two new development areas, and in order to align with our commitment to develop this acreage, the majority of our added proved undeveloped reserves are in these areas.

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 our insight gained as we drill and collect data across our acreage. We converted all 20 PUD locations we booked as of December 31, 2018 into proved producing locations in 2019. For 2020, we have increased our PUD count to 109 locations, which represent those that we have a high degree of confidence will be developed and have made a specific capital commitment to drill within a two year time frame. This strategy maintains our flexibility to add new PUD locations and convert other locations to proved developed reserves as we 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, 2019 and 2018 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 Planning and Business Development is the technical person primarily responsible for overseeing the preparation of our reserve estimates. He has more than 30 years of practical experience, with 29 years of this experience being in the estimation and evaluation of reserves. He has a Bachelors and Masters of Science in Petroleum Engineering from Texas A&M University. Our Vice President of Planning and Business Development reports to our President and Chief Executive Officer. 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 increased from 21,062 MBOE as of December 31, 2018 to 49,749 MBOE as of December 31, 2019. We estimate that we incurred $141.3 million of costs to convert 21,062 MBOE of proved undeveloped reserves from 20 locations into proved developed reserves in 2019. New proved undeveloped reserves of 49,749 MBOE were added during the year from 2 Cline, 19 Spraberry and 88 new horizontal Wolfcamp locations. 29,082 MBOE were added in our new acreage position in Howard County, Texas, 5,217 MBOE were added in our new acreage position in western Glasscock County, Texas and 15,450 MBOE were added in our established acreage. A final investment decision has been made on these 109 locations, and they are scheduled to be drilled and completed in 2020 to 2022.

Estimated total future development and abandonment costs related to the development of proved undeveloped reserves as shown in our December 31, 2019 reserve report are $540.8 million. Based on this report and our PUD booking methodology, the capital estimated to be spent in 2020 to develop the proved undeveloped reserves is $271.4 million, $207.9 million for 2021, $54.8 million for 2022 and $0 for each of 2023 and 2024. 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 and completed in 2020 to 2022. 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, drilling and production results, technology, acreage position and availability and other economic and regulatory factors may lead to changes in development plans.

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Sales volumes, revenues, prices and costs and expenses history

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

	Years ended December 31,			2019 compared to 2018	
(unaudited)	**2019**	**2018**	**2017**	**Change (#)**	**Change (%)**
Sales volumes:					
Oil (MBbl)	10,376	10,175	9,475	201	2 %
NGL (MBbl)	9,118	7,259	5,800	1,859	26 %
Natural gas (MMcf)	60,169	44,680	35,972	15,489	35 %
Oil equivalents (MBOE)(1)(2)	29,522	24,881	21,270	4,641	19 %
Average daily oil equivalent sales volumes (BOE/D)(2)	80,883	68,168	58,273	12,715	19 %
Average daily oil sales volumes (Bbl/D)(2)	28,429	27,878	25,958	551	2 %
Sales revenues (in thousands):					
Oil	$ 572,918	$ 605,197	$ 445,012	$ (32,279)	(5)%
NGL	$ 100,330	$ 149,843	$ 101,438	$ (49,513)	(33)%
Natural gas	$ 33,300	$ 53,490	$ 75,057	$ (20,190)	(38)%
Average sales prices(2):					
Oil ($/Bbl)(3)	$ 55.21	$ 59.48	$ 46.97	$ (4.27)	(7)%
NGL ($/Bbl)(3)	$ 11.00	$ 20.64	$ 17.49	$ (9.64)	(47)%
Natural gas ($/Mcf)(3)	$ 0.55	$ 1.20	$ 2.09	$ (0.65)	(54)%
Average sales price ($/BOE)(3)	$ 23.93	$ 32.50	$ 29.22	$ (8.57)	(26)%
Oil, with commodity derivatives ($/Bbl)(4)	$ 54.37	$ 55.49	$ 50.45	$ (1.12)	(2)%
NGL, with commodity derivatives ($/Bbl)(4)	$ 13.61	$ 20.03	$ 16.91	$ (6.42)	(32)%
Natural gas, with commodity derivatives ($/Mcf)(4)	$ 1.05	$ 1.77	$ 2.15	$ (0.72)	(41)%
Average sales price, with commodity derivatives ($/BOE)(4)	$ 25.45	$ 31.72	$ 30.71	$ (6.27)	(20)%
Average selected costs and expenses per BOE sold(2):					
Lease operating expenses	$ 3.08	$ 3.67	$ 3.53	$ (0.59)	(16)%
Production and ad valorem taxes	$ 1.38	$ 1.99	$ 1.78	$ (0.61)	(31)%
Transportation and marketing expenses	$ 0.86	$ 0.47	$ —	$ 0.39	83 %
Midstream service expenses	$ 0.15	$ 0.12	$ 0.19	$ 0.03	25 %
General and administrative:					
Cash	$ 1.57	$ 2.40	$ 2.85	$ (0.83)	(35)%
Non-cash stock-based compensation, net(5)	$ 0.28	$ 1.46	$ 1.68	$ (1.18)	(81)%
Depletion, depreciation and amortization	$ 9.00	$ 8.55	$ 7.45	$ 0.45	5 %

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

(2) The numbers presented in the years ended December 31, 2019, 2018 and 2017 columns are based on actual amounts and are not calculated using the rounded numbers presented in the table above.

(3) Price reflects the average of actual sales 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 delivery point.

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

(5) For the year ended December 31, 2019, non-cash stock-based compensation, net, excluding forfeitures related to our organizational restructuring on a per BOE sold basis was $0.66.

Productive wells

The following table sets forth certain information regarding productive wells in our core operating area as of December 31, 2019. All but three of our wells are classified as oil wells, all of which also produce liquids-rich natural gas and condensate. Wells are classified as oil or natural gas wells according to the predominant production stream. We also own royalty and overriding royalty interests in a small number of wells in which we do not own a working interest.

	Total producing wells				
	Gross			Net	
	Vertical	Horizontal	Total	Total	Average WI %
Permian-Midland Basin:					
Operated	794	475	1,269	1,236	97%
Non-operated	59	9	68	15	22%
Total	853	484	1,337	1,251	94%

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own an interest as of December 31, 2019 for our core operating area, including acreage HBP. A majority of our developed acreage is subject to liens securing our Senior Secured Credit Facility.

	Developed acres		Undeveloped acres		Total acres		%
	Gross	Net	Gross	Net	Gross	Net	HBP
Permian-Midland Basin	129,708	114,107	21,751	19,406	151,459	133,512	85%

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, 2019 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.

	Years ended December 31,							
	2020		2021		2022		2023	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian-Midland Basin	5,630	4,980	5,091	3,357	2,328	2,129	—	—

Of the total undeveloped acreage identified as potentially expiring over the next four years as of December 31, 2019, 3,799 net acres have associated PUD reserves on our reserve report as of December 31, 2019, which we anticipate drilling to hold or renewing the associated leases. These PUD reserves represent 28% of our total PUD reserves as of December 31, 2019.

Of the total undeveloped acreage identified as potentially expiring over the next four years as of December 31, 2018, 690 net acres had associated PUD reserves on our reserve report as of December 31, 2018, which all were retained by drilling in 2019.

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Drilling activity

The following table summarizes our drilling activity with respect to the number of wells completed for the periods presented. 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.

	Years ended December 31,					
	2019		2018		2017	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	59	56.2	74	71.2	62	60.7
Dry	—	—	—	—	—	—
Total development wells	59	56.2	74	71.2	62	60.7
Exploratory wells:						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total exploratory wells	—	—	—	—	—	—

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, 2019, 85% of our Permian-Midland Basin 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.

Hydraulic fracturing

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

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

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

Certain state regulations require disclosure of the components in the solutions used in hydraulic fracturing operations. Approximately 99% of the hydraulic fracturing fluids we use are made up of water and sand. The remainder of the constituents in the fracturing fluid are managed and used in accordance with applicable requirements. In accordance with Texas regulations, we report the constituents of the hydraulic fracturing fluids utilized in our well completions on FracFocus (www.fracfocus.org). Hydraulic fracture stimulation requires the use of a significant volume of water. Upon flowback of the water, we dispose of it by recycling or by discharging into the approved disposal wells. We currently do not discharge water to the surface. Based upon results of testing the performance of recycled flowback/produced water in our fracing operations, we have constructed and currently operate three water recycling 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, among other things, requiring permits and bonds for the drilling and operation of wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

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

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

Regulation of environmental and occupational health and safety matters

Our operations are subject to numerous stringent federal, state and local statutes and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment or occupational health and safety. Numerous governmental agencies, such as the EPA, issue regulations that often require difficult and costly compliance measures, the noncompliance with which carries substantial administrative, civil and criminal penalties and may result in injunctive obligations to remediate noncompliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines, govern the sourcing and disposal of water used in the drilling, completion and production process, limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier, seismically active areas and other protected areas, require some form of remedial action to prevent or mitigate pollution from current or former operations such as plugging abandoned wells or closing earthen pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of production.

Certain of these laws and regulations impose strict liability (i.e., no showing of "fault" is required) that, in some circumstances, may be joint and several. Public interest in the protection of the environment has tended to increase over time. The trend of more expansive and stringent environmental legislation and regulations applied to the oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. Changes in environmental laws and regulations occur frequently, and to the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and clean-up requirements, our business and prospects, as well as the oil and natural gas industry in general, could be materially adversely affected.

Hazardous substance and waste handling

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

The Oil Pollution Act of 1990 (the "OPA") is the primary federal law imposing oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. Under the OPA, strict, joint and several liability may be imposed on "responsible parties" for all containment and clean-up costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters and natural resource damages, resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" includes the owner or operator of an onshore facility. The OPA establishes a liability limit for onshore facilities, but these liability limits may not apply if: a spill is caused by a party's gross negligence or willful misconduct; the spill resulted from a 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 had until March 2019 to determine whether any revisions are necessary. However, in April 2019, the EPA concluded that revisions to the federal regulations for the management of oil and gas waste are not necessary at this time. 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. However, on October 22, 2019, the agencies repealed the 2015 rules. Both the 2015 rules and the 2019 repeal are subject to ongoing legal challenges. Also, on January 23, 2020, the EPA and the Corps published a final rule replacing the 2015 rules, and significantly reduced the waters subject to federal regulation under the Clean Water Act. This rule is anticipated to generate further legal challenges. Additionally, on April 23, 2019, the EPA published an interpretative statement and request for comment, clarifying that the Clean Water Act's permitting program for pollutant discharges does not apply to releases of pollutants to groundwater. 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.

Hydraulic fracturing

Hydraulic fracturing is a practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The SDWA regulates the underground injection of substances through the Underground Injection Control Program (the "UIC"). However, hydraulic fracturing is generally exempt from regulation under the UIC, and thus the process is typically regulated by state oil and gas commissions. Nevertheless, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the UIC. 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 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. 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. 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. Furthermore, on August 28, 2019, the EPA proposed amendments to the 2012 and 2016 NSPS requirements to ease regulatory burdens, including rescinding standards applicable to transmission or storage segments and eliminating methane requirements altogether. Legal challenges are anticipated and thus substantial uncertainty exists regarding the scope of NSPS requirements for oil and natural gas operations.

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.

The above 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 ensure 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. On November 4, 2019, the Trump Administration submitted its formal notification of withdrawal to the United Nations. It is not clear what steps, if any, will be taken to negotiate a new agreement, or what terms would be included in such an agreement. In response to the withdrawal 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

Certain of our operations are subject to applicable 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 certain information be provided to employees, state and local government authorities and citizens. We believe that we have measures, practices and policies in place to ensure that our operations are in substantial compliance with applicable federal OSHA and state occupational health and safety requirements.

National Environmental Policy Act

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

Endangered Species Act

The Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species or its habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act, though, in December 2017, the U.S. Fish and Wildlife Service ("USFWS") provided guidance limiting the reach of the Act. The USFWS may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development. If we were to have a portion of our leases designated as critical or suitable habitat, it could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas, which could adversely impact the value of our leases.

Summary

In summary, we believe we are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters during the years ended December 31, 2019, 2018 or 2017.

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", 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. PHMSA issued a final rule on October 1, 2019, to become effective on July 1, 2020, which, among other things, extends reporting requirements to certain hazardous liquid gathering lines; requires the inspection of pipelines in areas affected by extreme weather and natural disasters; requires integrity assessments at least once every 10 years of onshore hazardous liquid pipeline segments located outside of high consequence areas and that can accommodate in-lie inspection devices; extends the required use of leak detection systems beyond high consequence areas to all regulated, non-gathering hazardous liquid pipelines; and requires that all pipelines in or affecting high consequence areas be capable of accommodating in-line inspection tools within 20 years, unless the basic construction of the pipeline cannot be modified to permit that accommodation.

On October 1, 2019, the PHMSA issued a final rule, to become effective July 1, 2020, to increase the level of safety associated with the transportation of natural gas. This rule, among other things, addresses the following: integrity management requirements, focusing on the actions an operator must take to reconfirm the maximum allowable operating pressure of previously untested natural gas transmission pipelines and pipelines lacking certain material or operational records; the periodic assessment of pipelines in populated areas not designated as high consequence areas; the reporting of exceedances of maximum allowable operating pressure; and the consideration of seismicity as a risk factor in integrity management. In that rule, PHMSA indicated that it will be issuing two additional rules pertaining to natural gas pipelines. One will address repair criteria, requirements for inspecting pipelines following extreme events, updates to pipeline corrosion control requirements, codification of a management of change process, clarification of certain other integrity management requirements, and strengthening integrity management assessment requirements, and the other will address requirements related to gas gathering lines. PHMSA did not indicate when these two additional rules will be issued.

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

Pursuant to Section 13(r) of the Securities Exchange Act of 1934, we, Laredo, are required to disclose in our periodic reports to the SEC, whether we or any of our "affiliates" (as defined in Rule 12b-2 under the Exchange Act) knowingly engaged in certain 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. Because the SEC defines the term "affiliate" broadly, it includes any entity under common "control" with us (and the term "control" is also construed broadly by the SEC). Neither we nor any of our affiliates engaged in certain 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.

The description of the activities below has been provided to Laredo 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 Laredo; 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 Warburg Pincus had any involvement in or control over the disclosed activities, 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 the following in its next annual or quarterly SEC report:

"On September 11, 2019, EIGI's subsidiary P.D.R Solutions (U.S.) LLC, or PDR, suspended the domain name arabisc-haram.com, (the "Domain Name"), which was identified on September 10, 2019 by the Office of Foreign Assets Control ("OFAC"), as associated with Al Haram Commercial Company ("Al Haram"), a Specially Designated National ("SDN"), pursuant to 31 C.F.R. Part 594. The Domain Name was registered on November 13, 2017 through a third party domain registrar that uses PDR's platform to sell, register and manage domain names for customers of such third party domain registrar; there was no direct financial transaction between PDR and the registrant of the Domain Name. PDR debited the account of the third party domain registrar a total of USD sixty cents ($0.60) as a fee for such third party domain registrar's use of PDR's platform in connection with the Domain Name, all of which was debited prior to OFAC's designation of Al Haram. PDR reported the Domain Name to OFAC as potentially the property of an SDN subject to blocking pursuant to Executive Order 13224.

On January 24, 2020, our subsidiary MyDomain, LLC ("MyDomain") suspended the domain names FarsNews.com, FarNews.org and FarsNews.net, or the FarNews Domain Names, which are potentially associated with the Government of Iran. MyDomain’s records indicate that it collected a total of USD two-hundred sixteen dollars and eighty-four cents ($216.84) for products and services in connection with the subscriber account associated with the Farnews Domain Names since the subscriber account was migrated to our servers on or about August 10, 2012, following our acquisition of MyDomain on July 22, 2011. MyDomain reported the FarNews Domain Names to OFAC as property potentially associated with the Government of Iran subject to blocking pursuant to 31 C.F.R. §560.304."

Employees

As of December 31, 2019, we had 280 full-time employees. We also employed a total of 24 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 a corporate office in Midland.

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 and amendments to those reports, including related exhibits and supplemental schedules, filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, 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.

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. 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 and outbreak of disease;
- 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.

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.

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, concentrated geographic 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.

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.

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 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 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.

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

In addition, 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.

We may incur significant additional amounts of debt.

As of December 31, 2019, we had total long-term indebtedness of $1.18 billion. We may be able to incur substantial additional indebtedness, including secured indebtedness, in the future. The restrictions on the incurrence of additional indebtedness contained in the indentures governing our Senior Unsecured Notes and in our Senior Secured Credit Facility are subject to a number of significant qualifications and exceptions, and under certain circumstances, the amount of indebtedness that could be incurred in compliance with these restrictions could be substantial. If new debt is added to our existing debt levels, the related risks that we face would increase and may make it more difficult to satisfy our existing financial obligations. In addition, the restrictions on the incurrence of additional indebtedness contained in the indentures governing the Senior Unsecured Notes apply only to debt that constitutes indebtedness under the indentures. However, such increased debt may reduce the amount of outstanding debt allowed under the Senior Secured Credit Facility.

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.

Our 2019 positive revision of 9,049 MBOE of previously estimated quantities consisted of (i) 20,858 MBOE of positive revisions from performance of proved developed producing wells, (ii) 12,417 MBOE of negative revisions from a decrease in the Realized Prices for oil, NGL and natural gas and other changes to proved developed producing wells and (iii) 608 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, we had negative revisions of estimated quantities, primarily due to a sharp decline in commodity prices. It is possible that we 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 20.d to our consolidated financial statements included elsewhere in this Annual Report.

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

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

Our unamortized cost of evaluated oil and natural gas properties being depleted exceeded the full cost ceiling as of September 30, 2019 and December 31, 2019 and, as such, we recorded non-cash full cost ceiling impairments of $397.9 million and $222.7 million, respectively. No such impairments were recorded during the years ended December 31, 2018 and 2017. If prices remain at or below the current levels, subject to numerous factors and inherent limitations, and all other factors remain constant, we will incur an additional non-cash full cost ceiling impairment in the first quarter of 2020, which will 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.

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.

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 11, 2020 we had a borrowing base and aggregate elected commitment of $950.0 million each with $275.0 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 $950.0 million would result in increased annual interest expense of $9.5 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, a division of the McGraw-Hill Companies, 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.

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. Oil, NGL and natural gas prices continue to remain volatile. As of January 31, 2020, WTI Midland crude oil pricing and West Texas WAHA natural gas pricing are each at a discount to WTI Houston crude oil pricing and Henry Hub NYMEX natural gas pricing, respectively. Limited pipeline capacity is continuing to constrain transportation of natural gas out of the Permian Basin, and may continue to affect West Texas WAHA market natural gas pricing until further transportation capacity becomes operational or until basin-wide natural gas production decreases from its current level. We have open natural gas basis swap commodity derivatives to protect a portion of our future natural gas sales volumes from this potential future differential if greater than our basis swap transactions' fixed differentials. We are a contracted firm shipper to move oil to the U.S. Gulf Coast on the Bridgetex Pipeline and the Gray Oak Pipeline, the latter of which we began shipping on during the fourth quarter of 2019, and we plan to ship the majority of our oil to the U.S. Gulf Coast. We will continue to pursue avenues to attempt to protect our oil and natural gas value from basin differentials by securing transportation capacity, which enables us to transport and then sell our production in multiple markets, and entering into basis swap commodity 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.

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, export terminals and storage facilities owned by us or third parties. We do not control many of the trucks and other third-party facilities and pipelines 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 third parties or a significant disruption in the availability of our or third-party transportation facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil, NGL and natural gas and thereby cause a significant interruption in our operations. The oil pipelines that transport our oil to market have quality specifications, including a Reid Vapor Pressure ("RVP") specification 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 $950.0 million, which was reduced from $1.0 billion by our issuance of new senior unsecured notes in January 2020. 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 11, 2020, we had $660.3 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. In addition, we keep cash at certain banks that are not FDIC insured or such deposits that exceed the FDIC insured amount.

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.

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 and banks to meet their obligations to us may materially adversely affect our financial results.

In addition to credit risk related to derivative assets of $75.3 million from the fair values of our open commodity derivative contracts, our principal exposure to credit risk is through our (i) oil, NGL and natural gas sales ($54.7 million in receivables as of December 31, 2019), which we market to energy marketing companies, refineries and affiliates, (ii) sales of purchased oil and other products ($2.9 million in receivables as of December 31, 2019) and (iii) joint operations ($21.6 million in net receivables as of December 31, 2019). Additionally, as of December 31, 2019, we had $45.9 million in cash balances on deposit with three banks that were not insured by the FDIC. Our oil, NGL and natural gas production sales are made to a variety of purchasers, including intrastate and interstate pipelines or their marketing affiliates and independent marketing companies. The purchasers that individually accounted for 10% or more of our oil, NGL and natural gas sales for the year ended December 31, 2019 had the following %'s: 59%, 18%, 15% and 4%. Our sales of purchased oil are generally made to one to two customers. The purchasers that individually accounted for 10% or more of our sales of purchased oil for the year ended December 31, 2019 had the following %'s: 70%, 26% and 4%. 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. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. See Notes 2.e and 14 to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our accounts receivable and credit risk, respectively.

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 rig 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. If the United States were to limit or prohibit the exportation of crude oil it could create such an effect and have an adverse effect on our financial condition.

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 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 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 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 December 31, 2007, 2008, 2009, 2015, 2016 and 2019 of $6.1 million, $192.0 million, $184.5 million, $2.2 billion, $260.7 million and $342.5 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.

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. As of December 31, 2019, 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.

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;
- electronic system disruption and cyber-security threats;
- 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 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.

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, are 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. On November 4, 2019, the Trump administration submitted its formal notification of withdrawal to the United Nations. It is not clear what steps, if any, will be taken to negotiate a new agreement or what terms would be included in such an agreement. In response to the withdrawal announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

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

In addition, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Furthermore, claims have been made against certain energy companies alleging that GHG emissions from oil, NGL and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other liabilities. While we are currently not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

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

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

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

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

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

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

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

Although some of the rules necessary to implement the Dodd-Frank Act remain to be adopted, the CFTC, the SEC and the Prudential Regulators have issued many rules to implement the Dodd-Frank Act, including a rule, which we refer to as the "Mandatory Clearing Rule," requiring clearing of hedges, or swaps, that are subject to it (currently, only certain interest rate and credit default swaps, which we do not presently have), a rule, which we refer to as the "End User Exception," establishing an "end user" exception to the Mandatory Clearing Rule, a rule, which we refer to as the "Margin Rule," setting forth collateral requirements in connection with swaps that are not cleared and also an exception to the Margin Rule for end users that are not financial end users, which exception we refer to as the "Non-Financial End User Exception," and a rule, subsequently vacated by the United States District Court for the District of Columbia and remanded to the CFTC for further proceedings, imposing position limits. The CFTC has three times 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 "Latest-Proposed Position Limit Rule," with respect to which the comment period will close on April 29, 2020 unless extended and a final rule may or may not be issued. The Latest-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 Latest-Proposed Position Limit Rule, subject to the party claiming the exemption complying with the applicable filing, recordkeeping and reporting requirements of the Latest-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 Latest-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 Latest-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" and the U.S. adopted law and rules, which we call the "U.S. Resolution Stay Rules" clarifying similar rights of U.S. banking authorities with respect to banking institutions subject to their regulation, The Dodd-Frank Act, the rules which have been adopted and not vacated, and, to the extent that the Latest-Proposed Position Limit Rule is effected, such proposed rule, and the U.S. Resolution Stay Rules 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, the U.S. Resolution Stay Rules, 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, 2019, Warburg Pincus owned 21.6% 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.

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, 2019, we had federal net operating loss ("NOL") carryforwards totaling $1.9 billion and state of Oklahoma NOL carryforwards totaling $35.7 million. If we were to experience an "ownership change," as determined under Section 382 of the Internal Revenue Code, of which Oklahoma conforms to, 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 Internal Revenue 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, 2019, 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, 2019, 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, 2019, Warburg Pincus owned 21.6% 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 that it controls may compete with us for investment or business opportunities. These conflicts of interest may not be resolved in our favor.

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

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

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

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

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

Delaware law prohibits us from engaging in any business combination with any "interested stockholder," meaning generally that a stockholder who owns 15% of our stock cannot acquire us for a period of three years from the date such stockholder became an interested stockholder, unless various conditions are met, such as the approval of the transaction by our board of directors. Warburg Pincus, however, is not subject to this restriction. Provisions such as these are also not favored by various institutional investor services, which may periodically "grade" us on various factors, including stockholder rights and corporate governance policies. Certain institutional investors may have internal policies that prohibit investments in companies receiving a certain grade level from such services, and if we fail to meet such criteria, it could limit the number or type of certain investors which might otherwise be attracted to an investment in the Company, potentially negatively impacting the public float and/or market price of our common stock.

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

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

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

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

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

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

Item 3. Legal Proceedings

From time to time, we are subject to various legal proceedings arising in the ordinary course of business, including proceedings for which we may not have insurance coverage. While many of these matters involve inherent uncertainty 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.

Item 4. Mine Safety Disclosures

Not applicable.

Part II

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

Market for Registrant's Common Equity

Our common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "LPI." On February 12, 2020, the last sale price of our common stock, as reported on the NYSE, was $1.59 per share.

Holders

As of February 10, 2020, there were 36 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.

Issuer Purchases of Equity Securities

The following table summarizes purchases of common stock by Laredo:

Period	Total number of shares purchased(1)	Weighted-average price paid per share(1)	Total number of shares purchased as part of publicly announced program(2)	Maximum value that may yet be purchased under the program as of the respective period-end date(2)
October 1, 2019 - October 31, 2019	975	$ 2.26	—	$ 102,945,283
November 1, 2019 - November 30, 2019	—	$ —	—	$ 102,945,283
December 1, 2019 - December 31, 2019	—	$ —	—	$ 102,945,283
Total	975			

(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.

(2) In February 2018, our board of directors authorized a $200.0 million share repurchase program commencing in February 2018. The repurchase program expires in February 2020. Share repurchases under the share repurchase program may be made through a variety of methods, which may include open market purchases, privately negotiated transactions and block trades. The timing and actual number of shares repurchased, if any, will depend upon several factors, including market conditions, business conditions, the trading price of our common stock and the nature of other investment opportunities available to us.

Unregistered Sales of Equity Securities and Use of Proceeds

None.

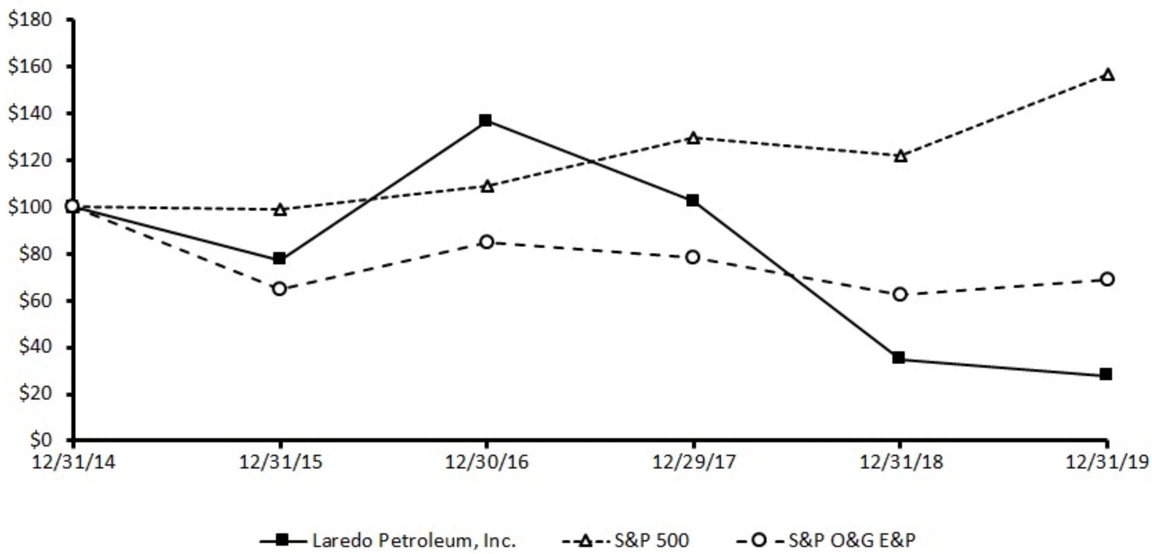
Stock Performance Graph

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

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

1. $100 was invested in our common stock, the S&P 500 and the S&P O&G E&P from December 31, 2014 to December 31, 2019; and

2. Dividends, if any, are reinvested.



Item 6. Selected Historical Financial Data

The selected historical consolidated financial data presented below is not intended to replace our consolidated financial statements. 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 ended and as of the dates indicated. The historical financial data for the years ended December 31, 2019, 2018 and 2017 and the balance sheet data as of December 31, 2019 and 2018 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, 2016 and 2015 and the balance sheet data as of December 31, 2017, 2016 and 2015 are derived from our consolidated financial statements not included in this Annual Report.

	Years ended December 31,				
(in thousands, except per share data)	**2019**	**2018**	**2017**	**2016**	**2015**
Statement of operations data:					
Total revenues	$ 837,281	$ 1,105,775	$ 822,162	$ 597,378	$ 606,640
Total costs and expenses[1]	1,245,872	757,283	572,490	685,340	3,078,154
Operating income (loss)	(408,591)	348,492	249,672	(87,962)	(2,471,514)
Total non-operating income (expense), net	63,544	(19,648)	301,102	(172,777)	84,633
Income (loss) before income taxes	(345,047)	328,844	550,774	(260,739)	(2,386,881)
Total income tax benefit (expense)	2,588	(4,249)	(1,800)	—	176,945
Net income (loss)	$ (342,459)	$ 324,595	$ 548,974	$ (260,739)	$ (2,209,936)
Net income (loss) per common share:					
Basic	$ (1.48)	$ 1.40	$ 2.30	$ (1.16)	$ (11.10)
Diluted	$ (1.48)	$ 1.39	$ 2.29	$ (1.16)	$ (11.10)

(1) Includes full cost ceiling impairment expense of $ 620.6 million, $161.1 million and $2.4 billion for the years ended December 31, 2019, 2016 and 2015, respectively.

	As of December 31,				
(in thousands)	**2019**	**2018**	**2017**	**2016**	**2015**
Balance sheet data[1]:					
Cash and cash equivalents	$ 40,857	$ 45,151	$ 112,159	$ 32,672	$ 31,154
Property and equipment, net	$ 2,000,221	$ 2,199,635	$ 1,768,385	$ 1,366,867	$ 1,200,255
Total assets	$ 2,264,437	$ 2,420,305	$ 2,023,289	$ 1,782,346	$ 1,813,287
Total current liabilities	$ 170,896	$ 200,465	$ 277,419	$ 187,945	$ 216,815
Long-term debt, net	$ 1,170,417	$ 983,636	$ 791,855	$ 1,353,909	$ 1,416,226
Total stockholders' equity	$ 841,874	$ 1,174,230	$ 765,579	$ 180,573	$ 131,447

(1) We adopted ASC 842 (defined below) on January 1, 2019 and recognized operating lease right-of-use assets and operating lease liabilities on the consolidated balance sheet for operating leases with a term greater than 12 months. See Notes 3 and 5 to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our adoption of this new standard.

(in thousands)	2019	2018	2017	2016	2015
	Years ended December 31,				
Other financial data:					
Net cash provided by operating activities	$ 475,074	$ 537,804	$ 384,914	$ 356,295	$ 315,947
Net cash provided by (used in) investing activities	$ (661,711)	$ (690,956)	$ 295,050	$ (564,402)	$ (667,507)
Net cash provided by (used in) financing activities	$ 182,343	$ 86,144	$ (600,477)	$ 209,625	$ 353,393

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 is for the year ended December 31, 2019 compared to 2018, and should be read in conjunction with our consolidated financial statements and notes thereto included elsewhere in this Annual Report. Additionally, see "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in our 2018 Annual Report on Form 10-K for discussion and analysis of our financial condition and results of operations for the year ended December 31, 2018 compared to 2017. 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 "Part I, Item 1A. Risk Factors." Unless otherwise specified, references to "average sales price" refer to average sales price excluding the effects of our derivative transactions. 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, 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 included the following for the periods presented:

	Years ended December 31,		2019 compared to 2018	
(in thousands)	**2019**	**2018**	**Change (#)**	**Change (%)**
Oil sales volumes (MBbl)	10,376	10,175	201	2 %
Oil equivalents sales volumes (MBOE)	29,522	24,881	4,641	19 %
Oil, NGL and natural gas sales(1)	$ 706,548	$ 808,530	$ (101,982)	(13)%
Net income (loss)(2)	$ (342,459)	$ 324,595	$ (667,054)	(206)%
Free Cash Flow (a non-GAAP financial measure)(3)	$ 59,687	$ (106,237)	$ 165,924	156 %
Adjusted EBITDA (a non-GAAP financial measure)(4)	$ 560,195	$ 588,862	$ (28,667)	(5)%
Proved developed and undeveloped reserves MBOE(5)	293,377	238,167	55,210	23 %

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(1) Our oil, NGL and natural gas sales decreased as a result of a 26% decrease in average sales price per BOE and were partially offset by a 19% increase in MBOE volumes sold.

(2) Our net loss for the year ended December 31, 2019 includes a non-cash full cost ceiling impairment of $620.6 million.

(3) See page 78 for a discussion and calculation of Free Cash Flow.

(4) See page 78 for a discussion and reconciliation of Adjusted EBITDA.

(5) See Note 20.d to our consolidated financial statements included elsewhere in this Annual Report for discussion of changes in our estimated proved reserve quantities of oil, NGL and natural gas.

Recent developments

Volatility in commodity prices

We review the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC on a quarterly basis. The substantial decrease in oil, NGL and natural gas prices in 2019, if continued or maintained, may require us to incur additional non-cash full cost ceiling impairments in the future, which could have a material adverse effect on our results of operations for the periods in which the impairments are incurred. See "Low commodity price impact on our fourth-quarter 2019 and potentially on our first-quarter 2020 full cost ceiling impairment test" below.

New Notes, Tender Offers and redemptions of Prior Notes

On January 24, 2020, we completed an offer and sale (the "Offering") of $600.0 million in aggregate principal amount of 9 1/2% senior unsecured notes due 2025 (the "January 2025 Notes") and $400.0 million in aggregate principal amount of 10 1/8% senior unsecured notes due 2028 (the "January 2028 Notes" and, together with the January 2025 Notes, the "New Notes"). Interest for the New Notes is payable on January 15 and July 15 of each year. The first interest payment will be made on July 15, 2020, and will consist of interest from closing to that date. The terms of the New Notes include covenants, which are in addition to but different than similar covenants in the Senior Secured Credit Facility, which limit our ability to incur indebtedness, make restricted payments, grant liens and dispose of assets.

We received net proceeds of approximately $982.0 million from the Offering, after deducting underwriting discounts and commissions and estimated offering expenses. The proceeds from the Offering have been or will be used (i) to fund Tender Offers (defined below) for any or all of our Prior Notes (defined below), (ii) to repay our $450.0 million in aggregate principal amount of 5 5/8% senior unsecured notes due 2022 (the "January 2022 Notes") and $350.0 million in aggregate principal amount of 6 1/4% senior unsecured notes due 2023 (the "March 2023 Notes" and, together with the January 2022 Notes, the "Prior Notes") that remain outstanding after the completion or termination of the Tender Offers and (iii) for general corporate purposes, including repaying a portion of the borrowings outstanding under our Senior Secured Credit Facility. We refer to the January 2022 Notes, March 2023 Notes, January 2025 Notes and January 2028 Notes collectively as the "Senior Unsecured Notes." Our subsidiaries, LMS and GCM, are guarantors of the obligations under our Senior Secured Credit Facility and Senior Unsecured Notes.

On January 6, 2020, we commenced cash tender offers and consent solicitations for any or all of our outstanding Prior Notes (collectively, the "Tender Offers"). On January 24, 2020 and February 6, 2020, we settled the Tender Offers. On January 29, 2020, we redeemed the remaining January 2022 Notes not tendered under the Tender Offers at a redemption price of 100.000% of the principal amount thereof, plus accrued and unpaid interest. On March 15, 2020, we anticipate redeeming the remaining $50.6 million of March 2023 Notes not tendered under the Tender Offers at a redemption price of 101.563% of the principal amount of the March 2023 Notes, plus accrued and unpaid interest.

Acquisitions

On June 20, 2019, we acquired 640 net acres in Reagan County, Texas for $2.9 million.

On December 6, 2019, we closed a bolt-on acquisition of 4,475 contiguous net acres and working interests in 49 producing wells in western Glasscock County, Texas, which included net production of 1,400 BOE per day, for $64.6 million, net of customary closing purchase price adjustments and subject to customary post-closing purchase price adjustments. This acquisition was financed through borrowings under the Senior Secured Credit Facility.

On December 12, 2019, we closed an acquisition of 7,360 net acres and 750 net royalty acres in Howard County, Texas for $131.7 million, net of customary closing purchase price adjustments and subject to customary post-closing purchase price adjustments. The acquisition also provides for a potential contingent payment, where the Company is required to pay $20 million, if the arithmetic average of the monthly settlement WTI NYMEX prices for each consecutive calendar month for the one-year period beginning January 1, 2020 through December 31, 2020 exceeds $60.00 per barrel. This acquisition was primarily financed through borrowings under the Senior Secured Credit Facility. The acreage is located in a region with significant offset development activity. Relevant offset production indicates first-year production that is 80% oil, primary locations on the acreage are targeting the Lower Spraberry and Upper and Middle Wolfcamp formations.

See Note 4.a included elsewhere in this Annual Report for discussion of the acquisitions of oil and natural gas properties.

On February 4, 2020, we closed a transaction for $22.5 million acquiring 1,180 net acres and divesting 80 net acres in Howard County, Texas.

Organizational restructuring

On April 2, 2019, we announced the retirement of two of our Senior Officers. Additionally, on April 8, 2019, we committed to a company-wide reorganization plan that included a workforce reduction of approximately 20%, which included an Executive Officer. Our board of directors approved the reorganization plan in response to market conditions and to reduce costs and better position us for the future. Also, in connection with the previously announced comprehensive succession planning process, effective as of October 1, 2019, Randy A. Foutch, Chairman of our board of directors, transitioned from his role as Chief Executive Officer. In connection with the retirements on April 2, 2019, the reorganization plan and the transition of Mr. Foutch, we incurred $16.4 million of one-time charges during the year ended December 31, 2019. See Note 18 to our consolidated financial statements included elsewhere in this Annual Report for discussion of the organizational restructuring.

Core area of operations

The oil and liquids-rich Permian Basin is characterized by multiple target horizons, extensive production histories, long-lived reserves, high drilling success rates and high initial production rates. As of December 31, 2019, we had assembled 133,512 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 commodity 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."

Our reserves as of December 31, 2019 and December 31, 2018 are reported in three streams: oil, NGL and natural gas. The Realized Prices utilized to value our proved reserves as of December 31, 2019 and December 31, 2018, were $52.12 per Bbl for oil, $12.21 per Bbl for NGL and $0.53 per Mcf for natural gas, and $59.29 per Bbl for oil, $21.42 per Bbl for NGL and $1.38 per Mcf for natural gas, respectively. The Realized Prices used to estimate proved reserves do not include derivative transactions. The unamortized cost of evaluated oil and natural gas properties being depleted exceeded the full cost ceiling as of September 30, 2019 and December 31, 2019 and, as such, we recorded non-cash full cost ceiling impairments of $397.9 million and $222.7 million at such dates, respectively. No such impairments were recorded during the year ended December 31, 2018. As more specifically addressed in "Low commodity price impact on our fourth-quarter 2019 and potentially on our first-quarter 2020 full cost ceiling impairment test" below, if prices remain at or below the current levels, subject to numerous factors and inherent limitations, and all other factors remain constant, we will incur an additional non-cash full cost ceiling impairment in the first quarter of 2020, which will 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, inventory 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 than originally anticipated and the decline curves may be 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.

The following table presents our depletion expense for our evaluated oil and natural gas properties per BOE sold for the periods presented:

	Years ended December 31,	
	2019	2018
Depletion expense per BOE sold	$ 8.50	$ 7.90

Low commodity price impact on our fourth-quarter 2019 and potentially on our first-quarter 2020 full cost ceiling impairment test

Our results of operations are heavily influenced by oil, NGL and natural gas prices, which remain at low levels. Oil, NGL and natural gas price fluctuations are caused by changes in global and regional supply and demand, market uncertainty, economic conditions and a variety of additional factors. Since the inception of our oil and natural gas activities, 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 use the full cost method of accounting for our oil and natural gas properties, with the full cost ceiling, as defined by the SEC, based principally on the estimated future net revenues from our proved oil and natural gas properties discounted at 10% under required SEC guidelines for pricing methodology. In the event the unamortized cost, or net book value, of evaluated oil and natural gas properties being depleted exceeds the full cost ceiling, the excess is charged to expense in the period such excess occurs. Once incurred, a write-down of evaluated oil and natural gas properties is not reversible.

The net book value of our evaluated oil and natural gas properties exceeded the full cost ceiling as of September 30, 2019 and December 31, 2019. As such, we recorded third-quarter and fourth-quarter 2019 non-cash full cost ceiling impairments of $397.9 million and $222.7 million, respectively. We did not record any similar impairments for the years ended December 31, 2018 or 2017, but did record non-cash full cost ceiling impairments of $161.1 million and $2.4 billion for the years ended December 31, 2016 and 2015, respectively.

If prices remain at or below the current levels, subject to numerous factors and inherent limitations, and all other factors remain constant, we will incur an additional non-cash full cost ceiling impairment in the first quarter of 2020, 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 completions 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-level 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) revisions to production curves based on additional data and (ix) the inherent significant volatility in the commodity prices for oil, NGL and natural gas.

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 proved reserves. Changes in circumstance, including commodity pricing, economic factors and the other uncertainties described above may lead to changes in our development plans.

Below is 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 2020 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.

Our hypothetical first-quarter 2020 full cost ceiling calculation has been prepared by substituting (i) $52.64 per Bbl for oil, (ii) $10.78 per Bbl for NGL and (iii) $0.27 per Mcf for natural gas (collectively, the "Pro Forma First-Quarter Prices") for the respective Realized Prices as of December 31, 2019. All other inputs and assumptions have been held constant. Accordingly, this estimation strictly isolates the estimated impact of low commodity prices on the first-quarter 2020 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, 2020 and holding the February 1, 2020 prices 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, 2019 proved reserve estimates, the implied first-quarter 2020 impairment would be $117 million. We believe that substituting these prices into our December 31, 2019 proved reserve estimates may help provide users with an understanding of the potential impact on our first-quarter 2020 full cost ceiling test.

See Note 6.a to our consolidated financial statements included elsewhere in this Annual Report for prices used to value our reserves and additional discussion of our full cost ceiling impairment for the year ended December 31, 2019. See "Part I, 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."

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 oil production to the U.S. Gulf Coast market.

Midstream service expenses

These are costs incurred to operate and maintain our (i) integrated 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.

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 payout of the number of shares of common stock to be delivered on the payment date for the performance period with expense adjusted at each reporting period. See Note 8.b to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our stock-based compensation.

Depletion, depreciation and amortization ("DD&A")

Under the full cost method of accounting for our oil and natural gas properties, all acquisition, exploration and development costs, including certain related employee costs incurred for the purpose of acquiring, exploring for or developing oil and natural gas properties, are capitalized and once evaluated, are depleted on a composite unit-of-production method based on estimates of proved oil, NGL and natural gas reserves. The depletion base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values. We exclude unevaluated property acquisition costs and exploration costs from the depletion calculation until it is determined whether or not proved reserves can be assigned to the properties. We calculate depreciation on our midstream service assets and other fixed assets using the straight-line method based on estimated useful lives of the assets or, in the case of leasehold improvements, 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

The full cost ceiling is based principally on the estimated future net revenues from proved oil, NGL and natural gas reserves discounted at 10%. The Realized Prices are utilized to calculate the discounted future net revenues in the full cost ceiling calculation. In the event the unamortized cost of evaluated oil and natural gas properties being depleted exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period such excess occurs. Once incurred, a write-down of oil and natural gas properties is not reversible. With the continuing volatility in commodity prices, we may incur additional write-downs on our evaluated 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. All inventory is carried at the lower of cost or net realizable value ("NRV"), with cost determined using the weighted-average cost method. See Notes 2.j, 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, 2019, 2018 and 2017 and firm transportation payments on excess pipeline capacity and other contractual penalties for the year ended December 31, 2017. See Notes 2.l and 15.c 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 on derivatives, net

Due to the inherent volatility in oil, NGL and natural gas prices and differences in the prices of oil, NGL and natural gas between where we produce and where we sell such commodities, we engage in commodity derivative transactions to hedge price risk associated with a portion of our anticipated sales volumes during the years ended December 31, 2019, 2018 and 2017. By removing a portion of the price volatility associated with future sales volumes, we expect to mitigate, but not eliminate, the potential effects of variability in cash flows from operations. Additionally, we utilized a contingent consideration derivative in the acquisition of evaluated and unevaluated oil and natural gas properties during the year ended December 31, 2019, which provides for a potential contingent payment by us. The gain on derivatives, net, includes the recognition of gains and losses resulting from (i) new, matured and early-terminated 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, (ii) settlements received or paid for matured derivatives based on the settlement prices of our matured derivatives compared to the prices specified in the derivative contracts and (iii) the changes in fair value of the contingent consideration derivative. 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 commodity 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.

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 Notes 4.d and 13.a 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.d and 13.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 Notes 7.c and 19.a to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding the redemption of our May 2022 Notes and the subsequent events related to our Senior Unsecured Notes and Senior Secured Credit Facility, respectively.

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.

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 5.b to our consolidated financials statements included elsewhere in this Annual Report for additional information regarding our sublease income.

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 carryforwards. 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 carryforwards. Such consideration includes (i) our earnings history, (ii) our ability to recover net operating loss carryforwards, (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.

Results of operations

Revenues

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 U.S. 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 fluctuate and vary due to oil throughput fees and the level of services provided to third parties for (i) integrated oil and natural gas gathering and transportation systems and related facilities, (ii) natural gas lift, rig fuel and centralized compression infrastructure and (iii) water storage, recycling and transportation infrastructure. See Notes 2.o and 13.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:

	Years ended December 31,		2019 compared to 2018	
	2019	2018	Change (#)	Change (%)
Oil sales	68%	55%	13 %	24 %
NGL sales	12%	13%	(1)%	(8)%
Natural gas sales	4%	5%	(1)%	(20)%
Midstream service revenues	2%	1%	1 %	100 %
Sales of purchased oil	14%	26%	(12)%	(46)%
Total	100%	100%		

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

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

	Years ended December 31,		2019 compared to 2018	
	2019	2018	Change (#)	Change (%)
Sales volumes:				
Oil (MBbl)	10,376	10,175	201	2 %
NGL (MBbl)	9,118	7,259	1,859	26 %
Natural gas (MMcf)	60,169	44,680	15,489	35 %
Oil equivalents (MBOE)[1][2]	29,522	24,881	4,641	19 %
Average daily oil equivalent sales volumes (BOE/D)[2]	80,883	68,168	12,715	19 %
Average daily oil sales volumes (Bbl/D)[2]	28,429	27,878	551	2 %
Sales revenues (in thousands):				
Oil	$ 572,918	$ 605,197	$ (32,279)	(5)%
NGL	100,330	149,843	(49,513)	(33)%
Natural gas	33,300	53,490	(20,190)	(38)%
Total oil, NGL and natural gas sales revenues	$ 706,548	$ 808,530	$ (101,982)	(13)%
Average sales prices[2]:				
Oil ($/Bbl)[3]	$ 55.21	$ 59.48	$ (4.27)	(7)%
NGL ($/Bbl)[3]	$ 11.00	$ 20.64	$ (9.64)	(47)%
Natural gas ($/Mcf)[3]	$ 0.55	$ 1.20	$ (0.65)	(54)%
Average sales price ($/BOE)[3]	$ 23.93	$ 32.50	$ (8.57)	(26)%
Oil, with commodity derivatives ($/Bbl)[4]	$ 54.37	$ 55.49	$ (1.12)	(2)%
NGL, with commodity derivatives ($/Bbl)[4]	$ 13.61	$ 20.03	$ (6.42)	(32)%
Natural gas, with commodity derivatives ($/Mcf)[4]	$ 1.05	$ 1.77	$ (0.72)	(41)%
Average sales price, with commodity derivatives ($/BOE)[4]	$ 25.45	$ 31.72	$ (6.27)	(20)%

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

(2) The numbers presented in the years ended December 31, 2019 and 2018 columns are based on actual amounts and are not calculated using the rounded numbers presented in the table above or the table below.

(3) Price reflects the average of actual sales 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 delivery point.

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

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

	Years ended December 31,		2019 compared to 2018	
(in thousands)	**2019**	**2018**	**Change ($)**	**Change (%)**
Settlements received (paid) for matured commodity derivatives:				
Oil	$ 9,539	$ (18,631)	$ 28,170	151%
NGL	23,749	(4,466)	28,215	632%
Natural gas	29,933	29,187	746	3%
Total	$ 63,221	$ 6,090	$ 57,131	938%
Premiums paid previously or upon settlement attributable to commodity derivatives that matured during the respective period:				
Oil	$ (18,323)	$ (21,890)	$ 3,567	16%
Natural gas	—	(3,385)	3,385	100%
Total	$ (18,323)	$ (25,275)	$ 6,952	28%

Changes in average sales prices without commodity derivatives and sales volumes caused the following changes to our oil, NGL and natural gas revenues between the years ended December 31, 2019 and 2018:

(in thousands)	**Oil**	**NGL**	**Natural gas**	**Total net effect of change**
2018 Revenues	$ 605,197	$ 149,843	$ 53,490	$ 808,530
Effect of changes in average sales prices	(44,234)	(87,877)	(38,733)	(170,844)
Effect of changes in sales volumes	11,955	38,364	18,543	68,862
2019 Revenues	$ 572,918	$ 100,330	$ 33,300	$ 706,548
Change ($)	$ (32,279)	$ (49,513)	$ (20,190)	$ (101,982)
Change (%)	(5)%	(33)%	(38)%	(13)%

Oil sales revenue

Our oil sales revenue is a function of oil production volumes sold and average oil sales prices received for those volumes. The decrease in oil sales revenue for the year ended December 31, 2019 compared to 2018, is due to a 7% decrease in average oil sales prices and was partially offset by a 2% increase in oil sales volumes.

NGL sales revenue

Our NGL sales revenue is a function of NGL production volumes sold and average NGL sales prices received for those volumes. The decrease in NGL sales revenue for the year ended December 31, 2019 compared to 2018, is due to a 47% decrease in average NGL sales prices and was partially offset by a 26% increase in NGL sales volumes. NGL prices have significantly declined in 2019.

Natural gas sales revenue

Our natural gas sales revenue is a function of natural gas production volumes sold and average natural gas sales prices received for those volumes. The decrease in natural gas sales revenue for the year ended December 31, 2019 compared to 2018, is due to a 54% decrease in average natural gas sales prices and was partially offset by a 35% increase in natural gas sales volumes.

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

	Years ended December 31,		2019 compared to 2018	
(in thousands)	**2019**	**2018**	**Change ($)**	**Change (%)**
Midstream service revenues	$ 11,928	$ 8,987	$ 2,941	33 %
Sales of purchased oil	$ 118,805	$ 288,258	$ (169,453)	(59)%

Midstream service revenues

Our midstream service revenues increased for the year ended December 31, 2019 compared to 2018, mainly due to increases in water service and oil throughput revenues. These revenues may fluctuate and 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 volumes and prices of purchased oil sold to customers and are offset by the volumes and costs of purchased oil. Sales of purchased oil decreased for the year ended December 31, 2019 compared to 2018. This change is due to an unusual increase in volumes of purchased oil in the second quarter of 2018, compared to all other quarters in 2018 and for all quarters in 2019.

We enter into purchase transactions with third parties and separate sale transactions. 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

Costs and expenses and average costs and expenses per BOE sold

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

	Years ended December 31,		2019 compared to 2018	
(in thousands except for per BOE sold data)	**2019**	**2018**	**Change ($)**	**Change (%)**
Costs and expenses:				
Lease operating expenses	$ 90,786	$ 91,289	$ (503)	(1)%
Production and ad valorem taxes	40,712	49,457	(8,745)	(18)%
Transportation and marketing expenses	25,397	11,704	13,693	117 %
Midstream service expenses	4,486	2,872	1,614	56 %
Costs of purchased oil	122,638	288,674	(166,036)	(58)%
General and administrative:				
Cash	46,439	59,742	(13,303)	(22)%
Non-cash stock-based compensation, net(1)	8,290	36,396	(28,106)	(77)%
Organizational restructuring expenses	16,371	—	16,371	100 %
Depletion, depreciation and amortization	265,746	212,677	53,069	25 %
Impairment expense	620,889	—	620,889	100 %
Other operating expenses	4,118	4,472	(354)	(8)%
Total costs and expenses	$ 1,245,872	$ 757,283	$ 488,589	65 %
Average selected costs and expenses per BOE sold(2):				
Lease operating expenses	$ 3.08	$ 3.67	$ (0.59)	(16)%
Production and ad valorem taxes	1.38	1.99	(0.61)	(31)%
Transportation and marketing expenses	0.86	0.47	0.39	83 %
Midstream service expenses	0.15	0.12	0.03	25 %
General and administrative:				
Cash	1.57	2.40	(0.83)	(35)%
Non-cash stock-based compensation, net(1)	0.28	1.46	(1.18)	(81)%
Depletion, depreciation and amortization	9.00	8.55	0.45	5 %
Total selected costs and expenses	$ 16.32	$ 18.66	$ (2.34)	(13)%

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(1) For the year ended December 31, 2019, non-cash stock-based compensation, net, excluding forfeitures related to our organizational restructuring, was $19.4 million and on a per BOE sold basis was $0.66.

(2) Average costs and expenses per BOE sold presented in the years ended December 31, 2019 and 2018 columns 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 ("LOE")

LOE, which includes workover expenses, and LOE per BOE sold both decreased for the year ended December 31, 2019 compared to 2018. We continue to focus on economic efficiencies associated with the usage and procurement of products and services related to LOE.

Production and ad valorem taxes

Production and ad valorem taxes decreased for the year ended December 31, 2019 compared to 2018. This decrease is partially attributable to a $4.5 million production tax refund, related to additional marketing costs claimed for fiscal years 2013 through 2016, recorded during the year ended December 31, 2019.

Transportation and marketing expenses

Transportation and marketing expenses increased for the year ended December 31, 2019 compared to 2018. In July 2018, we began recognizing transportation and marketing expenses incurred for the delivery of produced oil to a customer in the U.S. Gulf Coast market via the Bridgetex pipeline. In addition, during the fourth quarter of 2019, we began recognizing transportation and marketing expenses incurred for the delivery of produced oil to the U.S. Gulf Coast market via the Gray Oak pipeline. In 2020, we plan to ship the majority of our produced oil to the U.S. Gulf Coast.

Midstream service expenses

Midstream service expenses increased for the year ended December 31, 2019 compared to 2018. This change is due to an increase in water service costs, which corresponds to a similar increase in water service revenue included in midstream service revenues during the same period.

Costs of purchased oil

Costs of purchased oil decreased for the year ended December 31, 2019 compared to 2018. This change is due to an unusual increase in volumes of purchased oil in the second quarter of 2018, compared to all other quarters in 2018 and for all quarters in 2019. We are a firm shipper on both the Bridgetex and Gray Oak pipelines and from time to time may utilize purchased oil to fulfill all or a portion of our commitments.

General and administrative ("G&A")

Total G&A decreased for the year ended December 31, 2019 compared to 2018. This change includes decreases in cash G&A of $13.3 million, or 22%, and in stock-based compensation, net of $28.1 million, or 77%, and is a result of our measures taken during 2019 to align our cost structure with operational activity. The decrease in stock-based compensation, net is due to the forfeitures related to the transition of Randy A. Foutch from his role as Chief Executive Officer and our organizational restructuring. All stock-based compensation awards held by Mr. Foutch and by officers and employees who were affected by the organizational restructuring were recorded as reversals to stock-based compensation, net of $11.2 million during the year ended December 31, 2019. See Notes 8.b and 18 to our consolidated financial statements included elsewhere in this Annual Report for information regarding our stock-based compensation and organizational restructuring, respectively.

Organizational restructuring expenses

Organizational restructuring expenses for the year ended December 31, 2019 relate to (i) the retirement of two of our Senior Officers, (ii) the reorganization plan, which included a workforce reduction, implemented in response to recent market conditions and to reduce costs and better position ourselves for the future and (iii) our announcement, in connection with the previously announced comprehensive succession planning process, that, effective as of October 1, 2019, Randy A. Foutch, Chairman of our board of directors, transitioned from his role as Chief Executive Officer. We incurred $16.4 million of one-time charges during the year ended December 31, 2019, comprising of compensation, taxes, professional fees, outplacement and insurance-related expenses. No additional organizational restructuring expenses are expected to be incurred. See Note 18 to our consolidated financial statements included elsewhere in this Annual Report for further discussion of the organizational restructuring.

Depletion, depreciation and amortization ("DD&A")

The following table presents the components of our DD&A for the periods presented:

	Years ended December 31,		2019 compared to 2018	
(in thousands)	**2019**	**2018**	**Change ($)**	**Change (%)**
Depletion of evaluated oil and natural gas properties	$ 250,857	$ 196,458	$ 54,399	28 %
Depreciation of midstream service assets	10,206	10,144	62	1 %
Depreciation and amortization of other fixed assets	4,683	6,075	(1,392)	(23)%
Total DD&A	$ 265,746	$ 212,677	$ 53,069	25 %

DD&A increased for the year ended December 31, 2019 compared to 2018. This increase is mainly due to (i) the previous reduction in our December 31, 2018 proved reserves volumes, (ii) an increase in the depletion base and (iii) an increase in production volumes sold. Depletion expense per BOE sold increased by $0.60, or 8%, for the year ended December 31, 2019 compared to 2018. For further discussion of our depletion per BOE see Note 6 to our consolidated financial statements included elsewhere in this Annual Report and "—Pricing and reserves."

Depreciation and amortization of other fixed assets decreased mainly due to the sale of our corporate aircraft and hangar during the year ended December 31, 2019.

Impairment expense

Our net book value of evaluated oil and natural gas properties exceeded the full cost ceiling as of September 30, 2019 and December 31, 2019 and, as a result, we recorded a full cost ceiling impairment of $620.6 million for the year ended December 31, 2019. There were no full cost ceiling impairments for the year ended December 31, 2018. With the continuing volatility in commodity prices, we may incur additional write-downs on our oil and natural gas properties. For further discussion of our full cost ceiling impairment calculation, see Note 6.a to our consolidated financial statements included elsewhere in this Annual Report and "—Pricing and reserves."

During the year ended December 31, 2019, we reduced materials and supplies inventory by $0.3 million in order to reflect the balance at lower of cost or NRV. There were no comparable inventory impairments during the year ended December 31, 2018. For further discussion of long-lived assets and inventory impairment accounting policies, see Notes 2.j and 10.b 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), net for the periods presented:

	Years ended December 31,		2019 compared to 2018	
(in thousands)	2019	2018	Change ($)	Change (%)
Gain on derivatives, net	$ 79,151	$ 42,984	$ 36,167	84 %
Interest expense	(61,547)	(57,904)	(3,643)	(6)%
Litigation settlement	42,500	—	42,500	100 %
Loss on disposal of assets, net	(248)	(5,798)	5,550	96 %
Write-off of debt issuance costs	(935)	—	(935)	(100)%
Other income, net	4,623	1,070	3,553	332 %
Total non-operating income (expense), net	$ 63,544	$ (19,648)	$ 83,192	423 %

Gain on derivatives, net

The following table presents the components of gain on derivatives, net for the periods presented:

	Years ended December 31,		2019 compared to 2018	
(in thousands)	2019	2018	Change ($)	Change (%)
Non-cash gain on derivatives	$ 30,402	$ 57,229	$ (26,827)	(47)%
Settlements received for matured derivatives, net	63,221	6,090	57,131	938 %
Settlements paid for early terminations of commodity derivatives, net	(5,409)	—	(5,409)	(100)%
Premiums paid for commodity derivatives	(9,063)	(20,335)	11,272	55 %
Total gain on derivatives, net	$ 79,151	$ 42,984	$ 36,167	84 %

Non-cash gain on derivatives, net is the result of new, matured and early-terminated 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 outstanding contracts are held constant, 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, 2019, we completed hedge restructurings by early terminating puts and collars and entering into new swaps. We paid a net termination amount of $5.4 million that included the full settlement of the deferred premiums associated with these early-terminated puts and collars. The present value of these deferred premiums, classified under Level 3 of the fair value hierarchy, upon their early termination was $7.2 million. There were no comparable hedge restructurings during the year ended December 31, 2018.

One of our acquisitions of evaluated and unevaluated oil and natural gas properties that closed during the year ended December 31, 2019 provides for a potential contingent payment. If the arithmetic average of the monthly settlement WTI NYMEX prices for each consecutive calendar month for the one-year period beginning January 1, 2020 through December 31, 2020 exceeds $60.00 per barrel, we are required to pay to the counterparty an amount equal to $20 million. This contingent consideration is accounted for as a derivative. The fair values of the contingent consideration were $6.2 million as of the acquisition date, which is recorded as part of the basis in the oil and natural gas properties acquired in the associated asset acquisition, and $7.4 million as of December 31, 2019, respectively, and we recorded a $7.4 million derivative liability as of December 31, 2019. We recognized a loss of $1.2 million during the year ended December 31, 2019, which is included in "Gain on derivatives, net" under "Non-operating income (expense)" on the consolidated statements of operations located elsewhere in this Annual Report. At each subsequent quarterly reporting period, we will remeasure the contingent consideration with the changes in fair value recognized in earnings. See Notes 4.a, 9.b and 10.a included elsewhere in this Annual Report for additional discussion of this contingent consideration.

See Notes 2.f, 4.a, 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 increased for the year ended December 31, 2019 compared to 2018, mainly due to an increase in the amount outstanding on our Senior Secured Credit Facility.

Litigation settlement

During the year ended December 31, 2019, we finalized and received a favorable settlement of $42.5 million in connection with our damage claims asserted in a previously disclosed litigation matter relating to a breach and wrongful termination of a crude oil purchase agreement. We do not anticipate the receipt of further payments in connection with this matter as this settlement constituted a full and final satisfaction of our claims. For further discussion of the litigation settlement proceeds, see Note 15.a to our consolidated financial statements included elsewhere in this Annual Report.

Loss on disposal of assets, net

Loss on disposal of assets, net, decreased for the year ended December 31, 2019 compared to 2018. From time to time, we dispose of inventory, midstream service assets and other fixed assets. The associated gain or loss recorded during the period fluctuates depending upon the volume of the assets disposed, their associated net book value and, in the case of a disposal by sale, the sale price. During the year ended December 31, 2019, as part of our efforts to reduce G&A, we sold our corporate aircraft and hangar for gains totaling $1.4 million, which partially reduced our loss on disposal of assets for the year.

Write-off of debt issuance costs

We wrote-off $0.9 million of debt issuance costs during the year ended December 31, 2019 as a result of changes in the borrowing base and aggregate elected commitment of the Senior Secured Credit Facility. There were no comparable debt issuance costs written off during the year ended December 31, 2018. See Notes 7.e and 19.c to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our debt issuance costs and the subsequent events related to our Senior Secured Credit Facility.

Income tax benefit (expense)

The following table presents income tax benefit (expense) for the periods presented:

	Years ended December 31,		2019 compared to 2018	
(in thousands)	2019	2018	Change ($)	Change (%)
Current	$ —	$ 807	$ (807)	(100)%
Deferred	2,588	(5,056)	7,644	151 %
Total income tax benefit (expense)	$ 2,588	$ (4,249)	$ 6,837	161 %

Income tax benefit for the year ended December 31, 2019 is comprised of a deferred Texas franchise tax benefit of $2.6 million. 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. We are subject to federal and state income taxes and the Texas franchise tax.

During the years ended December 31, 2019 and 2018, we determined it was more likely than not that our federal and Oklahoma deferred tax assets were not realizable through future net income. As of December 31, 2019, a total valuation allowance of $306.6 million has been recorded to offset our federal and Oklahoma net deferred tax assets, resulting in a Texas net deferred tax liability of $2.5 million. As such, the effective tax rates for our operations were 1% for the years ended December 31, 2019 and 2018. For further discussion of our income taxes, see Note 12 to our consolidated financial statements included 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 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. We continuously look for other opportunities to maximize shareholder value.

Due to the inherent volatility in oil, NGL and natural gas prices and differences in the prices of oil, NGL and natural gas between where we produce and where we sell such commodities, we engage in commodity 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 sales volumes. By removing a portion of the price volatility associated with future sales volumes, 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 19.d to our consolidated financial statements included elsewhere in this Annual Report for a summary of open commodity derivative positions as of December 31, 2019 for commodity derivatives that were entered into through February 12, 2020. 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 commodity derivative positions as of December 31, 2019 for commodity derivatives that were entered into through December 31, 2019.

We continually seek to maintain a financial profile that provides operational flexibility. As of December 31, 2019, we had cash and cash equivalents of $40.9 million and available capacity under the Senior Secured Credit Facility, after the reduction for outstanding letters of credit, of $610.3 million, resulting in total liquidity of $651.2 million. As of February 11, 2020, we had cash and cash equivalents of $67.0 million, net of expected cash to be used to redeem the remaining March 2023 Notes, and available capacity under the Senior Secured Credit Facility, after the reduction for outstanding letters of credit and a reduction in our borrowing base, of $660.3 million, resulting in total liquidity of $727.3 million.

We believe that our operating cash flows 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 any share repurchases, pay down or refinance debt or increase our planned capital expenditure budget. 2019 has been a transitional year as we have tailored our operational cadence and corporate cost structure to target a balance between capital expenditures and cash flows from operations with a goal to generate Free Cash Flow. Such efforts included aligning our personnel costs with activity levels through a reduction in force and restructuring our oil hedges, securing additional cash flow to increase activity and substantially accelerating the time frame in which we began to generate free cash flow while also growing oil production.

Cash flows

The following table presents our cash flows:

	Years ended December 31,		2019 compared to 2018	
(in thousands)	**2019**	**2018**	**Change ($)**	**Change (%)**
Net cash provided by operating activities	$ 475,074	$ 537,804	$ (62,730)	(12)%
Net cash used in investing activities	(661,711)	(690,956)	29,245	4 %
Net cash provided by financing activities	182,343	86,144	96,199	112 %
Net decrease in cash and cash equivalents	$ (4,294)	$ (67,008)	$ 62,714	94 %

Cash flows from operating activities

Net cash provided by operating activities decreased from 2018 to 2019. Notable cash changes include (i) a decrease in oil, NGL and natural gas sales revenues of $102.0 million, (ii) an increase in net changes in operating assets and liabilities of $66.6 million, (iii) an increase in settlements received for matured and early terminations of commodity derivatives, net of premiums paid, of $63.0 million and (iv) receipt for litigation settlement of $42.5 million. The decrease in oil, NGL and natural gas sales revenues is due to a 26% decrease in average sales prices per BOE and was partially offset by a 19% increase in MBOE volumes sold. See "—Results of operations" for additional discussion of changes in our oil, NGL and natural gas sales revenues.

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.

Cash flows from investing activities

Net cash used in investing activities decreased from 2018 to 2019. This is mainly attributable to a decrease in capital expenditures on oil and natural gas properties and was partially offset by an increase in acquisitions of oil and natural gas properties.

See Notes 4 and 19.b to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our acquisitions and divestitures of oil and natural gas properties and the acquisition subsequent to December 31, 2019.

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

	Years ended December 31,		2019 compared to 2018	
(in thousands)	2019	2018	Change ($)	Change (%)
Acquisitions of oil and natural gas properties, net of closing adjustments	$ (199,284)	$ (17,538)	$ (181,746)	(1,036)%
Capital expenditures:				
Oil and natural gas properties	(458,985)	(673,584)	214,599	32 %
Midstream service assets	(7,910)	(6,784)	(1,126)	(17)%
Other fixed assets	(2,433)	(7,308)	4,875	67 %
Proceeds from disposition of equity method investee, net of selling costs (see Note 4.d)	—	1,655	(1,655)	(100)%
Proceeds from dispositions of capital assets, net of selling costs	6,901	12,603	(5,702)	(45)%
Net cash used in investing activities	$ (661,711)	$ (690,956)	$ 29,245	4 %

Cash flows from financing activities

Net cash provided by financing activities increased from 2018 to 2019. This is mainly attributable to the absence of share repurchases in 2019 under our share repurchase program. 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, 2019, we had authorization remaining to repurchase $102.9 million of common stock until expiration of the program in February 2020.

See the following Notes to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our financing activities: (i) Note 7 for our debt instruments, (ii) Note 8.a for our share repurchases and (iii) Notes 19.a and 19.c for subsequent events related to our Prior Notes, New Notes and Senior Secured Credit Facility. See "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 that commenced in February 2018.

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

	Years ended December 31,		2019 compared to 2018	
(in thousands)	2019	2018	Change ($)	Change (%)
Borrowings on Senior Secured Credit Facility	$ 275,000	$ 210,000	$ 65,000	31 %
Payments on Senior Secured Credit Facility	(90,000)	(20,000)	(70,000)	(350)%
Share repurchases	—	(97,055)	97,055	100 %
Stock exchanged for tax withholding	(2,657)	(4,418)	1,761	40 %
Proceeds from exercise of stock options	—	86	(86)	(100)%
Payments for debt issuance costs	—	(2,469)	2,469	100 %
Net cash provided by financing activities	$ 182,343	$ 86,144	$ 96,199	112 %

Capital expenditure budget

Due to the increased cash flow secured from the successful execution of our WTI NYMEX hedge restructuring and litigation settlement proceeds received earlier in the year, and due to improved drilling and completions efficiencies, we adjusted our expected capital expenditures during 2019 from $365.0 million to $490.0 million, excluding non-budgeted acquisitions. Our goal was to achieve cash flow neutrality at a minimum and, therefore, our capital spending in 2019 was ultimately influenced by commodity price changes and, among other factors, changes in service costs and drilling and completions efficiencies. As a result of our substantially improved well productivity, alignment of staffing with our moderated development plan and continued efforts to drive down both our well costs and operational expenses, we generated Free Cash Flow of $59.7 million. See "—Non-GAAP financial measures" for a reconciliation of net cash provided by operating activities (GAAP) to Free Cash Flow (non-GAAP).

The following table presents the components of our costs incurred, excluding non-budgeted acquisition costs:

	Years ended December 31,		2019 compared to 2018	
(in thousands)	**2019**	**2018**	**Change ($)**	**Change (%)**
Oil and natural gas properties(1)	$ 470,455	$ 631,674	$ (161,219)	(26)%
Midstream service assets	8,655	4,618	4,037	87 %
Other fixed assets	2,470	7,322	(4,852)	(66)%
Total costs incurred, excluding non-budgeted acquisition costs	$ 481,580	$ 643,614	$ (162,034)	(25)%

(1) See Note 20.a to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our costs incurred in the exploration and development of oil and natural gas properties.

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.

Debt

We are the borrower under our Senior Secured Credit Facility and a party to the indentures governing our Senior Unsecured Notes.

Senior Secured Credit Facility

As of December 31, 2019, the Senior Secured Credit Facility had a maximum credit amount of $2.0 billion and a borrowing base and an aggregate elected commitment of $1.0 billion each, with $375.0 million outstanding and was subject to an interest rate of 3.28%. The Senior Secured Credit Facility provides for the issuance of letters of credit, limited to the lesser of total capacity or $80.0 million. As of December 31, 2019, 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.

On January 24, 2020, effective upon the closing of the Offering, the borrowing base and aggregate elected commitment under the Senior Secured Credit Facility were automatically reduced to $950.0 million each.

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, 2019, 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.

As of December 31, 2019, 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, 2019, 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.

See Note 7.d to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our Senior Secured Credit Facility.

January 2022 Notes and March 2023 Notes

The following table presents principal amounts and applicable interest rates for our outstanding Prior Notes as of December 31, 2019:

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

See Notes 7.a, 7.b and 19.a to our consolidated financial statements included elsewhere in this Annual Report for further discussion of the March 2023 Notes, January 2022 Notes and subsequent events related to these Prior Notes and to our New 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.

Obligations and commitments

The following table presents significant contractual obligations and commitments as of December 31, 2019:

(in thousands)	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
March 2023 Notes and January 2022 Notes(1)	$ 47,188	$ 531,719	$ 360,937	$ —	$ 939,844
Senior Secured Credit Facility(2)	—	—	375,000	—	375,000
Firm sale and transportation commitments(3)	67,446	107,090	87,080	61,174	322,790
Asset retirement obligations(4)	2,027	19,855	7,615	33,221	62,718
Lease commitments(5)	15,939	13,752	2,630	3,285	35,606
Commodity derivative deferred premiums(6)	477	—	—	—	477
Total	$ 133,077	$ 672,416	$ 833,262	$ 97,680	$ 1,736,435

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(1) Values presented include both our principal and interest obligations. See Notes 7.a, 7.b and 19.a to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our March 2023 Notes, January 2022 Notes and subsequent events related to these notes, respectively.

(2) The principal on our Senior Secured Credit Facility is due on April 19, 2023. This table does not include future loan advances, repayments, commitment fees or other fees on our Senior Secured Credit Facility as we cannot determine with accuracy the timing of such items. Additionally, this table does not include interest expense as it is a floating rate instrument and we cannot determine with accuracy the future interest rates to be charged. See Notes 7.d and 19.c to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our Senior Secured Credit Facility and related subsequent events, respectively.

(3) We have committed to deliver, for sale or transportation, fixed volumes of product under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. If not fulfilled, we are subject to firm transportation payments on excess pipeline capacity and other contractual penalties. See "Part I. Item 1A. Risk Factors" and Note 15.c to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our firm sale and transportation commitments.

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

(5) Amounts represent our minimum lease payments for our operating lease liabilities. We have committed to drilling rig contracts with a third party to facilitate our drilling plans. Included in the value in the table is the gross amount we are committed to pay for our drilling rig contracts. However, we will record our proportionate share based on our working interest in our consolidated financial statements as incurred. See the following Notes to our consolidated financial statements included elsewhere in this Annual Report: (i) Notes 3 and 5 for discussion of our adoption of ASC 842 on January 1, 2019 and (ii) Note 15.b for additional discussion of our drilling rig contracts.

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

Non-GAAP financial measures

The non-GAAP financial measures of Free Cash Flow and Adjusted EBITDA, as defined by us, may not be comparable to similarly titled measures and calculations used by other companies. Therefore, these non-GAAP financial measures 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 flows from operating activities. Free Cash Flow and 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.

Free Cash Flow

Free Cash Flow, a non-GAAP financial measure, does not represent funds available for future discretionary use because it excludes funds required for future debt service, capital expenditures, acquisitions, working capital, income taxes, franchise taxes and other commitments and obligations. However, our management believes Free Cash Flow is useful to management and investors in evaluating operating trends in our business that are affected by production, commodity prices, operating costs and other related factors. There are significant limitations to the use of Free Cash Flow as a measure of performance, including the lack of comparability due to the different methods of calculating Free Cash Flow reported by different companies.

The following table presents a reconciliation of net cash provided by operating activities (GAAP) to cash flows from operating activities before changes in operating assets and liabilities, net, less costs incurred, excluding non-budgeted acquisition costs, for the calculation of Free Cash Flow (non-GAAP):

	Years ended December 31	
(in thousands)	2019	2018
Net cash provided by operating activities	$ 475,074	$ 537,804
Less:		
(Increase) decrease in current assets and liabilities, net	(64,123)	1,157
Increase in noncurrent assets and liabilities, net	(2,070)	(730)
Cash flows from operating activities before changes in operating assets and liabilities, net	541,267	537,377
Less costs incurred, excluding non-budgeted acquisition costs:		
Oil and natural gas properties(1)	470,455	631,674
Midstream service assets	8,655	4,618
Other fixed assets	2,470	7,322
Total costs incurred, excluding non-budgeted acquisition costs	481,580	643,614
Free Cash Flow (non-GAAP)	$ 59,687	$ (106,237)

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(1) Includes non-cash stock-based compensation, net of $4.5 million and $7.9 million and asset retirement costs of $0.6 million and $0.7 million for the years ended December 31, 2019 and 2018, respectively.

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for non-cash stock-based compensation, net, depletion, depreciation and amortization, impairment expense, mark-to-market on derivatives, premiums paid for commodity derivatives, accretion expense, gains or losses on disposal of assets, write-off of debt issuance costs, interest expense, income taxes 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 it excludes funds 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 that 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 and the lack of comparability of results of operations to different companies due to 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.

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

	Years ended December 31,	
(in thousands, unaudited)	**2019**	**2018**
Net income (loss)	$ (342,459)	$ 324,595
Plus:		
Non-cash stock-based compensation, net	8,290	36,396
Depletion, depreciation and amortization	265,746	212,677
Impairment expense	620,889	—
Mark-to-market on derivatives:		
Gain on derivatives, net	(79,151)	(42,984)
Settlements received for matured commodity derivatives, net	63,221	6,090
Settlements paid for early terminations of commodity derivatives, net	(5,409)	—
Premiums paid for commodity derivatives	(9,063)	(20,335)
Accretion expense	4,118	4,472
Loss on disposal of assets, net	248	5,798
Write-off of debt issuance costs	935	—
Interest expense	61,547	57,904
Organizational restructuring expenses	16,371	—
Litigation settlement	(42,500)	—
Income tax (benefit) expense	(2,588)	4,249
Adjusted EBITDA	$ 560,195	$ 588,862

Critical accounting policies and estimates

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

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

There have been no material changes in our critical accounting policies and procedures during the year ended December 31, 2019. See Note 2 to our consolidated financial statements included elsewhere in this Annual Report for discussion on significant accounting policies and estimates made by management.

Method of accounting for oil and natural gas properties

The accounting for our business is subject to special accounting rules that are unique to the oil and natural gas industry. There are two allowable methods of accounting for oil and natural gas business activities: the successful efforts method and the full cost method. We use the full cost method of accounting for our oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs incurred for the purpose of acquiring, exploring for or developing oil and natural gas properties, are capitalized and depleted on a composite unit-of-production method based on proved oil, NGL and natural gas reserves. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals and other costs related to such activities. Costs, including related employee costs, associated with production and general corporate activities are expensed in the period incurred. Sales of oil and natural gas properties, whether or not being depleted currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil, NGL and natural gas. If we maintain the same level of production year over year, the depletion expense may be significantly different if our estimate of remaining reserves or future development costs changes significantly.

We exclude unevaluated property acquisition costs and exploration costs from the depletion calculation until it is determined whether or not proved reserves can be assigned to the properties. We capitalize a portion of our interest costs to unevaluated properties and is subject to depletion when proved reserves can be assigned to the associated properties. All items classified as unevaluated properties are assessed on a quarterly basis for possible impairment. The assessment includes consideration of the following factors, among others: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of proved reserves and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion.

See Notes 2.h and 6.a to our consolidated financial statements included elsewhere in this Annual Report for discussion of our significant accounting policies for oil and natural gas properties and additional discussion of our full cost method of accounting for oil and natural gas properties, respectively.

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

On an annual basis, our independent reserve engineers prepare the estimates of oil, NGL and natural gas reserves and associated future net cash flows. The SEC has defined proved reserves as the estimated quantities of oil, NGL and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The process of estimating oil, NGL and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates. If such changes are material, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material. See Notes 20.d and 20.e to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our net proved oil, NGL and natural gas reserves and standardized measure of discounted future net cash flows, respectively.

Impairment of oil and natural gas properties

We review the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC on a quarterly basis. This quarterly review is referred to as a ceiling test. The full cost ceiling is based principally on the estimated future net revenues from proved oil, NGL and natural gas reserves discounted at 10%. The SEC guidelines require companies to use the Benchmark Prices. The Benchmark Prices are then adjusted, resulting in the Realized Prices. The Realized Prices are utilized to calculate the discounted future net revenues in the full cost ceiling calculation. Significant inputs included in the calculation of discounted cash flows used in the impairment analysis include our estimate of operating and development costs, anticipated production of proved reserves and other relevant data. In the event the unamortized cost of evaluated oil and natural gas properties being depleted exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period such excess occurs. Once incurred, a write-down of evaluated oil and natural gas properties is not reversible. See Note 6.a to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our full cost ceiling impairment recorded during the year ended 2019.

Revenue recognition

Oil, NGL and natural gas revenues are generally recognized at the point in time that control of the product is transferred to the customer. Under our oil sales contracts, we sell produced or purchased oil at the delivery point specified in the contract and collect an agreed-upon index price, net of pricing differentials. The delivery point may be at the wellhead, the inlet of the purchaser's pipeline or nominated pipeline or our truck unloading facility. At the delivery point, the purchaser typically takes custody, title and risk of loss of the product and, therefore, control as defined under ASC 606 typically passes at the delivery point. We recognize revenue at the net price received when control transfers to the purchaser.

From time to time, we engage in transactions in which we sell oil at the lease and subsequently repurchase the same volume of oil from that customer at a downstream delivery point under a separate agreement ("Repurchase Agreement") for use in the sale to the final customer. The commercial reasoning for such transactions may vary. Where a Repurchase Agreement exists, we must evaluate whether the customer obtains control of the oil at the lease and therefore whether it is appropriate to recognize revenue for the lease sale. Where we have an obligation or a right to repurchase the oil, the customer does not obtain control of the oil because it is limited in its ability to direct the use of, and obtain substantially all of the remaining benefits from the oil even though it may have physical possession of the oil. If we repurchase the oil for less than the original selling price, such a transaction will be classified as a lease. If we repurchase the oil for equal to or more than the original selling price, then the transaction represents a financing arrangement unless there is only a short passage of time between the sale and repurchase, in which case any excess amount paid represents an expense associated with the sale of oil to the final customer. We recognize such repurchase expense and any transportation expenses incurred for the delivery of the oil to the final customer in the "Transportation and marketing expenses" line item in the accompanying consolidated statements of operations.

Under certain of our customer contracts, we are subject to firm transportation payments on excess pipeline capacity and other contractual penalties if we fail to deliver contractual minimum volumes to our customers. Such amounts are recorded as a reduction to the transaction price as these amounts do not represent payments to the customer for distinct goods or services and instead relate specifically to the failure to perform under the specific customer contract. Such amounts are recorded as a reduction to the transaction price when payment is determined as probable, typically when such a deficiency occurs.

Under our natural gas processing contracts, we deliver produced natural gas to a midstream processing entity at the wellhead or the inlet of the processing entity's system. The processing entity processes the natural gas, sells the resulting NGL and residue gas to third parties and pays us for the NGL and residue gas with deductions that may include gathering, compression, processing and transportation fees. In these scenarios, we evaluate whether we are the principal or the agent in the transaction. For existing contracts, we have concluded that we are the agent in the ultimate sale to the third party and the midstream processing entity is the principal and that we have transferred control of unprocessed natural gas to the midstream processing entity; therefore, we recognize revenue based on the net amount of the proceeds received from the midstream processing entity who represents our customer. If for future contracts we were to conclude that we were the principal with the ultimate third party being the customer, we would recognize revenue for those contracts on a gross basis, with gathering, compression, processing, and transportation fees presented as an expense.

Midstream service revenues are generated from oil throughput fees and 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 (collectively, "Midstream Services"), and are recognized over time as the customer benefits from these services when provided.

See Note 13 to our consolidated financial statements included elsewhere in this Annual Report for discussion of our revenue recognition.

Income taxes

As of December 31, 2019 and 2018, we had a net deferred tax liability of $2.5 million and $5.1 million, respectively.

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

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

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

During 2019, in evaluating whether it was more-likely-than-not that our deferred tax asset was recoverable from future net income, we considered all positive and negative evidence available. We will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods. See Note 12 to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our income taxes.

Asset retirement obligations ("ARO")

The ARO represents the estimated amount we will incur to plug, abandon and remediate the properties at the end of their productive lives, in accordance with applicable state laws. Asset retirement obligations associated with the retirement of tangible long-lived assets are recognized as a liability in the period in which they are incurred and become determinable. The associated asset retirement costs are part of the carrying amount of the long-lived asset. Subsequently, the asset retirement cost included in the carrying amount of the related long-lived asset is charged to expense through depletion, or for midstream service assets through depreciation. Changes in the liability due to the passage of time are recognized as an increase in the carrying amount of the liability and accretion expense.

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

We are obligated by contractual and regulatory requirements to remove certain pipeline and gathering assets and perform other remediation of the sites where such pipeline and gathering assets are located upon the retirement of those assets. However, the fair value of the asset retirement obligation cannot currently be reasonably estimated because the settlement dates are indeterminate. We will record an asset retirement obligation for pipeline and gathering assets in the periods in which settlement dates are reasonably determinable. See Note 2.l to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our asset retirement obligations.

Derivatives

Derivatives are recorded at fair value and are presented on a net basis on the "Derivatives" line items on the consolidated balance sheets as assets and/or liabilities. We present the fair value of derivatives net by counterparty where the right of offset exists. We determine the fair value of its derivatives by utilizing pricing models for substantially similar instruments. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. Our derivatives were not designated as hedges for accounting purposes. Accordingly, the changes in fair value are recognized on the consolidated statements of operations in "Gain on derivatives, net". Gains and losses on derivatives are included in cash flows from operating activities. See Notes 9 and 10.a to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of derivatives and the fair value measurement of derivatives, respectively.

Compensation awards

Stock-based compensation expense, net, is included in "General and administrative" on our consolidated statements of operations over the awards' vesting periods and is based on the awards' grant date fair value. We utilize the closing stock price on the grant date, less an expected forfeiture rate, to determine the fair values of service vesting restricted stock awards and a Black-Scholes pricing model to determine the fair values of service vesting restricted stock option awards. We utilize a Monte Carlo simulation prepared by an independent third party to determine the fair values, less an expected forfeiture rate, of the performance share awards with market criteria and, in prior periods, the performance unit awards. For performance share awards with performance criteria, the grant-date fair value is equal to our stock price on the grant date, less an expected forfeiture rate, and for each reporting period, the associated expense fluctuates and is adjusted based on an estimated probability of how many shares will be earned at the end of the performance period. We capitalize a portion of stock-based compensation for employees who are directly involved in the acquisition, exploration and development of its oil and natural gas properties into the full cost pool. Capitalized stock-based compensation is included in "Evaluated properties" on the consolidated balance sheets. See Note 8.b to our consolidated financial statements included elsewhere in this Annual Report for further discussion regarding the restricted stock awards, stock option awards and performance share awards.

Leases

Prior to January 1, 2019, we accounted for leases under ASC 840 and did not record any right-of-use assets or corresponding lease liabilities. Upon the adoption of ASC 842 on January 1, 2019, we recognized operating lease right-of-use assets and operating lease liabilities on the consolidated balance sheet for operating leases with a term greater than 12 months. See Note 5 for further discussion of the ASC 842 adoption impact on our consolidated financial statements.

New accounting standards

See Notes 3.a and 5.a to our consolidated financial statements included elsewhere in this Annual Report for discussion of new accounting standards and for discussion related to the adoption of ASC 842, respectively.

Inflation

Inflation in the U.S. has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2019, 2018 and 2017. Although the impact of inflation has been insignificant in recent years, it continues to be a factor in the U.S. economy and, historically, we have experienced inflationary pressure on the costs of oilfield services and equipment as drilling activity increases in the areas in which we operate.

Off-balance sheet arrangements

Currently, we do not have any off-balance sheet arrangements other than our firm sale and transportation commitments, which are described in "—Obligations and commitments." In addition, we have certain operating leases with a term less than or equal to 12 months that we have made an accounting policy election to not record on the consolidated balance sheets.

See Notes 5 and 15 to our consolidated financial statements included elsewhere in this Annual Report for additional information on our leases and commitments and contingencies, respectively.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Oil, NGL and natural gas price risk

Due to the inherent volatility in oil, NGL and natural gas prices and differences in the prices of oil, NGL and natural gas between where we produce and where we sell such commodities, we engage in commodity 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 sales volumes. By removing a portion of the price volatility associated with future sales volumes, we expect to mitigate, but not eliminate, the potential effects of variability in cash flows from operations.

Oil, NGL and natural gas prices continue to remain volatile. As of January 31, 2020, WTI Midland crude oil pricing and West Texas WAHA natural gas pricing are each at a discount to WTI Houston crude oil pricing and Henry Hub NYMEX natural gas pricing, respectively. Limited pipeline capacity is continuing to constrain transportation of natural gas out of the Permian Basin, and may continue to affect West Texas WAHA market natural gas pricing until further transportation capacity becomes operational or until basin-wide natural gas production decreases from its current level. We have open natural gas basis swap commodity derivatives to protect a portion of our future natural gas sales volumes from this potential future differential if greater than our basis swap transactions' fixed differentials. We are a contracted firm shipper to move oil to the U.S. Gulf Coast on the Bridgetex Pipeline and the Gray Oak Pipeline, the latter of which we began shipping on during the fourth quarter of 2019, and we plan to ship the majority of our oil to the U.S. Gulf Coast. We will continue to pursue avenues to attempt to protect our oil and natural gas value from basin differentials by securing transportation capacity, which enables us to transport and then sell our production in multiple markets, and entering into basis swap commodity derivatives, which provides pricing protection.

The fair values of our open derivative positions are largely determined by the relevant forward commodity price curves of the indexes associated with our open derivative positions. We had a $67.6 million net asset position from the fair values of our open derivatives as of December 31, 2019. The following table provides a sensitivity analysis of the projected incremental effect on income (loss) before income taxes of a hypothetical 10% change in the relevant forward commodity price curves of the indexes associated with our open derivative positions as of December 31, 2019:

(in thousands)	10% Increase	10% Decrease
Commodity	$ (66,494)	$ 66,383
Contingent consideration	(4,450)	4,080
Total	$ (70,944)	$ 70,463

See Notes 2.f, 9, 10.a and 19.d to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our derivatives.

Interest rate risk

Our Senior Secured Credit Facility bears interest at a floating rate and our January 2022 Notes and March 2023 Notes bear interest at fixed rates. The maturity years, outstanding balances and interest rates on our long-term debt as of December 31, 2019 were as follows:

	Maturity year	
(in millions except for interest rates)	**2022**	**2023**
Senior Secured Credit Facility(1)	$ —	$ 375.0
Floating interest rate	—%	3.276%
January 2022 Notes(2)	$ 450.0	$ —
Fixed interest rate	5.625%	—%
March 2023 Notes(2)	$ —	$ 350.0
Fixed interest rate	—%	6.250%

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(1) The Senior Secured Credit Facility matures on April 19, 2023.

(2) See Note 19.a to our consolidated financial statements included elsewhere in this Annual Report for subsequent events related to these notes.

Counterparty and customer credit risk

See "Part I, Item 3. Legal Proceedings," Notes 14 and 15 to our consolidated financial statements included elsewhere in this Annual Report for discussion of credit risk and commitments and contingencies. See Notes 2.e and 13 to our consolidated financial statements included elsewhere in this Annual Report for discussion of our accounts receivable and revenue recognition, respectively. See Notes 2.f, 9, 10.a and 19.d to our consolidated financial statements included elsewhere in this Annual Report for discussion of our commodity derivatives.

Item 8. Financial Statements and Supplementary Data

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

Management's Report on Internal Control over Financial Reporting

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

As of December 31, 2019, management assessed the effectiveness of the Company's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in the 2013 "Internal Control - Integrated Framework," issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment and those criteria, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2019.

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

Grant Thornton LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report, has issued their report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2019. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2019, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Laredo Petroleum, Inc.

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Laredo Petroleum, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2019, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2019, and our report dated February 13, 2020 expressed an unqualified opinion on those financial statements.

Basis for opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

Definition and limitations of internal control over financial reporting

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

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

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 13, 2020

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

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

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of December 31, 2019 at the reasonable assurance level.

Design and Evaluation of Internal Control Over Financial Reporting

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, our management has included a report of their assessment of the design and effectiveness of our internal controls over financial reporting as part of this Annual Report for the year ended December 31, 2019. Grant Thornton LLP, the Company's independent registered public accounting firm, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting. Management's report and the independent registered public accounting firm's attestation report are included in "Item 8. Financial Statements and Supplementary Data" in this Annual Report under the caption entitled "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm," respectively, and are incorporated herein by reference.

Changes in Internal Control over Financial Reporting

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

Item 9B. Other Information

Not applicable.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Information regarding our Code of Conduct and Business Ethics, Code of Ethics For Senior Financial Officers and Corporate Governance Guidelines for our principal executive officer and principal financial and accounting officer are described in "Item 1. Business" in this Annual Report. Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 10 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2019.

Item 11. Executive Compensation

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 11 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2019.

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

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 12 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2019.

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

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 13 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2019.

Item 14. Principal Accounting Fees and Services

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 14 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2019.

Part IV

Item 15. Exhibits, Financial Statement Schedules

(a)(1) Financial Statements

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

(a)(2) Financial Statement Schedules

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

(a)(3) Exhibits

Exhibit Number	Description
2.1	Agreement and Plan of Merger by and between Laredo Petroleum, LLC and Laredo Petroleum Holdings, Inc., dated as of December 19, 2011 (incorporated by reference to Exhibit 2.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
2.2	Membership Interest Purchase and Sale Agreement, dated as of October 1, 2017, by and among Medallion Midland Acquisition, LLC, Medallion Gathering & Processing, LLC, Laredo Midstream Services, LLC, and Medallion Midstream Holdings, LLC (incorporated by reference to Exhibit 2.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on October 30, 2017).
3.1	Amended and Restated Certificate of Incorporation of Laredo Petroleum Holdings, Inc. (incorporated by reference to Exhibit 3.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
3.2	Certificate of Ownership and Merger, dated as of December 30, 2013 (incorporated by reference to Exhibit 3.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on January 6, 2014).
3.3	Second Amended and Restated Bylaws of Laredo Petroleum, Inc. (incorporated by reference to Exhibit 3.3 of Laredo's Annual Report on Form 10-K (File No. 001-35380) filed on February 17, 2016).
4.1	Form of Common Stock Certificate (incorporated by reference to Exhibit 4.1 of Laredo's Registration Statement on Form 8-A12B/A (File No. 001-35380) filed on January 7, 2014).
4.2*	Registered Pursuant to Section 12 of the Securities Exchange Act of 1934.
4.3	Indenture, dated as of January 23, 2014, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC and Wells Fargo Bank, N.A., as trustee (incorporated by reference to Exhibit 4.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on January 24, 2014).
4.4	First Supplemental Indenture, dated as of December 3, 2014, among Laredo Petroleum, Inc., Garden City Minerals, LLC, Laredo Midstream Services, LLC and Wells Fargo Bank, N.A., as trustee (incorporated by reference to Exhibit 4.9 of Laredo's Annual Report on Form 10-K (File No. 001-35380) filed on February 26, 2015).
4.5	Indenture, dated as of March 18, 2015, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC, Garden City Minerals, LLC and Wells Fargo Bank, N.A., as trustee (incorporated by reference to Exhibit 4.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on March 24, 2015).
4.6	First Supplemental Indenture, dated as of March 18, 2015, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC, Garden City Minerals, LLC and Wells Fargo Bank, N.A., as trustee (incorporated by reference to Exhibit 4.2 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on March 24, 2015).
4.7	Second Supplemental Indenture, dated as of January 22, 2020, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC, Garden City Minerals, LLC and Wells Fargo Bank, N. A., as trustee (incorporated by reference to Exhibit 4.3 of Laredo’s Current Report on Form 8-K (File No. 001-35380) filed on January 24, 2020).
4.8	Third Supplemental Indenture, dated as of January 24, 2020, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC, Garden City Minerals, LLC and Wells Fargo Bank, N.A., as trustee (incorporated by reference to Exhibit 4.4 of Laredo’s Current Report on Form 8-K (File No. 001-35380) filed on January 24, 2020).
4.9	Fourth Supplemental Indenture, dated as of January 24, 2020, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC, Garden City Minerals, LLC and Wells Fargo Bank, N.A., as trustee (incorporated by reference to Exhibit 4.6 of Laredo’s Current Report on Form 8-K (File No. 001-35380) filed on January 24, 2020).
10.1	Fifth Amended and Restated Credit Agreement, dated as of May 2, 2017, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, and the other financial institutions signatory thereto (incorporated by reference to Exhibit 10.1 of Laredo's Quarterly Report on Form 10-Q (File No. 001-35380) filed on May 4, 2017).
10.2	First Amendment to Fifth Amended and Restated Credit Agreement, dated as of October 24, 2017, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on October 30, 2017).
10.3	Second Amendment to Fifth Amended and Restated Credit Agreement, dated as of February 14, 2018, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto (incorporated by reference to Exhibit 10.3 of Laredo's Annual Report on Form 10-K (File No. 001-35380) filed on February 15, 2018).

Exhibit Number	Description
10.4	Third Amendment to Fifth Amended and Restated Credit Agreement, dated as of April 19, 2018, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on April 23, 2018).
10.5*	Schedule 1, amended and restated as of January 22, 2020, to the Third Amendment to the Fifth Amended and Restated Credit Agreement, dated as of April 19, 2018, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto.
10.6	Form of Registration Rights Agreement dated December 20, 2011 among Laredo Petroleum Holdings, Inc. and the signatories thereto (incorporated by reference to Exhibit 10.5 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
10.7	Amended and Restated Form of Indemnification Agreement between Laredo Petroleum Holdings, Inc. and each of the officers and directors thereof (incorporated by reference to Exhibit 10.5 of Laredo's Quarterly Report on Form 10-Q (File No. 001-35380) filed on May 2, 2019).
10.8#	Laredo Petroleum, Inc. Omnibus Equity Incentive Plan, as amended and restated as of May 16, 2019 (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on May 16, 2019).
10.9#	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.3 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on May 25, 2016).
10.10#	Form of Performance Share Unit Award Agreement (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on February 23, 2018).
10.11#	Form of Performance Share Unit Award Agreement (incorporated by reference to Exhibit 10.4 of Laredo's Quarterly Report on Form 10-Q (File No. 001-35380) filed on May 2, 2019).
10.12#	Laredo Petroleum, Inc. Change in Control Executive Severance Plan, as amended June 21, 2015, December 14, 2015 and September 9, 2016 (incorporated by reference to Exhibit 10.18 of Laredo's Annual Report on Form 10-K (File No. 001-35380) filed on February 16, 2017).
10.13#	Form of Officer Severance and Release Agreement, as of April 2019 (incorporated by reference to Exhibit 10.1 of Laredo's Quarterly Report on Form 10-Q (FIle No. 001-35380) filed on May 2, 2019).
10.14#	Offer Letter, dated April 17, 2019, between Laredo Petroleum, Inc. and Mr. Jason Pigott (incorporated by reference to Exhibit 10.3 of Laredo's Quarterly Report on Form 10-Q (file No. 001-35380) filed on May 2, 2019).
10.15	Consulting Agreement, dated April 3. 2019, between Laredo Petroleum, Inc. and Schooley Ventures, LLC (incorporated by reference to Exhibit 10.2 of Laredo's Quarterly Report on Form 10-Q (File No. 001-35380) files on May 2, 2019).
10.16#	Form of Outperformance Share Unit Award Agreement (incorporated by reference to Exhibit 10.8 of Laredo's Quarterly Report on Form 10-Q (File No. 001-35380) filed on August 1, 2019).
10.17#	Payment and Release Agreement, dated October 1, 2019, between Laredo Petroleum, Inc. and Mr. Randy Foutch (incorporated by reference to Exhibit 10.2 of Laredo's Quarterly Report on Form 10-Q (File No. 001-35380) filed on November 6, 2019).
10.18	Non-Exclusive Aircraft Lease Agreement, dated July 1, 2018 between Lariat Ranch, LLC and Laredo Petroleum, Inc. (incorporated by reference to Exhibit 10.1 of Laredo's Quarterly Report on Form 10-Q (File No. 001-35380) filed on November 6, 2018).
10.19	Purchase and Sale Agreement, dated November 4, 2019, by and between Cordero Energy Resources LLC and Laredo Petroleum, Inc. (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on November 5, 2019).
10.20#	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.2 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on May 25, 2016).
21.1*	List of Subsidiaries of Laredo Petroleum, Inc.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Ryder Scott Company, L.P.
31.1*	Certification of Chief Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
31.2*	Certification of Chief Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.

Exhibit Number	Description
32.1**	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18. U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Summary Report of Ryder Scott Company, L.P. (incorporated by reference to Exhibit 99.5 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on January 6, 2020).
101	The following financial information from Laredo's Annual Report on Form 10-K for the year ended December 31, 2019, formatted in Inline XBRL: (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Stockholders' Equity, (iv) Consolidated Statements of Cash Flows and (v) Notes to the Consolidated Financial Statements.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

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

Table of Contents

Signatures

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

Laredo Petroleum, Inc.

Date: February 13, 2020

By: /s/ Jason Pigott

Jason Pigott
President and *Chief Executive Officer*

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

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

Signatures	Title	Date
/s/ Jason Pigott Jason Pigott	President and Chief Executive Officer (principal executive officer)	2/13/2020
/s/ Michael T. Beyer Michael T. Beyer	Senior Vice President and Chief Financial Officer (principal financial officer and principal accounting officer)	2/13/2020
/s/ Randy A. Foutch Randy A. Foutch	Chairman	2/13/2020
/s/ Craig M. Jarchow Craig M. Jarchow	Director	2/13/2020
/s/ Peter R. Kagan Peter R. Kagan	Director	2/13/2020
/s/ James R. Levy James R. Levy	Director	2/13/2020
/s/ Pamela S. Pierce Pamela S. Pierce	Director	2/13/2020
/s/ Francis Powell Hawes Frances Powell Hawes	Director	2/13/2020
/s/ Dr. Myles W. Scoggins Dr. Myles W. Scoggins	Director	2/13/2020
/s/ Edmund P. Segner, III Edmund P. Segner, III	Director	2/13/2020

Index to Consolidated Financial Statements

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders

Laredo Petroleum, Inc.

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Laredo Petroleum, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2019 and 2018, the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2019, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated February 13, 2020 expressed an unqualified opinion.

Change in accounting principle

As disclosed in Note 5.a to the financial statements, the Company has changed its method of accounting for leases in the year ended December 31, 2019 due to the adoption of FASB Accounting Standards Codification Topic 842, *Leases*.

Basis for opinion

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

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

Critical audit matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee that (1) relate to accounts or disclosures that are material to the financial statements and (2) involve our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

- Depletion expense and impairment of oil and gas properties impacted by the Company's estimation of proved reserves

  As described further in Notes 2 and 6 to the financial statements, the Company accounts for its oil and natural gas properties using the full cost method of accounting which requires management to make estimates of proved reserve volumes and future net revenues to record depletion expense and to determine if any impairment exists for its oil and natural gas properties. To estimate the volume of proved reserves and future net revenues, management makes significant estimates and assumptions including forecasting the production decline rate of producing properties and forecasting the timing and volume of production associated with the Company's development plan for proved undeveloped properties. In addition, the estimation of proved reserves is also impacted by management's judgments and estimates regarding the financial performance of wells associated with proved reserves to determine if wells are expected, with reasonable certainty, to be economical under the appropriate pricing assumptions required in the estimation of depletion expense and impairment expense. We identified the estimation of proved reserves of oil and natural gas properties due to its impact on depletion expense and impairment of oil and natural gas properties as a critical audit matter.

The principal consideration for our determination that the estimation of proved reserves is a critical audit matter is that changes in certain inputs and assumptions, which require a high degree of subjectivity, necessary to estimate the volume and future revenues of the Company's proved reserves could have a significant impact on the measurement of depletion expense or impairment expense. In turn, auditing those inputs and assumptions required subjective and complex auditor judgment.

Our audit procedures related to the estimation of proved reserves included the following, among others.

- We tested the effectiveness of controls relating to management's estimation of proved reserves for the purpose of estimating depletion expense and assessing the Company's oil and natural gas properties for potential impairment. Specifically, these controls related to the use of historical information in the estimation of proved reserves derived from the Company's accounting records and the management review controls performed on information provided to the reservoir engineering specialists and the management review controls on the final proved reserves report prepared by the Company's reservoir engineering specialists.

- We evaluated the level of knowledge, skill, and ability of the Company's reservoir engineering specialists and their relationship to the Company, made inquiries of those reservoir engineers regarding the process followed and judgments made to estimate the Company's proved reserve volumes, and read the reserve report prepared by the Company's reservoir engineering specialists.

- We evaluated sensitive inputs and assumptions used to determine proved reserve volumes and other financial inputs and assumptions, including certain assumptions that are derived from the Company's accounting records. These assumptions included historical pricing differentials, future operating costs, estimated future capital costs, and ownership interests. We tested management's process for determining the assumptions, including examining the underlying support, on a sample basis. Specifically, our audit procedures involved testing management's assumptions as follows:
    - Compared the estimated pricing differentials used in the reserve report to realized prices related to revenue transactions recorded in the current year and examined contractual support for the pricing differentials;
    - Evaluated the models used to estimate the future operating costs at year-end and compared the models to historical operating costs;
    - Evaluated the models used to estimate future capital expenditures to amounts expended for recently drilled and completed wells;
    - Evaluated the ownership interests used in the reserve report by inspecting lease and title records;
    - Evaluated the Company's evidence supporting the amount of proved undeveloped properties reflected in the reserve report by examining historical conversion rates and support for the Company's ability to fund and intent to develop the proved undeveloped properties; and
    - Applied analytical procedures to the reserve report by comparing the reserve report to historical actual results and to the prior year reserve report.

/s/ GRANT THORNTON LLP

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

Tulsa, Oklahoma
February 13, 2020

Consolidated balance sheets

(in thousands, except share data)	December 31, 2019	December 31, 2018
Assets		
Current assets:		
Cash and cash equivalents	$ 40,857	$ 45,151
Accounts receivable, net	85,223	94,321
Derivatives	51,929	39,835
Other current assets	22,470	13,445
Total current assets	200,479	192,752
Property and equipment:		
Oil and natural gas properties, full cost method:		
Evaluated properties	7,421,799	6,752,631
Unevaluated properties not being depleted	142,354	130,957
Less accumulated depletion and impairment	(5,725,114)	(4,854,017)
Oil and natural gas properties, net	1,839,039	2,029,571
Midstream service assets, net	128,678	130,245
Other fixed assets, net	32,504	39,819
Property and equipment, net	2,000,221	2,199,635
Derivatives	23,387	11,030
Operating lease right-of-use assets	28,343	—
Other noncurrent assets, net	12,007	16,888
Total assets	$ 2,264,437	$ 2,420,305
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 40,521	$ 69,504
Accrued capital expenditures	36,328	29,975
Undistributed revenue and royalties	33,123	48,841
Derivatives	7,698	7,359
Operating lease liabilities	14,042	—
Other current liabilities	39,184	44,786
Total current liabilities	170,896	200,465
Long-term debt, net	1,170,417	983,636
Asset retirement obligations	60,691	53,387
Operating lease liabilities	17,208	—
Other noncurrent liabilities	3,351	8,587
Total liabilities	1,422,563	1,246,075
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $0.01 par value, 50,000,000 shares authorized and zero issued as of December 31, 2019 and 2018	—	—
Common stock, $0.01 par value, 450,000,000 shares authorized and 237,292,086 and 233,936,358 issued and outstanding as of December 31, 2019 and 2018, respectively	2,373	2,339
Additional paid-in capital	2,385,355	2,375,286
Accumulated deficit	(1,545,854)	(1,203,395)
Total stockholders' equity	841,874	1,174,230
Total liabilities and stockholders' equity	$ 2,264,437	$ 2,420,305

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

Consolidated statements of operations

(in thousands, except per share data)	Years ended December 31, 2019	2018	2017
Revenues:			
Oil sales	$ 572,918	$ 605,197	$ 445,012
NGL sales	100,330	149,843	101,438
Natural gas sales	33,300	53,490	75,057
Midstream service revenues	11,928	8,987	10,517
Sales of purchased oil	118,805	288,258	190,138
Total revenues	837,281	1,105,775	822,162
Costs and expenses:			
Lease operating expenses	90,786	91,289	75,049
Production and ad valorem taxes	40,712	49,457	37,802
Transportation and marketing expenses	25,397	11,704	—
Midstream service expenses	4,486	2,872	4,099
Costs of purchased oil	122,638	288,674	195,908
General and administrative	54,729	96,138	96,312
Organizational restructuring expenses	16,371	—	—
Depletion, depreciation and amortization	265,746	212,677	158,389
Impairment expense	620,889	—	—
Other operating expenses	4,118	4,472	4,931
Total costs and expenses	1,245,872	757,283	572,490
Operating income (loss)	(408,591)	348,492	249,672
Non-operating income (expense):			
Gain on derivatives, net	79,151	42,984	350
Interest expense	(61,547)	(57,904)	(89,377)
Litigation settlement	42,500	—	—
Income from equity method investee (see Note 4.d)	—	—	8,485
Gain on sale of investment in equity method investee (see Note 4.d)	—	—	405,906
Loss on early redemption of debt	—	—	(23,761)
Loss on disposal of assets, net	(248)	(5,798)	(1,306)
Write-off of debt issuance costs	(935)	—	—
Other income, net	4,623	1,070	805
Total non-operating income (expense), net	63,544	(19,648)	301,102
Income (loss) before income taxes	(345,047)	328,844	550,774
Income tax benefit (expense):			
Current	—	807	(1,800)
Deferred	2,588	(5,056)	—
Total income tax benefit (expense)	2,588	(4,249)	(1,800)
Net income (loss)	$ (342,459)	$ 324,595	$ 548,974
Net income (loss) per common share:			
Basic	$ (1.48)	$ 1.40	$ 2.30
Diluted	$ (1.48)	$ 1.39	$ 2.29
Weighted-average common shares outstanding:			
Basic	231,295	232,339	239,096
Diluted	231,295	233,172	240,122

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

Consolidated statements of stockholders' equity

(in thousands)	Common stock Shares	Common stock Amount	Additional paid-in capital	Treasury stock (at cost) Shares	Treasury stock (at cost) Amount	Accumulated deficit	Total
Balance, December 31, 2016	241,929	$ 2,419	$ 2,396,236	—	$ —	$ (2,218,082)	$ 180,573
Restricted stock awards	1,237	12	(12)	—	—	—	—
Restricted stock forfeitures	(302)	(3)	3	—	—	—	—
Performance share conversion	150	2	(2)	—	—	—	—
Stock exchanged for tax withholding	—	—	—	547	(7,662)	—	(7,662)
Retirement of treasury stock	(547)	(5)	(7,657)	(547)	7,662	—	—
Exercise of stock options	54	—	397	—	—	—	397
Stock-based compensation	—	—	43,297	—	—	—	43,297
Net income	—	—	—	—	—	548,974	548,974
Balance, December 31, 2017	242,521	2,425	2,432,262	—	—	(1,669,108)	765,579
Adjustment to the beginning balance of accumulated deficit upon adoption of ASC 606 (See Note 13.a)	—	—	—	—	—	141,118	141,118
Restricted stock awards	3,328	33	(33)	—	—	—	—
Restricted stock forfeitures	(367)	(4)	4	—	—	—	—
Share repurchases	—	—	—	11,049	(97,055)	—	(97,055)
Stock exchanged for tax withholding	—	—	—	518	(4,418)	—	(4,418)
Retirement of treasury stock	(11,567)	(115)	(101,358)	(11,567)	101,473	—	—
Exercise of stock options	21	—	86	—	—	—	86
Stock-based compensation	—	—	44,325	—	—	—	44,325
Net income	—	—	—	—	—	324,595	324,595
Balance, December 31, 2018	233,936	2,339	2,375,286	—	—	(1,203,395)	1,174,230
Restricted stock awards	7,613	76	(76)	—	—	—	—
Restricted stock forfeitures	(3,559)	(35)	35	—	—	—	—
Stock exchanged for tax withholding	—	—	—	698	(2,657)	—	(2,657)
Stock exchanged for cost of exercise of stock options	—	—	—	18	(76)	—	(76)
Retirement of treasury stock	(716)	(7)	(2,726)	(716)	2,733	—	—
Exercise of stock options	18	—	76	—	—	—	76
Stock-based compensation (See Note 18)	—	—	12,760	—	—	—	12,760
Net loss	—	—	—	—	—	(342,459)	(342,459)
Balance, December 31, 2019	237,292	$ 2,373	$ 2,385,355	—	$ —	$ (1,545,854)	$ 841,874

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

Consolidated statements of cash flows

(in thousands)	2019	2018	2017
	Years ended December 31,		
Cash flows from operating activities:			
Net income (loss)	$ (342,459)	$ 324,595	$ 548,974
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Non-cash stock-based compensation, net	8,290	36,396	35,734
Depletion, depreciation and amortization	265,746	212,677	158,389
Impairment expense	620,889	—	—
Mark-to-market on derivatives:			
Gain on derivatives, net	(79,151)	(42,984)	(350)
Settlements received for matured commodity derivatives, net	63,221	6,090	37,583
Settlements (paid) received for early terminations of commodity derivatives, net	(5,409)	—	4,234
Premiums paid for commodity derivatives	(9,063)	(20,335)	(25,853)
Amortization of debt issuance costs	3,341	3,331	4,086
Amortization of operating lease right-of-use assets	14,563	—	—
Gain on sale of investment in equity method investee (see Note 4.d)	—	—	(405,906)
Loss on early redemption of debt	—	—	23,761
Deferred income tax (benefit) expense	(2,588)	5,056	—
Other, net	3,887	12,551	(2,024)
Changes in operating assets and liabilities:			
Decrease (increase) in accounts receivable, net	8,924	4,669	(12,124)
Increase in other current assets	(14,059)	(1,865)	(3,461)
Decrease (increase) in other noncurrent assets, net	2,327	124	(4,774)
(Decrease) increase in accounts payable and accrued liabilities	(28,983)	11,163	9,137
(Decrease) increase in undistributed revenue and royalties	(16,037)	10,989	11,014
Decrease in other current liabilities	(13,968)	(23,799)	(2,327)
(Decrease) increase in other noncurrent liabilities	(4,397)	(854)	8,821
Net cash provided by operating activities	475,074	537,804	384,914
Cash flows from investing activities:			
Deposit utilized for sale of oil and natural gas properties	—	—	(3,000)
Acquisitions of oil and natural gas properties, net of closing adjustments	(199,284)	(17,538)	—
Capital expenditures:			
Oil and natural gas properties	(458,985)	(673,584)	(538,122)
Midstream service assets	(7,910)	(6,784)	(20,887)
Other fixed assets	(2,433)	(7,308)	(4,905)
Investment in equity method investee (see Note 4.d)	—	—	(31,808)
Proceeds from disposition of equity method investee, net of selling costs (see Note 4.d)	—	1,655	829,615
Proceeds from dispositions of capital assets, net of selling costs	6,901	12,603	64,157
Net cash provided by (used in) investing activities	(661,711)	(690,956)	295,050
Cash flows from financing activities:			
Borrowings on Senior Secured Credit Facility	275,000	210,000	190,000
Payments on Senior Secured Credit Facility	(90,000)	(20,000)	(260,000)
Early redemption of debt	—	—	(518,480)
Share repurchases	—	(97,055)	—
Stock exchanged for tax withholding	(2,657)	(4,418)	(7,662)
Proceeds from exercise of stock options	—	86	397
Payments for debt issuance costs	—	(2,469)	(4,732)
Net cash provided by (used in) financing activities	182,343	86,144	(600,477)
Net increase (decrease) in cash and cash equivalents	(4,294)	(67,008)	79,487
Cash and cash equivalents, beginning of period	45,151	112,159	32,672
Cash and cash equivalents, end of period	$ 40,857	$ 45,151	$ 112,159

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

Notes to the consolidated financial statements

Note 1 Organization

Laredo Petroleum, Inc. ("Laredo"), together with its wholly-owned subsidiaries, Laredo Midstream Services, LLC ("LMS") and Garden City Minerals, LLC ("GCM"), is an independent energy company focused on the acquisition, exploration and development of oil and natural gas properties, primarily in the Permian Basin of West Texas. LMS and GCM (together, the "Guarantors") guarantee all of Laredo's debt instruments. The Company has identified one operating segment: exploration and production. In these notes, the "Company" refers to Laredo, LMS and GCM collectively, unless the context indicates otherwise. All amounts, dollars and percentages presented in these consolidated financial statements and the related notes are rounded and, therefore, approximate.

Note 2 Basis of presentation and significant accounting policies

a. Basis of presentation

The accompanying consolidated financial statements were derived from the historical accounting records of the Company and reflect the historical financial position, results of operations and cash flows for the periods described herein. The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). All material intercompany transactions and account balances have been eliminated in the consolidation of accounts. The Company uses the equity method of accounting to record its net interests when the Company holds 20% to 50% of the voting rights and/or has the ability to exercise significant influence but does not control the entity. Under the equity method, the Company's proportionate share of the investee's net income is included in the consolidated statements of operations. See Note 4.d for additional discussion of the Company's former equity method investment.

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

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

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

c. Reclassifications

Certain amounts in the accompanying consolidated financial statements have been reclassified to conform to the 2019 presentation. These reclassifications had no impact on previously reported total assets, total liabilities, net income (loss), stockholders' equity or total operating, investing or financing cash flows.

d. Cash and cash equivalents

The Company defines cash and cash equivalents to include cash on hand, cash in bank accounts and highly liquid investments with original maturities of three months or less. The Company maintains cash and cash equivalents in bank deposit accounts and money market funds that may not be federally insured. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk on such accounts. See Note 14 for discussion regarding the Company's exposure to credit risk.

e. Accounts receivable

The Company sells its produced oil, NGL and natural gas and purchased oil to various customers and participates with other parties in the development and operation of oil and natural gas properties.

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

Accounts receivable consisted of the following components as of the dates presented:

(in thousands)	December 31, 2019	December 31, 2018
Oil, NGL and natural gas sales(1)	$ 54,668	$ 44,958
Joint operations, net(2)	21,567	16,772
Sales of purchased oil and other products(1)	2,883	10,244
Other	6,105	22,347
Total accounts receivable, net	$ 85,223	$ 94,321

(1) Includes the net positions of purchasers that we have netting arrangements with.

(2) Accounts receivable for joint operations are presented net of an allowance for doubtful accounts of $0.3 million and $0.1 million as of December 31, 2019 and 2018, respectively. As the operator of the majority of its wells, the Company has the ability to realize some or all of these receivables through the netting of revenues.

f. Derivatives

Derivatives are recorded at fair value and are presented on a net basis in "Derivatives" on the consolidated balance sheets as assets and/or liabilities. The Company presents the fair value of derivatives net by counterparty where the right of offset exists. The Company determines the fair value of its derivatives using fair value hierarchy level inputs to its valuation techniques. The Company's derivatives were not designated as hedges for accounting purposes, and the Company does not enter into such instruments for speculative trading purposes. Accordingly, the changes in fair value are recognized in "Gain on derivatives, net" under "Non-operating income (expense)" on the consolidated statements of operations. Cash settlements received or paid for matured, early terminated and modified commodity derivatives and premiums paid for commodity derivatives are included in "Settlements received for matured commodity derivatives, net," "Settlements (paid) received for early terminations of commodity derivatives, net" and "Premiums paid for commodity derivatives" each under "Cash flows from operating activities" on the consolidated statements of cash flows. If applicable in the future, settlement paid for the contingent consideration derivative will be under "Cash flows from financing activities" up to the acquisition date fair value with any excess under "Cash flows from operating activities." See Notes 9 and 10.a for additional discussion of derivatives and their fair value measurement on a recurring basis, respectively.

g. Other current assets and liabilities

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

(in thousands)	December 31, 2019	December 31, 2018
Line-fill in third-party pipelines[(1)]	$ 10,490	$ —
Prepaid expenses and other	6,496	6,555
Inventory[(1)]	5,484	6,890
Total other current assets	$ 22,470	$ 13,445

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(1) See Note 2.j for discussion of the Company's types of inventory.

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

(in thousands)	December 31, 2019	December 31, 2018
Accrued interest payable	$ 18,501	$ 18,281
Accrued compensation and benefits	17,038	13,317
Other accrued liabilities	3,645	13,188
Total other current liabilities	$ 39,184	$ 44,786

h. Oil and natural gas properties

The Company uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs incurred for the purpose of acquiring, exploring for or developing oil and natural gas properties, are capitalized and once evaluated, are depleted on a composite unit-of-production method based on estimates of proved oil, NGL and natural gas reserves. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals and other costs related to such activities. Costs, including related employee costs associated with production and general corporate activities are expensed in the period incurred. Sales of oil and natural gas properties, whether or not being depleted currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil, NGL and natural gas. See Note 6 for additional discussion of the Company's oil and natural gas properties and other property and equipment.

i. Leases

Prior to January 1, 2019, the Company accounted for leases under Accounting Standards Codification ("ASC") 840 and did not record any right-of-use assets or corresponding lease liabilities. Upon the adoption of ASC 842 on January 1, 2019, the Company recognized operating lease right-of-use assets and operating lease liabilities on the consolidated balance sheet for operating leases with a term greater than 12 months. See Note 5 for further discussion of the ASC 842 adoption impact on the Company's consolidated financial statements.

j. Inventory

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

For the year ended December 31, 2019 the Company recorded impairment expense of $0.3 million for line-fill. No impairment expense for line-fill was recorded for the years ended December 31, 2018 or 2017.

k. Debt issuance costs

Debt issuance costs, which are recorded at cost, net of amortization, are amortized over the life of the respective debt agreements utilizing the straight-line method. See Note 7.e for additional discussion of the Company's debt issuance costs.

l. Asset retirement obligations

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

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

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

The following table reconciles the Company's asset retirement obligation liability for the periods presented:

	Years ended December 31,	
(in thousands)	**2019**	**2018**
Liability at beginning of year	$ 56,882	$ 55,506
Liabilities added due to acquisitions, drilling, midstream service asset construction and other	4,755	995
Accretion expense	4,118	4,472
Liabilities settled due to plugging and abandonment or removed due to sale	(3,037)	(4,091)
Liability at end of year	$ 62,718	$ 56,882

m. Fair value measurements

The carrying amounts reported on the consolidated balance sheets for cash and cash equivalents, accounts receivable, accounts payable, accrued capital expenditures, undistributed revenue and royalties and other accrued assets and liabilities approximate their fair values. See Note 2.j for the fair value assumptions used in estimating the NRV of inventory used to account for the impairment of inventory. See Note 4.a for the fair value assumptions used in estimating the fair values of assets acquired and liabilities assumed for the acquisition of evaluated and unevaluated oil and natural gas properties accounted for as a business combination. See Note 10 for further discussion of fair value measurements.

n. Treasury stock

Treasury stock is recorded at cost, which includes incremental direct transaction costs, and is retired upon acquisition as a result of (i) share repurchases under the share repurchase program, (ii) the withholding of shares of stock to satisfy employee tax withholding obligations that arise upon the lapse of restrictions on their stock-based awards at the employees' election or (iii) the cost of exercise of stock options at the employees' election.

o. Revenue recognition

Oil, NGL and natural gas sales and sales of purchased oil are generally recognized at the point in time that control of the product is transferred to the customer. Midstream service revenues are generated through fees for products and services that need to be delivered by midstream infrastructure, including oil and liquids-rich natural gas gathering services as well as rig fuel, natural gas lift and water delivery, recycling and takeaway (collectively, "Midstream Services") and are recognized over time as the customer benefits from these services when provided. See Note 13.b for additional discussion of revenue recognition.

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

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

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

	Years ended December 31,		
(in thousands)	**2019**	**2018**	**2017**
Fees received for the operation of jointly-owned oil and natural gas properties	$ 468	$ 412	$ 460

q. Compensation awards

Stock-based compensation expense, net, is included in "General and administrative" on the consolidated statements of operations over the awards' vesting periods and is generally based on the awards' grant date fair value less an expected forfeiture rate. The Company utilizes the closing stock price on the grant date to determine the fair values of restricted stock awards and a Black-Scholes pricing model to determine the fair values of stock option awards. The Company utilizes a Monte Carlo simulation prepared by an independent third party to determine the fair values of the performance share awards and outperformance share award with market criteria. For performance share awards with performance criteria, the grant-date fair value is equal to the Company's stock price on the grant date, and for each reporting period, the associated expense fluctuates and is trued-up based on an estimated probability of how many shares will be earned at the end of the performance period. The Company capitalizes a portion of stock-based compensation for employees who are directly involved in the acquisition, exploration and development of its oil and natural gas properties into the full cost pool. Capitalized stock-based compensation is included in "Evaluated properties" on the consolidated balance sheets. See Note 8.b for further discussion of the Company's Equity Incentive Plan.

r. Income taxes

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

The Company evaluates uncertain tax positions for recognition and measurement in the consolidated financial statements. To recognize a tax position, the Company determines whether it is more likely than not that the tax position will be sustained upon examination, including resolution of any related appeals or litigation, based on the technical merits of the position. A tax position that meets the more-likely-than-not threshold is measured to determine the amount of benefit to be recognized in the consolidated financial statements. The amount of tax benefit recognized with respect to any tax position is measured as the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement. The Company has no unrecognized tax benefits related to uncertain tax positions in the consolidated financial statements at December 31, 2019 or 2018. See Note 12 for additional information regarding the Company's income taxes.

s. Supplemental cash flow and non-cash information

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

	Years ended December 31,		
(in thousands)	2019	2018	2017
Supplemental cash flow information:			
Cash paid for interest, net of $805, $988 and $1,152 of capitalized interest, respectively(1)	$ 58,216	$ 53,981	$ 91,548
Net cash (received) paid for income taxes(2)	$ (3,187)	$ 735	$ 5,500
Supplemental non-cash investing information:			
Fair value of contingent consideration on acquisition date(3)	$ 6,150	$ —	$ —
Increase (decrease) in accrued capital expenditures	$ 6,353	$ (52,746)	$ 51,876
Capitalized stock-based compensation in evaluated oil and natural gas properties	$ 4,470	$ 7,929	$ 7,563
Capitalized asset retirement cost	$ 4,755	$ 995	$ 787

(1) See Note 7.f for additional discussion of the Company's interest expense.

(2) See Note 12 for additional discussion of the Company's income taxes.

(3) See Notes 4.a and 10.b for additional discussion of the Company's 2019 acquisitions of evaluated and unevaluated oil and natural gas properties and fair value measurement on a nonrecurring basis, respectively.

The following table presents supplemental non-cash adjustments information related to operating leases for the period presented:

(in thousands)	Year ended December 31, 2019
Right-of-use assets obtained in exchange for operating lease liabilities(1)	$ 42,905

(1) See Note 5 for additional discussion of the Company's leases.

Note 3 New accounting standards

The Company considers the applicability and impact of all accounting standard updates ("ASU") issued by the Financial Accounting Standards Board ("FASB") to the ASC and has determined there are no ASUs that are not yet adopted and meaningful to disclose as of December 31, 2019.

a. Accounting standard adopted

On January 1, 2019, the Company adopted ASC 842 using the modified retrospective approach and applying the optional transition method as of the beginning of the period of adoption. Results for the period beginning after January 1, 2019 are presented under ASC 842, while prior periods are not adjusted and continue to be reported under ASC 840. The Company utilized the transition package of expedients for leases that commenced before the effective date. ASC 842 supersedes previous lease guidance in ASC 840. The core principle of the new guidance is that a lessee should recognize on the balance sheet a liability to make lease payments and a right-of-use asset representing its right to use the underlying asset for the lease term related to its leases. For leases with a term of 12 months or less, a lessee is permitted to make an accounting policy election, by class of underlying asset, not to recognize lease assets and lease liabilities. See Note 5 for further discussion of the ASC 842 adoption impact on the Company's consolidated financial statements.

Note 4 Acquisitions and divestitures

a. 2019 Acquisitions of evaluated and unevaluated oil and natural gas properties

Asset acquisitions

On December 12, 2019, the Company closed an acquisition of 7,360 net acres and 750 net royalty acres in Howard County, Texas for $131.7 million, net of customary closing purchase price adjustments and subject to customary post-closing purchase price adjustments. The acquisition also provides for a potential contingent payment, where the Company is required to pay $20 million if the arithmetic average of the monthly settlement West Texas Intermediate ("WTI") NYMEX prices for each consecutive calendar month for the one-year period beginning January 1, 2020 through December 31, 2020 exceeds $60.00 per barrel. The fair value of the contingent consideration was $6.2 million as of the acquisition date, which is recorded as part of the basis in the oil and natural gas properties acquired. See Notes 9.b and 10.a for discussion of the contingent consideration. All transaction costs were capitalized and are included in "Oil and natural gas properties" on the consolidated balance sheet. This acquisition was primarily financed through borrowings under the Senior Secured Credit Facility.

On June 20, 2019, the Company acquired 640 net acres in Reagan County, Texas for $2.9 million.

See Note 19.b for the asset acquisition that occurred subsequent to December 31, 2019.

Business combination

On December 6, 2019, the Company closed a bolt-on acquisition of 4,475 contiguous net acres and working interests in 49 producing wells in western Glasscock County, Texas, which included net production of 1,400 barrels of oil equivalent ("BOE") per day, for $64.6 million, net of customary closing purchase price adjustments and subject to customary post-closing purchase price adjustments. This acquisition was financed through borrowings under the Senior Secured Credit Facility.

This acquisition was accounted for as a business combination. Accordingly, the Company conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at the estimated acquisition date fair values, while transaction costs associated with the acquisition were expensed. The Company makes various assumptions in estimating the fair values of assets acquired and liabilities assumed. The most significant assumptions relate to the estimated fair values of evaluated and unevaluated oil and natural gas properties. The fair values of these properties were measured using a discounted cash flow model that converts future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) forecasted oil, NGL and natural gas reserve quantities; (ii) future commodity strip prices as of the closing dates adjusted for transportation and regional price differentials; (iii) forecasted ad valorem taxes, production taxes, income taxes, operating expenses and development costs; and (iv) a peer group weighted-average cost of capital rate subject to additional project-specific risk factors. To compensate for the inherent risk of estimating the value of the unevaluated properties, the discounted future net revenues of proved undeveloped and probable reserves are reduced by additional reserve adjustment factors. These assumptions represent Level 3 inputs under the fair value hierarchy, as described in Note 10.

The following table reflects an aggregate of the final estimate of the fair values of the assets and liabilities acquired in this business combination on December 6, 2019:

(in thousands)	Fair values of acquisition
Fair values of net assets:	
Evaluated oil and natural gas properties	$ 29,921
Unevaluated oil and natural gas properties	34,700
Asset retirement cost	2,728
Total assets acquired	67,349
Asset retirement obligations	(2,728)
Net assets acquired	$ 64,621
Fair values of consideration paid for net assets:	
Cash consideration	$ 64,621

b. 2018 Acquisitions of evaluated and unevaluated oil and natural gas properties

During the year ended December 31, 2018, through multiple transactions, the Company acquired 966 net acres of additional leasehold and working interests in 48 producing wells in Glasscock County, Texas for an aggregate purchase price of $17.5 million, net of post-closing adjustments. These acquisitions were accounted for as asset acquisitions.

c. 2018 Divestitures of evaluated and unevaluated oil and natural gas properties and midstream service assets

During the year ended December 31, 2018, through multiple transactions, the Company completed the sale of 3,070 net acres and working interests in 24 producing wells and associated midstream service assets in Glasscock County and Howard County in Texas to third-party buyers for an aggregate sales price of $12.0 million, net of post-closing adjustments. Of this amount, $11.5 million, net of post-closing adjustments, was recorded as adjustments to oil and natural gas properties pursuant to the rules governing full cost accounting. A loss of $1.0 million from the sale of the associated midstream service assets was included in the line item "Loss on disposal of assets, net" in the consolidated statements of operations. Effective at the closings, the operations and cash flows of these oil and natural gas properties and midstream service assets were eliminated from the ongoing operations of the Company, and the Company has no continuing involvement in the properties. These divestitures did not represent a strategic shift and will not have a major effect on the Company's future operations or financial results.

d. 2017 Medallion sale

Medallion Gathering & Processing, LLC, a Texas limited liability company formed on October 12, 2012, which, together with its wholly-owned subsidiaries (collectively, "Medallion"), was established for the purpose of developing midstream solutions and providing midstream infrastructure to bring oil to market in the Midland Basin. Prior to the Medallion Sale (defined below), LMS held 49% of Medallion's ownership units. LMS and the third-party 51% interest-holder agreed that the voting rights of Medallion, the profit and loss sharing and the additional capital contribution requirements would be equal to the ownership unit percentage held. Additionally, Medallion required a super-majority vote of 75% for many key operating and business decisions. The Company determined that Medallion was a variable interest entity ("VIE"). However, LMS was not considered to be the primary beneficiary of the VIE because LMS did not have the power to direct the activities that most significantly affected Medallion's economic performance. As such, prior to the Medallion Sale, Medallion was accounted for under the equity method of accounting. The Company's proportionate share of Medallion's net income is reflected in the consolidated statements of operations on the "Income from equity method investee" line item.

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

LMS has a Transportation Services Agreement (the "TA") with a wholly-owned subsidiary of Medallion under which LMS receives firm transportation of the Company's crude oil production from Reagan County and Glasscock County in Texas to Colorado City, Texas that continues to be in effect after the Medallion Sale. Historically, the Company's crude oil purchasers have fulfilled the commitment by transporting crude oil, purchased from the Company, under the TA, as agent. As a result of the Company's continuing involvement with Medallion by guaranteeing cash flows under the TA, the Company recorded a deferred gain in the amount of its maximum exposure to loss related to such guarantees that would have been amortized over the TA's firm commitment transportation term through 2024 had the Company not adopted new revenue recognition guidance on January 1, 2018. The deferred gain is included in the consolidated balance sheets in each of the "Other current liabilities" and "Other noncurrent liabilities" line items as of December 31, 2017. See Note 13.a for discussion of the impact to the deferred gain upon the adoption of ASC 606, *Revenue from Contracts with Customers* ("ASC 606").

e. 2017 Divestiture of evaluated and unevaluated oil and natural gas properties

In January 2017, the Company completed the sale of 2,900 net acres and working interests in 16 producing vertical wells in the Midland Basin to a third-party buyer for a purchase price of $59.7 million. After transaction costs reflecting an economic effective date of October 1, 2016, the proceeds were $59.5 million, net of working capital and post-closing adjustments. A significant portion of these proceeds was used to pay down borrowings on the Senior Secured Credit Facility. The purchase price was recorded as an adjustment to oil and natural gas properties pursuant to the rules governing full cost accounting. Effective at closing, the operations and cash flows of these oil and natural gas properties were eliminated from the ongoing operations of the Company, and the Company has no continuing involvement in the properties. This divestiture did not represent a strategic shift and will not have a major effect on the Company's future operations or financial results.

f. Exchange of unevaluated oil and natural gas properties

From time to time, the Company exchanges undeveloped acreage with third parties. The exchanges are recorded at fair value and the difference is accounted for as an adjustment of capitalized costs with no gain or loss recognized pursuant to the rules governing full cost accounting, unless such adjustment would significantly alter the relationship between capitalized costs and proved reserves of oil, NGL and natural gas.

Note 5 Leases

a. Impact of ASC 842 adoption

Prior to January 1, 2019, the Company accounted for leases under ASC 840 and did not record any right-of-use assets or corresponding lease liabilities. Upon the adoption of ASC 842 on January 1, 2019, the Company recognized $22.1 million in operating lease right-of-use assets and $25.3 million in operating lease liabilities on the consolidated balance sheet for operating leases with a term greater than 12 months. The difference between the two balances of $3.2 million is mainly due to free rent and lease build-out incentives that were recorded as deferred lease liabilities under ASC 840. These deferred lease liabilities are subtracted from the right-of-use asset opening balance under ASC 842. The transition did not result in a material impact to the consolidated statements of operations nor was there a related impact to the consolidated statements of stockholders' equity.

The Company utilized the modified retrospective approach in adopting the new standard and applied the optional transition method as of the beginning of the period of adoption, along with the transition package of practical expedients, and implemented certain accounting policy decisions which include: (i) short-term lease recognition exemption, (ii) establishing a balance sheet recognition capitalization threshold, (iii) not evaluating existing or expired land easements that were not previously accounted for as leases under ASC 840 and (iv) accounting for certain asset classes at a portfolio level by not separating the lease and non-lease components and accounting for the agreement as a single lease component.

The Company determines whether a contract is or contains a lease at inception of the contract, based on answers to a series of questions that address whether an identified asset exists and whether the Company has the right to obtain substantially all of the benefit of the asset and to control its use over the full term of the agreement. When available, the Company uses the rate implicit in the lease to discount lease payments to present value; however, most of the Company's leases do not provide a readily determinable implicit rate. In such cases, the Company is required to use its incremental borrowing rate ("IBR"). The Company determines its IBR using both a "credit notching" approach and a "recovery method" approach. The results of these approaches are then weighted equally and averaged in order to determine the concluded IBR. This concluded IBR is utilized to discount the lease payments based on information available at lease commencement. There are no material residual value guarantees, nor any restrictions or covenants included in the Company's lease agreements.

Mineral leases, including oil and natural gas leases granting the right to explore for those natural resources and rights to use the land in which those natural resources are contained, are not included in the scope of ASC 842.

The Company has recognized operating lease right-of-use assets and operating lease liabilities on the consolidated balance sheet for leases of commercial real estate with lease terms extending into 2027 and drilling, completion, production and other equipment leases with lease terms extending through 2021. The Company has various other drilling, completion and production equipment leases on a short-term basis which are reflected in short-term lease costs.

The Company's lease costs include those that are recognized in net income (loss) during the period and capitalized as part of the cost of another asset in accordance with other GAAP.

The lease costs related to drilling, completion and production activities are reflected at the Company's net ownership, which is consistent with the principals of proportional consolidation, and lease commitments are reflected on a gross basis. As of December 31, 2019, the Company had an average working interest of 97% in Laredo-operated active productive wells.

Certain of the Company's leases include provisions for variable payments. These variable payments are typically determined based on a measure of throughput, actual days or another measure of usage. For our drilling rigs, the variable lease costs include the payments that depend on the performance or usage of the underlying asset, the costs to move and the costs to repair the drilling rigs. For certain of our commercial office buildings, utilities and common area, the variable lease costs are the variable maintenance charges. For our equipment leases, the variable lease costs are the amounts incurred under our contracts that are beyond the minimum rental fee, inclusive of maintenance.

The Company subleases certain office space to third parties but remains the primary obligor under the head lease. The lease terms on those subleases each contain renewal options that do not extend past the term of the head lease. The subleases do not contain residual value guarantees. Sublease income is recognized based on the contract terms and, upon the adoption of ASC 842, is included as a reduction of lease expense under the head lease.

Certain of the Company's operating lease right-of-use asset classes include options to renew on a month-to-month basis. The Company considers contract-based, asset-based, market-based, and entity-based factors to determine the term over which it is reasonably certain to extend the lease in determining its right-of-use assets and liabilities.

The Company's material leases do not include options to purchase the leased property.

The Company does not have any significant finance leases.

b. Lease costs

The following table presents components of total lease costs, net for the period presented:

(in thousands)	Year ended December 31, 2019
Operating lease costs(1)	$ 16,530
Short-term lease costs(2)	160,547
Variable lease costs(3)	2,683
Sublease income	(988)
Total lease costs, net	$ 178,772

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(1) Amounts represent straight-line costs associated with the Company's operating lease right-of-use assets.

(2) Amounts include costs associated with the Company's short-term leases that are not included in the calculation of lease liabilities and right-of-use assets and, therefore, are not recorded on the consolidated balance sheets as such.

(3) Amounts are primarily comprised of the non-lease service component of drilling rig commitments above the minimum required payments, and are not included in the calculation of lease liabilities and right-of-use assets. Both the minimum required payments and the non-lease service component of the drilling rig commitments are capitalized as additions to oil and natural gas properties.

c. Operating leases

Supplemental cash flow information

The following table presents cash paid for amounts included in the measurement of operating lease liabilities, which may not agree to operating lease costs due to timing of cash payments and costs incurred for the periods presented:

(in thousands)	Year ended December 31, 2019
Operating cash flows from operating leases	$ 5,728
Investing cash flows from operating leases(1)	$ 11,103

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(1) Amounts associated with drilling operations are capitalized as additions to oil and natural gas properties.

Lease terms and discount rates

The following table presents the weighted-average remaining lease term and weighted-average discount rate for operating leases as of the date presented:

	December 31, 2019
Weighted-average remaining lease term	3.07 years
Weighted-average discount rate	8.05%

Maturities

The following table reconciles the undiscounted cash flows for recognized operating lease liabilities for each of the first five years and the total remaining years to the operating lease liabilities recorded on the consolidated balance sheet as of the date presented:

(in thousands)	December 31, 2019
2020	$ 15,939
2021	11,172
2022	2,580
2023	1,359
2024	1,271
Thereafter	3,285
Total minimum lease payments	35,606
Less: lease liability expense	(4,356)
Present value of future minimum lease payments	31,250
Less: current operating lease liabilities	(14,042)
Noncurrent operating lease liabilities	$ 17,208

Other information

See Note 2.s for disclosure of supplemental non-cash adjustments information related to operating leases. See Note 16 for disclosure of related-party lease amounts.

d. Disclosure for the periods prior to adoption of ASC 842

As of December 31, 2018, the Company leased office space under operating leases expiring on various dates through 2027. The following table presents future minimum rental payments required as of the date presented:

(in thousands)	December 31, 2018
2019	$ 3,092
2020	3,179
2021	3,128
2022	2,560
2023	1,358
Thereafter	4,556
Total future minimum rental payments required	$ 17,873

The Company subleased certain office space with $5.9 million of total future minimum rentals to be received as of December 31, 2018.

The following table presents rent expense for the periods presented:

	Years ended December 31,	
(in thousands)	2018	2017
Rent expense	$ 2,735	$ 2,696

Rent income for the year ended December 31, 2018 totaled $0.6 million. Rent income for the year ended December 31, 2017 totaled de minimis amounts.

The Company's office space lease agreements contained scheduled escalation in lease payments during the term of the leases. Prior to the adoption of ASC 842, the Company recorded rent expense and rent income on a straight-line basis and a deferred lease liability and deferred lease asset, respectively, for the difference between the straight-line amount and the actual amounts of the lease payments and lease receipts. Deferred lease liability, net is included in "Other current liabilities" and

"Other noncurrent liabilities" on the consolidated balance sheets as of December 31, 2018. Rent expense and rent income are included in "General and administrative" and "Other income, net," respectively, on the consolidated statements of operations for the years ending December 31, 2018 and 2017.

Note 6 Property and equipment

a. Oil and natural gas properties

The Company uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs incurred for the purpose of acquiring, exploring for or developing oil and natural gas properties, are capitalized and once evaluated, are depleted on a composite unit-of-production method based on estimates of proved oil, NGL and natural gas reserves. The depletion base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values.

The Company excludes unevaluated property acquisition costs and exploration costs from the depletion calculation until it is determined whether or not proved reserves can be assigned to the properties. The Company capitalizes a portion of its interest costs to its unevaluated properties and is subject to depletion when proved reserves can be assigned to the associated properties. All items classified as unevaluated properties are assessed on a quarterly basis for possible impairment. The assessment includes consideration of the following factors, among others: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of proved reserves and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion. See Note 2.h for discussion of the Company's significant accounting policies for oil and natural gas properties.

Oil and natural gas properties consisted of the following components as of the dates presented:

(in thousands)	December 31, 2019	December 31, 2018
Evaluated properties	$ 7,421,799	$ 6,752,631
Unevaluated properties not being depleted	142,354	130,957
Less accumulated depletion and impairment	(5,725,114)	(4,854,017)
Total oil and natural gas properties, net	$ 1,839,039	$ 2,029,571

The following table presents capitalized employee-related costs incurred in the acquisition, exploration and development of oil and natural gas properties for the periods presented:

	Years ended December 31,		
(in thousands)	2019	2018	2017
Capitalized employee-related costs	$ 18,299	$ 25,372	$ 25,553

See Note 20.a for total costs incurred in the acquisition, exploration and development of oil and natural gas properties, which includes the aforementioned capitalized employee-related costs.

The following table presents depletion and depletion per BOE sold of evaluated oil and natural gas properties for the periods presented:

	Years ended December 31,		
(in thousands except per BOE data)	2019	2018	2017
Depletion of evaluated oil and natural gas properties	$ 250,857	$ 196,458	$ 143,592
Depletion expense per BOE sold	$ 8.50	$ 7.90	$ 6.75

The full cost ceiling is based principally on the estimated future net revenues from proved oil, NGL and natural gas reserves discounted at 10%. The Securities and Exchange Commission ("SEC") guidelines require companies to use the unweighted arithmetic average first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period before differentials ("Benchmark Prices"). The Benchmark Prices are then adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead ("Realized Prices") without giving effect to the Company's commodity derivative transactions. The Realized Prices are utilized to calculate the discounted future net revenues in the full cost ceiling calculation. Significant inputs included in the calculation of discounted cash flows used in the impairment analysis include the Company's estimate of operating and development costs, anticipated production of proved reserves and other relevant data.

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

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

	December 31, 2019	December 31, 2018	December 31, 2017
Benchmark Prices:			
Oil ($/Bbl)	$ 52.19	$ 62.04	$ 47.79
NGL ($/Bbl)(1)	$ 21.14	$ 31.46	$ 26.13
Natural gas ($/MMBtu)	$ 0.87	$ 1.76	$ 2.63
Realized Prices:			
Oil ($/Bbl)	$ 52.12	$ 59.29	$ 46.34
NGL ($/Bbl)	$ 12.21	$ 21.42	$ 18.45
Natural gas ($/Mcf)	$ 0.53	$ 1.38	$ 2.06

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

The following table presents full cost ceiling impairment expense, which is included in "Impairment expense" on the consolidated statements of operations for the periods presented:

	Years ended December 31,		
(in thousands)	2019	2018	2017
Full cost ceiling impairment expense	$ 620,565	$ —	$ —

b. Midstream service assets

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

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

(in thousands)	December 31, 2019	December 31, 2018
Midstream service assets	$ 180,932	$ 172,308
Less accumulated depreciation and impairment	(52,254)	(42,063)
Total midstream service assets, net	$ 128,678	$ 130,245

The following table presents depreciation of midstream service assets for the periods presented:

	Years ended December 31,		
(in thousands)	2019	2018	2017
Depreciation of midstream service assets	$ 10,206	$ 10,144	$ 8,939

c. Other fixed assets

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

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

(in thousands)	December 31, 2019	December 31, 2018
Computer hardware and software	$ 9,881	$ 9,222
Vehicles	9,407	10,660
Leasehold improvements	7,619	7,608
Buildings	7,055	7,804
Aircraft	—	6,402
Other	3,932	3,735
Depreciable total	37,894	45,431
Less accumulated depreciation and amortization	(23,649)	(23,871)
Depreciable total, net	14,245	21,560
Land	18,259	18,259
Total other fixed assets, net	$ 32,504	$ 39,819

The following table presents depreciation and amortization of other fixed assets for the periods presented:

	Years ended December 31,		
(in thousands)	2019	2018	2017
Depreciation and amortization of other fixed assets	$ 4,683	$ 6,075	$ 5,858

Note 7 Debt

a. March 2023 Notes

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

Indenture, designation of a subsidiary guarantor as a non-guarantor restricted subsidiary or as an unrestricted subsidiary in accordance with the Indenture, release from guarantee under the Senior Secured Credit Facility, or liquidation or dissolution (collectively, the "Releases").

The March 2023 Notes were offered and sold pursuant to a prospectus supplement dated March 4, 2015 and the base prospectus dated March 22, 2013, relating to the Company's effective shelf registration statement on Form S-3 (File No. 333-187479). The Company received net proceeds of $343.6 million from the offering, after deducting the underwriters' discount and the estimated outstanding offering expenses. In April 2015, the Company used the net proceeds of the offering to fund a portion of the Company's redemption of previously issued senior unsecured notes.

The March 2023 Notes became callable by the Company on March 15, 2018. The Company may redeem, at its option, all or part of the March 2023 Notes at any time on or after March 15, 2018, at a price of 104.688% of face value with call premiums declining annually to 100% of face value on March 15, 2021 and thereafter plus accrued and unpaid interest to, but not including, the date of redemption. See Note 19.a for discussion of the settlement of the Tender Offers of the outstanding March 2023 Notes subsequent to December 31, 2019 and discussion of the anticipated redemption of the remaining March 2023 Notes not tendered.

b. January 2022 Notes

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

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

The January 2022 Notes became callable by the Company on January 15, 2017. The Company may redeem, at its option, all or part of the January 2022 Notes at any time on and after January 15, 2019, at a price of 101.406% of face value with call premiums declining to 100% of face value on January 15, 2020 and thereafter plus accrued and unpaid interest to the date of redemption. See Note 19.a for discussion of the settlement of the Tender Offers of the outstanding January 2022 Notes and the Company's redemption of the remaining January 2022 Notes not tendered subsequent to December 31, 2019.

c. May 2022 Notes

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

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

d. Senior Secured Credit Facility

The Fifth Amended and Restated Credit Agreement (as amended, the "Senior Secured Credit Facility") matures on April 19, 2023. As of December 31, 2019, the Senior Secured Credit Facility had a maximum credit amount of $2.0 billion and a borrowing base and an aggregate elected commitment of $1.0 billion each, with $375.0 million outstanding and was subject to an interest rate of 3.28%. The borrowing base is subject to a semi-annual redetermination occurring by May 1 and November 1 of each year based on the lenders' evaluation of the Company's oil, NGL and natural gas reserves. As defined in the Senior Secured Credit Facility, (i) the Adjusted Base Rate advances under the facility bear interest payable quarterly at an Adjusted Base Rate plus applicable margin, which ranges from 0.25% 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 the Company's election, at the end of one-month, two-month, three-month, six-month or, to the extent available, 12-month interest periods (and in the case of six-month and 12-month interest periods, every three months prior to the end of such interest period) at an Adjusted London Interbank Offered Rate plus an applicable margin, which ranges from 1.25% to 2.25%, based on the ratio of outstanding revolving credit to the borrowing base under the Senior Secured Credit Facility. Laredo is 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 Laredo and the Guarantors' assets and stock, including oil and natural gas properties constituting at least 85% of the present value of the Company's proved reserves. Further, the Company is subject to various financial and non-financial covenants on a consolidated basis, including a current ratio at the end of each calendar quarter, of not less than 1.00 to 1.00. As defined by the Senior Secured Credit Facility, the current ratio represents the ratio of current assets to current liabilities, inclusive of available capacity and exclusive of current balances associated with derivative positions. Additionally, the Company must maintain as of the last day of each calendar quarter a ratio of (a) its total debt (excluding reimbursement obligations in respect of undrawn letters of credit, if no loans are outstanding under the Senior Secured Credit Facility) minus a maximum of $50 million of unrestricted and unencumbered cash and cash equivalents, to (b) "Consolidated EBITDAX," as defined in the Senior Secured Credit Facility, for any period of four consecutive calendar quarters ending on the last day of such applicable calendar quarter of not greater than 4.25 to 1.00. Prior to the Company entering into the Fifth Amended and Restated Credit Agreement as of May 2, 2017, at the end of each calendar quarter, the Company was required to maintain a ratio of (I) its consolidated net income (loss) (a) plus each of the following; (i) any provision for (or less any benefit from) income or franchise taxes; (ii) consolidated net interest expense; (iii) depletion, depreciation and amortization expense; (iv) exploration expenses; and (v) other non-cash charges, and (b) minus other non-cash income "EBITDAX", as defined in the Senior Secured Credit Facility, to (II) the sum of consolidated net interest expense plus letter of credit fees of not less than 2.50 to 1.00, in each case for the four quarters then ending. The Company was in compliance with these covenants for all periods presented.

Additionally, the Senior Secured Credit Facility provides for the issuance of letters of credit, limited to the lesser of total capacity or $80.0 million. As of December 31, 2019 and 2018, the Company had one letter of credit outstanding of $14.7 million under the Senior Secured Credit Facility.

See Note 19.c for discussion of a payment on the Senior Secured Credit Facility and the reduction in the borrowing base and aggregate elected commitment subsequent to December 31, 2019.

e. Debt issuance costs

The Company capitalized $2.5 million and $4.7 million of debt issuance costs during the years ended December 31, 2018 and 2017, respectively, as a result of entering into amendments to the Senior Secured Credit Facility. No debt issuance costs were capitalized during the year ended December 31, 2019.

The Company wrote-off $0.9 million of debt issuance costs during the year ended December 31, 2019, which are the "Write-off of debt issuance costs" on the consolidated statement of operations, as a result of reductions in borrowing base and aggregate elected commitment under the Senior Secured Credit Facility pursuant to the semi-annual redetermination. The Company wrote-off $5.3 million of debt issuance costs during the year ended December 31, 2017 as a result of the early redemption of the May 2022 Notes, which are included in "Loss on early redemption of debt" in the consolidated statement of operations. No debt issuance costs were written off during the year ended December 31, 2018.

The Company had total debt issuance costs of $9.0 million and $13.3 million, net of accumulated amortization of $27.5 million and $24.2 million, as of December 31, 2019 and 2018, respectively. Debt issuance costs related to the Company's March 2023 Notes and January 2022 Notes are included in "Long-term debt, net" on the consolidated balance sheets. Debt issuance costs related to the Senior Secured Credit Facility are included in "Other noncurrent assets, net" on the consolidated balance sheets. See Note 7.g for additional discussion of debt issuance costs.

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

(in thousands)	December 31, 2019
2020	3,118
2021	3,118
2022	2,223
2023	579
Total	9,038

f. Interest expense

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

	Years ended December 31,		
(in thousands)	2019	2018	2017
Cash payments for interest	$ 59,021	$ 54,969	$ 92,700
Amortization of debt issuance costs and other adjustments	3,111	3,655	3,968
Change in accrued interest	220	268	(6,139)
Interest costs incurred	62,352	58,892	90,529
Less capitalized interest	(805)	(988)	(1,152)
Total interest expense	$ 61,547	$ 57,904	$ 89,377

g. Long-term debt, net

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

	December 31, 2019			December 31, 2018		
(in thousands)	Long-term debt	Debt issuance costs, net	Long-term debt, net	Long-term debt	Debt issuance costs, net	Long-term debt, net
January 2022 Notes	$ 450,000	$ (2,034)	$ 447,966	$ 450,000	$ (3,010)	$ 446,990
March 2023 Notes	350,000	(2,549)	347,451	350,000	(3,354)	346,646
Senior Secured Credit Facility (1)	375,000	—	375,000	190,000	—	190,000
Total	$ 1,175,000	$ (4,583)	$ 1,170,417	$ 990,000	$ (6,364)	$ 983,636

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(1) Debt issuance costs, net related to our Senior Secured Credit Facility of $4.5 million and $7.0 million as of December 31, 2019 and 2018, respectively, are reported in "Other noncurrent assets, net" on the consolidated balance sheets.

See Note 19.a for discussion of the Company's Tender Offers of the March 2023 Notes and the January 2022 Notes and the Company's completion of an underwritten Offering subsequent to December 31, 2019.

Note 8 Stockholders' equity, Equity Incentive Plan and 401(k) plan

a. Share repurchase program

In February 2018, the Company's board of directors authorized a $200 million share repurchase program commencing in February 2018. The repurchase program expires in February 2020. Share repurchases under the share repurchase program may be made through a variety of methods, which may include open market purchases, privately negotiated transactions and block trades. The timing and actual number of share repurchases depends upon several factors, including market conditions, business conditions, the trading price of the Company's common stock and the nature of other investment opportunities available to the Company. During the year ended December 31, 2018, the Company 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. There were no share repurchases under this program during the year ended December 31, 2019.

b. Equity Incentive Plan

The Laredo Petroleum, Inc. Omnibus Equity Incentive Plan, as amended and restated as of May 16, 2019 (the "Equity Incentive Plan"), provides for the granting of incentive awards in the form of restricted stock awards, stock option awards, performance share awards, outperformance share awards, performance unit awards and other awards. On May 16, 2019, the Company's stockholders approved an amendment to the Equity Incentive Plan, among other items, to increase the maximum number of shares of the Company's common stock issuable under the Equity Incentive Plan from 24,350,000 shares to 29,850,000 shares.

The Company recognizes the fair value of stock-based compensation awards expected to vest over the requisite service period as a charge against earnings, net of amounts capitalized. The Company's stock-based compensation awards are accounted for as equity awards and are included in "General and administrative" on the consolidated statements of operations. The Company capitalizes a portion of stock-based compensation for employees who are directly involved in the acquisition, exploration or development of oil and natural gas properties into the full cost pool. Capitalized stock-based compensation is included in "Evaluated properties" on the consolidated balance sheets. The Company's performance unit awards granted in 2019 were initially accounted for as liability awards and included in "General and administrative", net of amounts capitalized, on the consolidated statement of operations and the corresponding liabilities were included in "Other noncurrent liabilities" on the consolidated balance sheet. Upon their modification during 2019, these performance unit awards were converted to performance share awards and the performance unit award compensation was reversed. See "Performance share awards" and "Performance unit awards" below for additional discussion of the modification.

Restricted stock awards

All service vesting restricted stock awards are treated as issued and outstanding in the consolidated financial statements. Per the award agreement terms, if employment is terminated prior to the restriction lapse date for reasons other than death or disability, the restricted stock awards are forfeited and canceled and are no longer considered issued and outstanding. If the termination of employment is by reason of death or disability, all of the holder's restricted stock will automatically vest. Restricted stock awards granted to employees vest in a variety of schedules that mainly include (i) 33%, 33% and 34% vesting per year beginning on the first anniversary of the grant date and (ii) full vesting on the first anniversary of the grant date. Stock awards granted to non-employee directors vest immediately on the grant date. Restricted stock awards granted to non-employee directors prior to August 2017 vested fully on the first anniversary of the grant date.

The following table reflects the restricted stock award activity for the years presented:

(in thousands, except for weighted-average grant-date fair value)	Restricted stock awards	Weighted-average grant-date fair value (per award)
Outstanding as of December 31, 2016	3,878	$ 12.88
Granted	1,237	$ 13.87
Forfeited	(302)	$ 12.87
Vested	(1,644)	$ 13.75
Outstanding as of December 31, 2017	3,169	$ 12.81
Granted	3,328	$ 8.34
Forfeited	(367)	$ 10.13
Vested	(1,934)	$ 11.92
Outstanding as of December 31, 2018	4,196	$ 9.91
Granted	7,613	$ 3.26
Forfeited	(3,559)	$ 5.11
Vested(1)	(2,752)	$ 8.92
Outstanding as of December 31, 2019	5,498	$ 4.29

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(1) The aggregate intrinsic value of vested restricted stock awards for the year ended December 31, 2019 was $10.0 million.

The Company utilizes the closing stock price on the grant date to determine the fair value of restricted stock awards. As of December 31, 2019, unrecognized stock-based compensation related to the restricted stock awards expected to vest was $14.2 million. Such cost is expected to be recognized over a weighted-average period of 1.93 years.

See Note 18 for discussion of the Company's organizational restructuring, that accounts for the majority of the restricted stock award forfeitures during the year ended December 31, 2019.

Stock option awards

The following table reflects the stock option award activity for the years presented:

(in thousands, except for weighted-average exercise price and weighted-average remaining contractual term)	Stock option awards	Weighted-average exercise price (per award)	Weighted-average remaining contractual term (years)
Outstanding as of December 31, 2016	2,370	$ 12.54	7.71
Granted	391	$ 14.12	
Exercised	(54)	$ 7.43	
Expired or canceled	(60)	$ 20.41	
Outstanding as of December 31, 2017	2,647	$ 12.70	7.12
Exercised	(21)	$ 4.10	
Expired or canceled	(53)	$ 18.92	
Forfeited	(40)	$ 9.23	
Outstanding as of December 31, 2018	2,533	$ 12.69	5.99
Exercised(1)	(18)	$ 4.10	
Expired or canceled	(1,842)	$ 13.55	
Forfeited	(333)	$ 8.61	
Outstanding as of December 31, 2019	340	$ 12.56	5.00
Vested and exercisable as of December 31, 2019(2)	303	$ 12.91	4.79
Expected to vest as of December 31, 2019(3)	37	$ 9.65	6.69

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(1) The exercised stock option awards for the year ended December 31, 2019 had de minimis intrinsic value.

(2) The vested and exercisable stock option awards as of December 31, 2019 had no intrinsic value.

(3) The stock option awards expected to vest as of December 31, 2019 had no intrinsic value.

The Company utilizes the Black-Scholes option pricing model to determine the fair value of stock option awards and recognizes the associated expense on a straight-line basis over the four-year requisite service period of the awards. Determining the fair value of equity-based awards requires judgment, including estimating the expected term that stock option awards will be outstanding prior to exercise and the associated volatility. As of December 31, 2019, unrecognized stock-based compensation related to stock option awards expected to vest was $0.1 million. Such cost is expected to be recognized over a weighted-average period of 0.98 years.

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

	February 17, 2017
Risk-free interest rate(1)	2.14%
Expected option life(2)	6.25 years
Expected volatility(3)	60.84%
Fair value per stock option award	$ 8.22

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

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

(3) The Company utilized its own volatility in order to develop the expected volatility.

Stock option awards granted to employees vest and become exercisable in four equal installments on each of the four anniversaries of the grant date, in accordance with the following schedule:

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

Unless employment is terminated sooner, the vested stock option award will expire if and to the extent it is not exercised within 10 years from the grant date. The unvested portion of a stock option award shall forfeit upon termination of employment, and the vested portion of a stock option award shall remain exercisable for (i) one year following termination of employment by reason of the holder's death or disability, but not later than the expiration of the option period, or (ii) 90 days following termination of employment for any reason other than the holder's death or disability, and other than the holder's termination of employment for cause. The vested but unexercised portion of a stock option award shall expire upon the termination of the option holder's employment or service by the Company for cause.

See Note 18 for discussion of the Company's organizational restructuring, that accounts for the majority of the restricted stock option forfeitures, expirations and cancellations during the year ended December 31, 2019.

Performance share awards

Performance share awards, which the Company has determined are equity awards, are subject to a combination of market, performance and service vesting criteria. For performance share awards with market criteria or portions of awards with market criteria, which include: (i) the relative three-year total shareholder return comparing the Company's shareholder return to the shareholder return of the peer group specified in each award agreement ("RTSR Performance Percentage"), (ii) the Company's absolute three-year total shareholder return ("ATSR Appreciation") and (iii) the Company's total shareholder return ("TSR"), a Monte Carlo simulation prepared by an independent third party is utilized to determine the grant-date (or modification date) fair value, and the associated expense is recognized on a straight-line basis over the three-year requisite service period of the awards. For portions of awards with performance criteria, which is the Company's three-year return on average capital employed ("ROACE Percentage"), the fair value is equal to the Company's closing stock price on the grant date (or modification date), and for each reporting period, the associated expense fluctuates and is adjusted based on an estimated payout of the number of shares of common stock to be delivered on the payment date for the three-year performance period. Any shares earned under performance share awards are expected to be issued in the first quarter following the completion of the respective requisite service periods based on the achievement of certain market and performance criteria, and the payout can range from 0% to 200%. Per the award agreement terms, if employment is terminated prior to the restriction lapse date for reasons other than death or disability, the performance share awards are forfeited and canceled. If the termination of employment is by reason of death or disability, and the market and performance criteria are satisfied, then the holder of the earned performance share awards will receive a prorated number of shares based on the number of days the participant was employed with the Company during the performance period.

The following table reflects the performance share award activity for the years presented:

(in thousands, except for weighted-average grant-date fair value)	Performance share awards	Weighted-average grant-date fair value (per award)
Outstanding as of December 31, 2016	2,325	$ 18.35
Granted	696	$ 18.96
Forfeited	(76)	$ 18.12
Vested(1)	(200)	$ 28.56
Outstanding as of December 31, 2017	2,745	$ 17.77
Granted(2)	1,389	$ 9.22
Forfeited	(244)	$ 14.93
Vested(3)	(454)	$ 16.23
Outstanding as of December 31, 2018	3,436	$ 13.74
Granted(2)	588	$ 2.52
Converted from performance unit awards(2)(4)	1,558	$ 3.74
Forfeited	(1,737)	$ 10.48
Vested(5)	(1,545)	$ 17.31
Outstanding as of December 31, 2019	2,300	$ 5.34

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

(2) The amounts potentially payable in the Company's common stock at the end of the requisite service period for the performance share awards granted on February 16, 2018, February 28, 2019 and June 3, 2019 will be determined based on three criteria: (i) RTSR Performance Percentage, (ii) ATSR Appreciation and (iii) ROACE Percentage. The RTSR Performance Percentage, ATSR Appreciation and ROACE Percentage will be used to identify the "RTSR Factor," the "ATSR Factor" and the "ROACE Factor," respectively, which are used to compute the "Performance Multiple" and ultimately to determine the number of shares to be delivered on the payment date. In computing the Performance Multiple, the RTSR Factor is given a 25% weight, the ATSR Factor a 25% weight and the ROACE Factor a 50% weight. The performance share awards granted on February 16, 2018 have a performance period of January 1, 2018 to December 31, 2020. The performance share awards granted on February 28, 2019 and June 3, 2019 have a performance period of January 1, 2019 to December 31, 2021.

(3) The performance share awards granted on February 27, 2015 had a performance period of January 1, 2015 to December 31, 2017 and, as their market criteria were not satisfied, resulted in a TSR modifier of 0% based on the Company finishing in the 36th percentile of its peer group for relative TSR. As such, the units were not converted into the Company's common stock during the first quarter of 2018.

(4) On May 16, 2019, the board of directors elected to change the form of payment from cash to common stock for the awards granted on February 28, 2019. This change in election triggered modification accounting, and the awards, formerly accounted for as liability awards, were converted to equity awards and, accordingly, new fair values were determined based on the May 16, 2019 modification date.

(5) The performance share awards granted on May 25, 2016 had a performance period of January 1, 2016 to December 31, 2018 and, as their market criteria were not satisfied, resulted in a TSR modifier of 0% based on the Company finishing in the ninth percentile of its peer group for relative TSR. As such, the units were not converted into the Company's common stock during the first quarter of 2019.

The performance share awards granted on February 17, 2017 had a performance period of January 1, 2017 to December 31, 2019 and, as their market criteria were not satisfied, resulted in a TSR modifier of 0% based on the Company finishing in the 15th percentile of its peer group for relative TSR. As such, the units will not be converted into the Company's common stock during the first quarter of 2020.

As of December 31, 2019, unrecognized stock-based compensation related to the performance share awards expected to vest was $7.4 million. Such cost is expected to be recognized over a weighted-average period of 1.98 years.

The following table presents (i) the fair values per performance share award and the assumptions used to estimate these fair values per performance share award and (ii) the expense per performance share award, which is the fair value per performance share award adjusted for the estimated payout of the performance criteria, for the outstanding performance share awards as of December 31, 2019 for the grant dates presented:

	June 3, 2019	February 28, 2019[(1)]	February 16, 2018	February 17, 2017
Market criteria:	(.25) RTSR Factor + (.25) ATSR Factor			TSR
Fair value assumptions:				
Remaining performance period on grant date	2.58 years	2.63 years	2.87 years	2.87 years
Risk-free interest rate[(2)]	1.78%	2.14%	2.34%	1.44%
Dividend yield	—%	—%	—%	—%
Expected volatility[(3)]	55.45%	55.01%	65.49%	74.00%
Closing stock price on grant date	$ 2.59	$ 3.49	$ 8.36	$ 14.12
Grant-date fair value per performance share award	$ 2.45	$ 3.98	$ 10.08	$ 18.96
Expense per performance share award as of December 31, 2019	$ 2.45	$ 3.98	$ 10.08	$ 18.96
Performance criteria:	(.50) ROACE Factor			Not applicable
Fair value assumptions:				
Closing stock price on grant date	$ 2.59	$ 3.49	$ 8.36	Not applicable
Grant-date fair value per performance share award	$ 2.59	$ 3.49	$ 8.36	Not applicable
Estimated payout for expense as of December 31, 2019	200.00%	200.00%	75.00%	Not applicable
Expense per performance share award as of December 31, 2019[(4)]	$ 5.18	$ 6.98	$ 6.27	Not applicable
Combined:				
Grant-date fair value per performance share award[(5)]	$ 2.52	$ 3.74	$ 9.22	$ 18.96
Expense per performance share award as of December 31, 2019[(6)]	$ 3.82	$ 5.48	$ 8.18	$ 18.96

(1) The fair value assumptions of the performance share awards granted on February 28, 2019 are based on the May 16, 2019 modification date. The total incremental compensation expense resulting from the modification of $1.0 million, which will be recognized over the life of the awards, is calculated utilizing (i) the difference between the March 31, 2019 fair value and the May 16, 2019 fair value and (ii) the outstanding quantity of the converted performance share awards as of June 30, 2019. Such expense excludes the estimated payout component for expense for the (.50) ROACE Factor as this is redetermined at each reporting period and the expense will fluctuate accordingly.

(2) The remaining performance period matched zero-coupon risk-free interest rate was derived from the U.S. Treasury constant maturities yield curve on the grant date for each respective award, with the exception of the awards granted on February 28, 2019, which used the modification date of May 16, 2019.

(3) The Company utilized its own remaining performance period matched historical volatility in order to develop the expected volatility.

(4) As the (.50) ROACE Factor is based on performance criteria, the expense fluctuates based on the estimated payout and is redetermined each reporting period and the life-to-date recognized expense for the respective awards is adjusted accordingly.

(5) The combined grant-date fair value per performance share award is the combination of the fair value per performance share award weighted for the market and performance criteria for the respective awards.

(6) The combined expense per performance share award is the combination of the expense per performance share award for market and performance criteria for the respective awards.

See Note 18 for discussion of the Company's organizational restructuring, that accounts for the majority of the performance award forfeitures during the year ended December 31, 2019.

Outperformance share award

An outperformance share award was granted during the year ended December 31, 2019, in conjunction with the appointment of the Company's President, and is accounted for as an equity award. If earned, the payout ranges from 0 to 1,000,000 shares in the Company's common stock per the vesting schedule. This award is subject to a combination of market and service vesting criteria, therefore, a Monte Carlo simulation prepared by an independent third party was utilized to determine the grant-date fair value with the associated expense recognized over the requisite service period. The payout of this award is based on the highest 50 consecutive trading day average closing stock price of the Company that occurs during the performance period that commenced on June 3, 2019 and ends on June 3, 2022 ("Final Date"). Of the earned outperformance shares, one-third of the award will vest on the Final Date, one-third will vest on the first anniversary of the Final Date and one-third will vest on the second anniversary of the Final Date, provided that the participant has been continuously employed with the Company through the applicable vesting date. Per the award agreement terms, if employment is terminated prior to any vesting date for reasons other than death or disability, then any outperformance shares that have not vested as of such date shall be forfeited and canceled. If the participant's employment is terminated prior to any vesting date by reason of death or disability, and the market criteria is satisfied, then the participant will receive a prorated number of shares based on the number of days the employee was employed with the Company during the performance period.

The total fair value of the outperformance share award and the assumptions used to estimate the fair value of the outperformance share award as of the grant date presented are as follows:

	June 3, 2019
Performance period	3.00 years
Risk-free interest rate(1)	1.77%
Dividend yield	—%
Expected volatility(2)	55.77%
Closing stock price on grant date	$ 2.59
Total fair value of outperformance share award (in thousands)	$ 670

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

(2) The Company utilized its own performance period matched historical volatility in order to develop the expected volatility.

As of December 31, 2019, unrecognized stock-based compensation related to the outperformance share award expected to vest was $0.6 million. Such cost is expected to be recognized over a weighted-average period of 4.50 years.

Stock-based compensation expense

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

	Years ended December 31,		
(in thousands)	2019	2018	2017
Restricted stock award compensation	$ 13,169	$ 25,271	$ 22,223
Stock option award compensation	740	3,862	4,762
Performance share award compensation	(1,250)	15,192	16,312
Outperformance share award compensation	101	—	—
Total stock-based compensation, gross	12,760	44,325	43,297
Less amounts capitalized in evaluated oil and natural gas properties	(4,470)	(7,929)	(7,563)
Total stock-based compensation, net	$ 8,290	$ 36,396	$ 35,734

See Note 18 for discussion of the Company's organizational restructuring and the related stock-based compensation reversals during the year ended December 31, 2019.

Performance unit awards

The performance unit awards, granted on February 28, 2019, were determined to be liability awards due to the board of directors' election to settle the awards in cash. On May 16, 2019, the board of directors elected to change the form of payment from cash to common stock and, as a result, the performance unit awards were converted to performance share awards, which the Company determined were now equity awards. This change in election triggered modification accounting, resulting in the reversal of performance unit award compensation and determination of a new fair value for the converted performance share awards, and are included in stock-based compensation based on the May 16, 2019 modification date. For additional discussion of the modification, see "Performance share awards."

The following table reflects the performance unit award activity for the year ended December 31, 2019:

(in thousands)	Performance unit awards
Outstanding as of December 31, 2018	—
Granted	2,813
Forfeited	(1,255)
Converted to performance share awards	(1,558)
Outstanding as of December 31, 2019	—

c. 401(k) plan

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

The following table presents the contributions expense recognized for the Company's 401(k) plan for the years presented:

	Years ended December 31,		
(in thousands)	2019	2018	2017
Contributions	$ 1,742	$ 2,156	$ 1,929

Note 9 Derivatives

The company has two types of derivative instruments (i) sales volumes commodity derivatives ("Commodity") and (ii) contingent consideration derivative ("Contingent consideration"). For further discussion, see Notes (i) 2.f for the Company's significant accounting policies for derivatives and their presentation in the consolidated financial statements, (ii) 10.a for fair value measurement on a recurring basis and (iii) 19.d for derivatives subsequent events.

a. Commodity

Due to the inherent volatility in oil, NGL and natural gas prices and differences in the prices of oil, NGL and natural gas between where the Company produces and where the Company sells such commodities, the Company engages in commodity derivative transactions, such as puts, swaps, collars, basis swaps and, in the past, call spreads to hedge price risk associated with a portion of the Company's anticipated sales volumes. By removing a portion of the price volatility associated with future sales volumes, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flows from operations .

The following discussion regarding the Company's transaction types and settlement indexes pertain to the years ended December 31, 2019, 2018 and 2017 as well as the open positions as of December 31, 2019.

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

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

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

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

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

Other than the oil basis swaps, the Company's oil derivatives are settled based on the month's arithmetic average of the daily settlement prices for either (i) the NYMEX index price for the first nearby month of the West Texas Intermediate Light Sweet Crude Oil Futures Contract or (ii) the ICE index price for the first nearby month of the Brent Crude Oil Futures Contract except for the last day of trading for the applicable expiring Brent Crude Oil Futures Contract whereby the second nearby month of the Brent Crude Oil Futures Contract settlement price will be used. The oil basis swaps are settled based on the differential between the basis swaps' fixed differential price as compared to the differential between the arithmetic average of each day's index prices for the first nearby month on the pricing dates in each calculation period, for only days when both indices settle, with the index prices being either (i) the Argus Americas Crude's WTI Midland-weighted average and the Cushing-based NYMEX West Texas Intermediate Light Sweet Crude Oil Futures Contract, (ii) the Argus Americas Crude's WTI Midland-weighted average and the Cushing-based WTI formula basis or (iii) the Argus Americas Crude's WTI Houston-weighted average and the WTI Midland-weighted average. The Company's NGL commodity derivatives are settled based on the month's arithmetic average of the daily average of the high and low OPIS index prices for Mont Belvieu Purity Ethane, TET and Non-TET Propane, Non-TET Normal Butane, Non-TET Isobutane and Non-TET Natural Gasoline. Other than the natural gas basis swaps, the Company's natural gas commodity derivatives are settled based on the NYMEX index price for Henry Hub or the Inside FERC index price for West Texas WAHA for the calculation period. The natural gas basis swaps are settled based on the differential between the basis swaps' fixed differential price as compared to the differential between the Inside FERC index price for West Texas WAHA and the NYMEX index price for Henry Hub for the calculation period.

During the year ended December 31, 2019, the Company completed hedge restructurings by early terminating puts and collars and entering into new swaps. The Company paid a net termination amount of $5.4 million that included the full settlement of the deferred premiums associated with a portion of these early-terminated puts and collars. The present value of these deferred premiums, classified under Level 3 of the fair value hierarchy, upon their early termination was $7.2 million. See Note 10 for information about the fair value hierarchy levels.

The following table details the commodity derivatives that were terminated:

	Aggregate volumes (Bbl)	Weighted-average floor price ($/Bbl)	Weighted-average ceiling price ($/Bbl)	Contract period
WTI NYMEX - Puts	5,087,500	$ 46.03	$ —	April 2019 - December 2019
WTI NYMEX - Put	366,000	$ 45.00	$ —	January 2020 - December 2020
WTI NYMEX - Collars	1,134,600	$ 45.00	$ 76.13	January 2020 - December 2020

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

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

b. Contingent consideration

The Company's asset acquisition of evaluated and unevaluated oil and natural gas properties that closed on December 12, 2019 provides for a potential contingent payment. If the arithmetic average of the monthly settlement WTI NYMEX prices for each consecutive calendar month for the one-year period beginning January 1, 2020 through December 31, 2020 exceeds $60.00 per barrel, the Company is required to pay to the counterparty an amount equal to $20 million. See Notes 4.a and 10.a for additional discussion of this contingent consideration.

c. Open commodity derivative positions

The following table summarizes open commodity derivative positions as of December 31, 2019, for commodity derivatives that were entered into through December 31, 2019, for the settlement periods presented:

	Year 2020	Year 2021
Oil:		
WTI NYMEX - Swaps:		
Hedged volume (Bbl)	7,173,600	—
Weighted-average price ($/Bbl)	$ 59.50	$ —
WTI NYMEX - Collars:		
Hedged volume (Bbl)	—	912,500
Weighted-average floor price ($/Bbl)	$ —	$ 45.00
Weighted-average ceiling price ($/Bbl)	$ —	$ 71.00
Brent ICE - Swaps:		
Hedged volume (Bbl)	1,830,000	—
Weighted-average price ($/Bbl)	$ 62.19	$ —
Totals:		
Total volume hedged with floor price (Bbl)	9,003,600	912,500
Weighted-average floor price ($/Bbl) - WTI NYMEX	$ 59.50	$ 45.00
Weighted-average floor price ($/Bbl) - Brent ICE	$ 62.19	$ —
Total volume hedged with ceiling price (Bbl)	9,003,600	912,500
Weighted-average ceiling price ($/Bbl) - WTI NYMEX	$ 59.50	$ 71.00
Weighted-average ceiling price ($/Bbl) - Brent ICE	$ 62.19	$ —
NGL:		
Purity Ethane - Swaps:		
Hedged volume (Bbl)	366,000	912,500
Weighted-average price ($/Bbl)	$ 13.60	$ 12.01
Non-TET Propane - Swaps:		
Hedged volume (Bbl)	1,244,400	730,000
Weighted-average price ($/Bbl)	$ 26.58	$ 25.52
Non-TET Normal Butane - Swaps:		
Hedged volume (Bbl)	439,200	255,500
Weighted-average price ($/Bbl)	$ 28.69	$ 27.72
Non-TET Isobutane - Swaps:		
Hedged volume (Bbl)	109,800	67,525
Weighted-average price ($/Bbl)	$ 29.99	$ 28.79
Non-TET Natural Gasoline - Swaps:		
Hedged volume (Bbl)	402,600	237,250
Weighted-average price ($/Bbl)	$ 45.15	$ 44.31
Total volume hedged (Bbl)	2,562,000	2,202,775
Natural gas:		
Henry Hub NYMEX - Swaps:		
Hedged volume (MMBtu)	23,790,000	14,052,500
Weighted-average price ($/MMBtu)	$ 2.72	$ 2.63
Basis Swaps:		
Hedged volume (MMBtu)	32,574,000	23,360,000
Weighted-average price ($/MMBtu)	$ (0.76)	$ (0.47)

Note 10 Fair value measurements

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

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

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

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

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

a. Fair value measurement on a recurring basis

For further discussion of the Company's derivatives, see Notes (i) 2.f for the Company's significant accounting policies for derivatives, (ii) 9 for derivatives and (iii) 19.d for derivatives subsequent events.

Balance sheet presentation

The following tables summarize the Company's derivatives' three-level fair value hierarchy by (i) assets and liabilities, (ii) current and noncurrent, (iii) commodity derivatives or contingent consideration derivative and (iv) oil, NGL, natural gas and/or deferred premiums, on a gross basis and the net presentation included in "Derivatives" on the consolidated balance sheets as of the dates presented:

	December 31, 2019					
(in thousands)	Level 1	Level 2	Level 3	Total gross fair value	Amounts offset	Net fair value presented on the consolidated balance sheets
Assets:						
Current:						
Commodity - Oil	$ —	$ 11,723	$ —	$ 11,723	$ (5,301)	$ 6,422
Commodity - NGL	—	13,787	—	13,787	(1,297)	12,490
Commodity - Natural gas	—	33,494	—	33,494	—	33,494
Commodity - Oil deferred premiums	—	—	—	—	(477)	(477)
Noncurrent:						
Commodity - Oil	$ —	$ 1,577	$ —	$ 1,577	$ —	$ 1,577
Commodity - NGL	—	9,547	—	9,547	—	9,547
Commodity - Natural gas	—	12,263	—	12,263	—	12,263
Liabilities:						
Current:						
Commodity - Oil	$ —	$ (5,649)	$ —	$ (5,649)	$ 5,301	$ (348)
Commodity - NGL	—	(1,297)	—	(1,297)	1,297	—
Commodity - Natural gas	—	—	—	—	—	—
Commodity - Oil deferred premiums	—	—	(477)	(477)	477	—
Contingent consideration - Oil	—	(7,350)	—	(7,350)	—	(7,350)
Noncurrent:						
Commodity - Natural gas	$ —	$ —	$ —	$ —	$ —	$ —
Net derivative asset (liability) positions	$ —	$ 68,095	$ (477)	$ 67,618	$ —	$ 67,618

(in thousands)	December 31, 2018 Level 1	Level 2	Level 3	Total gross fair value	Amounts offset	Net fair value presented on the consolidated balance sheets
Assets:						
Current:						
Commodity - Oil	$ —	$ 44,425	$ —	$ 44,425	$ (7,907)	$ 36,518
Commodity - NGL	—	1,974	—	1,974	—	1,974
Commodity - Natural gas	—	18,991	—	18,991	(3,267)	15,724
Commodity - Oil deferred premiums	—	—	—	—	(14,381)	(14,381)
Noncurrent:						
Commodity - Oil	$ —	$ 10,626	$ —	$ 10,626	$ —	$ 10,626
Commodity - NGL	—	1,024	—	1,024	—	1,024
Commodity - Natural gas	—	108	—	108	(728)	(620)
Liabilities:						
Current:						
Commodity - Oil	$ —	$ (9,059)	$ —	$ (9,059)	$ 7,907	$ (1,152)
Commodity - NGL	—	—	—	—	—	—
Commodity - Natural gas	—	(7,290)	—	(7,290)	3,267	(4,023)
Commodity - Oil deferred premiums	—	—	(16,565)	(16,565)	14,381	(2,184)
Contingent consideration - Oil	—	—	—	—	—	—
Noncurrent:						
Commodity - Natural gas	$ —	$ (728)	$ —	$ (728)	$ 728	$ —
Net derivative asset (liability) positions	$ —	$ 60,071	$ (16,565)	$ 43,506	$ —	$ 43,506

Commodity

Significant Level 2 inputs associated with the calculation of discounted cash flows used in the fair value mark-to-market analysis of commodity derivatives include each commodity derivative contract's corresponding commodity index price(s), forward price curve models for substantially similar instruments and counterparty risk-adjusted discount rates generated from a compilation of data gathered by a third-party valuation specialist. The Company reviewed the valuations, including the related inputs, and analyzed changes in fair values between reporting dates.

The Company's deferred premiums associated with its commodity derivative contracts are categorized as Level 3, as the Company utilizes a net present value calculation to determine the valuation. They are considered to be measured on a recurring basis as the commodity derivative contracts they derive from are measured on a recurring basis. As commodity derivative contracts containing deferred premiums are entered into, the Company discounts the associated deferred premium to its net present value at the contract trade date, using the Senior Secured Credit Facility rate at the trade date (input rate), and then records the change in net present value to interest expense over the period from trade until the final settlement date at the end of the contract. After this initial valuation, the input rate of each deferred premium is not adjusted; therefore, significant increases (decreases) in the Senior Secured Credit Facility rate would result in a significantly lower (higher) fair value measurement for each new contract entered into that contained a deferred premium; however, the initial valuation for the deferred premiums already recorded would remain unaffected. While the Company believes the sources utilized to arrive at the fair value estimates are reliable, different sources or methods could have yielded different fair value estimates. The deferred premiums are included in "Derivatives" on the consolidated balance sheets and, as of December 31, 2019, each of their input rates is 2.31%.

The following table presents payments required for commodity derivative deferred premiums as of December 31, 2019 for the calendar year presented:

(in thousands)	December 31, 2019
2020	$ 477

The following table summarizes the changes in net assets and liabilities classified as Level 3 measurements for the periods presented:

	Years ended December 31,		
(in thousands)	2019	2018	2017
Balance of Level 3 at beginning of year	$ (16,565)	$ (28,683)	$ (8,998)
Change in net present value of commodity derivative deferred premiums(1)	(139)	(694)	(394)
Total purchases and settlements of commodity derivative deferred premiums:			
Purchases	—	(7,523)	(25,733)
Settlements(2)	16,227	20,335	6,442
Balance of Level 3 at end of year	$ (477)	$ (16,565)	$ (28,683)

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(1) These amounts are included in "Interest expense" on the consolidated statements of operations.

(2) The amount for the year ended December 31, 2019 includes $7.2 million that represents the present value of deferred premiums settled upon their early termination.

Contingent consideration

Significant Level 2 inputs for the option pricing model used in the fair value mark-to-market analysis of the contingent consideration include WTI NYMEX Futures price curves, implied volatility of futures contracts and the Company's credit risk-adjusted discount rate generated from a compilation of data gathered by a third-party valuation specialist. The Company reviewed the valuations, including the related inputs, and analyzed changes in fair values between the acquisition closing and the reporting dates.

The fair values of the contingent consideration were $6.2 million as of the acquisition date, which is recorded as part of the basis in the oil and natural gas properties acquired in the associated acquisition, and $7.4 million as of December 31, 2019, respectively, and the Company has recorded a $7.4 million derivative liability as of December 31, 2019. The Company recognized a loss of $1.2 million during the year ended December 31, 2019, which is included in "Gain on derivatives, net" under "Non-operating income (expense)" on the consolidated statements of operations. At each subsequent quarterly reporting period, the Company will remeasure the contingent consideration with the changes in fair value recognized in earnings. See Notes 4.a and 9.b for additional discussion of this contingent consideration.

b. Fair value measurement on a nonrecurring basis

See Note 2.j for the Level 2 fair value hierarchy input assumptions used in estimating the NRV of line-fill inventory used to account for the impairment of line-fill inventory recorded during the year ended December 31, 2019. There were no impairments of line-fill inventory recorded during the years ended December 31, 2018 or 2017.

See Note 4.a for the Level 3 fair value hierarchy input assumptions used in estimating the fair values of assets acquired and liabilities assumed for acquisitions of evaluated and unevaluated oil and natural gas properties accounted for as a business combination for the year ended December 31, 2019. There were no acquisitions of evaluated and unevaluated oil and natural gas properties accounted for as business combinations for the years ended December 31, 2018 or 2017.

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. For purposes of fair value measurement, it was determined that the impairment of long-lived assets is classified as Level 3, based on the use of internally developed cash flow models. There were no long-lived asset impairments recorded during the years ended December 31, 2019, 2018 or 2017.

c. Items not accounted for at fair value

The carrying amounts reported on the consolidated balance sheets for cash and cash equivalents, accounts receivable, accounts payable, accrued capital expenditures, undistributed revenue and royalties and other accrued assets and liabilities approximate their fair values.

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

	December 31, 2019		December 31, 2018	
(in thousands)	**Long-term debt**	**Fair value(1)**	**Long-term debt**	**Fair value(1)**
January 2022 Notes	$ 450,000	$ 439,875	$ 450,000	$ 402,885
March 2023 Notes	350,000	332,500	350,000	316,624
Senior Secured Credit Facility	375,000	375,275	190,000	190,054
Total	$ 1,175,000	$ 1,147,650	$ 990,000	$ 909,563

(1) The fair values of the outstanding debt on the January 2022 Notes and the March 2023 Notes were determined using the Level 1 fair value hierarchy quoted market prices for each respective instrument as of December 31, 2019 and 2018. The fair values of the outstanding debt on the Senior Secured Credit Facility were estimated utilizing the Level 2 fair value hierarchy pricing model for similar instruments as of December 31, 2019 and 2018. See the beginning of Note 10 for information about the fair value hierarchy levels.

Note 11 Net income (loss) per common share

Basic net income (loss) per common share is computed by dividing net income (loss) by the weighted-average common shares outstanding for the period. Diluted net income (loss) per common share reflects the potential dilution of non-vested restricted stock awards, outstanding stock option awards, non-vested performance share awards and the non-vested outperformance share award. See Note 8.b for additional discussion of these awards. For the year ended December 31, 2019, all of these awards were anti-dilutive due to the Company's net loss and, therefore, were excluded from the calculation of diluted net loss per common share. The dilutive effects of these awards were calculated utilizing the treasury stock method for the years ended December 31, 2018 and 2017.

The following table reflects the calculations of basic and diluted (i) weighted-average common shares outstanding and (ii) net income (loss) per common share for the periods presented:

	Years ended December 31,		
(in thousands, except for per share data)	**2019**	**2018**	**2017**
Net income (loss) (numerator)	$ (342,459)	$ 324,595	$ 548,974
Weighted-average common shares outstanding (denominator):			
Basic(1)	231,295	232,339	239,096
Dilutive non-vested restricted stock awards	—	813	880
Dilutive outstanding stock option awards	—	20	122
Dilutive non-vested performance share awards	—	—	24
Diluted	231,295	233,172	240,122
Net income (loss) per common share:			
Basic	$ (1.48)	$ 1.40	$ 2.30
Diluted	$ (1.48)	$ 1.39	$ 2.29

(1) Weighted-average common shares outstanding used in the computation of basic and diluted net income (loss) per common share was computed taking into account share repurchases that occurred during the year ended December 31, 2018. See Note 8.a for additional discussion of the Company's share repurchase program.

Note 12 Income taxes

The Company is subject to federal and state income taxes and the Texas franchise tax. The following table presents the federal and state income taxes included in "Current" and "Deferred" income tax benefit (expense) in the consolidated statements of operations for the periods presented:

	Years ended December 31,		
(in thousands)	2019	2018	2017
Current income tax benefit (expense):			
Federal	$ —	$ —	$ —
State	—	807	(1,800)
Deferred income tax benefit (expense):			
Federal	—	—	—
State	2,588	(5,056)	—
Total income tax benefit (expense)	$ 2,588	$ (4,249)	$ (1,800)

Texas net deferred tax liabilities of $2.5 million and $5.1 million were recorded as of December 31, 2019 and 2018, respectively, which are included in "Other noncurrent liabilities" on the consolidated balance sheets, along with the corresponding deferred income tax benefit (expense) for the years ended December 31, 2019 and 2018.

A current tax refund of $0.8 million of Texas franchise tax was received as a result of differences in estimated versus actual taxable income from the gain on the Medallion Sale and was recorded as a current income tax benefit for the year ended December 31, 2018.

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

For the year ended December 31, 2017, current tax expense recorded of $1.8 million is comprised of Texas franchise tax, mainly as a result of the Medallion Sale in 2017. Additionally, the Company paid Alternative Minimum Tax ("AMT") related to the Medallion Sale. The payment of AMT creates an AMT credit carryforward. Due to changes in the Tax Act, AMT credit carryforwards do not expire and are now refundable over a five-year period.

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

(in thousands)	December 31, 2019
2020(1)	1,031
2021(2)	516
2022(2)	515
AMT credit carryforward	$ 2,062

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(1) Included in "Accounts receivable, net" as of December 31, 2019.

(2) Included in "Other noncurrent assets, net" as of December 31, 2019.

Total income tax benefit (expense) differed from amounts computed by applying the applicable federal income tax rate of 21% for the years ended December 31, 2019 and December 31, 2018 and 35% for the year ended December 31, 2017 to pre-tax earnings as a result of the following:

	Years ended December 31,		
(in thousands)	2019	2018	2017
Income tax benefit (expense) computed by applying the statutory rate	$ 72,460	$ (69,057)	$ (192,141)
(Increase) decrease in deferred tax valuation allowance	(69,316)	74,289	417,518
State income tax and change in valuation allowance	1,863	(9,070)	696
Change in tax rate applicable to net deferred tax assets	—	—	(226,263)
Stock-based compensation tax deficiency	—	—	(64)
Other items	(2,419)	(411)	(1,546)
Total income tax benefit (expense)	$ 2,588	$ (4,249)	$ (1,800)

The effective tax rates for the Company's operations were 1% for the years ended December 31, 2019 and 2018 and 0% for the year ended December 31, 2017. The Company's effective tax rate is affected by changes in tax rates, valuation allowances, recurring permanent differences and by discrete items that may occur in any given year, but are not consistent from year to year. The Company's effective tax rate is expected to remain at 1%, due to the full valuation allowance against the Company's federal and Oklahoma net deferred tax assets.

On January 1, 2018, the Company adopted ASC 606 using the modified retrospective approach of adoption with the cumulative effect recognized as an adjustment to the 2018 beginning balance of accumulated deficit, presented in the consolidated statements of stockholders' equity. As the effect on income taxes of adoption and transition to ASC 606 are direct effects of the change, the beginning balances of the federal and state deferred tax assets and the offsetting valuation allowances relating to the reclassification of the $141.1 million deferred gain on Medallion Sale were reduced by $30.7 million during the year ended December 31, 2018. See Note 13.a for further discussion of the impact of ASC 606 adoption.

The Company is required to estimate the federal and state income taxes in each of the jurisdictions it operates in. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items for tax and financial accounting purposes. These differences and the Company's net operating loss carryforwards result in deferred tax assets and liabilities.

The following table presents significant components of the Company's net deferred tax liability as of the dates presented:

(in thousands)	December 31, 2019	December 31, 2018
Net operating loss carryforward	$ 410,697	$ 392,276
Oil and natural gas properties, midstream service assets and other fixed assets	(109,931)	(168,031)
Stock-based compensation	20,448	19,845
Derivatives	(14,543)	(8,188)
Loss on sale of assets	(7,773)	(7,693)
Other	5,186	3,997
Net deferred tax asset before valuation allowance	304,084	232,206
Valuation allowance	(306,552)	(237,262)
Net deferred tax liability	$ (2,468)	$ (5,056)

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

(in thousands)	December 31, 2019
2026	$ 2,741
2027	38,651
2028	228,661
2029	101,932
2030	80,963
Thereafter	1,284,150
Total expiring federal net operating loss carryforwards	1,737,098
Non-expiring federal net operating loss carryforwards	210,541
Total federal net operating loss carryforwards	$ 1,947,639

The Company had federal net operating loss carryforwards totaling $1.9 billion and state of Oklahoma net operating loss carryforwards totaling $35.7 million as of December 31, 2019, which begin expiring in 2026 and 2032, respectively. Due to the passing of the Tax Act, $210.5 million of the federal net operating loss carryforwards will not expire but may be limited in future periods.

A valuation allowance is established to reduce deferred tax assets if it is determined that it is more likely than not that the related tax benefit will not be realized. On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realizability of the deferred tax assets and adjusts the amount of such allowances, if necessary. To the extent a valuation allowance is established or is increased or decreased during a period, there is a corresponding expense or reduction of expense within the tax provision in the consolidated statement of operations.

During the years ended December 31, 2019 and 2018, in evaluating whether it was more likely than not that the Company's net deferred tax assets were realizable through future net income, the Company considered all available positive and negative evidence, including (i) its earnings history exclusive of the loss that created the future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition, (ii) its ability to recover net operating loss carryforward deferred tax assets in future years, (iii) the existence of significant proved oil, NGL and natural gas reserves, (iv) its ability to use tax planning strategies, such as electing to capitalize intangible drilling costs as opposed to expensing such costs in order to prevent an operating loss carryforward from expiring unused and future projections of Oklahoma sourced income, (v) its current price protection utilizing oil, NGL and natural gas hedges, (vi) future revenue and operating cost projections that indicate it will produce more than enough taxable income to realize the deferred tax asset based on existing sales prices and cost structures and (vii) current market prices for oil, NGL and natural gas. Based on all the evidence available, the Company determined it was more likely than not that the net deferred tax assets were not realizable. As of December 31, 2019, a total valuation allowance of $306.6 million has been recorded to offset the Company's federal and Oklahoma net deferred tax assets resulting in a Texas net deferred tax liability of $2.5 million that is included in "Other noncurrent liabilities" on the consolidated balance sheets.

The Company files a single return. The Company's income tax returns for the years 2016 through 2019 remain open and subject to examination by federal tax authorities and/or the tax authorities in Oklahoma and Texas, which are the jurisdictions where the Company has operations. Additionally, the statute of limitations for examination of federal net operating loss carryforwards typically does not begin to run until the year the attribute is utilized in a tax return. See Note 2.r for the Company's significant accounting policies for income taxes.

Note 13 Revenue recognition

a. Impact of ASC 606 adoption

Upon adoption of ASC 606 on January 1, 2018, for the year ended December 31, 2018, the Company reclassified certain firm transportation payments on excess pipeline capacity and other contractual penalties, historically included in the "Other operating expenses" line item in the consolidated statements of operations, and netted them with the revenue stream from which they derive as these payments to customers do not relate to the provision of a distinct good or service to the customer. In addition, there was an impact upon adoption related to the treatment of the gain on the Medallion Sale discussed below.

At December 31, 2017, the Medallion Sale was accounted for under the real estate guidance in ASC 360-20, *Property, Plant, and Equipment* ("ASC 360-20"), and the Company's maximum exposure to loss associated with future commitments under the TA was $141.1 million that was not recorded in the Company's consolidated balance sheets. Under ASC 360-20, as a result of the Company's continuing involvement with Medallion by guaranteeing cash flows under the TA, the Company recorded a deferred gain in the amount of its maximum exposure to loss related to such guarantees. This deferred gain would have been amortized over the TA's firm commitment transportation term through 2024 had the Company not adopted ASC 606 on January 1, 2018. See Note 4.d for further discussion of the Medallion Sale and the TA.

In adopting ASC 606, the guidance in ASC 360-20 was superseded by ASC 860, *Transfers and Servicing* ("ASC 860"). The Medallion Sale is within the scope of ASC 860 and qualifies for sale accounting and recognition of the previously deferred gain because as of the date of the Medallion Sale (i) the Company transferred and legally isolated its full interests in Medallion to GIP, (ii) GIP received the right to pledge or exchange Medallion ownership interests at its full discretion and (iii) the Company did not have effective control over Medallion. Therefore, the deferred gain of $141.1 million was recognized as an adjustment to the 2018 beginning balance of accumulated deficit, presented in the consolidated statements of stockholders' equity, in accordance with the modified retrospective approach of adoption. See Note 12 for discussion of the income tax effect of the adoption of ASC 606.

b. Revenue recognition

See Note 2.o for a summary of significant revenue recognition accounting policies. Additional discussion of the underlying contracts that give rise to the Company's revenue and method of recognition is included below.

Oil sales and sales of purchased oil

Under its oil sales contracts, the Company sells produced or purchased oil at the delivery point specified in the contract and collects an agreed-upon index price, net of pricing differentials. The delivery point may be at the wellhead, the inlet of the purchaser's pipeline or nominated pipeline or the Company's truck unloading facility. At the delivery point, the purchaser typically takes custody, title and risk of loss of the product and, therefore, control as defined under ASC 606 typically passes at the delivery point. The Company recognizes revenue at the net price received when control transfers to the purchaser.

The Company engages in transactions in which it sells oil at the lease and subsequently repurchases the same volume of oil from that customer at a downstream delivery point under a separate agreement ("Repurchase Agreement") for use in the sale to the final customer. The commercial reasoning for such transactions may vary. Where a Repurchase Agreement exists, the Company must evaluate whether the customer obtains control of the oil at the lease and therefore whether it is appropriate to recognize revenue for the lease sale. Where the Company has an obligation or a right to repurchase the oil, the customer does not obtain control of the oil because it is limited in its ability to direct the use of, and obtain substantially all of the remaining benefits from the oil even though it may have physical possession of the oil. If the Company repurchases the oil for less than the original selling price, such a transaction will be classified as a lease. If the Company repurchases the oil for equal to or more than the original selling price, then the transaction represents a financing arrangement unless there is only a short passage of time between the sale and repurchase, in which case any excess amount paid represents an expense associated with the sale of oil to the final customer. The Company recognizes such repurchase expense and any transportation expenses incurred for the delivery of the oil to the final customer in the "Transportation and marketing expenses" line item in the accompanying consolidated statements of operations.

Under certain of its customer contracts, the Company is subject to firm transportation payments on excess pipeline capacity and other contractual penalties if it fails to deliver contractual minimum volumes to its customers. Such amounts are recorded as a reduction to the transaction price as these amounts do not represent payments to the customer for distinct goods or services and instead relate specifically to the failure to perform under the specific customer contract. Such amounts are recorded as a reduction to the transaction price when payment is determined as probable, typically when such a deficiency occurs.

NGL and natural gas sales

Under its natural gas processing contracts, the Company delivers produced natural gas to a midstream processing entity at the wellhead or the inlet of the processing entity's system. The processing entity processes the natural gas, sells the resulting NGL and residue gas to third parties and pays the Company for the NGL and residue gas with deductions that may include gathering, compression, processing and transportation fees. In these scenarios, the Company evaluates whether it is the principal or the agent in the transaction. For existing contracts, the Company has concluded that it is the agent in the ultimate sale to the third party and the midstream processing entity is the principal and that the Company has transferred control of unprocessed natural gas to the midstream processing entity; therefore, the Company recognizes revenue based on the net amount of the proceeds received from the midstream processing entity who represents the Company's customer. If for future contracts the Company was to conclude that it was the principal with the ultimate third party being the customer, the Company would recognize revenue for those contracts on a gross basis, with gathering, compression, processing, and transportation fees presented as an expense.

Midstream service revenues

Revenue from oil throughput agreements is recognized based on a rate per barrel for volumes transported. Under the Company's oil throughput agreements, a volumetric deduction is taken from customer oil as a pipeline loss allowance. While these amounts represent non-cash consideration under ASC 606, such deductions are immaterial. Revenue from natural gas throughput agreements is recognized based on a rate per MMbtu for volumes transported. Revenue from water delivery, recycling and takeaway is recognized based on the volumes of water for which the services are provided at the applicable contractual rate.

Imbalances

The Company recognizes revenue for all oil, NGL and natural gas sold to purchasers regardless of whether the sales are proportionate to the Company's ownership interest in the property. Production imbalances are recognized as a liability to the extent an imbalance on a specific property exceeds the Company's share of remaining proved oil, NGL and natural gas reserves. The Company is also subject to natural gas pipeline imbalances, which are recorded as accounts receivable or payable at values consistent with contractual arrangements with the owner of the pipeline. The Company did not have any producer or pipeline imbalance positions as of December 31, 2019 or 2018.

Significant judgments

The Company engages in various types of transactions in which unaffiliated midstream entities process the Company's liquids-rich natural gas and, in some scenarios, subsequently market resulting NGL and residue gas to third-party customers on the Company's behalf. These types of transactions require judgment to determine whether the Company is the principal or the agent in the contract and, as a result, whether revenues are recorded gross or net. For existing contracts, the Company has determined that it serves as the agent in the sale of products under certain natural gas processing and marketing agreements with unaffiliated midstream entities in accordance with the control model in ASC 606. As a result, the Company presents revenue on a net basis for amounts expected to be received from third-party customers through the marketing process, with expenses and deductions incurred subsequent to control of the product(s) transferring to the unaffiliated midstream entity being netted against revenue.

Transaction price allocated to remaining performance obligations

A significant number of the Company's product sales are short-term in nature with a contract term of one year or less. For those contracts, the Company has utilized the practical expedient in ASC 606-10-50-14 that exempts the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For the Company's product sales that have a contract term greater than one year and for its Midstream Services, the Company has utilized the practical expedient in ASC 606-10-50-14A that states that it is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under the Company's product sales contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied. Under the Midstream Services contracts each unit of service represents a separate performance obligation and therefore performance obligations in respect of future services are wholly unsatisfied.

Contract balances

Under the Company's customer contracts, invoicing occurs once the Company's performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company's contracts do not give rise to contract assets or liabilities under ASC 606.

Prior-period performance obligations

For sales of oil, NGL, natural gas and purchased oil, the Company records revenue in the month production is delivered to the purchaser. However, settlement statements and payment may not be received for 30 to 90 days after the date production is delivered and, as a result, the Company is required to estimate the amount of production that was delivered to the purchaser and the price that will be received for the sale of the product. The Company records the differences between estimates and the actual amounts received for product sales once payment is received from the purchaser. Such differences have historically not been significant. The Company uses knowledge of its properties, its properties' historical performance, spot market prices and other factors as the basis for these estimates. For the years ended December 31, 2019, 2018 and 2017, revenue recognized related to performance obligations satisfied in prior reporting periods was not material.

Note 14 Credit risk

The Company uses commodity derivatives to hedge its exposure to oil, NGL and natural gas price volatility. These transactions expose the Company to potential credit risk from its counterparties. The Company has entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of its commodity derivative counterparties, each of whom is also a lender in the Company's Senior Secured Credit Facility, which is secured by the Company's oil, NGL and natural gas reserves; therefore, the Company is not required to post any collateral. The Company does not require collateral from its commodity derivative counterparties. The terms of the ISDA Agreements provide the non-defaulting or non-affected party the right to terminate the agreement upon the occurrence of certain events of default and termination events by a party and also provide for the marking to market of outstanding positions and the offset of the mark to market amounts owed to and by the parties (and in certain cases, the affiliates of the non-defaulting or non-affected party) upon termination; therefore, the credit risk associated with the Company's commodity derivative counterparties is somewhat mitigated. The Company minimizes the credit risk in commodity derivatives by: (i) limiting its exposure to any single counterparty, (ii) entering into commodity derivatives only with counterparties that meet its minimum credit quality standard or have a guarantee from an affiliate that meets the Company's minimum credit quality standard and (iii) monitoring the creditworthiness of the Company's counterparties on an ongoing basis. As of December 31, 2019, the Company had derivative assets of $75.3 million from the fair values of its open commodity derivative contracts. See "Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Oil, NGL and natural gas price risk" located elsewhere in this Annual Report and Notes 2.f, 9, 10.a and 19.d for additional information regarding the Company's commodity derivatives

The Company typically sells production to a relatively limited number of customers, as is customary in the exploration, development and production business. The Company's sales of purchased oil are generally made to one to two customers. The Company's joint operations accounts receivable are from a number of oil and natural gas companies, partnerships, individuals and others who own interests in the oil and natural gas properties operated by the Company.

The majority of the Company's accounts receivable are unsecured. On occasion the Company requires its customers to post collateral, and the inability or failure of the Company's significant customers to meet their obligations to the Company or their insolvency or liquidation may adversely affect the Company's financial results. In the current market environment, the Company believes that it could sell its production to numerous companies, so that the loss of any one of its major purchasers would not have a material adverse effect on its financial condition and results of operations solely by reason of such loss. Additionally, management believes that any credit risk imposed by a concentration in the oil and natural gas industry is offset by the creditworthiness of the Company's customer base and industry partners. The Company routinely assesses the recoverability of all material trade and other receivables to determine collectability. See Notes 2.e and 13.b for additional information regarding the Company's accounts receivable and revenue recognition, respectively.

The following table presents purchasers that individually accounted for 10% or more of the Company's oil, NGL and natural gas sales in at least one of the years presented:

	Years ended December 31,		
	2019	2018	2017
Purchaser A[1]	59%	30%	13%
Purchaser B	18%	24%	26%
Purchaser C	15%	16%	17%
Purchaser D	4%	16%	39%

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(1) This purchaser of the Company's oil, NGL and natural gas sales is also a purchaser of the Company's sales of purchased oil included in the table below.

The following table presents purchasers that individually accounted for 10% or more of the Company's sales of purchased oil in at least one of the years presented:

	Years ended December 31,		
	2019	2018	2017
Purchaser A	70%	64%	—%
Purchaser B[1]	26%	—%	—%
Purchaser C	4%	36%	98%

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(1) This purchaser of the Company's sales of purchased oil is also a purchaser of the Company's oil, NGL and natural gas sales included in the table above.

The following table presents the purchasers that individually accounted for 10% or more of the Company's accounts receivable, net in at least one of the years presented:

	As of December 31,	
	2019	2018
Purchaser A	27%	24%
Purchaser B	15%	17%
Purchaser C	5%	17%
Purchaser D	—%	11%

Note 15 Commitments and contingencies

a. Litigation

From time to time, the Company is subject to various legal proceedings arising in the ordinary course of business, including proceedings for which the Company may not have insurance coverage. While many of these matters involve inherent uncertainty, as of the date hereof, the Company does not currently believe that any such legal proceedings will have a material adverse effect on the Company's business, financial position, results of operations or liquidity. During the year ended December 31, 2019, the Company finalized and received a favorable settlement of $42.5 million in connection with the Company's damage claims asserted in a previously disclosed litigation matter relating to a breach and wrongful termination of a crude oil purchase agreement. This settlement is included in "Litigation settlement" on the consolidated statement of operations. The Company does not anticipate the receipt of further payments in connection with this matter as this settlement constituted a full and final satisfaction of the Company's claims.

b. Drilling rig contracts

The Company has committed to drilling rig contracts with a third party to facilitate the Company's drilling plans. Two of these contracts are for a term of multiple months and contain an early termination clause that requires the Company to potentially pay penalties to the third party should the Company cease drilling efforts. These penalties would negatively impact the Company's financial statements upon early contract termination. There were no penalties incurred for early contract termination for the years ended December 31, 2019, 2018 or 2017. Management does not currently anticipate the early termination of these contracts in 2020. As the Company's current drilling rig contracts are operating leases under the scope of ASC 842, the present value of the future commitments as of December 31, 2019 related to the drilling rig contracts with an initial term greater than 12 months is included in current and non-current "Operating lease liabilities" on the consolidated balance sheet as of December 31, 2019. See Note 5 for further discussion of the impact of the adoption of ASC 842. See Note 16 for additional information regarding the drilling rig contracts as they pertain to a related party.

c. Firm sale and transportation commitments

The Company has committed to deliver, for sale or transportation, fixed volumes of product under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. If not fulfilled, the Company is subject to firm transportation payments on excess pipeline capacity and other contractual penalties. These commitments are normal and customary for the Company's business. In certain instances, the Company has used spot market purchases to meet its commitments in certain locations or due to favorable pricing. Management anticipates continuing this practice in the future. The Company incurred firm transportation payments on excess pipeline capacity and other contractual penalties of $0.9 million, $4.7 million and $1.1 million during the years ended December 31, 2019, 2018 and 2017, respectively. In the consolidated statements of operations, these firm transportation payments on excess pipeline capacity and other contractual penalties are netted with their respective revenue stream for the years ended December 31, 2019 and 2018, and are included in "Other operating expenses" for the year ended December 31, 2017. Future firm sale and transportation commitments of $322.8 million as of December 31, 2019 are not recorded in the consolidated balance sheet. For information regarding the impact of the adoption of ASC 606 on the TA related to Medallion and the presentation of firm transportation payments on excess pipeline capacity and other contractual penalties, see Notes 4.d and 13.a.

d. Federal and state regulations

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

e. Environmental

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, among other things, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed in the period incurred. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. Management believes no material significant liabilities of this nature existed as of December 31, 2019 or 2018.

Note 16 Related party

a. Helmerich & Payne, Inc.

The Chairman of the Company's board of directors is on the board of directors of Helmerich & Payne, Inc. ("H&P"). The Company has drilling rig contracts with H&P that are operating leases. Two of the drilling rig contracts, which are accounted for as long-term operating leases under the scope of ASC 842 due to an initial term of greater than 12 months, are capitalized and are included in "Operating lease right-of-use-assets" and the present value of the future commitments is included in current and non-current "Operating lease liabilities" on the consolidated balance sheet as of December 31, 2019. Capital expenditures for oil and natural gas properties are capitalized and are included in "Evaluated oil and natural gas properties" on the consolidated balance sheets. See Note 5 for additional discussion of the Company's adoption of ASC 842. See Note 15.b for additional discussion of the Company's drilling rig contracts.

The following table presents the operating lease liabilities related to H&P included in the consolidated balance sheet:

(in thousands)	December 31, 2019
Operating lease liabilities:	
Current	$ 9,605
Noncurrent	6,907
Total operating lease liabilities	$ 16,512

The following table presents the capital expenditures for oil and natural gas properties related to H&P included in the consolidated statements of cash flows:

	Years ended December 31,		
(in thousands)	2019	2018	2017
Capital expenditures for oil and natural gas properties	$ 18,089	$ 3,040	$ —

Note 17 Subsidiary Guarantors

The Guarantors have fully and unconditionally guaranteed the January 2022 Notes, the March 2023 Notes and the Senior Secured Credit Facility (and had guaranteed the May 2022 Notes until the May 2022 Notes Redemption Date), subject to the Releases. In accordance with practices accepted by the SEC, Laredo has prepared condensed consolidating financial statements to quantify the balance sheets, results of operations and cash flows of such subsidiaries as subsidiary Guarantors. The following condensed consolidating balance sheets as of December 31, 2019 and 2018 and condensed consolidating statements of operations and condensed consolidating statements of cash flows each for the years ended December 31, 2019, 2018 and 2017 present financial information for Laredo on a stand-alone basis (carrying any investment in subsidiaries under the equity method), financial information for the subsidiary Guarantors on a stand-alone basis (carrying any investment in subsidiaries under the equity method), and the consolidation and elimination entries necessary to arrive at the information for the Company on a condensed consolidated basis. Income taxes for LMS and for GCM are recorded on Laredo's balance sheets, statements of operations and statements of cash flows as they are disregarded entities for income tax purposes. Laredo and the Guarantors are not restricted from making intercompany distributions to each other.

Condensed consolidating balance sheet
December 31, 2019

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Accounts receivable, net	$ 80,737	$ 4,486	$ —	$ 85,223
Other current assets	113,435	1,821	—	115,256
Oil and natural gas properties, net	1,858,401	8,980	(28,342)	1,839,039
Midstream service assets, net	—	128,678	—	128,678
Other fixed assets, net	32,497	7	—	32,504
Investment in subsidiaries	138,770	—	(138,770)	—
Other noncurrent assets, net	60,018	3,719	—	63,737
Total assets	$ 2,283,858	$ 147,691	$ (167,112)	$ 2,264,437
Accounts payable and accrued liabilities	$ 34,610	$ 5,911	$ —	$ 40,521
Other current liabilities	129,975	400	—	130,375
Long-term debt, net	1,170,417	—	—	1,170,417
Other noncurrent liabilities	78,640	2,610	—	81,250
Stockholders' equity	870,216	138,770	(167,112)	841,874
Total liabilities and stockholders' equity	$ 2,283,858	$ 147,691	$ (167,112)	$ 2,264,437

Condensed consolidating balance sheet
December 31, 2018

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Accounts receivable, net	$ 83,424	$ 10,897	$ —	$ 94,321
Other current assets	97,045	1,386	—	98,431
Oil and natural gas properties, net	2,043,009	9,113	(22,551)	2,029,571
Midstream service assets, net	—	130,245	—	130,245
Other fixed assets, net	39,751	68	—	39,819
Investment in subsidiaries	128,380	—	(128,380)	—
Other noncurrent assets, net	23,783	4,135	—	27,918
Total assets	$ 2,415,392	$ 155,844	$ (150,931)	$ 2,420,305
Accounts payable and accrued liabilities	$ 54,167	$ 15,337	$ —	$ 69,504
Other current liabilities	121,297	9,664	—	130,961
Long-term debt, net	983,636	—	—	983,636
Other noncurrent liabilities	59,511	2,463	—	61,974
Stockholders' equity	1,196,781	128,380	(150,931)	1,174,230
Total liabilities and stockholders' equity	$ 2,415,392	$ 155,844	$ (150,931)	$ 2,420,305

Condensed consolidating statement of operations
Year ended December 31, 2019

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total revenues	$ 737,957	$ 158,249	$ (58,925)	$ 837,281
Total costs and expenses	1,150,382	148,624	(53,134)	1,245,872
Operating income (loss)	(412,425)	9,625	(5,791)	(408,591)
Interest expense	(61,547)	—	—	(61,547)
Other non-operating income, net	134,716	1,056	(10,681)	125,091
Income (loss) before income taxes	(339,256)	10,681	(16,472)	(345,047)
Total income tax benefit	2,588	—	—	2,588
Net income (loss)	$ (336,668)	$ 10,681	$ (16,472)	$ (342,459)

Condensed consolidating statement of operations
Year ended December 31, 2018

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total revenues	$ 809,396	$ 365,633	$ (69,254)	$ 1,105,775
Total costs and expenses	466,895	353,806	(63,418)	757,283
Operating income	342,501	11,827	(5,836)	348,492
Interest expense	(57,904)	—	—	(57,904)
Other non-operating income (expense), net	50,083	(1,049)	(10,778)	38,256
Income before income taxes	334,680	10,778	(16,614)	328,844
Total income tax expense	(4,249)	—	—	(4,249)
Net income	$ 330,431	$ 10,778	$ (16,614)	$ 324,595

Condensed consolidating statement of operations
Year ended December 31, 2017

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total revenues	$ 623,028	$ 266,455	$ (67,321)	$ 822,162
Total costs and expenses	376,938	254,398	(58,846)	572,490
Operating income	246,090	12,057	(8,475)	249,672
Interest expense	(89,377)	—	—	(89,377)
Other non-operating income, net(1)	402,536	413,989	(426,046)	390,479
Income before income taxes	559,249	426,046	(434,521)	550,774
Total income tax expense	(1,800)	—	—	(1,800)
Net income	$ 557,449	$ 426,046	$ (434,521)	$ 548,974

(1) Includes $405.9 million for Subsidiary Guarantors related to gain on sale of investment in equity method investee. See Note 4.d for further discussion.

Condensed consolidating statement of cash flows
Year ended December 31, 2019

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Net cash provided by operating activities	$ 477,621	$ 8,134	$ (10,681)	$ 475,074
Net cash used in investing activities	(664,258)	(8,134)	10,681	(661,711)
Net cash provided by financing activities	182,343	—	—	182,343
Net decrease in cash and cash equivalents	(4,294)	—	—	(4,294)
Cash and cash equivalents, beginning of period	45,150	1	—	45,151
Cash and cash equivalents, end of period	$ 40,856	$ 1	$ —	$ 40,857

Condensed consolidating statement of cash flows
Year ended December 31, 2018

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Net cash provided by operating activities	$ 528,281	$ 20,301	$ (10,778)	$ 537,804
Net cash used in investing activities	(681,433)	(20,301)	10,778	(690,956)
Net cash provided by financing activities	86,144	—	—	86,144
Net decrease in cash and cash equivalents	(67,008)	—	—	(67,008)
Cash and cash equivalents, beginning of period	112,158	1	—	112,159
Cash and cash equivalents, end of period	$ 45,150	$ 1	$ —	$ 45,151

Condensed consolidating statement of cash flows
Year ended December 31, 2017

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

Note 18 Organizational restructuring

On April 2, 2019, the Company announced the retirement of two of its Senior Officers. Additionally, on April 8, 2019 (the "Effective Date"), the Company committed to a company-wide reorganization effort (the "Plan") that included a workforce reduction of approximately 20%, which included an Executive Officer. The reduction in workforce was communicated to employees on the Effective Date and implemented immediately, subject to certain administrative procedures. The Company's board of directors approved the Plan in response to recent market conditions and to reduce costs and better position the Company for the future. All stock-based compensation awards held by the two Senior Officers, the Executive Officer and the employees who were affected by the Plan were forfeited and the corresponding stock-based compensation was reversed.

On September 27, 2019, in connection with the previously announced comprehensive succession planning process, the Company announced that, effective as of October 1, 2019, Randy A. Foutch would transition from his role as Chief Executive Officer. In connection with this transition and in recognition of his efforts as the Company's founder, Mr. Foutch entered into an agreement under which he received the following payments and benefits: (i) a "Founder's Bonus" of $5.9 million approved by the board of directors and (ii) 18 months of COBRA employer contributions following October 1, 2019. All stock-based compensation awards held by Mr. Foutch were forfeited and the corresponding stock-based compensation was reversed.

In connection with the retirements on April 2, 2019, the Plan and the transition of Mr. Foutch, the Company incurred $16.4 million of one-time charges during the year ended December 31, 2019 comprising of compensation, taxes, professional fees, outplacement and insurance-related expenses. These incurred charges were recorded as "Organizational restructuring expenses" on the consolidated statement of operations. Additionally, the total gross stock-based compensation reversal included in "General and administrative" on the consolidated statement of operations was $11.7 million during the year ended ended December 31, 2019. See Note 8.b for additional information on the associated forfeiture activity.

Note 19 Subsequent events

a. New Notes, Tender Offers and redemptions of Prior Notes

On January 24, 2020, the Company completed an offer and sale (the "Offering") of $600.0 million in aggregate principal amount of 9 1/2% senior unsecured notes due 2025 (the "January 2025 Notes") and $400.0 million in aggregate principal amount of 10 1/8% senior unsecured notes due 2028 (the "January 2028 Notes" and, together with the January 2025 Notes, the "New Notes"). Interest for the New Notes is payable on January 15 and July 15 of each year. The first interest payment will be made on July 15, 2020, and will consist of interest from closing to that date. The terms of the New Notes include covenants, which are in addition to but different than similar covenants in the Senior Secured Credit Facility, which limit the Company's ability to incur indebtedness, make restricted payments, grant liens and dispose of assets. The New Notes are fully and unconditionally guaranteed on a senior unsecured basis by the Guarantors and certain of the Company's future restricted subsidiaries subject to certain Releases.

The Company received net proceeds of approximately $982.0 million from the Offering, after deducting underwriting discounts and commissions and estimated offering expenses. The proceeds from the Offering have been or will be used (i) to fund Tender Offers (defined below) for any or all of the Company's Prior Notes (defined below), (ii) to repay the Company's $450.0 million January 2022 Notes and $350.0 million March 2023 Notes (together, the "Prior Notes") that remain outstanding after the completion or termination of the Tender Offers and (iii) for general corporate purposes, including repaying a portion of the borrowings outstanding under the Company's Senior Secured Credit Facility.

On January 6, 2020, the Company commenced cash tender offers and consent solicitations for any or all of its outstanding Prior Notes (collectively, the "Tender Offers"). On January 24, 2020 and February 6, 2020, the Company settled the Tender Offers. On January 29, 2020, the Company redeemed the remaining January 2022 Notes not tendered under the Tender Offers at a redemption price of 100.000% of the principal amount thereof, plus accrued and unpaid interest. On March 15, 2020, the Company anticipates redeeming the remaining $50.6 million of March 2023 Notes not tendered under the Tender Offers at a redemption price of 101.563% of the principal amount of the March 2023 Notes, plus accrued and unpaid interest. See 7.g for discussion of the Prior Notes' debt issuance costs recorded at December 31, 2019.

b. Asset acquisition

On February 4, 2020, the Company closed a transaction for $22.5 million acquiring 1,180 net acres and divesting 80 net acres in Howard County, Texas.

c. Senior Secured Credit Facility

On January 24, 2020, effective upon the closing of the Offering, the borrowing base and aggregate elected commitment under the Company's Senior Secured Credit Facility were automatically reduced to $950.0 million each.

On January 29, 2020, the Company paid $100.0 million on the Senior Secured Credit Facility. As a result, the outstanding balance under the Senior Secured Credit Facility was $275.0 million as of February 11, 2020.

d. Derivatives

Subsequent to December 31, 2019, the Company completed a hedge restructuring by early terminating collars and entering into new swaps. The following table details the commodity derivatives that were terminated:

	Aggregate volumes (Bbl)	Floor price ($/Bbl)	Ceiling price ($/Bbl)	Contract period
WTI NYMEX - Collars	912,500	$ 45.00	$ 71.00	January 2021 - December 2021

The following table summarizes open commodity derivative positions as of December 31, 2019 for commodity derivatives that were entered into through February 12, 2020, for the settlement periods presented:

	Year 2020	Year 2021
Oil:		
WTI NYMEX - Swaps:		
Hedged volume (Bbl)	7,173,600	—
Weighted-average price ($/Bbl)	$ 59.50	$ —
Brent ICE - Swaps:		
Hedged volume (Bbl)	2,379,000	1,825,000
Weighted-average price ($/Bbl)	$ 63.07	$ 60.13
Totals:		
Total volume hedged (Bbl)	9,552,600	1,825,000
Weighted-average price ($/Bbl) - WTI NYMEX	$ 59.50	$ —
Weighted-average price ($/Bbl) - Brent ICE	$ 63.07	$ 60.13
NGL:		
Purity Ethane - Swaps:		
Hedged volume (Bbl)	366,000	912,500
Weighted-average price ($/Bbl)	$ 13.60	$ 12.01
Non-TET Propane - Swaps:		
Hedged volume (Bbl)	1,244,400	730,000
Weighted-average price ($/Bbl)	$ 26.58	$ 25.52
Non-TET Normal Butane - Swaps:		
Hedged volume (Bbl)	439,200	255,500
Weighted-average price ($/Bbl)	$ 28.69	$ 27.72
Non-TET Isobutane - Swaps:		
Hedged volume (Bbl)	109,800	67,525
Weighted-average price ($/Bbl)	$ 29.99	$ 28.79
Non-TET Natural Gasoline - Swaps:		
Hedged volume (Bbl)	402,600	237,250
Weighted-average price ($/Bbl)	$ 45.15	$ 44.31
Total volume hedged (Bbl)	2,562,000	2,202,775
Natural gas:		
Henry Hub NYMEX Swaps:		
Hedged volume (MMBtu)	23,790,000	14,052,500
Weighted-average price ($/MMBtu)	$ 2.72	$ 2.63
Basis Swaps:		
Hedged volume (MMBtu)	32,574,000	23,360,000
Weighted-average price ($/MMBtu)	$ (0.76)	$ (0.47)

See Note 9.a for discussion regarding the Company's derivative settlement indexes.

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

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

The following table presents costs incurred in the acquisition, exploration and development of oil and natural gas properties, with asset retirement obligations included in evaluated property acquisition costs and development costs, for the periods presented:

	Years ended December 31,		
(in thousands)	2019	2018	2017
Property acquisition costs:			
Evaluated	$ 126,372	$ 15,072	$ —
Unevaluated	83,738	2,790	—
Exploration costs	19,954	23,884	36,257
Development costs	450,501	607,790	560,919
Total costs incurred	$ 680,565	$ 649,536	$ 597,176

b. Aggregate capitalized oil, NGL and natural gas costs

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

(in thousands)	December 31, 2019	December 31, 2018
Gross capitalized costs:		
Evaluated properties	$ 7,421,799	$ 6,752,631
Unevaluated properties not being depleted	142,354	130,957
Total gross capitalized costs	7,564,153	6,883,588
Less accumulated depletion and impairment	(5,725,114)	(4,854,017)
Net capitalized costs	$ 1,839,039	$ 2,029,571

The following table presents a summary of the unevaluated property costs not being depleted as of December 31, 2019, by year in which such costs were incurred:

(in thousands)	2019	2018	2017	2016 and prior	Total
Unevaluated properties not being depleted	$ 97,213	$ 5,028	$ 4,905	$ 35,208	$ 142,354

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

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

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

	Years ended December 31,		
(in thousands)	2019	2018	2017
Revenues:			
Oil, NGL and natural gas sales	$ 706,548	$ 808,530	$ 621,507
Production costs:			
Lease operating expenses	90,786	91,289	75,049
Production and ad valorem taxes	40,712	49,457	37,802
Transportation and marketing expenses	25,397	11,704	—
Total production costs	156,895	152,450	112,851
Other costs:			
Depletion	250,857	196,458	143,592
Accretion of asset retirement obligations	3,926	4,233	3,567
Impairment expense	620,565	—	—
Income tax (benefit) expense(1)	(3,257)	4,554	—
Total other costs	872,091	205,245	147,159
Results of operations	$ (322,438)	$ 450,835	$ 361,497

(1) During each of the years ended December 31, 2019, 2018 and 2017, the Company recorded valuation allowances against its deferred tax assets related to its oil, NGL and natural gas producing activities. Accordingly, the income tax (benefit) expense was computed utilizing the Company's effective tax rates of 1% for the years ended December 31, 2019 and 2018 and 0% for the year ended December 31, 2017, which reflects tax deductions and tax credits and allowances relating to the oil, NGL and natural gas producing activities that are reflected in the Company's "Total income tax benefit (expense)" on the consolidated statements of operations.

d. Net proved oil, NGL and natural gas reserves

Ryder Scott Company, L.P. ("Ryder Scott"), the Company's independent reserve engineers, estimated 100% of the Company's proved reserves as of December 31, 2019, 2018 and 2017. In accordance with SEC regulations, the reserves as of December 31, 2019, 2018 and 2017 were estimated using the Realized Prices, which reflect adjustments to the Benchmark Prices for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. See Note 6.a for these Realized Prices. The Company's reserves as of December 31, 2019, 2018 and 2017 are reported in three streams: oil, NGL and natural gas.

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

The following tables provide an analysis of the changes in estimated proved reserve quantities of oil, NGL and natural gas for the years ended December 31, 2019, 2018 and 2017, all of which are located within the U.S.

	Year ended December 31, 2019			
	Oil (MBbl)	NGL (MBbl)	Natural gas (MMcf)	MBOE
Proved developed and undeveloped reserves:				
Beginning of year	61,894	86,647	537,756	238,167
Revisions of previous estimates	(7,865)	5,301	69,678	9,049
Extensions, discoveries and other additions	13,573	12,614	83,345	40,078
Acquisitions of reserves in place	21,413	6,754	44,627	35,605
Production	(10,376)	(9,118)	(60,169)	(29,522)
End of year	78,639	102,198	675,237	293,377
Proved developed reserves:				
Beginning of year	55,893	79,241	491,828	217,105
End of year	52,711	90,861	600,334	243,628
Proved undeveloped reserves:				
Beginning of year	6,001	7,406	45,928	21,062
End of year	25,928	11,337	74,903	49,749

	Year ended December 31, 2018			
	Oil (MBbl)	NGL (MBbl)	Natural gas (MMcf)	MBOE
Proved developed and undeveloped reserves:				
Beginning of year	79,413	67,371	414,592	215,883
Revisions of previous estimates	(20,921)	11,089	72,028	2,173
Extensions, discoveries and other additions	13,330	15,112	93,762	44,069
Acquisitions of reserves in place	596	457	2,810	1,521
Divestitures of reserves in place	(349)	(123)	(756)	(598)
Production	(10,175)	(7,259)	(44,680)	(24,881)
End of year	61,894	86,647	537,756	238,167
Proved developed reserves:				
Beginning of year	68,877	60,441	371,946	191,309
End of year	55,893	79,241	491,828	217,105
Proved undeveloped reserves:				
Beginning of year	10,536	6,930	42,646	24,574
End of year	6,001	7,406	45,928	21,062

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

The following discussion is for the year ended December 31, 2019. The Company's positive revision of 9,049 MBOE of previously estimated quantities consisted of (i) 20,858 MBOE of positive revisions from performance of proved developed producing wells, (ii) 12,417 MBOE of negative revisions from a decrease in the Realized Prices for oil, NGL and natural gas and other changes to proved developed producing wells and (iii) 608 MBOE of positive revisions due to proved undeveloped locations that were removed from the development plan in prior years. Extensions, discoveries and other additions of 40,078 MBOE consisted of (i) 24,629 MBOE that resulted from new wells drilled and (ii) 15,449 MBOE that resulted from new horizontal proved undeveloped locations added in our established acreage. Acquisitions of reserves in place of 35,605 MBOE consisted of (i) 1,306 MBOE from new proved developed producing wells and (ii) 34,299 MBOE from 86 new proved undeveloped locations in Howard and western Glasscock Counties of Texas.

The following discussion is for the year ended December 31, 2018. The Company's 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, eight of these locations were drilled in 2018 and two were scheduled to be drilled in 2019. Extensions, discoveries and other additions of 44,069 MBOE consisted of (i) 25,617 MBOE that resulted from new wells drilled and (ii) 18,452 MBOE that resulted from new horizontal proved undeveloped locations added.

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

e. Standardized measure of discounted future net cash flows

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

The estimates of future cash flows and future production and development costs as of December 31, 2019, 2018 and 2017 are based on the Realized Prices, which reflect adjustments to the Benchmark Prices for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. All Realized

Prices are held flat over the forecast period for all reserve categories in calculating the discounted future net revenues. Any effect from the Company's commodity hedges is excluded. In accordance with SEC regulations, the proved reserves were anticipated to be economically producible from the "as of date" forward based on existing economic conditions, including prices and costs at which economic producibility from a reservoir was determined. These costs, held flat over the forecast period, include development costs, operating costs, ad valorem and production taxes and abandonment costs after salvage. Future income tax expenses are computed using the appropriate year-end statutory tax rates applied to the future pretax net cash flows from proved oil, NGL and natural gas reserves, less the tax basis of the Company's oil and natural gas properties. The estimated future net cash flows are then discounted at a rate of 10%. The Company's unamortized cost of evaluated oil and natural gas properties being depleted exceeded the full cost ceiling as of September 30, 2019 and December 31, 2019, but did not record any similar impairments for the years ended December 31, 2018 or 2017. See Note 6.a for discussion of the Benchmark Prices, Realized Prices and the 2019 full cost ceiling impairment recorded.

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

	Years ended December 31,		
(in thousands)	**2019**	**2018**	**2017**
Future cash inflows	$ 5,702,580	$ 6,266,862	$ 5,777,533
Future production costs	(1,994,732)	(1,977,401)	(1,675,837)
Future development costs	(615,839)	(257,310)	(307,689)
Future income tax expenses	(24,392)	(226,183)	(237,153)
Future net cash flows	3,067,617	3,805,968	3,556,854
10% discount for estimated timing of cash flows	(1,405,356)	(1,691,731)	(1,786,533)
Standardized measure of discounted future net cash flows	$ 1,662,261	$ 2,114,237	$ 1,770,321

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

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

	Years ended December 31,		
(in thousands)	**2019**	**2018**	**2017**
Standardized measure of discounted future net cash flows, beginning of year	$ 2,114,237	$ 1,770,321	$ 978,494
Changes in the year resulting from:			
Sales, less production costs	(549,653)	(656,080)	(508,656)
Revisions of previous quantity estimates	36,182	(179,912)	289,150
Extensions, discoveries and other additions	361,479	521,605	296,129
Net change in prices and production costs	(900,019)	365,902	474,831
Changes in estimated future development costs	14,876	7,246	10,989
Previously estimated development costs incurred during the period	158,631	207,865	192,332
Acquisitions of reserves in place	207,636	11,411	—
Divestitures of reserves in place	—	(6,015)	(793)
Accretion of discount	217,119	181,693	97,849
Net change in income taxes	46,939	(10,340)	(46,610)
Timing differences and other	(45,166)	(99,459)	(13,394)
Standardized measure of discounted future net cash flows, end of year	$ 1,662,261	$ 2,114,237	$ 1,770,321

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

Note 21 Supplemental quarterly financial data (unaudited)

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

(in thousands, except per share data)	December 31, 2019 First Quarter	December 31, 2019 Second Quarter(1)	December 31, 2019 Third Quarter(2)	December 31, 2019 Fourth Quarter(2)
Revenues	$ 208,947	$ 216,643	$ 193,569	$ 218,122
Operating income (loss)	$ 54,397	$ 57,828	$ (350,439)	$ (170,377)
Net income (loss)	$ (9,491)	$ 173,382	$ (264,629)	$ (241,721)
Net income (loss) per common share:				
Basic	$ (0.04)	$ 0.75	$ (1.14)	$ (1.04)
Diluted	$ (0.04)	$ 0.75	$ (1.14)	$ (1.04)

____

(1) See Note 15 for discussion of a favorable litigation settled received.

(2) See Note 6.a for discussion of the Company's full cost ceiling impairments recorded.

(in thousands, except per share data)	December 31, 2018 First Quarter	December 31, 2018 Second Quarter	December 31, 2018 Third Quarter	December 31, 2018 Fourth Quarter
Revenues	$ 259,696	$ 351,046	$ 279,746	$ 215,287
Operating income	$ 93,192	$ 94,767	$ 104,410	$ 56,123
Net income	$ 86,520	$ 33,452	$ 55,050	$ 149,573
Net income per common share:				
Basic	$ 0.36	$ 0.14	$ 0.24	$ 0.65
Diluted	$ 0.36	$ 0.14	$ 0.24	$ 0.65

EXHIBIT 4.2

DESCRIPTION OF THE REGISTRANT'S SECURITIES REGISTERED PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

The following is a summary of the common stock, $0.01 par value per share ("Common Stock"), of Laredo Petroleum, Inc., a Delaware corporation (the "Company," "we," "us," and "our"), which is the only class of our securities registered under Section 12 of the Securities Exchange Act of 1934, as amended. The following summary is not complete. You should refer to the applicable provisions of our amended and restated certificate of incorporation (the "Charter"), our second amended and restated bylaws, as amended (the "Bylaws"), and the General Corporation Law of the State of Delaware ("DGCL") for a complete statement of the terms and rights of the Common Stock. Copies of the Charter and Bylaws have been filed with the Securities and Exchange Commission as exhibits 3.1 and 3.3, respectively, to the Company's Annual Report on Form 10-K.

Authorized Capital Stock

Under our Charter, our authorized capital stock consists of 450.0 million shares of Common Stock and 50.0 million shares of preferred stock, par value $1.00 per share ("Preferred Stock").

Common Stock

Voting Rights

Except as provided by law or in a Preferred Stock designation, holders of Common Stock ("stockholders") are entitled to one vote for each share held of record on all matters submitted to a vote of the stockholders, have the exclusive right to vote for the election of directors and do not have cumulative voting rights. Except as otherwise required by law, stockholders are not entitled to vote on any amendment to the Charter (including any certificate of designations relating to any series of Preferred Stock) that relates solely to the terms of any outstanding series of Preferred Stock if the holders of such affected series are entitled, either separately or together with the holders of one or more other such series, to vote thereon pursuant to the Charter (including any certificate of designations relating to any series of Preferred Stock) or pursuant to the DGCL.

Dividend Rights

Subject to preferences that may be applicable to any outstanding shares or series of Preferred Stock and restrictions in the Company debt agreements, stockholders are entitled to receive ratably such dividends (payable in cash, stock or otherwise), if any, as may be declared from time to time by our board of directors (the "Board of Directors") out of funds legally available for dividend payments.

Rights Upon Liquidation

In the event of any liquidation, dissolution or winding-up of our affairs, stockholders will be entitled to share ratably in our assets that are remaining after payment or provision for payment of all of our debts and obligations and after liquidation payments to holders of outstanding shares of Preferred Stock, if any.

Fully Paid and Non-assessable

Our issued and outstanding shares of Common Stock are fully paid and non-assessable.

No Preemptive, Redemption or Conversion Rights

Stockholders have no preferences or rights of conversion, exchange, pre-emption or other subscription rights. There are no redemption or sinking fund provisions applicable to the Common Stock.

Preferred Stock

Our Charter authorizes our Board of Directors, subject to any limitations prescribed by law, without further stockholder approval, to establish and to issue from time to time one or more classes or series of Preferred Stock, par value $0.01 per share, covering up to an aggregate of 50,000,000 shares of Preferred Stock. Each class or series of Preferred Stock will cover the number of shares and will have the powers, preferences, rights, qualifications, limitations and restrictions determined by our Board of Directors, which may include, among others, dividend rights, liquidation preferences, voting rights, conversion rights, preemptive rights and redemption rights.

Listing

Our Common Stock is listed on the New York Stock Exchange (“NYSE”) under the symbol “LPI.”

Transfer Agent and Registrar

The transfer agent and registrar for our Common Stock is American Stock Transfer & Trust Company, LLC.

Anti-Takeover Effects of Provisions of our Charter, Bylaws and Delaware Law

Some provisions of Delaware law, and our Charter and Bylaws described below, contain provisions that may be deemed to have an anti-takeover effect. Such provisions could make the following transactions more difficult: (i) acquisition of us by means of a tender offer, a proxy contest or otherwise and (ii) removal of our incumbent officers and directors. These provisions may also have the effect of preventing changes in our management. It is possible that these provisions could delay, make it more difficult to accomplish or deter transactions that stockholders may otherwise consider to be in their best interest or in our best interests, including transactions that might result in a premium over the market price for shares of our Common Stock.

These provisions, summarized below, are expected to discourage coercive takeover practices and inadequate takeover bids. These provisions are also designed to encourage persons seeking to acquire control of us to first negotiate with us. We believe that the benefits of increased protection and our potential ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire or restructure us outweigh the disadvantages of discouraging these proposals because, among other things, negotiation of these proposals could result in an improvement of their terms.

Advance Notice of Stockholder Proposals and Nominations

Our Bylaws provide for advance notice procedures with regard to stockholder nomination of candidates for election as directors or proposals of business to be brought before meetings of our stockholders. These procedures provide that notice of stockholder nominations or proposals must be timely given in writing to our corporate secretary prior to the meeting at which the action is to be taken. Generally, to be timely, notice must be received at our principal executive offices not less than 45 days nor more than 75 days prior to the first anniversary date of the date on which we first mailed our proxy materials for the annual meeting for the preceding year. Our Bylaws specify the requirements as to form and content of all stockholders’ notices.

Issuance of Preferred Stock

Our Charter authorizes the Board of Directors with the ability to establish the terms of undesignated Preferred Stock. This ability makes it possible for our Board of Directors to issue, without stockholder approval, Preferred Stock with voting or other rights or preferences that could impede the success of any attempt to change control of us.

Issuance of Rights

The Board of Directors is expressly authorized to cause the Company to issue, whether or not in connection with the issue and sale of any shares of Common Stock, rights to enter into any agreements necessary or convenient for such issuance, and to enter into other agreements necessary and convenient to the conduct of the business of the Company.

Control of Board of Directors

Our Board of Directors is divided into three classes with each class serving staggered three year terms, and the authorized number of directors may be changed only by resolution of the Board of Directors without consent of the stockholders. Additionally, all vacancies, including newly created directorships, shall, except as otherwise required by law or by resolution of the Board of Directors and subject to the rights of the holders of any series of Preferred Stock, be filled by the affirmative vote of a majority of directors then in office, even if less than a quorum. Subject to the rights of the holders of any series of Preferred Stock, a director may only be removed from office “for cause” by the affirmative vote of the stockholders of at least 75% of our then outstanding Common Stock.

Meeting Requirement

Any action required or permitted to be taken by the stockholders must be effected at a duly called annual or special meeting of stockholders and may not be effected by any consent in writing in lieu of a meeting of such stockholders, subject to the rights of the holders of any series of Preferred Stock.

Supermajority Approval Requirements

Certain provisions of our Charter may be amended only with the affirmative vote of the stockholders of at least 75% of our then outstanding Common Stock. Our Bylaws may be amended by the affirmative vote of the stockholders of at least 75% of our then outstanding Common Stock or our Board of Directors.

Special Meetings of Stockholders

Our Bylaws provide that a special meeting of stockholders may only be called by the Board of Directors.

Corporate Opportunity

Our Charter provides that we renounce our (and our subsidiaries') ability to engage in any business opportunity, transaction or other matter in which Warburg Pincus LLC ("Warburg Pincus") or any private fund that it manages or advises, any of their officers, directors, partners, employees, and any portfolio company in which such entities or persons have an equity interest (other than us and our subsidiaries) (each a "specified party") participates or desires or seeks to participate in and that involves any aspect of the energy business or industry, unless any such business opportunity, transaction or matter 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 opportunity solely in his or her capacity as one of our directors, officers or employees.

Forum Selection Clause

Under our Charter, unless we consent in writing to the selection of an alternative forum, the sole and exclusive forum for (i) any derivative action or proceeding brought on behalf of the Company, (ii) any action asserting a claim of breach of a fiduciary duty owed by any director, officer or other employee of the Company to the Company or the Company's stockholders, (iii) any action asserting a claim arising pursuant to any provision of the DGCL or (iv) any action asserting a claim governed by the internal affairs doctrine.

Section 203 of the DGCL

We are subject to the provisions of Section 203 of the DGCL, which regulates corporate takeovers. In general, those provisions prohibit a Delaware corporation, including those whose securities are listed for trading on the NYSE, from engaging in any business combination with any interested stockholder for a period of three years following the date that the stockholder became an interested stockholder, unless:

- the business combination or transaction in which the person became interested is approved by the board of directors before the date the interested stockholder attained that status;
- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced other than, for purposes of determining the voting stock outstanding (but not the outstanding stock owned by the interested stockholder), shares owned by persons who are directors and also officers of us and by certain employee stock plans; or
- on or after such time the business combination is approved by the board of directors and authorized at a meeting of stockholders by an affirmative vote of at least two-thirds of the outstanding voting stock that is not owned by the interested stockholder.

In general, Section 203 defines a "business combination" to include the following:

- certain mergers or consolidations involving the corporation and the interested stockholder;

- any sale, transfer, pledge or other disposition of 10% or more of the assets of the corporation to or with the interested stockholder;
- subject to certain exceptions, any transaction that results in the issuance or transfer by the corporation of any stock of the corporation to the interested stockholder;
- subject to certain exceptions, any transaction involving the corporation that has the effect of increasing the proportionate share of the stock of any class or series of the corporation beneficially owned by the interested stockholder; or
- the receipt by the interested stockholder of the benefit of loans, advances, guarantees, pledges or other financial benefits provided by or through the corporation.

In general, Section 203 defines an interested stockholder as any entity or person beneficially owning 15% or more of the outstanding voting stock of the corporation and any entity or person affiliated with or controlling or controlled by any of these entities or persons. Affiliates of Warburg Pincus owned their equity in us at the time we completed our corporate reorganization in December 2011 in connection with our initial public offering, and, therefore, Warburg Pincus is not subject to the restrictions of Section 203.

EXHIBIT 10.5

Schedule 1, amended and restated as of January 22, 2020, to the Third Amendment to Fifth Amended and Restated Credit Agreement, dated as of April 19, 2018, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto.

SCHEDULE 1

Bank	Maximum Credit Amount	Elected Commitment	Commitment Percentage
Wells Fargo Bank, N.A.	$191,666,666.67	$91,041,666.67	9.583%
Bank of America, N.A.	166,666,666.66	79,166,666.66	8.333%
BMO Harris Financing, Inc.	166,666,666.66	79,166,666.66	8.333%
Capital One, National Association	166,666,666.66	79,166,666.66	8.333%
The Bank of Nova Scotia, Houston Branch	141,666,666.66	67,291,666.66	7.083%
Societe Generale	141,666,666.66	67,291,666.66	7.083%
ABN AMRO Capital USA LLC	116,666,666.66	55,416,666.67	5.833%
Barclays Bank PLC	116,666,666.66	55,416,666.67	5.833%
BOKF, NA DBA Bank of Oklahoma	116,666,666.66	55,416,666.67	5.833%
Branch Banking and Trust Company	116,666,666.66	55,416,666.67	5.833%
Credit Suisse AG, Cayman Islands Branch	116,666,666.66	55,416,666.67	5.833%
Citibank, N.A.	116,666,666.66	55,416,666.67	5.833%
Compass Bank	116,666,666.66	55,416,666.67	5.833%
Goldman Sachs Bank USA	116,666,666.66	55,416,666.67	5.833%
Comerica Bank	91,666,666.66	43,541,666.67	4.583%
Totals:	**$2,000,000,000.00**	**$950,000,000.00**	**100.00%**

Administrative Agent	**Address for Notice**
Wells Fargo Bank, N.A.	*Credit Contact:* 1445 Ross Ave., Suite 4500, T9216-451 Dallas, TX 75202 Attn: Muhammad A. Dhamani Tel: 214-721-6430 Email: Muhammad.dhamani@wellsfargo.com *Primary Operations Contact:* 1525 W WT Harris Blvd, 1st Floor Charlotte, NC 28262-8522 MAC D1109-019 Attn: Agency Services Tel: 704-590-2706 Fax: 704-590-2782

EXHIBIT 21.1

List of Subsidiaries of Laredo Petroleum, Inc.

Name of Subsidiary	Jurisdiction of Organization
Laredo Midstream Services, LLC	Delaware
Garden City Minerals, LLC	Delaware

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated February 13, 2020, with respect to the consolidated financial statements, and internal control over financial reporting included in the Annual Report of Laredo Petroleum, Inc. on Form 10-K for the year ended December 31, 2019. We consent to the incorporation by reference of said reports in the Registration Statements of Laredo Petroleum, Inc. on Form S-3 (File No. 333-230427) and on Forms S-8 (File No. 333-178828, File No. 333-211610 and File No. 333-231593).

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 13, 2020

EXHIBIT 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

Ryder Scott Company, L.P. hereby consents to the references to its firm in the form and context in which they appear in this Annual Report on Form 10-K filed by Laredo Petroleum, Inc. (the “Annual Report”). Ryder Scott Company, L.P. hereby further consents to the use and incorporation by reference of information from its reports regarding those quantities estimated by Ryder Scott of proved reserves of Laredo Petroleum, Inc. and its subsidiaries, the future net revenues from those reserves and their present value for the years ended December 31, 2019, 2018 and 2017, and to the inclusion of its summary report dated January 3, 2020 as an exhibit to the Annual Report. We further consent to the incorporation by reference thereof into Laredo Petroleum, Inc.'s Registration Statements on Form S-8 (File No. 333-178828, effective December 30, 2011, File No. 333-211610, effective May 25, 2016, and File No. 333-231593, effective May 20, 2019) and the Registration Statement of Laredo Petroleum, Inc. on Form S-3 (File No. 333-230427, effective March 21, 2019).

/s/ RYDER SCOTT COMPANY, L.P.
RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas
February 13, 2020

EXHIBIT 31.1

CERTIFICATION

I, Jason Pigott, certify that:

1. I have reviewed this Annual Report on Form 10-K of Laredo Petroleum, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2020

/s/ Jason Pigott

Jason Pigott
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Michael T. Beyer, certify that:

1. I have reviewed this Annual Report on Form 10-K of Laredo Petroleum, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2020

/s/ Michael T. Beyer

Michael T. Beyer
Senior Vice President and Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, Jason Pigott, President and Chief Executive Officer of Laredo Petroleum, Inc. (the "Company"), and Michael T. Beyer, Senior Vice President and Chief Financial Officer of the Company, certify that, to their knowledge:

(1) the Annual Report on Form 10-K of the Company for the period ending December 31, 2019, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

February 13, 2020

/s/ Jason Pigott

Jason Pigott

President and Chief Executive Officer

February 13, 2020

/s/ Michael T. Beyer

Michael T. Beyer

Senior Vice President and Chief Financial Officer