Laredo Petroleum, Inc.
Form 10-K
February 17, 2016

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

ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2015
or

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

Commission file number: 001-35380
Laredo Petroleum, Inc.
(Exact name of registrant as specified in its charter)

Delaware	45-3007926
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
15 W. Sixth Street, Suite 900 Tulsa, Oklahoma (Address of principal executive offices)	74119 (Zip code)
(918) 513-4570 (Registrant's telephone number, including area code)	

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange On Which Registered
Common Stock, $0.01 par value per share	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No o

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller

reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ý	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates was approximately $1.2 billion on June 30, 2015, based on $12.58 per share, the last reported sales price of the common stock on the New York Stock Exchange on such date.

Number of shares of registrant's common stock outstanding as of February 12, 2016: 213,747,873

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2016 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2015, are incorporated by reference into Part III of this report for the year ended December 31, 2015.

Laredo Petroleum, Inc.
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GLOSSARY OF OIL AND NATURAL GAS TERMS

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

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

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

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

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

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

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

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

"BOE/D"—BOE per day.

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

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

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

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

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

"Earth Model"—An integrated workflow process combining geoscience and engineering data with multivariate statistics.

"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.

"Facies"—A lateral change in a stratigraphic rock unit due to variance in the formation's petrophysical attribute(s).

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

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

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

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

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

"HBP"—Acreage that is held by production.

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

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

"Initial Production"—The measurement of production from an oil or gas well when first brought on stream. Often stated in terms of production during the first thirty days.
"Liquids"—Describes oil, water, condensate and natural gas liquids.
"MBbl"—One thousand barrels of crude oil, condensate or natural gas liquids.
"MBOE"—One thousand BOE.
"MMBOE"—One million BOE.
"Mcf"—One thousand cubic feet of natural gas.
"MMBtu"—One million British thermal units.
"MMcf"—One million cubic feet of natural gas.
"Natural gas liquids" or "NGL"—Components of natural gas that are separated from the gas state in the form of liquids, which include propane, butanes and ethane, among others.
"Net acres"—The percentage of gross acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.
"NYMEX"—The New York Mercantile Exchange.
"Production corridor"—Infrastructure put in place over an extended area, usually several miles, containing multiple pipelines to facilitate the transfer of oil, natural gas and/or water. A specific production corridor may also contain water recycling facilities, artificial gas lift and fuel gas distribution lines.
"Productive well"—A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.
"Proved developed non-producing reserves" or "PDNP"—Developed non-producing reserves.
"Proved developed reserves" or "PDP"—Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
"Proved reserves"—The estimated quantities of oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.
"Proved undeveloped reserves" or "PUD"—Proved reserves that are expected to be recovered within five years from new wells on undrilled locations or from existing wells where a relatively major expenditure is required for recompletion.
"Recompletion"—The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.
"Reservoir"—A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.
"Resource play"—An expansive contiguous geographical area, potentially supporting numerous drilling locations, with prospective crude oil and/or natural gas reserves that has the potential to be developed uniformly with repeatable commercial success due to advancements in horizontal drilling and multi-stage fracturing technologies.
"Spacing"—The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.
"Standardized measure"—Discounted future net cash flows estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.
"Two stream"—Production or reserve volumes of oil and wet natural gas, where the natural gas liquids have not been removed from the natural gas stream and the economic value of the natural gas liquids is included in the wellhead natural gas price.

"Three stream"—Production or reserve volumes of oil, natural gas liquids and natural gas, where the natural gas liquids have been removed from the natural gas stream and the economic value of the natural gas liquids is separated from the wellhead natural gas price.
"Undeveloped acreage"—Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.
"Wellhead natural gas"—Natural gas produced at or near the well.
"Wolfberry"—A general industry term that applies to the vertical stratigraphic interval that can include the shallow Spraberry formation to the deeper Woodford formation throughout the Permian Basin.
"Working interest" or "WI"—The right granted to the lessee of a property to explore for and to produce and own natural gas or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in or incorporated by reference into this Annual Report are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These forward-looking statements include statements, projections and estimates concerning our operations, performance, business strategy, oil and natural gas reserves, drilling program capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation or other claims and disputes, derivative activities and potential financing. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "will," "foresee," "plan," "goal," "should," "intend," "pursue," "target," "continue," "suggest" or the negative thereof or other variations thereof or other words that convey the uncertainty of future events or outcomes. Forward-looking statements are not guarantees of performance. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Among the factors that significantly impact our business and could impact our business in the future are:

- the volatility of, and substantial and continued decline in, oil, NGL and natural gas prices;
- revisions to our reserve estimates as a result of changes in commodity prices and uncertainties;
- impacts to our financial statements as a result of impairment write-downs;
- our ability to discover, estimate, develop and replace oil, NGL and natural gas reserves;
- uncertainties about the estimates of our oil, NGL and natural gas reserves;
- changes in domestic and global production, supply and demand for oil, NGL and natural gas;
- 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;
- the ongoing instability and uncertainty in the U.S. and international financial and consumer markets that could adversely affect the liquidity available to us and our customers and the demand for commodities, including oil, NGL and natural gas;
- capital requirements for our operations and projects;
- our ability to maintain the borrowing capacity under our Senior Secured Credit Facility (as defined below) or access other means of obtaining capital and liquidity, especially during periods of sustained low commodity prices;
- restrictions contained in our debt agreements, including our Senior Secured Credit Facility and the indentures governing our Senior Unsecured Notes (as defined below), as well as debt that could be incurred in the future;
- our ability to generate sufficient cash to service our indebtedness, fund our capital requirements and generate future profits;
- regulations that prohibit or restrict our ability to apply hydraulic fracturing to our oil and natural gas wells and to access and dispose of water used in these operations;
- legislation or regulations that prohibit or restrict our ability to drill new allocation wells;
- our ability to execute our strategies, including but not limited to our hedging strategies;
- competition in the oil and natural gas industry;
- changes in the regulatory environment and changes in international, legal, political, administrative or economic conditions;
- drilling and operating risks, including risks related to hydraulic fracturing activities;
- risks related to the geographic concentration of our assets;
- the availability and costs of drilling and production equipment, labor and oil and natural gas processing and other services;
- the availability of sufficient pipeline and transportation facilities and gathering and processing capacity;
- our ability to comply with federal, state and local regulatory requirements; and
- our ability to recruit and retain the qualified personnel necessary to operate our business.

These forward-looking statements involve a number of risks and uncertainties that could cause actual results to differ materially from those suggested by the forward-looking statements. Forward-looking statements should therefore be considered

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

Part I

On December 31, 2013, Laredo Petroleum Holdings, Inc., a Delaware corporation, completed an internal corporate reorganization and changed its name to Laredo Petroleum, Inc. See "Item 1. Business - Corporate history and structure" for more information. On October 24, 2014, Laredo formed Garden City Minerals, LLC, a Delaware limited liability company ("GCM"), as a wholly-owned subsidiary. Unless the context otherwise requires, references in this Annual Report to "Laredo," the "Company," "we," "our," "us," or similar terms refer to Laredo Petroleum Holdings, Inc. and its subsidiaries, including Laredo Petroleum, Inc., a Delaware corporation, before the completion of our internal corporate reorganization and to Laredo Petroleum, Inc. and its subsidiaries, Laredo Midstream Services, LLC ("LMS") and GCM, as of the completion of our internal corporate reorganization and thereafter, as applicable.

In this Annual Report, the consolidated and historical financial information, operational data and reserve information for Laredo and our acquired subsidiary, Broad Oak Energy, Inc., a Delaware corporation ("Broad Oak"), present the assets and liabilities of Laredo and its subsidiaries and Broad Oak at historical carrying values and their operations as if they were consolidated for all periods presented prior to July 1, 2011. Although the financial and other information is reported on a consolidated basis, such presentation is not necessarily indicative of the results that would have been obtained if Laredo had owned and operated Broad Oak from its inception.

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

Item 1. Business

Overview

Laredo is an independent energy company focused on the acquisition, exploration and development of oil and natural gas properties, and the transportation of oil and natural gas from such properties, primarily in the Permian Basin in West Texas. The oil and liquids-rich Permian Basin is characterized by multiple target horizons, extensive production histories, long-lived reserves, high drilling success rates and high initial production rates. We operate and analyze our results of operations through our two principal business segments:

- Exploration and production of oil and natural gas properties - conducted principally by Laredo Petroleum, Inc. through the exploration and development of our acreage in the Permian Basin. As of December 31, 2015, we had assembled 135,408 net acres in the Permian Basin and had total proved reserves, presented on a three-stream basis, of 125,698 MBOE.
- Midstream and marketing - conducted principally by our wholly-owned subsidiary, LMS. LMS buys, sells, gathers and transports oil, natural gas and water primarily for the account of Laredo. In addition, LMS owns a 49% interest in Medallion Gathering & Processing, LLC ("Medallion"), which, upon completion of current projects, will own and operate 500 miles of pipeline in the Permian Basin. This system gathered, transported and delivered 69,000 Bbls per day in the fourth quarter of 2015.

Financial information and other disclosures relating to our business segments are provided in the notes to our consolidated financial statements included elsewhere in this Annual Report (see Note 17 to our consolidated financial statements included elsewhere in this Annual Report).

2015 segment operation highlights

Exploration and production

- Produced a Company record 16.3 MMBOE in 2015, an increase of 18% from 2014
- Received $255.3 million of cash settlements on commodity derivatives that matured during 2015
- Reduced general and administrative ("G&A") expenses to $5.53 per BOE in 2015, a decrease of 28% from 2014
- Reduced capital expenditures in exploration and development activities and other fixed assets to $530.2 million in 2015, a decrease of 60% from 2014, to more appropriately align capital with expected cash flows
- Utilized the Company's proprietary Earth Model to design the drilling plan for the majority of horizontal wells drilled in 2015

Midstream and marketing

- Gathered 4.6 million barrels of crude oil, an increase of 190% from 2014
- Gathered 28.5 Bcf of natural gas, an increase of 55% from 2014
- Supplied 12.9 Bcf of natural gas lift supply, an increase of 480% from 2014
- Commenced commercial operations of the Medallion crude oil gathering system, in which LMS owns a 49% interest, growing Medallion transported volumes of oil to 69,000 Bbls per day in the fourth quarter and 15.2 million barrels of crude oil for the year
- Commenced operations of our water treatment facility in the second half of the year that provided 1.2 million barrels of recycled water for completion operations in the second half of the 2015 and 800,000 barrels during the last seven weeks of the year
- Invested capital of $159.6 million in pipelines and related infrastructure held by LMS, including investments in the Medallion pipeline system

Our core assets

Exploration and production

The Permian Basin is comprised of several distinct geological provinces, including the Midland Basin to the east, the Delaware Basin to the west and the Central Platform in the middle. Our primary development and production fairway is located on the east side of the Midland Basin, 35 miles east of Midland, Texas. Our acreage is largely contiguous in the neighboring counties of Howard, Glasscock, Reagan, Sterling and Irion, Texas. We refer to this acreage block in this Annual Report as our "Permian-Garden City" area. As of December 31, 2015, we held 135,408 net acres in the Permian Basin, with 131,763 of the net acres held in 250 sections in the Permian-Garden City area, with an average working interest of 95% in all Laredo-operated producing wells.

We believe our acreage in the Permian-Garden City area is a resource play for multiple producing formations that partially make up the vertical Wolfberry interval. To date, we have focused the majority of our development activities in four targets for horizontal drilling (Upper, Middle and Lower Wolfcamp and Cline formations), although we have established the existence of additional producing zones, including the Spraberry and Canyon. From our inception in 2006 through December 31, 2015, we have drilled and completed (i.e., the particular well is flowing) 230 horizontal wells in these initial four identified target zones and 967 vertical wells in the Wolfberry interval. We have completed 97 horizontal Upper Wolfcamp wells, 48 horizontal Middle Wolfcamp wells, 30 horizontal Lower Wolfcamp wells and 55 horizontal Cline wells.

Beginning in mid-2012, we started focusing our horizontal activity on drilling longer laterals (typically 7,000 to 7,500 feet). Where our contiguous acreage position allows, we have now evolved to drilling 10,000-foot laterals.

Due to the sharp decline in oil, NGL and natural gas prices that began in the second half of 2014 and continued through 2015 and the beginning of 2016, we reduced our 2016 planned capital program. In connection with the reduced capital program, we have approved a capital budget of $345 million for 2016. Of this budget, $330 million is allocated to our exploration and production segment and $15 million is allocated to our midstream and marketing segment. Substantially all of the planned capital budget is anticipated to be invested in the Permian-Garden City area for both of our segments. Our near-term goal is to concentrate our drilling activities along our previously established production corridors that have the infrastructure in place to allow us the flexibility to most efficiently and economically drill wells at an attractive rate of return, even during the current period of depressed commodity prices. We will also continue to seek cost saving measures to more efficiently deploy our capital, including decreasing our unit lease operating and G&A expenses. We anticipate that in conjunction with the continued downward trend in commodity prices, capital and service costs may continue to decline as well, although there can be no assurance of any such decline.

In connection with our reduced capital budget, we are decreasing the number of horizontal drilling rigs and eliminating vertical drilling rigs working our properties in the Permian-Garden City area as we do not believe that any vertical drilling is currently necessary under our leases. On December 31, 2015, we had a total of three operated drilling rigs drilling horizontal wells. Our current drilling schedule anticipates that we will average 2.5 horizontal rigs and no vertical rigs in 2016.

The timing of drilling our potential locations is influenced by several factors, including commodity prices, capital requirements and availability, the Texas Railroad Commission ("RRC") well-spacing requirements and the continuation of the positive results from our ongoing development drilling program.

We expect our Permian-Garden City acreage to continue to be the primary driver of our reserves, production and cash flow for the foreseeable future.

Since our inception, we have established and realized our reserves, production and cash flow primarily through our drilling program coupled with select strategic acquisitions, including our July 2011 acquisition of Broad Oak. Our net proved reserves were estimated at 125,698 MBOE on a three-stream basis as of December 31, 2015, of which 80% are classified as proved developed reserves and 42% are attributed to oil reserves. For all periods prior to January 1, 2015, our reserves and production were reported in two streams: crude oil and liquids-rich natural gas. This means the economic value of the natural gas liquids in our natural gas was included in the wellhead natural gas price and total volumes on a BOE-basis are lower. Beginning on January 1, 2015, we started reporting our production volumes on a three-stream basis, which separately reports NGL from crude oil and natural gas. In this Annual Report, the information presented with respect to our estimated proved reserves has been prepared by Ryder Scott Company, L.P. ("Ryder Scott"), our independent reserve engineers, in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") applicable to the periods presented.

The following table summarizes our total estimated net proved reserves presented on a three-stream basis, net acreage and producing wells as of December 31, 2015, and average daily production presented on a three-stream basis for the year ended December 31, 2015. Based on estimates in the report prepared by Ryder Scott, we operated wells that represent 99% of the economic value of our proved developed oil, NGL and natural gas reserves as of December 31, 2015.

	As of December 31, 2015 Estimated net proved reserves[1]			Producing wells		Year ended December 31, 2015
	MBOE	% of total reserves	% Oil	Net acreage	Gross	Net	average daily production (BOE/D)
Permian Basin	125,698	100 %	42 %	135,408	1,195	1,109	44,782
Other properties	—	— %	— %	17,612	—	—	—
Total	125,698	100 %	42 %	153,020	1,195	1,109	44,782

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

Our net average daily production for the year ended December 31, 2015 was 44,782 BOE/D, 47% of which was oil, 26% of which was NGLs and 27% of which was natural gas.

As discussed previously in this Annual Report, during 2015 commodity prices for crude oil, NGL and natural gas experienced sharp declines, and this downward trend has accelerated further into the first quarter of 2016, with crude oil prices reaching a twelve-year low in February 2016. We have significantly reduced our capital budget for 2016. In addition, we have purposely significantly reduced the portion of our reserves that have historically been categorized as "proved undeveloped" or "PUD." We have adjusted our long-range five-year SEC PUD bookings methodology because given the current economic price environment, coupled with (i) our efforts to develop our acreage in the most efficient manner possible and determine which potential locations will be most profitable and (ii) the uncertain effect that such environment will have on the industry's access to the capital markets, we believe that we can optimize the value for our shareholders by maintaining greater flexibility in choosing the specific drilling locations that may yield the greatest rates of return.

As our activities to date have indicated, the majority of our acreage represents a resource play. In the near-term, our goal is to drill those locations that we anticipate have the potential to provide the greatest economic return and enhance shareholder value, and we have determined that the most efficient way to accomplish this is to maintain the flexibility to choose those locations based upon our continuing insight as we drill and collect data across our acreage, regardless of SEC reserve-booking status. Reducing our future PUD commitments provides us the most flexibility to maximize our rate of return at prevailing conditions and minimize the requirement to drill wells previously assigned under very different circumstances as specific PUD locations. Accordingly, we have reduced our booked PUD locations to those we have reasonable certainty to believe that we will develop in at least a two-year time horizon

while maintaining the flexibility to add new PUD locations and convert other locations to proved developed reserves as our plans deem appropriate and opportunistic.

We have built an extensive proprietary technical database that includes 398 in-house, core-calibrated petrophysical logs, 992 square miles of 3D seismic, 44 microseismic surveys, more than 1,090 open and cased-hole logging suites, including 133 dipole sonic logs, 2,866 feet of proprietary whole cores in 13 wells, 859 sidewall cores, 39 single-zone tests and 42 production logs. Our strategic interest in assembling a rich database is directed at efficiently gaining a knowledge base on our resource play in the Permian-Garden City area and maximizing value during the field development phase.

A key component of our reservoir characterization process is internally referred to as the "Earth Model," which represents a proprietary integrated workflow combining geoscience and engineering data with multivariate statistics. The workflow employed in the Earth Model process differs from the more conventional earth science/engineering approach in that the Earth Model involves parallel workflows, multivariate statistics and significant input from multiple disciplines. The goal of the Earth Model is to develop a predictive three-dimensional model that can forecast production rates through associating empirical subsurface data with proved methods.

We have been developing the Earth Model process over a period of four years, covering an area where calibrated pre-stack inversion attributes have been extensively developed and tested to determine fundamental controls on reservoir performance. The four major components of the Earth Model are (i) geophysical data (i.e., 3D seismic and micro-seismic surveys), (ii) logs (i.e., conventional open-hole, dipole sonic, and in-house core calibrated petrophysical logs), (iii) cores (both whole and sidewall) and (iv) production history, production logs and single-zone tests. By integrating data that represent mechanical properties, natural fractures, reservoir properties and lithology within a multivariate statistical model, we were generally able to develop a relationship to production with correlation coefficients for our 2016 targeted zones.

We consider the Earth Model a potentially significant tool in planning development wells in complex geology by optimizing landing points, lateral lengths and geo-steering targets while integrating horizontal and vertical spacing considerations for well laterals.

We estimate that more than 90% of our horizontal wells to be drilled in 2016 will utilize at least some aspects of the Earth Model, demonstrating evolution from a calibrated backward-looking model into a primary tool for development and delineation well planning. If our preliminary applications of the Earth Model are replicated in forward-looking well planning, we anticipate that the Earth Model may positively impact our ability to increase initial production rates and estimated ultimate recoveries.

Midstream and marketing

We are actively involved in seeking midstream solutions for our oil, NGL and natural gas production. Capitalizing on our large acreage blocks, we have built crude oil, natural gas and/or water systems in four production corridors on our Permian-Garden City acreage. These production corridors provide high-pressure centralized natural gas lift systems and crude oil and natural gas gathering, with certain corridors also capable of water delivery, takeaway and recycling (including 77 miles of fresh, produced and recycled water lines). In 2015, we commenced operations at our water treatment facility, which is capable of recycling more than 28,000 Bbls of water per day and has a storage capacity of 1.4 million Bbls. We believe the fact that these production corridors and associated facilities and infrastructure are already in place will enable us to more economically undertake our anticipated 2016 drilling program.

Additionally, we have built and maintain more than 40 miles of crude oil gathering pipelines to connect Laredo-operated wells in our Permian-Garden City asset, providing a safer and more economic transportation alternative than trucking. We have also installed and maintain 175 miles of natural gas gathering pipelines across our Permian-Garden City acreage, providing us with takeaway optionality that enables us to maintain lower operating pressures and more consistent well performance.

LMS is a 49% owner in the Medallion crude oil gathering system which commenced operations in March of 2015. Upon completion of current projects, the system will have 500 miles of laid pipeline in the following counties in Texas: Mitchell, Howard, Martin, Midland, Glasscock, Reagan, Upton, Crane and Crockett. During the portion of the year in 2015 that it was operational, the system transported 15.2 million Bbls of crude oil. See Notes 15 and 16.a to our consolidated financial statements included elsewhere in this Annual Report for a discussion of Medallion.

Our midstream and marketing activities continue to focus on achieving increased efficiencies and cost reductions for (i) the transportation and marketing of our oil and natural gas through the utilization of our oil and natural gas gathering systems to provide access to multiple markets and reduce the potential for production shut-ins caused by downstream capacity issues and (ii) the handling of fresh, recycled and produced water.

We market the majority of production from properties we operate for both our account and the account of the other working interest owners in our operated properties. We sell substantially all of our production under contracts ranging from one month to several years, all at market prices. We normally sell production to a relatively limited number of customers, as is customary in the exploration, development and production business; however, we believe that our

customer diversification affords us optionality in our sales destination. We have committed a portion of our Permian crude oil production under firm

transportation agreements, including with Medallion, which agreements will enhance our ability to move our crude oil out of the Permian Basin and give us access to potentially more favorable Gulf Coast pricing.

As of December 31, 2015, we were committed to deliver for sale or transportation the following fixed quantities of production under certain contractual arrangements that specify the delivery of a fixed and determinable quantity.

	Total	2016	2017	2018	2019 and after
Crude oil (MBbl)					
Sales commitments	24,340	10,304	8,030	6,006	—
Transportation commitments:					
Field	100,995	9,736	13,106	12,410	65,743
To U.S. gulf coast	33,450	3,660	3,650	3,650	22,490
Natural gas (MMcf)					
Sales commitments	66,971	5,220	5,966	7,373	48,412
Total commitments (MBOE)[1]	169,947	24,570	25,780	23,295	96,302

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

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

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

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

Corporate history and structure

Laredo Petroleum, Inc. was founded in October 2006 by our Chairman and Chief Executive Officer, Randy Foutch. In 2007, Laredo Petroleum, LLC was formed pursuant to the laws of the State of Delaware by affiliates of Warburg Pincus LLC ("Warburg Pincus"), our institutional investor, and the management of Laredo Petroleum, Inc., to acquire Laredo Petroleum, Inc. and through such subsidiary, to develop and operate oil and natural gas properties in the Permian and Mid-Continent regions of the United States. In August 2011, we incorporated Laredo Petroleum Holdings, Inc. ("Holdings"), pursuant to the laws of the State of Delaware for purposes of a corporate reorganization and initial public offering ("IPO"). The corporate reorganization, pursuant to which Laredo Petroleum, LLC was merged with and into Holdings, with Holdings surviving the merger, was completed on December 19, 2011 (the "Corporate Reorganization"). In the Corporate Reorganization, all of the outstanding preferred equity interests and certain of the incentive equity interests in Laredo Petroleum, LLC were exchanged for shares of common stock of Holdings. Holdings completed an IPO of its common stock on December 20, 2011. As of December 31, 2015, Warburg Pincus owned 41.0% of our common stock.

On July 1, 2011, we completed the acquisition of Broad Oak, which became a wholly-owned subsidiary of Laredo Petroleum, Inc. Broad Oak was formed in 2006 with financial support from its management and Warburg Pincus. On July 19, 2011, we changed the name of Broad Oak to Laredo Petroleum-Dallas, Inc.

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

Effective December 31, 2013, we completed an internal corporate reorganization, which simplified our corporate structure. Our two former subsidiaries, Laredo Petroleum Texas, LLC and Laredo Petroleum-Dallas, Inc. were merged with and into Laredo Petroleum, Inc. The then sole remaining wholly-owned subsidiary of Laredo Petroleum, Inc., formerly known as Laredo Gas Services, LLC, changed its name to Laredo Midstream Services, LLC. Laredo Petroleum, Inc., a wholly-owned subsidiary of Holdings, merged with and into Holdings with Holdings surviving and changing its name to "Laredo Petroleum, Inc." We refer to the events described in this paragraph collectively as the "Internal Consolidation."

On October 24, 2014, GCM, a wholly-owned subsidiary of Laredo Petroleum, Inc., was formed primarily to hold certain mineral interests owned by the Company. The creation of GCM, the Corporate Reorganization, the IPO and the Internal Consolidation are discussed in Note 1 to our consolidated financial statements included elsewhere in this Annual Report.

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

Our business strategy

Our goal is to enhance shareholder value by protecting and potentially growing our reserves, production and cash flow by executing the following strategy:

Exploration and production

Proactively manage risk to limit downside

- We actively attempt to limit our business and operating risks by focusing on safety, flexibility in our financial profile, operation efficiencies, hedging, reducing G&A and developing oil and natural gas takeaway capacity with multiple delivery points.

Develop our acreage in the most cost-efficient manner possible and target our wells with the highest rate of return potential

- In the current price environment, we believe the best way to develop our acreage is to take a long-term approach and develop at a deliberate pace that targets our locations with the potential highest rates of return.
- We believe that our entire acreage position and multiple zones will be a part of our future strategy if prices for commodities rise and/or further cost reductions and technological advances make wells more economic.

Deploy our capital in a conservative and strategic manner and review opportunities to bolster our liquidity

- In the current economic environment, maintaining liquidity is critical. Therefore, we will be highly selective in the projects that we fund and will review opportunities to bolster our liquidity and financial position through accessing the capital markets, utilizing our Senior Secured Credit Facility and asset dispositions.

- Continue to hedge our production to protect cash flows and diminish the effects of commodity price fluctuations
During 2015, we realized a significant benefit through our hedging program and the certainty that it provided to our cash flow. In the future, we will seek hedging opportunities to further protect our cash flows from commodity price fluctuations.
- Maintain our operational flexibility
As reflected in our December 31, 2015 reserves, we deliberately reduced our PUD bookings. While this decision impacts our booked reserves on a current basis, we also believe that it provides us with the crucial flexibility necessary to allow us to alter our drilling plans as may be necessary to develop our highest rate of return properties to benefit our shareholders.
- Evaluate and pursue value-enhancing acquisitions, mergers, joint ventures and divestitures
We will continue to monitor the market for strategic acquisitions that we believe could be accretive and enhance shareholder value. However, as a result of our past years of data collection and delineation drilling, we have established the production capability of a substantial portion of our acreage in multiple zones, which provides us with a significant drilling inventory even at the current depressed commodity prices.
- Capitalize on technical expertise and database
We will continue to leverage our operating and technical expertise to further delineate and develop our core acreage positions. We believe the development and use of the Earth Model will enable us to better identify the best locations and drill them more efficiently, thereby capturing more hydrocarbons than would otherwise be possible.

Midstream and marketing

- Expand the use of our previously built infrastructure and look for opportunities for strategic expansion
We believe that our infrastructure provides us with optionality and efficiencies in developing and transporting production from our Permian-Garden City acreage position. Because of the value we ascribe to this infrastructure, we will continue to look for strategic expansion opportunities while maintaining our core strategy of providing marketing optionality for our oil, NGL and natural gas production.
- Participate in the growth and expansion of Medallion
We believe the Medallion pipeline is a valuable and unique asset in our area of operations that provides benefit to us both in terms of transporting our production and financially through our 49% ownership. We will continue to closely monitor all proposed expansions and participate in those that we feel will be beneficial to our shareholders.

Our competitive strengths

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

Exploration and production

- Extensive Permian technical database and expertise
We have made a substantial upfront investment to understand the geology, geophysics and reservoir parameters of the rock formations and production characteristics that define our drilling and development program. We have utilized this information in the creation of the Earth Model, which we believe will assist us in optimizing our well results.
- Contiguous acreage position that contains multiple zones with a substantial drilling inventory
We have 131,763 net acres in the Permian-Garden City area that are largely contiguous, have identified at least seven zones from which we can produce and have a significant drilling inventory even at the current depressed commodity prices. Our contiguous acreage position also allows us to drill long laterals (10,000 feet or greater) in many locations,

which we estimate will provide an even greater rate of return as we continue to refine our spacing, drilling and completion techniques.

Significant operational control

- We operate wells that represent 99% of the economic value of our proved developed reserves as of December 31, 2015, 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, completion and stimulation techniques. We expect to maintain operating control over most of our potential drilling locations.

Significant hedges in place to guard against price volatility

- We engage in an active hedging program in an effort to decrease the volatility of our cash flow due to changes in commodity prices. We currently have hedges in place for oil that represent 85% to 90% of anticipated oil sales in 2016 with a weighted-average floor price of $70.84 per Bbl, and hedges in place for natural gas that represent 70% to 75% of anticipated natural gas sales in 2016 with a weighted-average floor price of $3.00 per MMBtu. For 2017, we have hedges in place for 2,628,000 barrels of oil with a weighted-average floor price of $77.22 per Bbl and hedges for natural gas for 13,515,000 MMBtu with a weighted-average floor price of $2.70 per MMBtu. For 2018, we have hedges in place for natural gas for 8,220,000 MMBtu with a weighted-average floor price of $2.50 per MMBtu. We believe that the price certainty associated with these hedges enables us to better plan and forecast our upcoming capital and operational spending.

Strong corporate governance and institutional investor support

- Our board of directors is well qualified and represents a meaningful resource to our management team. Our board of directors, which is comprised of representatives of Warburg Pincus, other independent directors and our Chief Executive Officer, has extensive oil and natural gas industry and general business expertise. We actively engage our board of directors, on a regular basis, for their expertise on strategic, financial, governance and risk management activities. In addition, Warburg Pincus has many years of relevant experience in financing and supporting exploration and production companies and management teams. During the last two decades, Warburg Pincus has been the lead investor in many such companies, including Broad Oak and two previous companies operated by members of our management team.

Midstream and marketing

Owned gathering infrastructure

- We own and operate more than 200 miles of pipeline in our crude oil and natural gas gathering systems in the Permian Basin as of December 31, 2015. Additionally, through our joint venture with Medallion, upon completion of current projects we will have access to 500 miles of oil gathering systems and pipelines connected to Colorado City, Texas. As a 49% owner of Medallion, we financially benefit from our share of the net income from the shipment of crude oil on the system. These systems and pipelines provide greater operational efficiency and potentially lower price differentials for our production and enable us to coordinate our activities to connect our wells to market upon completion with minimal pipeline delays.

Our production corridors allow us to more efficiently develop our acreage and utilize/dispose of water

- We have built production corridors on our contiguous acreage position that we believe increase efficiencies in oil and natural gas takeaway capacity, water supply and field level operations. We believe 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. In addition, we believe that drilling wells within these corridors increases our production consistency and allows us to better plan our development program.
- The use and disposal of water is one of the most challenging aspects of horizontal drilling in the Permian Basin and our production corridors provide us with a reliable and consistent means to ensure that we have the water we need to complete our wells while also providing take away capacity for flowback and produced water.

- Our water treatment facility allows us to more sustainably utilize recycled flowback and produced water in our completion operations and reduce our capital and operating expenses for water supply and disposal.

Other properties

In addition to our Permian-Garden City acreage, as of December 31, 2015 we held 21,257 net acres in other areas, including the Palo Duro Basin and Permian-China Grove area. We anticipate little or no activity on these other properties in 2016. Approximately 29% of this acreage will expire in 2016, absent drilling or renegotiation of the applicable leases.

Our operations

Estimated proved reserves

Our reserves are reported in three streams: crude oil, NGL and natural gas. In this Annual Report, the information with respect to our estimated proved reserves presented below has been prepared by Ryder Scott, in accordance with the rules and regulations of the SEC applicable to the periods presented.

Per SEC guidelines, companies are required to use the unweighted arithmetic average first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period before differentials ("Benchmark Prices"). The Benchmark Prices are then adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead ("Realized Prices"). The Realized Prices are held constant and utilized to calculate estimated reserves and the associated future cash flows. The following table presents the Benchmark Prices and Realized Prices as of the periods presented.

	For the years ended December 31, 2015	December 31, 2014[1]
Benchmark Prices		
Oil ($/Bbl)	$46.79	$91.48
NGL ($/Bbl)	$18.75	$—
Natural gas ($/MMBtu)	$2.47	$4.25
Realized Prices		
Oil ($/Bbl)	$45.58	$89.57
NGL ($/Bbl)	$12.50	$—
Natural gas ($/Mcf)	$1.89	$6.39

(1) For periods prior to January 1, 2015, the Company presented reserves for oil and natural gas, which combined NGL with the natural gas stream, and did not separately report NGL. This change impacts the comparability of 2015 with prior periods.

Our net proved reserves were estimated at 125,698 MBOE on a three-stream basis as of December 31, 2015, of which 80% were classified as proved developed reserves and 42% are attributable to oil reserves. The following table presents summary data for our core operating area as of December 31, 2015. Our estimated proved reserves as of December 31, 2015 assume our ability to fund the capital costs necessary for their development and are affected by pricing assumptions. See "Item 1A. Risk Factors—Risks related to our business—Estimating reserves and future net revenues involves uncertainties. Decreases in commodity prices, or negative revisions to reserve estimates or assumptions as to future oil, NGL and natural gas prices, may lead to decreased earnings, losses or impairment of oil and natural gas assets."

	As of December 31, 2015		
Area:	Proved reserves (MBOE)	% of total	
Permian Basin	125,698	100	%
Other properties	—	—	%
Total	125,698	100	%

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The following table sets forth more information regarding our estimated proved reserves as of December 31, 2015 and 2014 (with 2014 results presented on a two-stream basis). Ryder Scott estimated 100% of our proved reserves as of December 31, 2015 and 2014. The reserve estimates as of December 31, 2015 and 2014 were prepared in accordance with the SEC's rules regarding oil and natural gas reserve reporting applicable to the periods presented.

	As of December 31,	
	2015	2014
Proved developed producing:		
Oil and condensate (MBbl)	40,493	53,270
NGL (MBbl)	29,009	—
Natural gas (MMcf)	178,519	272,674
Total proved developed producing (MBOE)	99,255	98,715
Proved developed non-producing:		
Oil and condensate (MBbl)	451	3,705
NGL (MBbl)	340	—
Natural gas (MMcf)	2,094	18,819
Total proved developed non-producing (MBOE)	1,140	6,842
Proved undeveloped:		
Oil and condensate (MBbl)	11,695	83,215
NGL (MBbl)	6,718	—
Natural gas (MMcf)	41,339	351,301
Total proved undeveloped (MBOE)	25,303	141,765
Estimated proved reserves:		
Oil and condensate (MBbl)	52,639	140,190
NGL (MBbl)	36,067	—
Natural gas (MMcf)	221,952	642,794
Total estimated proved reserves (MBOE)	125,698	247,322
Percent developed	80 %	43 %

Technology used to establish proved reserves

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

To establish reasonable certainty with respect to our estimated proved reserves, our internal reserve engineers and Ryder Scott, our independent reserve engineers, employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, open-hole logs, core analyses, geologic maps, available downhole and production data and seismic data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves, material balance calculations or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated primarily by performance from analogous wells in the surrounding area and the use of geologic data to assess the reservoir

continuity. These wells were considered to be analogous based on production performance from the same formation and completion using similar techniques.

As discussed previously in this Annual Report, during 2015 commodity prices for crude oil, NGL and natural gas experienced sharp declines, and this downward trend has accelerated further into the first quarter of 2016, with crude oil prices reaching a twelve-year low in February 2016. We have significantly reduced our capital budget for 2016. In addition, we have purposely significantly reduced the portion of our reserves that have historically been categorized as "proved undeveloped" or "PUD." We have adjusted our long-range five-year SEC PUD bookings methodology because given the current economic price environment, coupled with (i) our efforts to develop our acreage in the most efficient manner possible and determine which potential locations will be most profitable and (ii) the uncertain effect that such environment will have on the industry's access to the capital markets, we believe that we can optimize the value for our shareholders by maintaining greater flexibility in choosing the specific drilling locations that may yield the greatest rates of return.

As our activities to date have indicated, the majority of our acreage represents a resource play. In the near-term, our goal is to drill those locations that we anticipate have the potential to provide the greatest economic return and enhance shareholder value, and we have determined that the most efficient way to accomplish this is to maintain the flexibility to choose those locations based upon our continuing insight as we drill and collect data across our acreage, regardless of SEC reserve-booking status. Reducing our future PUD commitments provides us the most flexibility to maximize our rate of return at prevailing conditions and minimize the requirement to drill wells previously assigned under very different circumstances as specific PUD locations. Accordingly, we have reduced our booked PUD locations to those we have reasonable certainty to believe that we will develop in at least a two-year time horizon while maintaining the flexibility to add new PUD locations and convert other locations to proved developed reserves as our plans deem appropriate and opportunistic.

Qualifications of technical persons and internal controls over reserves estimation process

In accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and guidelines established by the SEC, Ryder Scott, our independent reserve engineers, estimated 100% of our proved reserve information as of December 31, 2015 and 2014 included in this Annual Report. The technical persons responsible for preparing the reserves estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to Ryder Scott in their reserves estimation process. Our technical team meets regularly with representatives of Ryder Scott to review properties and discuss methods and assumptions used in Ryder Scott's preparation of the year-end reserves estimates. The Ryder Scott reserve report is reviewed with representatives of Ryder Scott and our internal technical staff before dissemination of the information. Additionally, our senior management reviews the Ryder Scott reserve report.

Our Vice President of Reservoir Modeling and Field Development Planning, is the technical person primarily responsible for overseeing the preparation of our reserves estimates. He has more than 40 years of practical experience with 32 years of this experience being in the estimation and evaluation of reserves. He has a Bachelors of Science degree in Chemical Engineering and is a life member in good standing of the Society of Petroleum Engineers. Our Vice President of Reservoir Modeling and Field Development Planning reports directly to our Chairman and Chief Executive Officer. Reserves estimates are reviewed and approved by our senior engineering staff, other members of senior management and our technical staff, our audit committee and our Chief Executive Officer and then submitted to our board of directors for final approval.

Proved undeveloped reserves

Our proved undeveloped reserves decreased from 141,765 MBOE, reported on a two-stream basis, as of December 31, 2014, to 25,303 MBOE, reported on a three-stream basis, as of December 31, 2015. We estimate that we incurred $162 million of costs to convert 10,563 MBOE of proved undeveloped reserves from 37 locations into proved developed reserves in 2015. New proved undeveloped reserves of 2,669 MBOE were added during the year from four new horizontal Middle Wolfcamp locations. Negative revisions to proved undeveloped reserves of 106,883 MBOE were due to the combined effect of our adjusted booking methodology with the removal of 378 proved undeveloped

locations and the net effect of reinterpreting 34 undeveloped locations. The 378 locations that were removed were comprised of 182 vertical Wolfberry wells due to lower commodity prices and 196 horizontal wells to better align the timing of their development with our future drilling plans. In addition, 1,685 MBOE were removed due to the sale of nine undeveloped locations in August 2015.

Estimated total future development and abandonment costs related to the development of proved undeveloped reserves as shown in our December 31, 2015 reserve report are $266 million. Based on this report, the capital estimated to be spent in 2016 and 2017 to develop the proved undeveloped reserves is $192 million and $74 million, respectively, and $0 for each of

2018, 2019 and 2020. Based on our anticipated cash flows and capital expenditures, as well as the availability of capital markets transactions, all of the proved undeveloped locations are expected to be drilled within a two-year period. Reserve calculations at any end-of-year period are representative of our development plans at that time. Changes in circumstance, including commodity pricing, oilfield service costs, technology, acreage position and availability and other economic factors may lead to changes in development plans.

Sales volume, revenues and price history

The following table sets forth information regarding sales volumes, revenues, average sales prices and average costs per BOE sold for the years ended December 31, 2015, 2014 and 2013. For the 2013 and 2014 periods, our reserves and production were reported in two streams: crude oil and liquids-rich natural gas, and for 2015, our reserves and production are reported in three streams: crude oil, NGL and natural gas. For additional information on price calculations, see the information in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	For the years ended December 31,		
(unaudited)	2015	2014	2013
Sales volumes:[1]			
Oil (MBbl)	7,610	6,901	5,487
NGL (MBbl)	4,267	—	—
Natural gas (MMcf)	26,816	28,965	34,348
Oil equivalents (MBOE)[2][3]	16,346	11,729	11,211
Average daily sales volumes (BOE/D)[3]	44,782	32,134	30,716
Oil, NGL and natural gas revenues (in thousands):[1]			
Oil	$329,301	$571,620	$494,676
NGL	$50,604	$—	$—
Natural gas	$51,829	$165,583	$170,168
Average sales prices without hedges:[1]			
Index oil ($/Bbl)[4]	$48.80	$93.00	$97.97
Oil, realized ($/Bbl)[5]	$43.27	$82.83	$90.16
Index NGL ($/Bbl)[4]	$18.81	$—	$—
NGL, realized ($/Bbl)[5]	$11.86	$—	$—
Index natural gas ($/MMBtu)[4]	$2.66	$4.41	$3.65
Natural gas, realized ($/Mcf)[5]	$1.93	$5.72	$4.95
Average price, realized ($/BOE)[5]	$26.41	$62.86	$59.29
Average sales prices with hedges:[1][6]			
Oil, hedged ($/Bbl)	$74.41	$85.77	$88.68
NGL, hedged ($/Bbl)	$11.86	$—	$—
Natural gas, hedged ($/Mcf)	$2.42	$5.73	$4.98
Average price, hedged ($/BOE)	$41.71	$64.62	$58.66
Average cost per BOE sold:[1]			
Lease operating expenses	$6.63	$8.23	$7.06
Production and ad valorem taxes	$2.01	$4.29	$3.78
Midstream service expenses	$0.36	$0.46	$0.30
General and administrative[7]	$5.53	$9.04	$8.00
Depletion, depreciation and amortization	$16.99	$21.01	$20.87

(1) For periods prior to January 1, 2015, we presented our sales volumes, revenues, average sales prices for oil and natural gas and average costs per BOE sold, which combined NGL with the natural gas stream, and did not separately report NGL. This change impacts the comparability of the three periods presented.

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

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

(4) Index oil prices are the simple average of the daily settlement price for NYMEX West Texas Intermediate Light Sweet Crude Oil each month for the period indicated. Index NGL price is the simple arithmetic average of the monthly average of the daily high and low prices for each NGL component, during the month of delivery as reported for Mont Belvieu, Texas by the Oil Price Information Service using the Purity Ethane price for the ethane component and the Non-TET prices for the propane, butane and natural gasoline components multiplied by the simple arithmetic average of the monthly average percentage makeup of each NGL component in Laredo's composite NGL barrel. Index natural gas prices are the simple arithmetic average of each month's settlement price of the NYMEX Henry Hub natural gas First Nearby Month Contract upon expiration.

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

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

(7) General and administrative includes non-cash stock-based compensation, net of amounts capitalized, of $24.5 million, $23.1 million and $21.4 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Productive wells

The following table sets forth certain information regarding productive wells in each of our core areas as of December 31, 2015. All but two 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	Average WI	%
	Vertical	Horizontal	Total	Total		
Permian Basin:						
Operated Permian-Garden City	913	236	1,149	1,095	95	%
Non-operated Permian-Garden City	40	6	46	14	29	%
Other properties	—	—	—	—	—	%
Total	953	242	1,195	1,109	93	%

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own an interest as of December 31, 2015 for each of our core operating areas, including acreage held by production ("HBP"). A majority of our developed acreage is subject to liens securing our Senior Secured Credit Facility.

	Developed acres		Undeveloped acres		Total acres		%	
	Gross	Net	Gross	Net	Gross	Net	HBP	
Permian Basin:								
Permian-Garden City	122,706	106,765	29,717	24,998	152,423	131,763	81	%
Permian-China Grove	—	—	4,686	3,645	4,686	3,645	—	%
Permian total	122,706	106,765	34,403	28,643	157,109	135,408		
Other properties	—	—	23,746	17,612	23,746	17,612	—	%
Total	122,706	106,765	58,149	46,255	180,855	153,020	70	%

Undeveloped acreage expirations

The following table sets forth the gross and net undeveloped acreage in our core operating areas as of December 31, 2015 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.

	2016		2017		2018		2019	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian Basin:								
Permian-Garden City	7,684	5,408	3,290	2,449	10,556	9,772	—	—
Permian-China Grove	4,686	3,645	—	—	—	—	—	—
Permian total	12,370	9,053	3,290	2,449	10,556	9,772	—	—
Other properties	1,641	2,418	15,787	10,902	6,148	4,122	170	170
Total	14,011	11,471	19,077	13,351	16,704	13,894	170	170

Of the total undeveloped acreage identified as expiring over the next four years, 40 net acres have associated PUD reserves, which we anticipate drilling to hold the associated leases. These PUD reserves represent an insignificant amount of our overall PUD reserves.

Of the 3,165 net acres of leasehold that were identified at December 31, 2014 as attributable to PUD reserves and potentially expiring, 80 net acres actually expired in 2015. As of December 31, 2015, the locations from those expired acres were no longer classified as PUD reserves. The remainder of such acreage was retained either through lease extensions or drilling.

Drilling activity

The following table summarizes our drilling activity for the years ended December 31, 2015, 2014 and 2013. 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.

	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	93	80.4	219	183.9	171	127.2
Dry	—	—	—	—	—	—
Total development wells	93	80.4	219	183.9	171	127.2
Exploratory wells:						
Productive	2	2.0	2	1.8	2	2.0
Dry	—	—	1	1.0	—	—
Total exploratory wells	2	2.0	3	2.8	2	2.0

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 profits 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 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, 2015, 70% of all of our net leasehold acreage was held by production and 81% of our Permian-Garden City acreage was held by production.

Seasonality

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

Competition

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

Hydraulic fracturing

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

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

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

Certain state regulations require disclosure of the components in the solutions used in hydraulic fracturing operations. Approximately 99% of the hydraulic fracturing fluids we use are made up of water and sand. The remainder of the constituents in the fracturing fluid are managed and used in accordance with applicable requirements. In accordance

with Texas regulations, we report the constituents of the hydraulic fracturing fluids utilized in our well completions on FracFocus (www.fracfocus.org). Hydraulic fracture stimulation requires the use of a significant volume of water. Upon flowback of the water, we dispose of it by recycling or by discharging into approved disposal wells, so as to minimize the potential for impact to nearby surface water.

We currently do not discharge water to the surface. Based upon results of testing the performance of recycled flowback/produced water in our fracing operations on a limited number of wells, we have constructed and operate a water recycle facility on one of our production corridors and anticipate expanding our recycling activities in the future. For information regarding existing and proposed governmental regulations regarding hydraulic fracturing and related environmental matters, please read "-Regulation of environmental and occupational health and safety matters-Water and other waste discharges and spills." For related risks to our stockholders, please read "Item 1A. Risk Factors—Risks related to our business—Federal and state legislation and regulatory initiatives relating to hydraulic fracturing and water disposal wells could prohibit projects or result in materially increased costs and additional operating restrictions or delays because of the significance of hydraulic fracturing and water disposal wells in our business."

Regulation of the oil and natural gas industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. The state of Texas has statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area and the pooling of crude oil and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. 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 Congress, the states, the Environmental Protection Agency ("EPA"), Federal Energy Regulatory Commission ("FERC") and the courts. We cannot predict when or whether any such proposals may become effective.

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

Regulation of production of oil and natural gas

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 conservation matters, including provisions for the pooling of oil and natural gas properties, including the permitting of allocation wells, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, Texas imposes a production or severance tax with respect to the production and sale of oil, NGL and natural gas within its jurisdiction. Texas further regulates drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. State laws also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells that may be drilled, pooling of oil and natural gas properties and establishment of maximum rates of production from oil and natural gas wells. Texas further has the power to prorate production to the

market demand for oil and natural gas. 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.

Regulation of environmental and occupational health and safety matters

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

Hazardous substance and waste handling

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

The Oil Pollution Act of 1990 (the "OPA") is the primary federal law imposing oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing

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

RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA's hazardous waste regulations. These wastes, instead, are regulated under RCRA's less stringent solid waste provisions, state laws or other federal laws. It is also possible that these wastes, which could include wastes currently generated during our operations, will be designated as "hazardous wastes" in the future and, therefore, be subject to more rigorous and costly disposal requirements. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration and production wastes as "hazardous wastes." Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

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

Water and other waste discharges and spills

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act, the Safe Drinking Water Act ("SDWA"), the OPA and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. The State of Texas also maintains groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The underground injection of fluids is subject to permitting and other requirements under state laws and regulation. Obtaining permits has the potential to delay the development of oil and natural gas projects. These same regulatory programs also limit the total volume of water that can be discharged, hence limiting the rate of development, and require us to incur compliance costs. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances and may impose substantial potential liability for the costs of removal, remediation and damages. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and the underground injection of fluids and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of significant quantities of oil. We maintain all required discharge permits necessary to conduct our operations, and we believe we are in substantial compliance with their terms.

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

authority for UIC Class II programs in Texas, where we maintain acreage, the EPA is encouraging state programs to review and consider use of this permit guidance. Furthermore, legislation has been proposed in recent sessions of Congress to repeal the hydraulic fracturing exemption from the SDWA, provide for federal regulation of hydraulic fracturing and require public disclosure of the chemicals used in the fracturing process.

In addition, in May 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking public comment on its intent to develop and issue regulations under the Toxic Substances Control Act regarding the disclosure of information related to the chemicals used in hydraulic fracturing. The public comment period ended on September 18, 2014. The EPA plans to develop a Notice of Proposed Rulemaking by December 2016, which would describe a proposed mechanism-regulatory,

voluntary or a combination of both-to collect data on hydraulic fracturing chemical substances and mixtures. 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 April 7, 2015, the EPA published a proposed rule establishing federal pre-treatment standards for wastewater discharged from onshore unconventional oil and gas extraction facilities to publicly owned treatment works ("POTWs"). The EPA asserts that wastewater from such facilities can be generated in large quantities and can contain constituents that may disrupt POTW operations and/or be discharged, untreated, from the POTW to receiving waters. If adopted, the new pre-treatment rule would require unconventional oil and gas facilities to pre-treat wastewater before transferring it to POTWs. The public comment period ended on July 17, 2015, and the EPA is expected to publish a final rule by August 2016. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities. We cannot predict the impact that these standards may have on our business at this time, but these standards could have a material impact on our business, financial condition and results of operation.

Also, on March 26, 2015, the Bureau of Land Management (the "BLM") published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing, implementation of a casing and cementing program, management of recovered fluids, and submission to the BLM of detailed information about the proposed operation, including wellbore geology, the location of faults and fractures, and the depths of all usable water. The rule took effect on June 24, 2015, although it is the subject of several pending lawsuits filed by industry groups and at least four states, alleging that federal law does not give the BLM authority to regulate hydraulic fracturing. On September 30, 2015, the United States District Court for Wyoming issued a preliminary injunction preventing the BLM from implementing the rule nationwide. This order has been appealed to the Tenth Circuit Court of Appeals.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. For example, the EPA has commenced a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health. In June 2015, the EPA released its draft assessment report for peer review and public comment, finding that, while there are certain mechanisms by which hydraulic fracturing activities could potentially impact drinking water resources, there is no evidence available showing that those mechanisms have led to widespread, systemic impacts. 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 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. 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. 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. 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.

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. In August 2012, the EPA published final rules that subject oil and natural gas production, processing, transmission, and storage operations to regulation under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP"). The rule includes NSPS for completions of hydraulically fractured gas wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rule seeks to achieve a 95% reduction in volatile organic compounds ("VOC") emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of these requests for reconsideration. For example, in September 2013 and December 2014, the EPA amended its rules to extend compliance deadlines and to clarify the NSPS. Further, on July 31, 2015, the EPA finalized two updates to the NSPS to address the definition of low-pressure wells and references to tanks that are connected to one another (referred to as connected in parallel). In addition, on September 18, 2015, the EPA published a suite of proposed rules to reduce methane and VOC emissions from the oil and gas industry, including new "downstream" requirements covering equipment in the natural gas transmission segment of the industry that was not regulated by the 2012 rules. The public comment period closed on December 4, 2015. Also, on January 22, 2016, the BLM announced a proposed rule to reduce the flaring, venting and leaking of methane from oil and gas operations on federal and Indian lands. The proposed rule would require 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 would also clarify when operators owe the government royalties for flared gas. These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or utilize specific equipment or technologies to control emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions.

We have incurred additional capital expenditures to insure compliance with these new regulations as they come into effect. We may also be required to incur additional capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits addressing other air emission related issues, which may have a material adverse effect on our operations. Obtaining permits also has the potential to delay the development of oil and natural gas projects. We believe that we currently are in substantial compliance with all air emissions regulations and that we hold all necessary and valid construction and operating permits for our current operations.

Regulation of "greenhouse gas" emissions

Congress has from time to time considered legislation to reduce emissions of greenhouse gases ("GHGs") and almost one-half of the states have already taken legal measures to reduce emissions of GHGs through the planned development of GHG emission inventories and/or regional GHG cap and trade programs, although in recent years some states have scaled back their commitment to GHG initiatives. Most cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal

is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Some states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources.

In addition, in December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In response to its endangerment finding, the EPA adopted two sets of rules regarding possible

future regulation of GHG emissions under the Clean Air Act. The motor vehicle rule, which became effective in July 2010, purports to limit emissions of GHGs from motor vehicles. The EPA adopted the stationary source rule (or the "tailoring rule") in May 2010, and it became effective in January 2011. The tailoring rule established new GHG emissions thresholds that determine when stationary sources must obtain permits under the Prevention of Significant Deterioration ("PSD") and Title V programs of the Clean Air Act. On June 23, 2014, in Utility Air Regulatory Group v. EPA ("UARG v. EPA"), the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD and Title V programs. On December 19, 2014, the EPA issued two memoranda providing initial guidance on GHG permitting requirements in response to the Court's decision in UARG v. EPA. In its preliminary guidance, the EPA indicated it would promulgate a rule to rescind any PSD permits issued under the portions of the tailoring rule that were vacated by the Court. In the interim, the EPA issued a narrowly crafted "no action assurance" indicating it will exercise its enforcement discretion not to pursue enforcement of the terms and conditions relating to GHGs in an EPA-issued PSD permit, and for related terms and conditions in a Title V permit. On April 30, 2015, the EPA issued a final rule allowing permitting authorities to rescind PSD permits issued under the invalid regulations.

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

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

In December 2015, the United States joined the international community at the 21st Conference of the Parties ("COP-21") of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature, and to conserve and enhance sinks and reservoirs of GHGs. The Paris Agreement, if ratified, establishes a framework for the parties to cooperate and report actions to reduce GHG emissions.

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

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

Moreover, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornados and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured.

However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

Occupational Safety and Health Act

We are also subject to the requirements of the federal Occupational Safety and Health Act, as amended ("OSHA") and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Departments of Interior and Agriculture, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency prepares an environmental assessment to evaluate the potential direct, indirect and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a more detailed environmental impact study that is made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands 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' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We conduct operations on federal oil and natural gas leases in areas where certain species, such as the lesser prairie chicken, that are listed as threatened or endangered and where other species, such as the sage grouse, that potentially could be listed as threatened or endangered under the ESA exist. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development. If we were to have a portion of our leases designated as critical or suitable habitat, it could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas, which could adversely impact the value of our leases.

Summary

In summary, we believe we are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2015, 2014 or 2013.

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

Pursuant to Section 13(r) of the Exchange Act, we are required to include certain disclosures in our periodic reports if we or any of our "affiliates" (as defined in Rule 12b-2 under the Exchange Act) knowingly engaged in certain specified activities, transactions or dealings relating to Iran or with certain individuals or entities targeted by United States' economic sanctions during the period covered by the report. Disclosure is generally required even where the activities, transactions or dealings were conducted in compliance with applicable law. Neither we nor any of our controlled affiliates or subsidiaries knowingly engaged in any of the specified activities relating to Iran or otherwise engaged in any activities associated with Iran during the reporting period. However, because the SEC defines the term "affiliate" broadly, it includes any entity controlled by us as well as any person or entity that controlled us or is under common control with us.

The description of the activities below has been provided to us by Warburg Pincus, affiliates of which: (i) beneficially own more than 10% of our outstanding common stock and are members of our board of directors and (ii) beneficially

own more than 10% of the equity interests of, and have the right to designate members of the board of directors of, Endurance International Group ("Endurance") and Santander Asset Management Investment Holdings Limited ("SAMIH"). Endurance

and SAMIH may therefore be deemed to be under "common control" with us; however, this statement is not meant to be an admission that common control exists.

The disclosure below relates solely to activities conducted by Endurance and SAMIH and their respective affiliates. The disclosure does not relate to any activities conducted by Laredo or by Warburg Pincus and does not involve our or Warburg Pincus' management. Neither Laredo nor Warburg Pincus had any involvement in or control over the disclosed activities of Endurance or SAMIH, and neither Laredo nor Warburg Pincus has independently verified or participated in the preparation of the disclosure. Neither Laredo nor Warburg Pincus is representing as to the accuracy or completeness of the disclosure nor do we or Warburg Pincus undertake any obligation to correct or update it.

As to SAMIH:

Laredo understands that SAMIH's affiliates intend to disclose in their next annual or quarterly SEC report that:

"Santander UK plc ("Santander UK") holds frozen savings accounts and one current account for two customers resident in the U.K. who are currently designated by the U.S. for terrorism. The accounts held by each customer were blocked after the customer's designation and remained blocked and dormant throughout 2015. Revenue generated by Santander UK on these accounts is negligible.

An Iranian national, resident in the U.K., who is currently designated by the U.S. under the Iranian Financial Sanctions Regulations and the Weapons of Mass Destruction Proliferators Sanctions Regulations ("NPWMD sanctions program"), holds a mortgage with Santander UK that was issued prior to any such designation. No further drawdown has been made (or would be permitted) under this mortgage although Santander UK continues to receive repayment installments. In 2015, total revenue in connection with the mortgage was approximately £3,876 and net profits were negligible relative to the overall profits of Santander UK. The same Iranian national also holds two investment accounts with Santander Asset Management UK Limited. The funds within both accounts are invested in the same portfolio fund. The accounts have remained frozen during 2015. The investment returns are being automatically reinvested, and no disbursements have been made to the customer. Total revenue for the Santander Group in connection with the investment accounts was £188 and net profits in 2015 were negligible relative to the overall profits of Banco Santander, S.A.

During the third quarter 2015, two additional Santander UK customers were designated. First, a U.K. national designated by the U.S. under the Specially Designated Global Terrrorist ("SDGT") sanctions program who is on the U.S. Specially Designated National ("SDN") list. This customer holds a bank account which generated revenue of approximately £180 during the third and fourth quarters of 2015. The account is blocked. Net profits in the third and fourth quarters of 2015 were negligible relative to the overall profits of Santander. Second, a U.K. national also designated by the U.S. under the SDGT sanctions program who is on the U.S. SDN list, held a bank account. No transactions were made in the third and fourth quarter of 2015 and the account is blocked and in arrears.

In addition, during the fourth quarter of 2015, Santander UK has identified one additional customer. A U.K. national designated by the U.S. under the SDGT sanctions program who is on the U.S. SDN list, held a bank account which generated negligible revenue during the fourth quarter of 2015. The account was closed during the fourth quarter of 2015. Net profits in the fourth quarter of 2015 were negligible relative to the overall profits of Banco Santander, S.A."

As to Endurance:

Laredo understands that Endurance's affiliates intend to disclose in their next annual or quarterly SEC report that:

"On December 2, 2015, Endurance terminated a subscriber account ("the Subscriber Account") that Endurance believes to be associated with Issam Shammout and Sky Blue Bird Aviation ("Shammout") identified by the Office of Foreign Assets Control ("OFAC"), as a Specially Designated National, or ("SDN"), on May 21, 215, pursuant to 31 C.F.R. Part 594. The Subscriber Account was inadvertently migrated to Endurance's servers following its acquisition of the assets of Arvixe LLC ("Arvixe") on October 31, 2014. Pursuant to the terms of the asset purchase agreement between Endurance and Arvixe, any customer accounts prohibited by OFAC were expressly excluded from the acquisition. Accordingly, Endurance does not believe it took legal ownership of the Subscriber Account, and no revenue was collected by Endurance in connection with the Subscriber Account since the date on which Shammout was added to the SDN list. Nonetheless, upon identifying that the Subscriber Account had been migrated to its servers, Endurance promptly suspended all services and terminated the Subscriber Account. Endurance reported the Subscriber Account to OFAC as potentially the property of a SDN subject to blocking pursuant to Executive Order 13223. As of

January 25, 2016, Endurance has not received any correspondence from OFAC regarding this matter."

Employees

As of December 31, 2015, we had 340 full-time employees. We also employed a total of 22 contract personnel who assist our full-time employees with respect to specific tasks and perform various field and other services. Our future success will depend partially on our ability to identify, attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory.

Our offices

Our executive offices are located at 15 W. Sixth Street, Suite 900, Tulsa, Oklahoma 74119, and the phone number at this address is (918) 513-4570. We also lease corporate offices in Midland, Texas. On January 20, 2015, we announced the closing of our Dallas, Texas area office. We are currently still subject to the lease covering this office space, but are actively exploring alternative arrangements for its use.

Available information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any documents filed by us with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Our filings with the SEC are also available to the public from commercial document retrieval services and at the SEC's website at http://www.sec.gov.

Our common stock is listed and traded on the New York Stock Exchange under the symbol "LPI." Our reports, proxy statements and other information filed with the SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

We also make available on our website (http://www.laredopetro.com) all of the documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Our Code of Conduct and Business Ethics, Code of Ethics For Senior Financial Officers, Corporate Governance Guidelines and the charters of our audit committee, compensation committee and nominating and corporate governance committee are also available on our website and in print free of charge to any stockholder who requests them. Requests should be sent by mail to our corporate secretary at our executive office at 15 W. Sixth Street, Suite 900, Tulsa, Oklahoma 74119. Information contained on our website is not incorporated by reference into this Annual Report. We intend to disclose on our website any amendments or waivers to our Code of Ethics that are required to be disclosed pursuant to Item 5.05 of Form 8-K.

Item 1A. Risk Factors

Our business involves a high degree of risk. If any of the following risks, or any risks described elsewhere in this Annual Report, were actually to occur, our business, financial condition or results of operations could be materially adversely affected and the trading price of our shares could decline resulting in the loss of part or all of your investment. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial may also adversely affect us.

Risks related to our business

Oil, NGL and natural gas prices are volatile. The continuing and extended decline in oil, NGL and natural gas prices has adversely affected, and may continue to adversely affect, our business, financial condition and results of operations and may in the future affect our ability to meet our capital expenditure obligations and financial commitments as well as negatively impact our stock price further.

The prices we receive for our oil, NGL and natural gas production heavily influence our revenue, profitability, access to capital and future rate of growth. Oil, NGL and natural gas are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the market for oil, NGL and natural gas has been volatile, and this volatility exhibited a negative trend in the second half of 2014 which has continued through 2015 and into the first quarter of 2016. This 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;
- the level of global oil, NGL and natural gas exploration and production;
- the level of global oil, NGL and natural gas supplies, in particular due to supply growth from the United States;
- foreign and domestic supply capabilities for oil, NGL and natural gas;
- the price and quantity of U.S. imports and exports of oil, natural gas, including liquefied natural gas, and NGL;
- political conditions in or affecting other oil, NGL and natural gas-producing countries, including the current conflicts in the Middle East, and conditions in South America, Africa, Ukraine and Russia;
- 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 extent to which U.S. shale producers become "swing producers" adding or subtracting to the world supply totals of oil, NGL and natural gas;
- future regulations prohibiting or restricting our ability to apply hydraulic fracturing to our wells;
- current and future regulations regarding well spacing;
- prevailing prices on local oil, NGL and natural gas price indexes in the areas in which we operate;
- localized and global supply and demand fundamentals and transportation availability;
- weather conditions;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- domestic, local and foreign governmental regulation and taxes.

Lower oil, NGL and natural gas prices have and will continue to reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our oil, NGL and natural gas reserves as existing reserves are depleted. A continuing decrease in oil, NGL and natural gas prices could render uneconomic an even larger portion of our exploration, development and exploitation projects. This has already resulted in us having to make significant downward adjustments to our estimated proved reserves, and we may need to make further downward adjustments in the future. Furthermore, under our Senior Secured Credit Facility, scheduled borrowing base redeterminations occur on each May 1 and November 1, and the lenders have the right to call for an interim redetermination of the borrowing base one time between any two redetermination dates and in other specified circumstances. We expect that the extended decline in oil, NGL and natural gas prices will adversely impact our borrowing base in future borrowing base redeterminations, which could trigger repayment obligations under the Senior Secured Credit Facility to the extent our outstanding loans under the Senior Secured Credit Facility exceed the

redetermined borrowing base and otherwise materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. In addition, lower oil, NGL and natural gas prices may cause a further decline in our stock price.

Currently, we receive incremental cash flows as a result of our hedging activity. To the extent we are unable to obtain future hedges at attractive prices or our derivative activities are not effective, our cash flows and financial condition may be adversely impacted.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of oil, NGL and natural gas, we enter into derivative instrument contracts for a portion of our oil, NGL and natural gas production, including swaps, collars, puts and basis swaps. In accordance with applicable accounting principles, we are required to record our derivatives at fair market value, and they are included on our consolidated balance sheet as assets or liabilities and in our consolidated statements of operations as gain (loss) on derivatives. Gain (loss) on derivatives are included in our cash flows from operating activities. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair market value of our derivative instruments. Although our current hedges provide us with a benefit as they are priced above the current depressed prices for oil, NGL and natural gas, as these hedges expire, there is significant uncertainty that we will be able to put new hedges in place that will provide us with similar benefit.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

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

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

Estimating reserves and future net revenues involves uncertainties. Decreases in oil, NGL and natural gas prices, increases in service costs or negative revisions to reserve estimates or assumptions as to future oil, NGL and natural gas prices, may lead to decreased earnings and losses or impairment of oil, NGL and natural gas assets.

The reserve data included in this Annual Report represent estimates. Reserves estimation is a subjective process of evaluating underground accumulations of oil, NGL and natural gas that cannot be measured in an exact manner. Reserves that are "proved reserves" are those estimated quantities of oil, NGL and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions and that relate to specific locations for which the extraction of hydrocarbons must have commenced or the operator must be reasonably certain will commence within a five-year period.

The estimation process relies on interpretations of available geological, geophysical, engineering and production data. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of developmental expenditures, including higher decline curves in the first year of production and many other factors beyond the control of the producer. In addition, the estimates of future net revenues from our proved reserves and the present value of such estimates are based upon certain assumptions about future production levels, prices and costs that may not prove to be correct. Further, initial production rates reported by us or other operators may not be indicative of future or long-term production rates. A production decline may be rapid and irregular when compared to a well's initial production.

Quantities of proved reserves are estimated based on economic conditions in existence during the period of assessment. Changes to oil, NGL and natural gas prices in the markets for such commodities may have the impact of shortening the economic lives of certain fields because it becomes uneconomic to produce all recoverable reserves on such fields, which reduces proved property reserves estimates. In 2015, negative revisions of 124,180 MBOE of previously estimated quantities are primarily attributable to the removal of 106,883 MBOE due to the combined effect of the removal of 378 proved undeveloped locations and the net effect of reinterpreting 34 undeveloped locations. The 378 locations that were removed were comprised of 182 vertical Wolfberry wells due to lower commodity prices and 196 horizontal wells to better align the timing of their development with our future drilling plans. The remaining 17,297 MBOE of negative revisions are due to a combination of pricing, performance and other changes to the proved developed producing and proved developed non-producing wells.

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.

Also, the substantial decrease in oil, NGL and natural gas prices has had the effect of rendering uneconomic a portion of our exploration, development and exploitation projects. This resulted in our having to make downward adjustments to our estimated proved reserves. It is possible that we may need to make additional downward adjustments in the future (which could be significant).

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

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

Oil, NGL and natural gas prices have significantly declined since mid-2014 and have remained low in the first-quarter of 2016. Primarily as a result of these lower prices, our December 31, 2015 estimated proved reserves decreased 171 MMBOE from our December 31, 2014 reserves, converted to three streams. Additionally, we recorded non-cash full cost ceiling impairments of $488.0 million, $906.4 million and $975.0 million in the second, third and fourth quarters of 2015, respectively. If prices remain at or below current levels and all other factors remain the same, we will incur further charges in the future. Such charges could have a material adverse effect on our results of operations for the periods in which they are taken. See Note 2.g to our consolidated financial statements included elsewhere in this Annual Report for additional information.

Any significant reduction in our borrowing base under our Senior Secured Credit Facility as a result of a periodic borrowing base redetermination or otherwise will negatively impact our liquidity and, consequently, our ability to fund our operations, and we may not have sufficient funds to repay borrowings under our Senior Secured Credit Facility or any other obligation if required as a result of a borrowing base redetermination.

Availability under our Senior Secured Credit Facility is currently subject to a borrowing base of $1.15 billion. The borrowing base is subject to scheduled semiannual (May 1 and November 1) and other elective borrowing base redeterminations based upon, among other things, projected revenues from, and asset values of, the oil and natural gas properties securing the Senior Secured Credit Facility. The lenders under our Senior Secured Credit Facility can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our Senior Secured Credit Facility. Reductions in estimates of our oil, NGL and natural gas reserves will result in a reduction in our borrowing base (if prices are kept constant). Given the ongoing decline in commodity prices for oil, NGL and natural gas, it is likely that reductions in our borrowing base could also arise from other factors, including but not limited to:

- lower commodity prices or production;
- increased leverage ratios;
- inability to drill or unfavorable drilling results;
- changes in crude oil, NGL and natural gas reserve engineering;
- increased operating and/or capital costs;
- the lenders' inability to agree to an adequate borrowing base; or
- adverse changes in the lenders' practices (including required regulatory changes) regarding estimation of reserves.

As of February 16, 2016, we had $170.0 million of borrowings outstanding under our Senior Secured Credit Facility. We may make further borrowings under our Senior Secured Credit Facility in the future. Any significant reduction in our borrowing base as a result of such borrowing base redeterminations or otherwise will negatively impact our liquidity and our ability to fund our operations and, as a result, would have a material adverse effect on our financial position, results of operation and cash flow. Further, if the outstanding borrowings under our Senior Secured Credit Facility were to exceed the borrowing base as a result of any such redetermination, we could be required to repay the excess. We may not have sufficient funds to make such repayments. If we do not have sufficient funds and we are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

Our business requires significant capital expenditures and we may be unable to obtain needed capital or financing on satisfactory terms or at all.

Our exploration, development, marketing, transportation and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations,

borrowings on our Senior Secured Credit Facility, equity offerings and proceeds from the sale of our Senior Unsecured Notes. We do not have commitments from anyone to contribute capital to us. Future cash flows are subject to a number of variables, including the level of production from existing wells, prices of oil, NGL and natural gas and our success in developing and producing new reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may have limited ability to obtain the additional capital necessary to sustain our operations at current levels. We may not be able to obtain debt or equity financing on terms favorable to us or at all. The failure to obtain additional capital could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a decline in our oil, NGL and natural gas production or reserves and, in some areas, a loss of properties.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce our cash flow and/or liquidity available for drilling and place us at a competitive disadvantage. For example, as of February 16, 2016 we had $1.0 billion of elected commitment on our Senior Secured Credit Facility, subject to compliance with financial covenants. The impact of a 1.0% increase in interest rates on an assumed borrowing of the full $1.0 billion elected commitment on our Senior Secured Credit Facility would result in increased annual interest expense of $10.0 million and a decrease in our net income before income taxes. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in our cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

We have incurred losses from operations for various periods since our inception and may do so in the future.

We incurred net losses from our inception to December 31, 2006 of $1.8 million and for each of the years ended December 31, 2007, 2008, 2009 and 2015 of $6.1 million, $192.0 million, $184.5 million and $2.2 billion, respectively. Our development of and participation in an increasingly larger number of locations has required and will continue to require substantial capital expenditures. The uncertainty and factors described throughout this section may impede our ability to economically find, develop, exploit and acquire oil, NGL and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows from operating activities in the future. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical accounting policies and estimates."

We require a significant amount of cash to service our indebtedness. Our ability to generate cash depends on many factors beyond our control.

Our ability to make payments on and to refinance our indebtedness and to fund planned capital expenditures depends on our ability to generate cash in the future. This, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control. We cannot assure you that we will generate sufficient cash flow from operations or that future funding will be available to us under our Senior Secured Credit Facility, equity offerings or other actions in an amount sufficient to enable us to pay our indebtedness or to fund our other liquidity needs. We may need to refinance all or a portion of our indebtedness at or before maturity. We cannot assure you that we will be able to refinance any of our indebtedness on commercially reasonable terms or at all.

Our debt agreements contain restrictions that limit our flexibility in operating our business.

Our Senior Secured Credit Facility and the indentures governing our Senior Unsecured Notes each contain, and any future indebtedness we incur may contain, various covenants that limit our ability to engage in specified types of transactions. These covenants limit our ability to, among other things:

- incur additional indebtedness;
- pay dividends on, repurchase or make distributions in respect of our capital stock or make other restricted payments;
- make certain investments;
- 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, we are limited in the manner in which we may conduct our business and we may be

unable to engage in favorable business activities or finance future operations or our capital needs. In addition, the covenants in our Senior Secured Credit Facility require us to maintain a minimum working capital ratio and minimum interest coverage ratio and also limit our capital expenditures. A breach of any of these covenants could result in a default under one or more of these agreements, including as a result of cross default provisions and, in the case of our Senior Secured Credit Facility, permit the lenders to cease making loans to us. Upon the occurrence of an event of default under our Senior Secured Credit Facility, the lenders could elect to declare all amounts outstanding under our Senior Secured Credit Facility to be immediately due and payable and terminate all commitments to extend further credit. Such actions by those lenders could cause cross defaults under our other indebtedness, including the Senior Unsecured Notes. If we were unable to repay those amounts, the lenders under our Senior Secured Credit Facility could proceed against the collateral granted to them to secure that indebtedness. We pledged a significant portion of our assets as collateral under our Senior Secured Credit Facility. If the lenders under our Senior Secured Credit Facility accelerate the repayment of the borrowings thereunder, the proceeds from the sale or foreclosure upon such assets will first be used to repay debt under our Senior Secured Credit Facility, and we may not have sufficient assets to repay our unsecured indebtedness thereafter.

If we were to experience an ownership change, we could be limited in our ability to use net operating losses arising prior to the ownership change to offset future taxable income. In addition, our ability to use net operating loss carry forwards to reduce future tax payments may be limited if our taxable income does not reach sufficient levels.

As of December 31, 2015, we had a net operating loss ("NOL") carryforward for federal income tax purposes of $1.4 billion. If we were to experience an "ownership change," as determined under Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"), our ability to offset taxable income arising after the ownership change with NOLs arising prior to the ownership change would be limited, possibly substantially. An ownership change would establish an annual limitation on the amount of our pre-change NOL we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate. In general, an ownership change will occur if there is a cumulative increase in our ownership of more than 50 percentage points by one or more "5% shareholders" (as defined in the Code) at any time during a rolling three-year period. In addition, under the Code, NOL can generally be carried forward to offset future taxable income for a period of 20 years. Our ability to use our NOL during this period will be dependent on our ability to generate taxable income, and the NOL could expire before we generate sufficient taxable income. As of December 31, 2015, based on evidence available to us, including projected future cash flows from our oil and natural gas reserves and the timing of those cash flows, we believe a portion of our NOL is not fully realizable. As a result, as of December 31, 2015 a valuation allowance has been recorded against our NOL tax assets.

The potential drilling locations for our future wells that we have tentatively internally identified will be drilled, if at all, over many years. This makes them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, which in certain instances could prevent production prior to the expiration date of leases for such locations.

Although our management team has established certain potential drilling locations as a part of our long-range planning related to future drilling activities on our existing acreage, our ability to drill and develop these locations depends on a number of uncertainties, including oil, NGL and natural gas prices, the availability and cost of capital, drilling and production costs, the availability of drilling services and equipment, drilling results (including the impact of increased horizontal drilling and longer laterals), lease expirations, gathering systems, marketing and pipeline transportation constraints, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous potential drilling locations we have currently identified will ever be drilled or if we will be able to produce oil, NGL or natural gas from these or any other potential drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. As such, it is likely our actual drilling activities, especially in the long term, could materially differ from those presently anticipated.

Drilling for and producing oil, NGL and natural gas are high-risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our exploration, exploitation, development and production activities. Our oil, NGL and natural gas exploration, exploitation, development and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil, NGL and natural gas production. Our decisions to purchase, explore, develop or otherwise exploit locations or properties will depend in part on the evaluation of information obtained through geophysical and geological analyses, production data, engineering studies and our Earth Model, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see "—Estimating reserves and future net revenues involves uncertainties. Decreases in oil, NGL and natural gas prices, or negative revisions to reserves estimates or assumptions as to future oil, NGL and natural gas prices, may lead to decreased earnings, losses or impairment of oil, NGL and natural gas

assets." In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences. Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- declines in oil, NGL and natural gas prices;
- limited availability of financing or capital at acceptable rates or terms;
- limitations in the market for oil, NGL and natural gas;
- delays imposed by or resulting from compliance with regulatory and contractual requirements and related lawsuits, which may include limitations on hydraulic fracturing or the discharge of greenhouse gases;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- fires and blowouts;
- adverse weather conditions, such as hurricanes, blizzards and ice storms; and
- title problems.

We are involved as a passive minority-interest partner in joint ventures and are subject to risks associated with joint venture partnerships.

We are involved as a passive minority-interest partner in joint venture relationships and may initiate future joint venture projects. Entering into a joint venture as a passive minority-interest partner involves certain risks that include: the need to contribute funds to the joint venture to support its operating and capital needs; the inability to exercise voting control over the joint venture; economic or business interests that are not aligned with our venture partners, including the holding period and timing of ultimate sale of the ventures' underlying assets; and the inability for the venture partner to fulfill its commitments and obligations due to financial or other difficulties. Our interest in Medallion is as a passive minority-interest partner.

In many instances (including Medallion), we depend on the venture partner for elements of the arrangements that are important to the success of the joint venture, such as agreed payments of substantial development costs pertaining to the joint venture and its share of other costs of the joint venture. The performance of these venture partner obligations or the ability of the venture partner to meet its obligations under these arrangements is outside our control. If the venture partner does not meet or satisfy its obligations under these arrangements, the performance and success of these arrangements, and their value to us, may be adversely affected.

If our current or future venture partners are unable to meet their obligations because of insolvency, bankruptcy or other reasons, we may be forced to undertake the obligations ourselves and/or incur additional expenses in order to have some other party perform such obligations. In addition, the insolvency of a venture partner could result in our liability to governmental authorities for compliance with environmental, safety and other regulatory requirements, to the joint venture’s suppliers and vendors and to other third parties. In such cases, we may also be required to enforce our rights, which may cause disputes among our venture partners and us. If any of these events occur, they may adversely impact us, our financial performance and results of operations, the joint ventures and/or our ability to enter into future joint ventures. Likewise, we may have similar obligations to third parties for properties we operate.

Some of our drilling and development activities are subject to joint ventures or operations controlled by third parties, which could negatively impact our control over these operations and have a material adverse effect on our business, results of operations, financial condition and prospects.

A portion of our drilling and development activities is conducted through joint operating agreements under which we own partial interests in oil and natural gas properties. If we do not operate the properties in which we own an interest, (i) we have limited ability to influence or control the day-to-day operation of such properties, including compliance with environmental, safety and other regulations, (ii) we cannot control the amount of capital expenditures that we are required to fund with respect to properties or the future development plans for the properties, (iii) we are dependent on third parties to fund their required share of capital expenditures the same as our dependency on third parties where we are the operator and (iv) we may have restrictions or limitations on our ability to sell our interests in these jointly owned assets. The failure of an operator of our wells to adequately perform operations or an operator's breach of the applicable agreements could materially reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others, therefore, depends upon a number of factors outside of

our control, including the operator's timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells and use of technology. Because we do not have a majority interest in most wells that we do not operate, we may not be in a position to remove the operator in the event of poor performance.

In addition, the insolvency of an operator of any of our properties, the failure of an operator of any of our properties to adequately perform operations or an operator’s breach of applicable agreements could reduce our production and revenue and result in our liability to governmental authorities for compliance with environmental, safety and other regulatory requirements, to the operator's suppliers and vendors and to royalty owners under oil and gas leases jointly owned with the operator or another insolvent owner. Finally, an operator of our properties may have the right, if another non-operator fails to pay its share of costs because of its insolvency or otherwise, to require us to pay our proportionate share of the defaulting party's share of costs.

The inability of our significant customers to meet their obligations to us may materially adversely affect our financial results.

In addition to credit risk related to receivables from commodity derivative contracts, our principal exposure to credit risk is through net joint operations receivables ($21.4 million as of December 31, 2015) and the sale of our oil, NGL and natural gas production ($25.6 million in receivables as of December 31, 2015), which we market to energy marketing companies, refineries and affiliates. Joint interest receivables arise from billing entities who own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We are generally unable to control which co-owners participate in our wells. We are also subject to credit risk due to the concentration of our oil, NGL and natural gas production receivables with several significant customers. The largest purchaser of our oil, NGL and natural gas production accounted for 37.5% of our total oil, NGL and natural gas revenues for the year ended December 31, 2015 and our sales of purchased oil are made to one customer. See Note 11 to our consolidated financial statements included elsewhere in this Annual Report for additional information. The inability or failure of our significant customers or joint working interest owners to meet their obligations to us or their insolvency or liquidation may materially adversely affect our financial results. Current economic circumstances may further increase these risks.

Our operations are substantially dependent on the availability, use and disposal of water. New legislation and regulatory initiatives or restrictions relating to water disposal wells could have a material adverse effect on our future business, financial condition, operating results and prospects.

Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners and other sources for use in our operations. During the past several years, Texas has experienced the lowest inflows of water in recent history. As a result of these conditions, some local water districts may begin restricting the use of water subject to their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil, NGL and natural gas, which could have an adverse effect on our results of operations, cash flows and financial condition.

Additionally, our drilling procedures produce large volumes of water that we must properly dispose. The Clean Water Act of 1977, as amended, the Safe Drinking Water Act of 1974, as amended, the Oil Pollution Act of 1990, as amended, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the U.S. Environmental Protection Agency (the "EPA") or the state. Furthermore, the State of Texas maintains groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The underground injection of fluids is subject to permitting and other requirements under state laws and regulation. Obtaining permits has the potential to delay the development of oil, NGL and natural gas projects. These same regulatory programs also limit the total volume of water that can be discharged, hence limiting the rate of development, and require us to incur compliance costs. In October 2014, the RRC adopted new regulations effective as of November 17, 2014 that require additional supporting documentation, including records from the U.S. Geological Survey regarding previous seismic events in the area, as part of applications for new disposal wells. The new regulations also clarify the RRC's ability to modify, suspend or terminate a disposal well permit if scientific data indicates it is likely to contribute to seismic activity. The RRC has used this authority to deny permits for waste disposal sites.

Moreover, the EPA is examining regulatory requirements for "indirect dischargers" of wastewater - i.e., those that send their discharges to private or publicly owned treatment facilities, which treat the wastewater before discharging it

to regulated waters. On April 7, 2015, the EPA published a proposed rule establishing federal pre-treatment standards for wastewater discharged from onshore unconventional oil and gas extraction facilities to publicly owned treatment works ("POTWs"). The EPA asserts that wastewater from such facilities can be generated in large quantities and can contain constituents that may disrupt POTW operations and/or be discharged, untreated, from the POTW to receiving waters. If adopted, the new pre-treatment rule would require unconventional oil and gas facilities to pre-treat wastewater before transferring it to POTWs. The public comment period ended on July 17, 2015, and the EPA is expected to publish a final rule by August 2016. The EPA is also

conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities.

Because of the necessity to safely dispose of water produced during drilling and production activities, these regulations, or others like them, could have a material adverse effect on our future business, financial condition, operating results and prospects. See "Item 1. Business—Regulation of the oil and natural gas industry" for a further description of the laws and regulations that affect us.

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

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

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

On May 9, 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking public comment on its intent to develop and issue regulations under the Toxic Substances Control Act regarding the disclosure of information related to the chemicals used in hydraulic fracturing. The public comment period ended on September 18, 2014. The EPA plans to develop a Notice of Proposed Rulemaking by December 2016, which would describe a proposed mechanism, regulatory, voluntary, or a combination of both, to collect data on hydraulic fracturing chemical substances and mixtures.

Also, on March 26, 2015, the Bureau of Land Management (the "BLM") published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing, implementation of a casing and cementing program, management of recovered fluids, and submission to the BLM of detailed information about the proposed operation, including wellbore geology, the location of faults and fractures, and the depths of all usable water. The rule took effect on June 24, 2015, although it is the subject of several pending lawsuits filed by industry groups and at least four states, alleging that federal law does not give the BLM authority to regulate hydraulic fracturing. On September 30, 2015, the United States District Court for Wyoming issued a preliminary injunction preventing the BLM from implementing the rule nationwide. This order has been appealed to

the Tenth Circuit Court of Appeals.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. For example, the EPA has commenced a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health. In June 2015, the EPA released its draft assessment report for peer review and public comment, finding that, while there are certain mechanisms by which hydraulic fracturing activities could potentially impact drinking water resources, there is no evidence available showing that those mechanisms have led to widespread, systemic impacts. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and

minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanism.

On August 16, 2012, the EPA published final rules that subject oil, NGL and natural gas production, processing, transmission, and storage operations to regulation under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP") programs. The rule includes NSPS Standards for completions of hydraulically fractured gas wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rule seeks to achieve a 95% reduction in volatile organic compounds ("VOC") emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of these requests for reconsideration. For example, in September 2013 and December 2014, the EPA amended its rules to extend compliance deadlines and to clarify the NSPS. Further, on July 31, 2015, the EPA finalized two updates to the NSPS to address the definition of low-pressure wells and references to tanks that are connected to one another (referred to as connected in parallel). In addition, on September 18, 2015, the EPA published a suite of proposed rules to reduce methane and VOC emissions from oil and gas industry, including new "downstream" requirements covering equipment in the natural gas transmission segment of the industry that was not regulated by the 2012 rules. The public comment period closed on December 4, 2015. Also, on January 22, 2016, the BLM announced a proposed rule to reduce the flaring, venting and leaking of methane from oil and gas operations on federal and Indian lands. The proposed rule would require 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 would also clarify when operators owe the government royalties for flared gas.

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

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

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 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 or water disposal wells are enacted into law.

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

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

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

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

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

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

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

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

Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, through the planned development of GHG emission inventories and/or regional GHG cap and trade programs or other mechanisms. Most cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing

plants, to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Some states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources.

In addition, in December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In response to its endangerment finding, the EPA recently adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act. The motor vehicle rule, which became effective in July 2010, purports to limit emissions of GHGs from motor vehicles. The EPA adopted the stationary source rule (or the "tailoring rule") in May 2010, and it became effective in January 2011. The tailoring rule established new GHG emissions thresholds that determine when stationary sources must obtain permits under the Prevention of Significant Deterioration ("PSD") and Title V programs of the Clean Air Act. On June 23, 2014, in Utility Air Regulatory Group v. EPA ("UARG v. EPA"), the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD and Title V programs. On December 19, 2014, the EPA issued two memoranda providing initial guidance on GHG permitting requirements in response to the Court's decision in UARG v. EPA. In its preliminary guidance, the EPA indicated it would promulgate a rule to rescind any PSD permits issued under the portions of the tailoring rule that were vacated by the Court. In the interim, the EPA issued a narrowly crafted "no action assurance" indicating it will exercise its enforcement discretion not to pursue enforcement of the terms and conditions relating to GHGs in an EPA-issued PSD permit, and for related terms and conditions in a Title V permit. On April 30, 2015, the EPA issued a final rule allowing permitting authorities to rescind PSD permits issued under the invalid regulations.

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

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

In December 2015, the United States joined the international community at 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, if ratified, establishes a framework for the parties to cooperate and report actions to reduce GHG emissions.

Restrictions on GHG emissions that may be imposed could adversely affect the oil and natural 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, claims have been made against certain energy companies alleging that GHG emissions from oil, NGL and

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

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

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

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

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

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

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

or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

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

If we are unable to drill new allocation wells it could have a material adverse impact on our future production results.
In the State of Texas, allocation wells allow an oil and gas producer to drill a horizontal well under two or more leaseholds that are not pooled. We are active in drilling and producing allocation wells. If there are regulatory changes with regard to allocation wells, the RRC denies or significantly delays the permitting of allocation wells or if legislation is enacted that negatively impacts the current process under which allocation wells are currently permitted, it could have an adverse impact on our ability to drill long horizontal lateral wells on some of our leases, which in turn could have a material adverse impact on our anticipated future production.
Unless we replace our oil, NGL and natural gas production, our reserves and production will continue to decline, which would adversely affect our future cash flows and results of operations.
Producing oil, NGL and natural gas reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploration, development and exploitation activities or continually acquire properties containing proved reserves, our proved reserves will continue to decline as those reserves are produced. Our future oil, NGL and natural gas reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.
A decrease in our production of oil, NGL and natural gas could negatively impact our ability to meet our contractual obligations to deliver oil, NGL and natural gas and our ability to retain our leases.
A portion of our oil, NGL and gas production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss or unavailability of pipeline or gathering system access and capacity, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions, including low oil, NGL and gas prices. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow. Furthermore, if we were required to shut in wells, we might also be obligated to pay shut-in royalties to certain mineral interest owners to maintain our leases.
In addition, we have entered into agreements with third party shippers, including Medallion, and purchasers that require us to deliver minimum amounts of crude oil and natural gas. Pursuant to these agreements, we must deliver specific amounts, either from our own production or from oil we acquire, over the next ten years. If we are unable to fulfill all of our contractual delivery obligations from our own production, we may be required to pay penalties or damages pursuant to these agreements or we may have to purchase oil from third parties to fulfill our delivery obligations. This could adversely impact our cash flows, profit margins and net income.
We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.
We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil, NGL and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil, NGL and natural gas, including the possibility of:

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

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

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

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

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

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

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

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

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

Although some of the rules necessary to implement the Dodd-Frank Act remain to be adopted, the CFTC, the SEC and the Prudential Regulators have issued many rules to implement the Dodd-Frank Act, including a rule, which we refer to as the "Mandatory Clearing Rule," requiring clearing of hedges, or swaps, that are subject to it (currently, only certain interest rate and credit default swaps, which we do not presently have), a rule, which we refer to as the "End User Exception," establishing an "end user" exception to the Mandatory Clearing Rule, a rule, which we refer to as the "Margin Rule," setting forth collateral requirements in connection with swaps that are not cleared and also an exception to the Margin Rule for end users that are not financial end users, which exception we refer to as the "Non-Financial End User Exception," and a rule, subsequently vacated by the United States District Court for the

District of Columbia and remanded to the CFTC for further proceedings, imposing position limits. The CFTC proposed a new version of this rule, which we refer to as the "Re-Proposed Position Limit Rule," with respect to which the comment period has closed but a final rule has not been issued.

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 the quantities under the swaps in which we participate are well within applicable limits under the Re-Proposed Position Limit Rule, 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, which we refer to collectively as "Foreign Regulations" which may apply to our transactions with counterparties subject to such Foreign Regulations. The Dodd-Frank Act, the rules which have been adopted and not vacated, and, to the extent that the Re-Proposed Position Limit Rule is effected, such proposed rule could significantly increase the cost of our derivative contracts, materially alter the terms of our derivative contracts, reduce the availability of derivatives to us that we have historically used to protect against risks that we encounter in our business, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. The Foreign Regulations could have similar effects. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations and Foreign Regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition, and our results of operations.

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

Our producing properties are geographically concentrated in the Permian Basin. At December 31, 2015, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, water shortages or other drought-related conditions or interruption of the processing or transportation of oil or natural gas.

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

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

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

Even when properly used and interpreted, 2D and 3D seismic data and other data, such as that incorporated into our Earth Model that provide either visualization techniques and/or statistical analyses are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable geoscientists to know whether hydrocarbons are, in fact, present in those structures or the amount of hydrocarbons. We employ 3D seismic technology with respect to certain of our projects. The implementation and practical use of 3D seismic technology is relatively unproven, which can lessen its effectiveness, at least in the near term, and increase our costs. In addition, the

use of 3D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur greater drilling and exploration expenses as a result of such expenditures, which may result in a reduction in our returns. As a result, our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline.

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

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

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

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

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

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

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

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

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

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

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

Warburg Pincus is our largest stockholder and two members of our board of directors are affiliates of Warburg Pincus. As of December 31, 2015, Warburg Pincus owned 41.0% of our outstanding common stock. We believe that Warburg Pincus' substantial ownership interest in us provides them with an economic incentive to assist us to be successful.

However, Warburg Pincus is not obligated to maintain its ownership interest in us and may elect at any time to change its ownership position in our stock. If Warburg Pincus sells all or a substantial portion of its ownership interest in us, Warburg Pincus may have less incentive to assist in our success and its affiliates that are members of our board of directors may resign. Such actions could

adversely affect our ability to successfully implement our business strategies, which could adversely affect our cash flows or results of operations.

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

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

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

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

We may incur significant additional amounts of debt.

As of February 16, 2016, we had total long-term indebtedness of $1.5 billion. In addition, we may be able to incur substantial additional indebtedness, including secured indebtedness, in the future. The restrictions on the incurrence of additional indebtedness contained in the indentures governing our Senior Unsecured Notes and in our Senior Secured Credit Facility are subject to a number of significant qualifications and exceptions, and under certain circumstances, the amount of indebtedness that could be incurred in compliance with these restrictions could be substantial. If new debt is added to our existing debt levels, the related risks that we face would increase and may make it more difficult to satisfy our existing financial obligations. In addition, the restrictions on the incurrence of additional indebtedness contained in the indentures governing the Senior Unsecured Notes apply only to debt that constitutes indebtedness under the indentures.

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

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

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

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

effect on our business.

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

Risks relating to our common stock

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

As of December 31, 2015, Warburg Pincus owned 41.0% of our outstanding common stock. Consequently, Warburg Pincus has significant influence over all matters that require approval by our stockholders, including the election of directors and approval of significant corporate transactions. This concentration of ownership limits the ability of other stockholders to influence corporate matters.

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

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

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

Our amended and restated certificate of incorporation authorizes our board of directors to issue preferred stock without any further vote or action by the stockholders. The rights of the holders of our common stock will be subject

to the rights of the holders of any preferred stock that may be issued in the future. The issuance of preferred stock could delay, deter or prevent a change in control and could adversely affect the voting power or economic value of our shares.

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

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

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

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

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

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

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

Item 1B. Unresolved Staff Comments

During 2015, the SEC issued comment letters relating to the Company's previously filed annual report on Form 10-K for the fiscal year ended December 31, 2014 inquiring about the potential impact of current commodity prices and our development plans for our reserves. The Company responded to these comment letters and was notified by the SEC that it completed its review on February 11, 2016. No amendments to any prior filings were required.

Item 2. Properties

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

Item 3. Legal Proceedings

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

Item 4. Mine Safety Disclosures

Not applicable.

Part II

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

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

	Price per share	
	High	Low
2015:		
Fourth Quarter	$13.96	$7.05
Third Quarter	$12.02	$7.79
Second Quarter	$15.80	$12.58
First Quarter	$14.61	$8.31
2014:		
Fourth Quarter	$22.82	$7.39
Third Quarter	$30.80	$21.36
Second Quarter	$30.98	$25.43
First Quarter	$28.08	$22.91

On February 16, 2016, the last sale price of our common stock, as reported on the NYSE, was $4.79 per share.

Holders. As of February 12, 2016, there were 56 holders of record of our common stock.

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

Repurchase of Equity Securities.

Period	Total number of shares withheld[(1)]	Average price per share	Total number of shares purchased as part of publicly announced plans	Maximum number of shares that may yet be purchased under the plan
October 1, 2015 - October 31, 2015	2,846	$11.18	—	—
November 1, 2015 - November 30, 2015	597	$11.64	—	—
December 1, 2015 - December 31, 2015	2,810	$8.37	—	—

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

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

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

The performance graph below shows the cumulative total return to our common stockholders from December 15, 2011, the date on which our common stock began trading on the NYSE, through December 31, 2015, as compared to the returns on the Standard and Poor's 500 Index ("S&P 500") and the Standard and Poor's 500 Oil & Gas Exploration & Production Index ("S&P O&G E&P"). The comparison was prepared based upon the following assumptions:

1. $100 was invested in our common stock at its initial public offering price of $17 per share and invested in the S&P 500 and the S&P O&G E&P on December 15, 2011 at the closing price on such date; and
2. Dividends, if any, are reinvested.

Item 6. Selected Historical Financial Data

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

Presented below is our historical financial data for the periods and as of the dates indicated. The historical financial data for the years ended December 31, 2015, 2014 and 2013 and the balance sheet data as of December 31, 2015 and 2014 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, 2012 and 2011 and the balance sheet data as of December 31, 2013, 2012 and 2011 are derived from our consolidated financial statements not included in this Annual Report.

	For the years ended December 31,				
(in thousands, except per share data)	2015[2]	2014	2013[3]	2012	2011
Statement of operations data[1]:					
Total revenues	$606,640	$793,885	$665,257	$583,894	$506,347
Total costs and expenses	3,078,154	567,499	450,906	411,954	303,827
Operating income (loss)	(2,471,514)	226,386	214,351	171,940	202,520
Non operating income (expense), net	84,633	203,473	(23,267)	(77,176)	(36,932)
Income (loss) from continuing operations before income taxes	(2,386,881)	429,859	191,084	94,764	165,588
Income tax benefit (expense)	176,945	(164,286)	(74,507)	(33,003)	(59,612)
Income (loss) from continuing operations	(2,209,936)	265,573	116,577	61,761	105,976
Income (loss) from discontinued operations, net of tax	—	—	1,423	(107)	(422)
Net income (loss)	$(2,209,936)	$265,573	$118,000	$61,654	$105,554
Net income (loss) per common share:					
Basic:					
Income (loss) from continuing operations	$(11.10)	$1.88	$0.88	$0.49	$0.99
Income from discontinued operations, net of tax	—	—	0.01	—	(0.01)
Net income (loss) per share	$(11.10)	$1.88	$0.89	$0.49	$0.98
Diluted:					
Income (loss) from continuing operations	$(11.10)	$1.85	$0.87	$0.48	$0.98
Income from discontinued operations, net of tax	—	—	0.01	—	—
Net income (loss) per share	$(11.10)	$1.85	$0.88	$0.48	$0.98

(1) The oil and natural gas properties that were a component of the Anadarko Basin Sale are not presented as held for sale nor are their results of operations presented as discontinued operations for the historical periods presented pursuant to the rules governing full cost accounting for oil and gas properties. The results of operations of the associated pipeline assets and various other associated property and equipment are presented as results of discontinued operations, net of tax.

(2) Includes full cost ceiling impairment expense of $2.4 billion for the year ended December 31, 2015.

(3) See Note 4.d to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our Anadarko Basin Sale.

	As of December 31,				
(in thousands)	2015	2014	2013	2012	2011
Balance sheet data:					
Cash and cash equivalents	$31,154	$29,321	$198,153	$33,224	$28,002
Net property and equipment	1,200,255	3,354,082	2,204,324	2,113,891	1,378,509
Total assets[1]	1,813,287	3,910,701	2,606,610	2,318,368	1,615,381
Current liabilities	216,815	353,834	253,969	262,068	214,361
Long-term debt, net[1]	1,416,226	1,779,447	1,038,022	1,196,824	624,690
Stockholders' equity	131,447	1,563,201	1,272,256	831,723	760,013
	For the years ended December 31,				
(in thousands)	2015	2014	2013[2]	2012	2011
Other financial data:					
Net cash provided by operating activities	$315,947	$498,277	$364,729	$376,776	$344,076
Net cash used in investing activities	(667,507)	(1,406,961)	(329,884)	(940,751)	(706,787)
Net cash provided by financing activities	353,393	739,852	130,084	569,197	359,478

(1) Amounts have been reclassified to conform to the 2015 presentation. See Notes 2.c, 2.k, 5.h, 7 and 14 to our consolidated financial statements included elsewhere in this Annual Report for additional information.

(2) Net cash used in investing activities for the year ended December 31, 2013 is offset by proceeds received for the Anadarko Basin Sale. See Note 4.d to our consolidated financial statements included elsewhere in this Annual Report for additional information.

Non-GAAP financial measure

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

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

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

The following presents a reconciliation of net income (loss) for continuing and discontinued operations to Adjusted EBITDA:

	For the years ended December 31,				
(in thousands, unaudited)	2015	2014	2013	2012	2011
Net income (loss)	$(2,209,936)	$265,573	$118,000	$61,654	$105,554
Plus:					
Deferred income tax (benefit) expense	(176,945)	164,286	75,288	32,949	59,374
Depletion, depreciation and amortization	277,724	246,474	234,571	243,649	176,366
Bad debt expense	255	342	653	—	—
Impairment expense	2,374,888	3,904	—	—	243
Non-cash stock-based compensation, net of amounts capitalized	24,509	23,079	21,433	10,056	6,111
Restructuring expenses	6,042	—	—	—	—
Gain on derivatives, net	(214,291)	(327,920)	(79,878)	(8,388)	(19,736)
Cash settlements received for matured commodity derivatives, net	255,281	28,241	4,046	27,025	3,719
Cash settlements received for early terminations and modification of commodity derivatives, net	—	76,660	6,008	—	—
Premiums paid for derivatives that matured during the period[(1)]	(5,167)	(7,419)	(11,292)	(9,135)	(4,104)
Interest expense	103,219	121,173	100,327	85,572	50,580
Write-off of debt issuance costs	—	124	1,502	—	6,195
Loss on disposal of assets, net	2,127	3,252	1,508	52	40
Loss on early redemption of debt	31,537	—	—	—	—
Buyout of minimum volume commitment	3,014	—	—	—	—
Adjusted EBITDA	$472,257	$597,769	$472,166	$443,434	$384,342

(1) Reflects premiums incurred previously or upon settlement that are attributable to instruments settled in the respective periods presented.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and notes thereto appearing elsewhere in this Annual Report. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions or beliefs about future events may, and often do, vary from actual results and the differences can be material. Some of the key factors that could cause actual results to vary from our expectations include changes in oil, NGL and natural gas prices, the timing of planned capital expenditures, availability of acquisitions, joint ventures and dispositions, uncertainties in estimating proved reserves and forecasting production results, potential failure to achieve production from development projects, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital and financial markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this Annual Report, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Cautionary Statement Regarding Forward-Looking Statements" and "Item 1A. Risk Factors." All amounts, dollars and percentages presented in this Annual Report are rounded and therefore approximate.

Executive overview

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

Our financial and operating performance for the year ended December 31, 2015 included the following:

- Oil, NGL and natural gas sales of $431.7 million, compared to $737.2 million for the year ended December 31, 2014;
- Average daily sales volumes of 44,782 BOE/D, compared to 32,134 BOE/D for the year ended December 31, 2014;
- Net loss of $2.2 billion, including an after-tax non-cash full cost ceiling impairment of $2.4 billion, compared to net income of $265.6 million for the year ended December 31, 2014; and
- Adjusted EBITDA (a non-GAAP financial measure) of $472.3 million, compared to $597.8 million for the year ended December 31, 2014.

Three-stream reporting

As of January 1, 2015, all of our natural gas processing agreements with various processors had been modified to allow us to take title to the NGL resulting from the processing of our natural gas. This enables us to report reserves, sales volumes, prices and revenues for NGL and natural gas separately for periods after January 1, 2015. As such, our reserves as of December 31, 2015 are reported in three streams: oil, NGL and natural gas. Our sales volumes, prices and reserves as of December 31, 2014 and 2013 were reported in two streams: crude oil and liquids-rich natural gas with the economic value of the NGL in our natural gas included in the wellhead natural gas price. This change impacts the comparability of 2015 with prior periods.

Reserves and non-cash full cost ceiling impairment

Our results of operations are heavily influenced by oil, NGL and natural gas prices, which have significantly declined and have remained low. These oil, NGL and natural gas price fluctuations are caused by changes in the global and regional supply of and demand for oil, NGL and natural gas, 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 drilling projects, as well as the economic valuation and economic recovery of oil, NGL and natural gas reserves.

As discussed previously in this Annual Report, during 2015 commodity prices for crude oil, NGL and natural gas experienced sharp declines, and this downward trend has accelerated further into the first quarter of 2016, with crude oil prices reaching a twelve-year low in February 2016. We have significantly reduced our capital budget for 2016. In addition, we have purposely significantly reduced the portion of our reserves that have historically been categorized as

"proved undeveloped" or "PUD." We have adjusted our long-range five-year SEC PUD bookings methodology because given the current economic price environment, coupled with (i) our efforts to develop our acreage in the most efficient manner possible and determine which

potential locations will be most profitable and (ii) the uncertain effect that such environment will have on the industry's access to the capital markets, we believe that we can optimize the value for our shareholders by maintaining greater flexibility in choosing the specific drilling locations that may yield the greatest rates of return.

As our activities to date have indicated, the majority of our acreage represents a resource play, and with the benefit of improved technology, infrastructure investments and focused cost reduction efforts, we believe we have a significant number of acreage locations to drill even at the current commodity prices. In the near-term, our goal is to drill those locations that we anticipate have the potential to provide the greatest economic return and enhance shareholder value, and we have determined that the most efficient way to accomplish this is to maintain the flexibility to choose those locations based upon our continuing insight as we drill and collect data across our acreage, regardless of SEC reserve-booking status. Reducing our future PUD commitments provides us the most flexibility to maximize our rate of return at prevailing conditions and minimize the requirement to drill wells previously assigned under very different circumstances as specific PUD locations. Accordingly, we have reduced our booked PUD locations to those we have reasonable certainty to believe that we will develop in at least a two-year time horizon while maintaining the flexibility to add new PUD locations and convert other locations to proved developed reserves as our plans deem appropriate and opportunistic.

Ryder Scott, our independent reserve engineers, estimated 100% of our proved reserves as of December 31, 2015, 2014 and 2013. As of December 31, 2015, we had 125,698 MBOE of estimated proved reserves as compared to 247,322 MBOE of estimated proved reserves as of December 31, 2014 and 203,615 MBOE of estimated proved reserves as of December 31, 2013. For prices used to value our reserves, see Note 2.g to our consolidated financial statements included elsewhere in this Annual Report. Our net book value of evaluated oil and natural gas properties exceeded the full cost ceiling amount during the second, third and fourth quarters of 2015, and as such, we recorded non-cash full cost ceiling impairments during these periods of $488.0 million, $906.4 million and $975.0 million, respectively. See Note 2.g to our consolidated financial statements included elsewhere in this Annual Report for additional discussions of our full cost impairments.

We have entered into a number of commodity derivatives, which have enabled us to offset a portion of the changes in our cash flow caused by price fluctuations on our oil and natural gas production as discussed in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Potential future low commodity price impact on our development plans, reserves and full cost impairment

Oil, NGL and natural gas prices have remained low in the first quarter of 2016. If prices remain at or below the current low levels, subject to numerous factors and inherent limitations, and all other factors remain constant, we will incur an additional non-cash full cost impairment in the first quarter of 2016, which will have an adverse effect on our results of operations.

There are numerous uncertainties inherent in the estimation of proved reserves and accounting for oil and natural gas properties in future periods. In addition to unknown future commodity prices, other uncertainties include (i) changes in drilling and completion costs, (ii) changes in oilfield service costs, (iii) production results, (iv) our ability, in a low price environment, to strategically drill the most economic locations in our multi-stack horizontal targets, (v) income tax impacts, (vi) potential recognition of additional proved undeveloped reserves, (vii) any potential value added to our proved reserves when testing recoverability from drilling unbooked locations and (viii) the inherent significant volatility in the commodity prices for oil and natural gas recently exemplified by the large changes in recent months. Each of the above factors is evaluated on a quarterly basis and if there is a material change in any factor it is incorporated into our internal reserve estimation utilized in our quarterly accounting estimates. We use our internal reserve estimates to evaluate, also on a quarterly basis, the reasonableness of our reserve development plans for our reported reserves. Changes in circumstance, including commodity pricing, economic factors and the other uncertainties described above may lead to changes in our reserve development plans.

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

Both our hypothetical first-quarter 2016 full cost ceiling calculation and our hypothetical reserves estimates have been prepared by substituting (i) $41.38 per barrel for oil, (ii) $11.33 per barrel for NGL and (iii) $1.78 per MMBtu for natural gas (the "Pro Forma Prices") for the respective Realized Prices as of December 31, 2015. All other inputs and assumptions have been held constant. Accordingly, this estimation strictly isolates the estimated impact of more current commodity prices on the first-quarter 2016 Realized Prices that will be utilized in our full cost ceiling calculation and our reserves estimate. The Pro Forma 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 on the first day of the month for the 11 months ended February 1, 2016, with the price for February 1, 2016 held constant for the remaining twelfth month of the calculation. Based solely on the substitution of the Pro Forma Prices into our December 31, 2015 reserve estimates, the implied first-quarter impairment would be $132 million and the implied impact to our December 31, 2015 reserves of 126 MMBOE would be a reduction of 9 MMBOE. We believe that substituting the Pro Forma Prices into our December 31, 2015 internal reserve estimates may help provide users with an understanding of the potential first-quarter price impact on our March 31, 2016 full cost ceiling test and in preparing our year-end reserve estimates.

Mergers and acquisitions

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

On September 6, 2013, we completed the acquisition of evaluated and unevaluated oil and natural gas properties located in Glasscock County, Texas in the Permian Basin, from private parties for $36.7 million consisting of cash and 123,803 shares of our restricted common stock, subject to customary closing adjustments.

On February 25, 2014, we completed the acquisition of the mineral interests underlying 278 net acres in Glasscock County, Texas in the Midland Basin for $7.3 million. These mineral interests entitle us to receive royalties on all production from this acreage with no additional future capital or operating expenses required.

On June 11, 2014, we completed the acquisition of evaluated and unevaluated oil and natural gas properties, totaling 460 net acres, located in Reagan County, Texas in the Midland Basin for $4.7 million, net of closing adjustments.

On June 23, 2014, we completed the acquisition of evaluated and unevaluated oil and natural gas properties, totaling 24 net acres, located in Glasscock County, Texas for $1.8 million.

On August 26, 2014, we completed a material acquisition of leasehold interests totaling 8,156 net acres in the Midland Basin, primarily within our core development area, for $192.5 million.

Divestitures

On August 1, 2013, we completed the Anadarko Basin Sale, consisting of oil and natural gas properties located in the Anadarko Granite Wash, Eastern Anadarko and Central Texas Panhandle (the "Anadarko Basin") in the State of Oklahoma and the State of Texas, associated pipeline assets and various other related property and equipment for a purchase price of $438.0 million. The purchase price (including the buyers' deposits) consisted of $400.0 million from certain affiliates of EnerVest, Ltd. and $38.0 million from other third parties in connection with the exercise of such third parties' preferential rights associated with certain of the oil and gas properties. Approximately $388.0 million of the purchase price, excluding closing adjustments, was allocated to oil and natural gas properties pursuant to the rules governing full cost accounting. After transaction costs and adjustments at closing reflecting an economic effective date of April 1, 2013, the net proceeds were $428.3 million, net of working capital adjustments. The net proceeds were used to pay off our Senior Secured Credit Facility and for working capital purposes.

Effective August 1, 2013, the operations and cash flows of these properties were eliminated from our ongoing operations, and we do not have continued involvement in the operation of these properties. The oil and natural gas properties, which are a component of the assets sold, are not presented as discontinued operations pursuant to the rules governing full cost accounting for oil and gas properties. The results of operations of the associated pipeline assets and various other related property and equipment have been presented as results of discontinued operations, net of tax. Accordingly, we have reclassified certain prior period amounts in the consolidated financial statements included elsewhere in this Annual Report as discontinued operations. See Note 4.d to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of these reclassifications and the Anadarko Basin Sale.

On December 20, 2013, we completed the sale of 37,000 net acres in the Dalhart Basin, including one producing well, for $20.4 million, subject to customary closing adjustments. The net proceeds were used for working capital purposes.

On September 15, 2015, we completed the sale of non-strategic and primarily non-operated properties and associated production totaling 6,060 net acres and 123 producing properties in the Midland Basin to a third-party buyer for a purchase price of $65.5 million. After transaction costs reflecting an economic effective date of July 1, 2015, the net proceeds were $64.8

million, net of working capital and post-closing adjustments. The net proceeds were used for working capital purposes. This divestiture did not represent a strategic shift and will not have a major effect on our operations or financial results.

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, 2015, we had assembled 135,408 net acres in the Permian Basin.

Sources of our revenue

Our revenues are primarily derived from the sale of oil, NGL and natural gas and the sale of purchased oil within the continental United States and do not include the effects of derivatives. For the year ended December 31, 2015, our revenues were comprised of sales of 54% oil, 8% NGL, 9% natural gas, 28% purchased oil and 1% midstream service revenues. Our oil, NGL and natural gas revenues may vary significantly from period to period as a result of changes in volumes of production and/or changes in commodity prices. Our midstream service revenues may vary due to the level of services provided to third parties for (i) gathered natural gas, (ii) gas lift fees, (iii) oil throughput fees and (iv) water services. Our sales of purchased oil revenue may vary due to changes in oil prices.

Principal components of our cost structure

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

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

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

Costs of purchased oil. These are costs associated with purchasing oil from other producers and the transportation costs to bring it to market.

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

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

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

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

Impairment expense. Long-lived assets are considered impaired when their net carrying value is greater than the future undiscounted cash flows. Once an asset is recognized as impaired, costs are incurred to write the asset down. With the

continuing volatility in commodity prices, we may incur additional write-downs on our oil and natural gas properties.
Materials

and supplies and line-fill are recorded at the lower of cost or market ("LCM"), with costs determined using the weighted-average cost method.

Other income (expense)

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

Gain (loss) on interest rate derivatives. In prior periods, we utilized interest rate swaps and caps to reduce our exposure to fluctuations in interest rates on our outstanding debt. This amount represents (i) the recognition of gains and losses associated with interest rate derivatives as interest rates change and interest rate derivatives expire or new ones are entered into, and (ii) our gains and losses on the settlement of these interest rate contracts. We classify these gains and losses as operating activities in our consolidated statements of cash flows. During each of the years ended December 31, 2013 and 2012, we had one interest rate swap and one interest rate cap outstanding for a total notional amount of $100.0 million with fixed pay rates ranging from 1.11% to 3.00% until their expiration in September 2013. We had no interest rate derivatives in place in 2015 or 2014.

Income (loss) from equity method investee. We have invested in a company where we own 49% of the ownership units. As such, we account for this investment under the equity method of accounting with our proportionate share of net income (loss) reflected in the consolidated statements of operations as "Loss from equity method investee" and the carrying amount reflected in the consolidated balance sheet as "Investment in equity method investee." See Note 15 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding this investment.

Interest expense. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our Senior Secured Credit Facility and our Senior Unsecured Notes. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. In prior periods, we entered into various interest rate derivatives to mitigate the effects of interest rate changes. We do not designate these derivatives as hedges and therefore hedge accounting treatment is not applicable. Gains or losses on these interest rate contracts are included in non-operating income (expense) as discussed above. We reflect interest paid to the lenders and bondholders in interest expense. In addition, we include the amortization of debt issuance costs (including origination and amendment fees), commitment fees and annual agency fees in interest expense.

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

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

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

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

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

On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realization of the deferred tax assets and adjusts the amount of such allowances, if necessary. We considered all available evidence, both positive and negative, in determining whether, based on the weight of that evidence, a valuation allowance was needed on either the federal or Oklahoma net operating loss carry-forwards. Such consideration included estimated future projected earnings based on existing reserves and projected future cash flows from our oil and natural gas reserves (including

the timing of those cash flows), the reversal of deferred tax liabilities recorded as of December 31, 2015, our ability to capitalize intangible drilling costs rather than expensing these costs in order to prevent an operating loss carry-forward from expiring unused and future projections of Oklahoma sourced income. During the year ended December 31, 2015, we determined it is more likely than not that we will not realize our net deferred tax assets. See Note 7 to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our valuation allowance.

Results of operations consolidated

For the year ended December 31, 2015 as compared to the year ended December 31, 2014, and for the year ended December 31, 2014 as compared to the year ended December 31, 2013

Sales volume, revenue and pricing

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

	For the years ended December 31,		
	2015	2014	2013
Sales volumes:[1]			
Oil (MBbl)	7,610	6,901	5,487
NGL (MBbl)	4,267	—	—
Natural gas (MMcf)	26,816	28,965	34,348
Oil equivalents (MBOE)[2][3]	16,346	11,729	11,211
Average daily sales volumes (BOE/D)[3]	44,782	32,134	30,716
% Oil	47 %	59 %	49 %
Oil, NGL and natural gas revenues (in thousands):[1]			
Oil	$329,301	$571,620	$494,676
NGL	50,604	—	—
Natural gas	51,829	165,583	170,168
Oil, NGL and natural gas sales	$431,734	$737,203	$664,844
Average sales prices:[1]			
Oil, realized ($/Bbl)[4]	$43.27	$82.83	$90.16
NGL, realized ($/Bbl)[4]	11.86	—	—
Natural gas, realized ($/Mcf)[4]	1.93	5.72	4.95
Average price, realized ($/BOE)[4]	26.41	62.86	59.29
Oil, hedged ($/Bbl)[5]	74.41	85.77	88.68
NGL, hedged ($/Bbl)[5]	11.86	—	—
Natural gas, hedged ($/Mcf)[5]	2.42	5.73	4.98
Average price, hedged ($/BOE)[5]	41.71	64.62	58.66

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

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

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

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

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

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

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Cash settlements received (paid) for matured commodity derivatives:			
Oil	$241,391	$26,803	$(149)
Natural gas	13,890	1,438	4,195
Total	$255,281	$28,241	$4,046
Premiums paid attributable to contracts that matured during the respective period:			
Oil	$(4,464)	$(6,497)	$(7,970)
Natural gas	(703)	(922)	(3,322)
Total	$(5,167)	$(7,419)	$(11,292)

Changes in prices and volumes caused the following changes to our oil, NGL and natural gas revenues between the years ended December 31, 2015, 2014 and 2013:

(in thousands)	Oil	NGL	Natural gas	Total net dollar effect of change
2013 Revenue	$494,676	$—	$170,168	$664,844
Effect of changes in price	(50,587)	—	22,303	(28,284)
Effect of changes in volumes	127,544	—	(26,645)	100,899
Other	(13)	—	(243)	(256)
2014 Revenue	571,620	—	165,583	737,203
Effect of changes in price	(301,036)	50,603	(101,631)	(352,064)
Effect of changes in volumes	58,660	—	(12,293)	46,367
Other	57	1	170	228
2015 Revenue	$329,301	$50,604	$51,829	$431,734

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

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

The following table sets forth information regarding midstream service revenue and sales of purchased oil revenues for the periods presented:

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Revenues:			

Midstream service revenues	$6,548	$2,245	$413
Sales of purchased oil	168,358	54,437	—
Total revenues	$174,906	$56,682	$413

Midstream service revenues. Our midstream service revenues from operations increased by $4.3 million during the year ended December 31, 2015 as compared to the year ended December 31, 2014, and $1.8 million during the year ended December 31, 2014 as compared to the year ended December 31, 2013. These increases were due to the increased sale of natural gas, NGL and condensate off our pipelines and facilities during each respective period as well as an increase in third-party volumes transported through our oil and natural gas gathering and transportation systems and related facilities.

Sales of purchased oil. During the year ended December 31, 2014, in order to fulfill our firm transportation commitment on the Bridgetex pipeline, we began purchasing oil in West Texas, transporting the product on the Bridgetex Pipeline and selling the product to a third party in the Houston market. Our revenues from sales of purchased oil increased by $113.9 million during the year ended December 31, 2015 as compared to the year ended December 31, 2014 due to a full year of activity in 2015 compared to a three month period during 2014.

Costs and expenses

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

	For the years ended December 31,		
(in thousands except for per BOE sold data)	2015	2014	2013
Costs and expenses:			
Lease operating expenses	$108,341	$96,503	$79,136
Production and ad valorem taxes	32,892	50,312	42,396
Midstream service expenses	5,846	5,429	3,368
Minimum volume commitments	5,235	2,552	891
Costs of purchased oil	174,338	53,967	—
Drilling rig fees	—	527	—
General and administrative[1]	90,425	106,044	89,696
Restructuring expenses	6,042	—	—
Accretion of asset retirement obligations	2,423	1,787	1,475
Depletion, depreciation and amortization	277,724	246,474	233,944
Impairment expense	2,374,888	3,904	—
Total costs and expenses	$3,078,154	$567,499	$450,906
Average costs per BOE sold:[2]			
Lease operating expenses	$6.63	$8.23	$7.06
Production and ad valorem taxes	2.01	4.29	3.78
Midstream service expenses	0.36	0.46	0.30
General and administrative[1]	5.53	9.04	8.00
Depletion, depreciation and amortization	16.99	21.01	20.87
Total	$31.52	$43.03	$40.01

(1) General and administrative includes non-cash stock-based compensation, net of amounts capitalized, of $24.5 million, $23.1 million and $21.4 million for the years ended December 31, 2015, 2014 and 2013, respectively.

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

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

expenses.

Lease operating expenses, which include workover expenses, increased by $17.4 million, or 22%, compared to a 5% increase in production, for the year ended December 31, 2014 compared to 2013. On a per BOE sold basis, lease operating expenses increased in total to $8.23 per BOE sold as of December 31, 2014 from $7.06 per BOE sold as of December 31, 2013. The increases were mainly due to (i) higher average lease operating expenses per BOE sold on our higher oil-weighted Permian production following the Anadarko Basin Sale, (ii) an increase in well count and (iii) higher well service and workover expenses.

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

Production and ad valorem taxes increased to $50.3 million for the year ended December 31, 2014 from $42.4 million for the year ended December 31, 2013, an increase of $7.9 million, or 19%. Ad valorem taxes decreased by $1.6 million for the year ended December 31, 2014 compared to 2013, primarily as a result of the Anadarko Basin Sale. The ad valorem tax decreases were partially offset by the ad valorem tax expense incurred for new wells drilled during the year ended December 31, 2014.

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

Minimum volume commitments. Minimum volume commitments increased by $2.7 million for the year ended December 31, 2015 compared to 2014, mainly as a result of the second-quarter 2015 negotiated buyout of a minimum volume commitment to Medallion, which was related to natural gas gathering infrastructure constructed by Medallion on acreage that we do not plan to develop.

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

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

(in thousands)	Year ended December 31, 2015 compared to 2014	Year ended December 31, 2014 compared to 2013
Changes in G&A:		
Professional fees	$(6,066)	$6,851
Salaries, benefits and bonuses, net of amounts capitalized	(4,084)	6,249
Charitable contributions	(3,208)	3,106
Performance unit awards	3,481	(4,132)
Stock-based compensation, net of amounts capitalized[(1)]	1,430	1,646
Other	(7,172)	2,628
Total change in G&A	$(15,619)	$16,348

(1) On January 1, 2014, we began capitalizing a portion of stock-based compensation for employees who are directly involved in the acquisition and exploration of oil and natural gas properties into the full cost pool. Capitalized stock-based compensation is included as an addition to "Oil and natural gas properties" in the consolidated balance sheets included elsewhere in this Annual Report.

Year ended December 31, 2015 compared to 2014. G&A expense, excluding stock-based compensation, decreased by $17.0 million, or 21%, for the year ended December 31, 2015 compared to 2014. The decrease is primarily due to (i) professional fees paid to a consulting company in 2014 that was engaged to assist us with the optimization of our development operations, (ii) reduced personnel expenses as a result of the reduction in force (the "RIF") which occurred early in the first quarter of 2015 and (iii) our $3.0 million charitable contribution pledge expensed in 2014, which will be paid in annual installments through 2024.

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

The fair values for each of our restricted stock awards issued were calculated based on the value of our stock price on the grant date in accordance with GAAP and are being expensed on a straight-line basis over their associated requisite service

periods. The fair values for each of our non-qualified restricted stock options awards were determined using a Black-Scholes valuation model in accordance with GAAP and are being expensed on a straight-line basis over their associated four-year requisite service periods.

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

Our performance unit awards were accounted for as liability awards. The associated expense for these awards increased by $3.5 million for the year ended December 31, 2015 compared to 2014, mainly due to the 2013 performance unit awards fair value at the end of the performance period compared to their quarterly re-measurement value as of December 31, 2014 that was based on the performance of our stock price relative to the peer group utilized in the forward-looking Monte Carlo simulation. The fair value and corresponding liability related to the 2013 performance unit awards as of December 31, 2015 was $6.4 million. The 2013 performance unit awards had a performance period of January 1, 2013 to December 31, 2015 and, as their performance criteria were satisfied, they were paid at $143.75 per unit during the first quarter of 2016. The 2012 performance unit awards had a performance period of January 1, 2012 to December 31, 2014 and, as their performance criteria were satisfied, they were paid at $100 per unit during the first quarter of 2015.

Year ended December 31, 2014 compared to 2013. G&A expense, excluding stock-based compensation, increased to $83.0 million for the year ended December 31, 2014 from $68.3 million for the year ended December 31, 2013, an increase of $14.7 million, or 22%. The increase is primarily due to the growth of our business, and accordingly our professional fees and salaries and benefits have increased $13.1 million for the year ended December 31, 2014 compared to 2013. The increase during the year ended December 31, 2014 was offset by the $6.4 million combined decrease in the fair value of our performance unit awards and increase in production income and reduced employee bonuses. Professional fees increased mainly due to fees paid to a consulting company engaged in 2014 to assist us with the optimization of our development operations. We also pledged a $3.0 million charitable contribution during the year ended December 31, 2014, which will be paid in annual payments through 2024. On a per BOE sold basis, G&A expense, excluding stock-based compensation, increased to $7.07 per BOE sold during the year ended December 31, 2014 from $6.09 per BOE sold during the year ended December 31, 2013. This increase was a result of the growth in our overhead combined with our Permian production growth being partially offset by the production associated with the divestiture of our Anadarko Basin assets.

Stock-based compensation increased to $27.7 million for the year ended December 31, 2014 from $21.4 million for the year ended December 31, 2013, an increase of $6.3 million, mainly due to the issuance of 1,234,255 restricted stock awards at a weighted-average grant price of $25.68 per share and 336,140 non-qualified restricted stock options to new and existing employees and non-employee directors in the year ended December 31, 2014 compared to the issuance of 1,469,295 restricted stock awards at a weighted-average grant price of $18.17 per share and 1,018,849 non-qualified restricted stock options to new and existing employees and non-employee directors in 2013. Additionally, during the year ended December 31, 2014, we issued 271,667 performance share awards to management and the associated expense amounted to $2.1 million for the year ended December 31, 2014. No comparable awards were issued during 2013. This increase in stock-based compensation was partially offset by management's decision to begin capitalizing a portion of stock-based compensation for employees who are directly involved in the acquisition and exploration of our oil and natural gas properties into the full cost pool in 2014. Capitalized stock-based compensation amounted to $4.7 million for the year ended December 31, 2014. No amounts were capitalized during 2013.

The associated expense for our 2013 and 2012 performance unit awards awards decreased by $4.1 million for the year ended December 31, 2014 compared to 2013 due to (i) the quarterly re-measurement of the 2013 performance unit awards based on the performance of our stock price relative to the peer group utilized in the forward-looking Monte Carlo simulation and (ii) the final pay-out value of the 2012 performance unit awards due to the performance of our

stock relative to the peer group during the corresponding performance period. The fair value and corresponding liability related to the 2012 performance unit awards as of December 31, 2014 was $2.7 million and represents the cash payment made in the first quarter of 2015.

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

Restructuring expenses. Restructuring expenses relate to the first-quarter 2015 RIF which was an effort to reduce costs and better position ourselves for ongoing efficient growth. Restructuring expenses of $6.0 million were incurred in the first quarter of 2015. See Note 13 to our consolidated financial statements included elsewhere in this Annual Report for further discussion of the RIF.

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

	For the years ended December 31,		
(in thousands except for per BOE sold data)	2015	2014	2013
Depletion of evaluated oil and natural gas properties	$263,666	$237,067	$227,992
Depreciation of midstream service assets	7,529	4,303	1,510
Depreciation and amortization of other fixed assets	6,529	5,104	4,442
Total DD&A	$277,724	$246,474	$233,944
DD&A per BOE sold	$16.99	$21.01	$20.87

DD&A increased by $31.3 million, or 13%, for the year ended December 31, 2015 as compared to 2014, mainly due to (i) the reduction in our reserves volume, (ii) the impact of $152.5 million in unevaluated properties' carrying costs being added to the depletion base during the year ended December 31, 2015 and (iii) higher total production levels. These contributors were partially offset by our second-quarter and third-quarter 2015 impairments. We expect DD&A per BOE will decrease in the first quarter of 2016 due to our fourth-quarter 2015 impairment.

DD&A increased by $12.5 million, or 5%, for the year ended December 31, 2014 as compared to 2013. The increase is mainly due to (i) increased book value on new reserves added, (ii) higher total production levels, (iii) increased capitalized costs for new wells completed in the year ended December 31, 2014, (iv) the impact of the Anadarko Basin Sale to the year ended December 31, 2013 depletion and (v) the impact of $35.5 million in unevaluated properties' carrying costs being added to the depletion base during the three months ended December 31, 2014, as management determined that we do not intend to drill this non-core acreage.

Impairment expense. Our net book value of evaluated oil and natural gas properties exceeded the full cost ceiling amount as of June 30, 2015, September 30, 2015 and December 31, 2015. As a result, we recorded non-cash full cost ceiling impairments for the second quarter, third quarter and fourth quarter of 2015 of $488.0 million, $906.4 million and $975.0 million, respectively. There were no comparable full cost impairments in 2014 or 2013. During the years ended December 31, 2015 and 2014, we reduced materials and supplies by $2.8 million and $1.8 million, respectively, in order to reflect the balance at LCM. There were no comparable materials and supplies impairments in 2013.

Beginning in the fourth quarter of 2014, we owned oil line-fill in third-party pipelines, which is accounted for at LCM. For the years ended December 31, 2015 and 2014, we recorded LCM adjustments of $1.3 million and $2.1 million, respectively, related to our line-fill.

Non-operating income and expense. The following table sets forth the components of non-operating income and expense from continuing operations for the periods presented:

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Non-operating income (expense):			
Gain (loss) on derivatives:			
Commodity derivatives, net	$214,291	$327,920	$79,902
Interest rate derivatives, net	—	—	(24)
Income (loss) from equity method investee	6,799	(192)	29
Interest expense	(103,219)	(121,173)	(100,327)
Interest and other income	426	294	163
Loss on early redemption of debt	(31,537)	—	—
Write-off of debt issuance costs	—	(124)	(1,502)
Loss on disposal of assets, net	(2,127)	(3,252)	(1,508)
Non-operating income (expense), net	$84,633	$203,473	$(23,267)

Commodity derivatives, net. The table below shows the changes in the components of gain on commodity derivatives, net for the periods presented:

(in thousands)	Year ended December 31, 2015 compared to 2014	Year ended December 31, 2014 compared to 2013
Changes in gain on commodity derivatives, net:		
Fair value of commodity derivatives outstanding	$(264,009)	$153,171
Early terminations and modification of commodity derivatives received	(76,660)	70,652
Cash settlements received for matured commodity derivatives	227,040	24,195
Total change in gain on commodity derivatives, net	$(113,629)	$248,018

The year ended December 31, 2015 compared to 2014 decrease in fair value of commodity derivatives outstanding is the result of some of our contracts expiring and the changing relationship between our outstanding contract prices and the associated forward curves used to calculate the fair value of our derivatives in relation to expected market prices. During the year ended December 31, 2014, we received $76.7 million in net proceeds from the early termination of our oil basis swap differential between the Light Louisiana Sweet Argus and the Brent International Petroleum Exchange index oil prices and the related physical contract. There were no comparable early termination amounts in 2015. Net cash settlements received for matured derivatives are based on the cash settlement prices of our matured derivatives compared to the prices specified in the derivative contracts.

The year ended December 31, 2014 compared to 2013 increase in fair value of commodity derivatives outstanding is the result of the changing relationship between our contract prices and the associated forward curves used to calculate the fair value of our commodity derivatives in relation to expected market prices. In general, we experience gains during periods of decreasing market prices and losses during periods of increasing market prices. During the year ended December 31, 2014, we received $76.7 million in net proceeds from the early termination of our oil basis swap differential between the Light Louisiana Sweet Argus and the Brent International Petroleum Exchange index oil prices and the related physical contract. During the year ended December 31, 2013, we received net cash settlements on early terminations and modifications of derivatives of $6.0 million as a result of unwinding nine natural gas commodity contracts in connection with the Anadarko Basin Sale.

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

Income (loss) from equity method investee. Income (loss) from equity method investee increased by $7.0 million for the year ended December 31, 2015 compared to 2014, and decreased by $0.2 million for the year ended December 31, 2014 compared to 2013. During the year ended December 31, 2015, Medallion, our equity method investee, continued expansion activities on existing portions of its pipeline infrastructure in order to gather additional third-party oil production and began recognizing revenue due to its main pipeline becoming fully operational.

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

(in thousands)	Year ended December 31, 2015 compared to 2014	Year ended December 31, 2014 compared to 2013
Changes in interest expense:		
January 2019 Notes	$(38,002)	$(162)
March 2023 Notes	17,135	—
Senior Secured Credit Facility, net of capitalized interest[(1)]	1,969	(2,587)
January 2022 Notes	1,477	23,836
Other	(533)	(241)
Total change in interest expense	$(17,954)	$20,846

(1) Our Senior Secured Credit Facility was paid in full on August 1, 2013 and remained undrawn until September 3, 2014.

Interest expense decreased by $18.0 million, or 15%, for the year ended December 31, 2015 compared to 2014. The decrease is primarily due to the early redemption of the January 2019 Notes on April 6, 2015, which is partially offset by the

issuance of the March 2023 Notes. The March 2023 Notes, which began accruing interest on March 18, 2015, have both a lower interest rate and a lower principal amount than the January 2019 Notes.

Interest expense increased by $20.8 million, or 21%, for the year ended December 31, 2014 compared to 2013. The increase is primarily due to the issuance of the January 2022 Notes in January 2014, which was partially offset by the reduction in the amount outstanding under our Senior Secured Credit Facility and the related commitment fees on the unused portion of the banks' commitment on our Senior Secured Credit Facility.

We had entered into certain variable-to-fixed interest rate derivatives that hedged our exposure to interest rate variations on our variable interest rate debt that expired in September 2013. During the year ended December 31, 2013 we had one interest rate swap and one interest rate cap outstanding for a total notional amount of $100.0 million with fixed pay rates ranging from 1.11% to 3.00% until their expiration in September 2013.

Loss on early redemption of debt. During the year ended December 31, 2015, we redeemed the entire $550.0 million outstanding principal amount of the January 2019 Notes at a redemption price of 104.750% of the principal amount, plus accrued and unpaid interest up to the Redemption Date. We recognized a loss on extinguishment of $31.5 million related to the difference between the redemption price and the net carrying amount of the January 2019 Notes. There were no comparable early redemption of debt amounts in 2014 and 2013.

Write-off of debt issuance costs. In January 2014, we wrote-off $0.1 million of debt issuance costs as a result of changes in the borrowing base under our Senior Secured Credit Facility due to the issuance of the January 2022 Notes. In August 2013, we wrote-off $1.5 million in debt issuance costs as a result of changes in the borrowing base under our Senior Secured Credit Facility due to the Anadarko Basin Sale. There was no comparable amount in 2015.

Loss on disposal of assets, net. Loss on disposal of assets, net decreased by $1.1 million for the year ended December 31, 2015 compared to 2014 as a result of lower losses related to the sales and write-off of materials and supplies and other fixed assets during 2015 as compared to 2014.

Loss on disposal of assets, net increased by $1.7 million for the year ended December 31, 2014 compared to 2013. The 2014 increase over the prior year is a result of losses related to sales of materials and supplies, vehicles and a write-off of abandoned internally developed software during 2014, compared to a net gain recorded in 2013 mainly related to the sale of pipeline assets and various other property and equipment associated with the Anadarko Basin Sale.

Income tax benefit (expense). The fluctuations in income (loss) from continuing operations before income taxes is shown in the table below:

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Income (loss) from continuing operations before income taxes	$(2,386,881)	$429,859	$191,084
Income tax benefit (expense)	176,945	(164,286)	(74,507)
Income (loss) from continuing operations	$(2,209,936)	$265,573	$116,577

Our effective tax rate is affected by recurring changes in valuation allowances, recurring permanent differences and discrete items that may occur in any given year but are not consistent from year to year. The effective tax rate on income (loss) before income taxes was 7%, 38% and 39% for the years ended December 31, 2015, 2014 and 2013, respectively. For the year ended December 31, 2015, we recorded a valuation allowance of $676.0 million for our deferred tax assets due to uncertainty regarding their realization. For further discussion of our valuation allowance, see Note 7 to our consolidated financial statements located elsewhere in this Annual Report.

During the years ended December 31, 2015, 2014 and 2013, certain shares related to restricted stock awards vested at times when our stock price was lower than the fair value of those shares on the grant date. As a result, the income tax deduction related to such shares is less than the expense previously recognized for book purposes. During the years ended December 31, 2014 and 2013, certain restricted stock options were exercised, for which the related income tax deduction was less than the expense previously recognized for book purposes. There were no stock options exercised during the year ended December 31, 2015. As a result of these differences in book compensation cost and related tax deduction, the tax impact of these shortfalls increased by $3.1 million for the year ended December 31, 2015 compared to 2014, and decreased by $0.3 million for the year ended December 31, 2014 compared to 2013.

We utilize a one-pool approach when accounting for the pool of windfall tax benefits in which employees and non-employees are grouped into a single pool. As of December 31, 2015, 2014 and 2013, we did not have any eligible windfall tax benefits to offset future shortfalls as no excess tax benefits had been recognized, and therefore the tax impact of these shortfalls

is included in income tax expense for these respective periods. We expect income tax provisions for future reporting periods will be impacted by this stock compensation tax deduction shortfall; however, we cannot predict the stock compensation shortfall impact because of dependency upon the future market price of our stock. See Notes 6.a, 6.b and 7 to our consolidated financial statements included elsewhere in this Annual Report for additional information.

Income from discontinued operations, net of tax. The table below shows our income from discontinued operations, net of tax for the periods presented:

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Income from discontinued operations, net of tax	$—	$—	$1,423

Effective on the August 1, 2013 completion of the Anadarko Basin Sale, the operations and cash flows of these properties were eliminated from our ongoing operations and we do not have continuing involvement in the operations of these properties.

Results of operations - midstream and marketing

The following table presents selected financial information regarding our midstream and marketing operating segment on a stand-alone basis for the periods presented:

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Natural gas sales	$1,692	$1,660	$—
Midstream service revenues	27,965	7,838	8,824
Sales of purchased oil	168,358	54,437	—
Total revenues	198,015	63,935	8,824
Midstream service expenses, including minimum volume commitments	18,393	9,641	1,571
Costs of purchased oil	174,338	53,967	—
General and administrative[1]	8,174	6,969	2,745
Depletion, depreciation and amortization[2]	8,093	4,640	2,241
Impairment expense	2,592	2,102	—
Other operating costs and expenses[3]	342	66	—
Operating income (loss)	$(13,917)	$(13,450)	$2,267
Other financial information:			
Income (loss) from equity method investee	$6,799	$(192)	$29
Interest expense[4]	$(5,179)	$(3,613)	$(1,647)
Loss on early redemption of debt[5]	$(1,481)	$—	$—
Income tax benefit (expense)[6]	$4,993	$6,265	$(1,031)

(1) G&A was allocated based on the number of employees in the midstream and marketing segment for the years ended December 31, 2015, 2014 and 2013. Certain components of G&A were not allocated and were based on actual costs to the midstream and marketing segment which primarily consisted of payroll, deferred compensation and vehicle costs for the years ended December 31, 2015 and 2014 and payroll and deferred compensation for the year ended December 31, 2013. Costs associated with land and geology were not allocated to the midstream and marketing segment for the years ended December 31, 2015, 2014 and 2013.

(2) DD&A was based on actual costs for the midstream and marketing segment with the exception of the allocation of other fixed asset depreciation, which was based on the number of employees in the midstream and marketing segment for the years ended December 31, 2015, 2014 and 2013.

(3) Other operating costs and expenses include restructuring expense and accretion of asset retirement obligations for the year ended December 31, 2015 and accretion of asset retirement obligations for the years ended December 31, 2014 and 2013. These expenses are based on actual costs to the midstream and marketing segment and are not allocated.

(4) Interest expense was allocated to the midstream and marketing segment based on gross property and equipment and life-to-date contributions to the Company's equity method investee for the years ended December 31, 2015, 2014 and 2013.

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

(6) Income tax benefit or expense for the midstream and marketing segment was calculated by multiplying income (loss) from continuing operations before income taxes by 36% for the years ended December 31, 2015, 2014 and 2013.

For additional information, see "—Costs and expenses."

Natural gas sales. These revenues are related to our midstream and marketing segment providing our exploration and production segment with processed natural gas for use in the field. The corresponding cost component of these transactions are included in "Midstream service expenses." See Note 17 to our consolidated financial statements

included elsewhere in this Annual Report for additional information on the operating segments.

Midstream service revenues. Our midstream service revenues from operations increased by $20.1 million for the year ended December 31, 2015 compared to 2014. This increase is mainly due to (i) water service revenue that we began

recognizing in the third quarter of 2015, (ii) oil throughput fees generated by our oil gathering line which was not operational until July of 2014, (iii) higher volumes of gathered natural gas and (iv) natural gas lift fees generated in our production corridors that were not operational until September of 2014. Our midstream service revenues from operations decreased by $1.0 million during the year ended December 31, 2014 compared to 2013. This decrease is mainly due to changes in the gathering fee structure.

Sales of purchased oil. Sales of purchased oil was $168.4 million and $54.4 million for the years ended December 31, 2015 and 2014, respectively. During the fourth quarter of 2014, we began purchasing oil in West Texas, transporting the product on the Bridgetex Pipeline and selling the product to a third party in the Houston market.

Midstream service expenses, including minimum volume commitments. Midstream service expenses, including minimum volume commitments, increased by $8.8 million for the year ended December 31, 2015 compared to 2014 and increased by $8.1 million for the year ended December 31, 2014 compared to 2013. Midstream service expenses primarily represent costs incurred to operate and maintain our (i) oil and natural gas gathering and transportation systems and related facilities, (ii) centralized oil storage tanks, (iii) natural gas lift, rig fuel and centralized compression infrastructure and (iv) water storage, recycling and transportation facilities. The increases are due to continued expansion of the midstream service component of our business. Minimum volume commitments increased by $2.7 million for the year ended December 31, 2015 compared to 2014, mainly as a result of the second-quarter 2015 negotiated buyout of a minimum volume commitment with Medallion, which was related to natural gas gathering infrastructure constructed by Medallion on acreage that we do not plan to develop.

Costs of purchased oil. Costs of purchased oil was $174.3 million and $54.0 million for the years ended December 31, 2015 and 2014, respectively. These costs include purchasing oil from producers and transporting the purchased oil on the Bridgetex Pipeline to the Houston market.

Income (loss) from equity method investee. We own 49% of the ownership units of Medallion. As such, we account for this investment under the equity method of accounting with our proportionate share of net income (loss) reflected in the consolidated statements of operations as "Income (loss) from equity method investee" and the carrying amount reflected in the consolidated balance sheets as "Investment in equity method investee." During the year ended December 31, 2015, Medallion began recognizing revenue due to its main pipeline becoming fully operational. See Note 15 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding this investment.

Interest expense. Interest expense increased by $1.6 million for the year ended December 31, 2015 compared to 2014 and increased by $2.0 million for the year ended December 31, 2014 compared to 2013. Interest is allocated to the midstream and marketing segment based on its gross property and equipment and life-to-date contributions to its equity method investee. We have expanded the midstream and marketing component of our business and built out our service facilities significantly in the past year, thereby increasing the interest expense that is allocated to this segment.

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

Liquidity and capital resources

Our primary sources of liquidity have been cash flows from operations, proceeds from equity offerings, proceeds from senior unsecured note offerings, borrowings under our Senior Secured Credit Facility and proceeds from asset dispositions. In 2016, 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 expected capital expenditures. A significant portion of our capital expenditures can be adjusted and managed by us. We continually monitor and consider which financing alternatives, including debt and equity capital resources, joint ventures and asset sales, are available to meet our future planned or accelerated capital expenditures. Our primary operational uses of capital have been for the acquisition, exploration and development of oil and natural gas properties, LMS's infrastructure development and investments in Medallion, our equity method investee.

We continually seek to maintain a financial profile that provides operational flexibility. However, as evidenced by the decline in our Realized Prices used in our 2015 reserve report compared to 2014, the decrease in oil, NGL and natural

gas prices may have a negative impact on our ability to raise additional capital and/or maintain our desired levels of liquidity. As of December 31, 2015, we had $865.0 million available for borrowings under our Senior Secured Credit Facility and total outstanding debt of $1.4 billion, of which $135.0 million was outstanding under our Senior Secured Credit Facility. Our total outstanding debt, less available cash on the balance sheet, was 3.0 times our Adjusted EBITDA (a non-GAAP financial

measure, see "Item 6. Selected Historical Financial Data—Non-GAAP financial measure") for the year ended December 31, 2015. We believe that our operating cash flow and the aforementioned liquidity sources provide us with the financial resources to implement our planned exploration and development activities.

We use derivatives to reduce exposure to fluctuations in the prices of oil and natural gas. As of February 16, 2016, approximately 85% to 90% of our anticipated oil production for 2016 is hedged at a weighted-average floor price of $70.84 per Bbl and approximately 70% to 75% of our anticipated natural gas production for 2016 is hedged at a weighted-average floor price of $3.00 per MMBtu.

As of December 31, 2015, we had $135.0 million outstanding under our Senior Secured Credit Facility and $1.3 billion in Senior Unsecured Notes. We had $865.0 million available for borrowings under our Senior Secured Credit Facility and $31.2 million in cash on hand for total available liquidity of $896.2 million as of December 31, 2015. Subsequent to December 31, 2015, we borrowed an additional $35.0 million on our Senior Secured Credit Facility. As of February 16, 2016, we had $1.5 billion in debt outstanding, $830.0 million available for borrowings under our Senior Secured Credit Facility and $16.8 million in cash on hand for total available liquidity of $846.8 million. A continued decline in oil and natural gas prices will negatively impact our future borrowing base redeterminations.

The following table summarizes our hedge positions as of December 31, 2015, adjusted for any new hedge transactions entered into between January 1, 2016 and February 16, 2016, for the calender years presented:

	Year 2016	Year 2017[1]	Year 2018[1]
Oil positions:[2]			
Total volume hedged with floor price (Bbl)	6,523,800	2,628,000	—
Weighted-average floor price ($/Bbl)	$70.84	$77.22	$—
Natural gas positions:[3]			
Total volume hedged with floor price (MMBtu)	18,666,000	13,515,000	8,220,000
Weighted-average floor price ($/MMBtu)	$3.00	$2.70	$2.50

(1) Includes derivatives entered into subsequent to December 31, 2015.

(2) Oil derivatives are settled based on the WTI NYMEX index oil prices.

(3) Natural gas derivatives are settled based on the Inside FERC index price for West Texas Waha ("Waha") for the calculation period.

The following table presents a projection of estimated cash received in future periods from oil and natural gas derivative contracts in place as of December 31, 2015, adjusted for any new hedge transactions entered into between January 1, 2016 and February 16, 2016, utilizing the total volumes hedged with a floor price and the weighted-average floor price for the periods presented:

(in thousands)	Year 2016	Year 2017	Year 2018
Projected oil and natural gas hedge cash proceeds[1]	$265,043	$120,965	$1,753

(1) For this illustration we utilized the January 2016 WTI index oil price of $31.78 held constant for all periods presented. For this illustration we utilized the January 2016 Waha natural gas price of $1.99 held constant for all periods presented. Additionally, we reduced our projected oil and natural gas hedge cash proceeds by the actual cash payments required for deferred premiums for the calendar years presented.

Our commodity derivative positions will help us stabilize a portion of our expected cash flows from operations in the event of further declines in the price of oil and natural gas. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" below.

Cash flows

Our cash flows from continued and discontinued operations for the periods presented are as follows:

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Net cash provided by operating activities	$315,947	$498,277	$364,729
Net cash used in investing activities	(667,507)	(1,406,961)	(329,884)
Net cash provided by financing activities	353,393	739,852	130,084
Net increase (decrease) in cash and cash equivalents	$1,833	$(168,832)	$164,929

For the year ended December 31, 2013, the results of operations of the pipeline assets and various other related property and equipment sold as a component of the Anadarko Basin Sale have been presented as results of discontinued operations, net of tax. We do not disclose cash flows of discontinued operations separately from cash flows of continued operations due to the immateriality of the cash flows from discontinued operations. The absence of these discontinued operations will not materially affect future liquidity or capital resources.

Cash flows provided by operating activities

Net cash provided by operating activities was $315.9 million, $498.3 million and $364.7 million for the years ended December 31, 2015, 2014 and 2013, respectively. The decrease of $182.3 million from 2014 to 2015 is mainly due to the price related decrease in oil, NGL and natural gas revenue, however notable cash flow changes consist of (i) impairment expense of $2.4 billion mainly due to our full cost ceiling impairments throughout 2015, (ii) a net increase of $150.4 million of proceeds from derivative settlements due to maturity or early termination, (iii) an increase of $31.5 million related to our loss on the early redemption of our January 2019 Notes and (iv) $56.6 million in decreased changes in working capital.

The increase of $133.5 million from 2013 to 2014 was largely due to an increase of $70.7 million net proceeds received for early terminations and modifications of commodity derivative contracts, a net increase of $26.4 million in working capital, a change in fair value of performance unit awards and a change in other noncurrent liabilities and an increase of $24.5 million in cash settlements received for matured derivatives and an increase of $11.9 million in DD&A.

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

Cash flows used in investing activities

Net cash used in investing activities decreased $739.5 million from 2014 to 2015 and is mainly attributable to decreased capital expenditures due to our decreased capital budget and $64.8 million in proceeds from our sale of non-strategic and primarily non-operated properties, partially offset by increased contributions to our equity method investee, Medallion. Medallion significantly expanded their pipeline network during 2015. See Note 4 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our divestiture of non-strategic and primarily non-operated properties and Note 15 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding Medallion.

Net cash used in investing activities increased $1.1 billion from 2013 to 2014 and is mainly attributable to (i) increased capital expenditures for oil and natural gas properties and midstream service assets during the year ended December 31, 2014, (ii) significant leasehold acquisitions during the year ended December 31, 2014, which are included in the "Oil and natural gas properties" line item below, and (iii) proceeds from our Anadarko Basin Sale in the prior period, which offset the total cash flows used in investing activities for the year ended ended December 31, 2013.

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

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Capital expenditures:			
Acquisitions of oil and natural gas properties	$—	$(6,493)	$(33,710)
Acquisition of mineral interests	—	(7,305)	—
Oil and natural gas properties	(588,017)	(1,251,757)	(702,349)
Midstream service assets	(35,459)	(60,548)	(24,409)
Other fixed assets	(9,125)	(27,444)	(16,257)
Investment in equity method investee	(99,855)	(55,164)	(3,287)
Proceeds from dispositions of capital assets, net of costs	64,949	1,750	450,128
Net cash used in investing activities	$(667,507)	$(1,406,961)	$(329,884)

Capital expenditure budget

Our board of directors approved a capital expenditure budget of approximately $345.0 million for calendar year 2016, excluding investments in Medallion and acquisitions. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted. Since we do not direct the expansion activities of Medallion as a 49% owner, we cannot predict future capital commitments.

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, reduction of service costs, contractual obligations, internally generated cash flow and other factors both within and outside our control. For additional information on the impact of changing prices on our financial position, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Cash flows provided by financing activities

For the year ended December 31, 2015, net cash provided by financing activities was the result of proceeds from our March 2015 Equity Offering of $754.2 million, our issuance of our March 2023 Notes of $350.0 million and borrowings on our Senior Secured Credit Facility of $310.0 million. The cash inflows were offset by the redemption of our January 2019 Notes of $576.2 million, payments on our Senior Secured Credit Facility of $475.0 million, payments for debt issuance costs totaling $6.8 million and the purchase of treasury stock to satisfy employee tax withholding obligations that arose upon the lapse of restrictions on restricted stock totaling $2.8 million.

For the year ended December 31, 2014, net cash provided by financing activities was the result of the issuance of our January 2022 Notes of $450.0 million, borrowings of $300.0 million on our Senior Secured Credit Facility and proceeds from the exercise of employee stock options of $1.9 million. These cash inflows were partially offset by payments for debt issuance costs totaling $7.8 million and the purchase of treasury stock to satisfy employee tax withholding obligations that arose upon the lapse of restrictions on restricted stock totaling $4.2 million.

For the year ended December 31, 2013, net cash provided by financing activities was the result of net proceeds from our August 2013 equity offering of $298.1 million and proceeds from the exercise of employee stock options of $2.1 million. These cash inflows were partially offset by the $165.0 million net payments on our Senior Secured Credit Facility, payments for debt issuance costs totaling $3.0 million and the purchase of treasury stock to satisfy employee tax withholding obligations that arose upon the lapse of restrictions on restricted stock totaling $2.1 million.

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

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Borrowings on Senior Secured Credit Facility	$310,000	$300,000	$230,000
Payments on Senior Secured Credit Facility	(475,000)	—	(395,000)
Issuance of March 2023 Notes	350,000	—	—
Issuance of January 2022 Notes	—	450,000	—
Redemption of January 2019 Notes	(576,200)	—	—
Proceeds from issuance of common stock, net of offering costs	754,163	—	298,104
Purchase of treasury stock	(2,811)	(4,242)	(2,083)
Proceeds from exercise of employee stock options	—	1,885	2,050
Payments for debt issuance costs	(6,759)	(7,791)	(2,987)
Net cash provided by financing activities	$353,393	$739,852	$130,084

Debt

As of December 31, 2015, we were a party only to our Senior Secured Credit Facility and the indentures governing our Senior Unsecured Notes.

Senior Secured Credit Facility. As of December 31, 2015, our Senior Secured Credit Facility, which matures November 4, 2018, had a maximum credit amount of $2.0 billion, a borrowing base of $1.15 billion, an aggregate elected commitment of $1.0 billion with $135.0 million outstanding.

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

The borrowing base under our Senior Secured Credit Facility is subject to a semi-annual redetermination based on the lenders' evaluation of our oil, NGL and natural gas reserves. The lenders have the right to call for an interim redetermination of the borrowing base once between any two redetermination dates and in other specified circumstances. A continued decline in oil, NGL and natural gas prices will negatively impact our future borrowing base redeterminations. The next semi-annual redetermination will occur on May 1, 2016.

As of December 31, 2015, 2014 and 2013, borrowings outstanding under our Senior Secured Credit Facility totaled $135.0 million, $300.0 million and zero, respectively. As of February 16, 2015, $170.0 million was outstanding under our Senior Secured Credit Facility and the amount available for borrowings was $830.0 million.

Our Senior Secured Credit Facility is secured by a first-priority lien on our assets, including oil and natural gas properties constituting at least 80% of the present value of our proved reserves owned now or in the future. Our Senior Secured Credit Facility contains both financial and non-financial covenants. We were in compliance with these covenants as of December 31, 2015, 2014 and 2013.

As of December 31, 2015, we were subject to the following financial ratios on a consolidated basis:

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

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

- incur indebtedness;

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

As of December 31, 2015, 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, 2015, each of the following would be an event of default:

- failure to pay any principal of any note or any reimbursement obligation under any letter of credit when due or any interest, fees or other amount within certain grace periods;
- failure to perform or otherwise comply with the covenants in our Senior Secured Credit Facility and other loan documents, subject, in certain instances, to certain grace periods;
- a representation, warranty, certification or statement is proved to be incorrect in any material respect when made;
- failure to make any payment in respect of any other indebtedness in excess of $25.0 million, any event occurs that permits or causes the acceleration of any such indebtedness or any event of default or termination event under a hedge agreement occurs in which the net hedging obligation owed is greater than $25.0 million;
- voluntary or involuntary bankruptcy or insolvency events involving us or our subsidiary and in the case of an involuntary proceeding, such proceeding remains undismissed and unstayed for the applicable grace period;
- one or more adverse judgments in excess of $25.0 million to the extent not covered by acceptable third party insurers, are rendered and are not satisfied, stayed or paid for the applicable grace period;
- incurring environmental liabilities that exceed $25.0 million to the extent not covered by acceptable third-party insurers;
- the loan agreement or any other loan paper ceases to be in full force and effect, or is declared null and void, or is contested or challenged, or any lien ceases to be a valid, first-priority, perfected lien;
- failure to cure any borrowing base deficiency in accordance with our Senior Secured Credit Facility;
- a change of control, as defined in our Senior Secured Credit Facility; and
- notification if an "event of default" shall occur under the indentures governing our Senior Unsecured Notes.

Additionally, our Senior Secured Credit Facility provides for the issuance of letters of credit, limited in the aggregate to the lesser of $20.0 million and the total availability under the facility. No letters of credit were outstanding as of December 31, 2015. See Note 5.f to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our Senior Secured Credit Facility.

Senior Unsecured Notes. The following table presents principal amounts and applicable interest rates for our outstanding Senior Unsecured Notes as of December 31, 2015:

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

(1) See Note 5 of our consolidated financial statements included elsewhere in this Annual Report for further discussion of our Senior Unsecured Notes.

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

As of February 16, 2016, we had a total of $1.3 billion of Senior Unsecured Notes outstanding.

Obligations and commitments

We had the following significant contractual obligations and commitments that will require capital resources as of December 31, 2015:

(in thousands)	Payments due Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
Senior Secured Credit Facility[1]	$—	$135,000	$—	$—	$135,000
Senior Unsecured Notes[2]	84,062	168,125	168,125	1,447,969	1,868,281
Drilling rig commitments[3]	10,253	—	—	—	10,253
Firm sale and transportation commitments[4]	55,091	123,970	81,992	164,598	425,651
Derivatives[5]	8,629	6,222	—	—	14,851
Asset retirement obligations[6]	1,547	5,151	6,664	32,944	46,306
Office leases[7]	3,087	6,404	3,702	8,217	21,410
Performance unit liability awards[8]	6,394	—	—	—	6,394
Capital contribution commitment to equity method investee[9]	27,583	—	—	—	27,583
Total	$196,646	$444,872	$260,483	$1,653,728	$2,555,729

(1) Includes outstanding principal amount at December 31, 2015. This table does not include future commitment fees, interest expense or other fees on our Senior Secured Credit Facility because it is a floating rate instrument and we cannot determine with accuracy the timing of future loan advances, repayments or future interest rates to be charged. As of December 31, 2015, the principal on our Senior Secured Credit Facility is due on November 4, 2018.

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

(3) As of December 31, 2015, we had several drilling rigs under term contracts which expire during 2016. The value in the table represents the gross amount that we are committed to pay. However, we will record our proportionate share based on our working interest in our consolidated financial statements as incurred. See Note 12.c to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our drilling contract commitments.

(4) As of December 31, 2015, we have committed to deliver for sale or transportation fixed quantities of production under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. If not fulfilled, we are subject to minimal volume penalties. See "Item 1A. Risk Factors" and Note 12.d to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our firm sale and transportation commitments.

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

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

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

(8) Represents cash awards that were granted on February 15, 2013 under the 2011 Omnibus Equity Incentive Plan. The February 15, 2013 performance awards were paid in January 2016. See Note 6.e to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our performance units.

(9) See Note 15 to our consolidated financial statements included elsewhere in this Annual Report for a discussion of our equity method investee.

Critical accounting policies and estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires

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

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

There have been no material changes in our critical accounting policies and procedures during the year ended December 31, 2015. See Note 2.b to our consolidated financial statements included elsewhere in this Annual Report for a discussion of additional accounting policies and estimates made by management.

Method of accounting for oil and natural gas properties

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

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

Oil 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 and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates. If such changes

are material, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

Impairment of oil and natural gas properties

We review the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues less estimated future expenditures to be incurred in developing and producing the evaluated reserves, less

any related income tax effects. For the year ended December 31, 2015, we recorded a full cost impairment expense of $2.4 billion. For the years ended December 31, 2014 and 2013, the results of the ceiling test concluded that the carrying amount of our oil and natural gas properties was significantly below the calculated ceiling test value and as such, our properties were not impaired and a write-down was not required. In calculating future net revenues, current prices are calculated as the average oil and natural gas prices during the 12-month period prior to the end of the current reporting period, determined as the unweighted arithmetic average first-day-of-the-month prices for the prior 12-month period and costs used are those as of the end of the appropriate quarterly period. See Note 2.g to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our impairment of oil and natural gas properties.

Revenue recognition

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

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

Income taxes

As of December 31, 2015, and 2014, we had a net deferred tax liability of zero and $176.9 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, 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 and natural gas reserves;
- our ability to use tax planning strategies, such as electing to capitalize intangible drilling costs as opposed to expensing such costs;
- current price protection utilizing oil and natural gas hedges; and
- future revenue and operating cost projections that indicate we will produce more than enough taxable income to realize the deferred tax asset based on existing sales prices and cost structures.
- current market prices for oil, NGL and natural gas

During 2015, in evaluating whether it was more-likely-than-not that our deferred tax asset was recoverable from future net income, we considered our earnings history for the current and most recent two years.
In performing our analysis, we used inputs from third-party sources, which came primarily from our reserve reports that were independently estimated by Ryder Scott. Based on our forecasted results from multiple analyses, during the year

ended December 31, 2015, we determined it is more likely than not that we will not realize our net deferred tax assets. Therefore, a 2015 valuation allowance of $676.0 million was recorded.

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

Income tax windfalls and shortfalls. For certain stock-based compensation awards that are expected to result in a tax deduction under existing tax law, a deferred tax asset is established as we recognize compensation cost for book purposes. Book compensation cost is determined on the grant date and recognized over the award's requisite service period. The corresponding deferred tax asset also is measured on the grant date and recognized over the service period. The related tax deduction is measured on the vesting date for restricted stock and on the exercise date for stock options. As a result, there will almost always be a difference in the amount of compensation cost recognized for book purposes versus the amount of tax deduction that a company may receive. If the tax deduction exceeds the cumulative book compensation cost that we recognized, the tax benefit associated with any excess deduction will be considered an excess benefit or windfall and will be recognized as additional paid-in capital ("APIC"). If the tax deduction is less than the cumulative book compensation cost, the tax effect of the resulting difference is a deficiency or shortfall, and should be charged first to APIC, to the extent of our pool of windfall tax benefits, with any remainder recognized in income tax expense. We utilize a one-pool approach when accounting for the pool of windfall tax benefits. In the one-pool approach, employees and non-employees are grouped into a single pool. As of December 31, 2015 and 2014, we did not have any eligible windfall tax benefits to offset future shortfalls as no excess tax benefits have been recognized, therefore all shortfalls have been recognized in income tax expense.

Variable interest entities

An entity is referred to as a variable interest entity ("VIE") pursuant to accounting guidance for consolidation if it possesses one of the following criteria: (i) it is thinly capitalized, (ii) the residual equity holders do not control the entity, (iii) the equity holders are shielded from the economic losses, (iv) the equity holders do not participate fully in the entity's residual economics, or (v) the entity was established with non-substantive voting interests. We would consolidate a VIE when we are the primary beneficiary of a VIE. A primary beneficiary has the power to direct the activities that most significantly impact the activities of the VIE and the right to receive the benefits or the obligation to absorb the losses of the entity that could be potentially significant to the VIE. We continually monitor our unconsolidated VIE exposure in order to determine if any events have occurred that could cause the primary beneficiary to change. See Notes 15 and 16.a to our consolidated financial statements included elsewhere in this Annual Report for a discussion of our unconsolidated VIE, Medallion.

Asset retirement obligations ("ARO")

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

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

Derivatives

We record all derivatives on the balance sheet as either assets or liabilities measured at their estimated fair value. We have not designated any derivatives as hedges for accounting purposes, and we do not enter into such instruments for

speculative trading purposes. Gains and losses from the settlement of commodity derivatives and gains and losses from valuation changes in the remaining unsettled commodity derivatives are reported under "Non-operating income (expense)" in our consolidated statements of operations.

Stock-based compensation

We measure stock-based compensation expense at the grant date based on the fair value of an award and recognize the compensation expense on a straight-line basis over the service period, which is usually the vesting period. The fair value of the awards is based on the value of our common stock on the grant date. The determination of the fair value of an award requires significant estimates and subjective judgments regarding, among other things, the appropriate option pricing model, the expected life of the award and forfeiture rate assumptions. We utilize the Black-Scholes option pricing model to measure the fair value of stock options granted under our 2011 Omnibus Equity Incentive Plan. During the year ended December 31, 2014, we began capitalizing a portion of stock-based compensation for employees who are directly involved in the acquisition, exploration and development of our properties into the full cost pool. Capitalized stock-based compensation is included as an addition to "Oil and natural gas properties" in the consolidated balance sheets.

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

Performance unit and performance share compensation

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

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

Recent accounting pronouncements

We early adopted new guidance regarding the presentation of debt issuance costs and the presentation of income taxes as of September 30, 2015 and December 31, 2015, respectively. For additional discussion of these early adoptions and other recent accounting pronouncements, see Note 14 to our consolidated financial statements included elsewhere in this Annual Report.

Inflation

Inflation in the U.S. has been relatively low in recent years and did not have a material impact on our results of operations for the period from December 31, 2013 through the year ended December 31, 2015. Although the impact of inflation has been insignificant in recent years, it continues to be a factor in the U.S. economy and historically, we have experienced inflationary pressure on the costs of oilfield services and equipment as drilling activity increases in the areas in which we operate.

Off-balance sheet arrangements

Currently, we do not have any off-balance sheet arrangements other than operating leases, drilling contracts and firm sale and transportation commitments. See Notes 12.a, 12.c and 12.d to our consolidated financial statements included

elsewhere in this Annual Report and "Item 1. Business—Our core assets—Midstream and marketing" for additional information.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity price exposure

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

The fair values of our commodity derivatives are largely determined by estimates of the forward curves of the relevant price indices. As of December 31, 2015, a 10% change in the forward curves associated with our commodity derivatives would have changed our net positions to the following amounts:

(in thousands)	10% Increase	10% Decrease
Commodity derivatives	$238,652	$318,542

As of December 31, 2015 and 2014, the fair values of our open derivatives contracts were $276.2 million and $312.3 million, respectively. Refer to Notes 2.f, 8 and 9 of our consolidated financial statements included elsewhere in this Annual Report for additional disclosures regarding our derivatives.

Interest rate risk

Our Senior Secured Credit Facility bears interest at a floating rate and, as of December 31, 2015, we had $135.0 million outstanding on our Senior Secured Credit Facility. Our January 2022 Notes, May 2022 Notes and March 2023 Notes bear fixed interest rates and we had $450.0 million, $500.0 million and $350.0 million outstanding, respectively, as of December 31, 2015, as shown in the table below.

	Expected maturity date													
(in millions except for interest rates)	2016		2017		2018		2019		2020		Thereafter		Total	
January 2022 Notes - fixed rate	$—		$—		$—		$—		$—		$450.0		$450.0	
Average interest rate	—	%	—	%	—	%	—	%	—	%	5.625	%	5.625	%
May 2022 Notes - fixed rate	$—		$—		$—		$—		$—		$500.0		$500.0	
Average interest rate	—	%	—	%	—	%	—	%	—	%	7.375	%	7.375	%
March 2023 Notes - fixed rate	$—		$—		$—		$—		$—		$350.0		$350.0	
Average interest rate	—	%	—	%	—	%	—	%	—	%	6.250	%	6.250	%
Senior Secured Credit Facility - variable rate	$—		$—		$135.0		$—		$—		$—		$135.0	
Average interest rate	—	%	—	%	1.903	%	—	%	—	%	—	%	1.903	%

Counterparty and customer credit risk

As of December 31, 2015, our principal exposures to credit risk are through receivables of (i) $276.2 million from the fair values of our open derivative contracts, (ii) $27.5 million from matured derivatives, (iii) $25.6 million from the sale of our oil, NGL and natural gas production, that we market to energy marketing companies and refineries, (iv) $21.4 million from joint-interest partners and (v) $11.8 million from midstream product sales.

We are subject to credit risk due to the concentration of (i) our oil, NGL and natural gas receivables with several significant customers and (ii) our midstream service product sales receivables with one significant customer. On occasion we require our customers to post collateral, and the inability of our significant customers to meet their

obligations to us or their insolvency or liquidation may adversely affect our financial results.

We have entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of

our derivative counterparties, who also are lenders in our Senior Secured Credit Facility. The terms of the ISDA Agreements provide the counterparties and us with rights of offset upon the occurrence of defined acts of default by either a counterparty or us to a derivative, whereby the party not in default may offset all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party.

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

Item 8. Financial Statements and Supplementary Data

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

As of December 31, 2015, 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, 2015.

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 on Form 10-K, has issued their report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2015. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2015, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Laredo Petroleum, Inc.

We have audited the internal control over financial reporting of Laredo Petroleum, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2015, based on criteria established in the 2013 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in the 2013 Internal Control-Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended December 31, 2015, and our report dated February 17, 2016 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP
Tulsa, Oklahoma
February 17, 2016

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, 2015 at the reasonable assurance level.

Design and Evaluation of Internal Control Over Financial Reporting. Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, our management has included a report of their assessment of the design and effectiveness of our internal controls over financial reporting as part of this Annual Report for the fiscal year ended December 31, 2015. Grant Thornton LLP, the Company's independent registered public accounting firm, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting. Management’s report and the independent registered public accounting firm's attestation report are included in "Item 8. Financial Statements and Supplementary Data" in this Annual Report under the caption entitled "Management’s Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm," respectively, and are incorporated herein by reference.

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

Item 9B. Other Information

Item 5.03 Amendments to Articles of Incorporation or Bylaws; Change in Fiscal Year.

On February 10, 2016, the Company's board of directors approved and adopted the second amended and restated bylaws of the Company (as amended and restated, the "Second A&R Bylaws"). The Second A&R Bylaws became effective immediately upon approval and adoption by the Company's board of directors on February 10, 2016. Pursuant to the Second A&R Bylaws, Article IV, Section 6 (the "Amended Provision") of the Company's amended and restated bylaws was amended to provide that "one senior vice president may be designated by the board of directors to perform the duties and exercise the powers of the president in the event of the president's absence or disability." Prior to the adoption of the Second A&R Bylaws, the Amended Provision provided that "one senior vice president shall be designated by the board of directors to perform the duties and exercise the powers of the president in the event of the president's absence or disability."

The foregoing description of the Second A&R Bylaws is a summary only and is qualified in its entirety by reference to the complete text of the Second A&R Bylaws, a copy of which is attached as Exhibit 3.3 to this Annual Report and incorporated herein by reference.

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, 2015.

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, 2015.

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, 2015.

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, 2015.

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, 2015.

Part IV

Item 15. Exhibits, Financial Statement Schedules

(a)(1) Financial Statements

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

(a)(2) Financial Statement Schedules

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

(a)(3) Exhibits

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

4.6	Amended and Restated Supplemental Indenture, dated as of June 24, 2014, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 of Laredo's Quarterly Report on Form 10-Q (File No. 001-35380) filed on August 7, 2014).

Exhibit Number	Description
4.7	Fourth Supplemental Indenture, dated as of December 3, 2014, among Laredo Petroleum, Inc., Garden City Minerals, LLC, Laredo Midstream Services, LLC and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.7 of Laredo's Annual Report on Form 10-K (File No. 001-35380) filed on February 26, 2015).
4.8	Indenture, dated as of January 23, 2014, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on January 24, 2014).
4.9	First Supplemental Indenture, dated as of December 3, 2014, among Laredo Petroleum, Inc., Garden City Minerals, LLC, Laredo Midstream Services, LLC and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.9 of Laredo's Annual Report on Form 10-K (File No. 001-35380) filed on February 26, 2015).
4.10	Indenture, dated as of March 18, 2015, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC, Garden City Minerals, LLC and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on March 24, 2015).
4.11	First Supplemental Indenture, dated as of March 18, 2015, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC, Garden City Minerals, LLC and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on March 24, 2015).
10.1	Fourth Amended and Restated Credit Agreement, dated as of December 31, 2013, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the other financial institutions signatory thereto (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on January 6, 2014).
10.2	First Amendment to Fourth Amended and Restated Credit Agreement, dated as of January 31, 2014, among Laredo Petroleum, Inc., Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and the banks signatory thereto (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on February 4, 2014).
10.3	Second Amendment to Fourth Amended and Restated Credit Agreement, dated as of May 8, 2014, among Laredo Petroleum, Inc., Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and the banks signatory thereto (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on May 8, 2014).
10.4	Third Amendment to Fourth Amended and Restated Credit Agreement, dated as of May 4, 2015, among Laredo Petroleum, Inc., Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC, Garden City Minerals, LLC and the banks signatory thereto (incorporated by reference to Exhibit 10.3 of Laredo's Quarterly Report on Form 10-Q (File No. 001-35380) filed on May 7, 2015).
10.5	Fourth Amendment to Fourth Amended and Restated Credit Agreement, dated as of October 30, 2015, among Laredo Petroleum, Inc., Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream

	Services, LLC, Garden City Minerals, LLC and the banks signatory thereto (incorporated by reference to Exhibit 10.1 of Laredo's Quarterly Report on Form 10-Q (File No. 001-35380) filed on November 5, 2015).
10.6	Waiver Letter to Fourth Amended and Restated Credit Agreement, dated as of March 3, 2015, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the banks signatory thereto (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on March 4, 2015).
10.7	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).
10.8#	Form of Indemnification Agreement between Laredo Petroleum Holdings, Inc. and each of the officers and directors thereof (incorporated by reference to Exhibit 10.6 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
10.9#	Laredo Petroleum Holdings, Inc. 2011 Omnibus Equity Incentive Plan (incorporated by reference to Exhibit 10.4 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
10.10#	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on February 9, 2012).
10.11#	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.3 of Laredo's Quarterly Report on Form 10-Q (File No. 001-35380) filed on August 9, 2012).

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

* Filed herewith.
** Furnished herewith.

Management contract or compensatory plan or arrangement.

SIGNATURES

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

LAREDO PETROLEUM, INC.

Date: February 17, 2016 By: /s/ Randy A. Foutch
Randy A. Foutch
Chief Executive Officer

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

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

Signatures	Title	Date
/s/ Randy A. Foutch Randy A. Foutch	Chairman and Chief Executive Officer (principal executive officer)	2/17/2016
/s/ Richard C. Buterbaugh Richard C. Buterbaugh	Executive Vice President and Chief Financial Officer (principal financial officer)	2/17/2016
/s/ Michael T. Beyer Michael T. Beyer	Vice President - Controller and Chief Accounting Officer (principal accounting officer)	2/17/2016
/s/ Peter R. Kagan Peter R. Kagan	Director	2/17/2016
/s/ James R. Levy James R. Levy	Director	2/17/2016
/s/ B.Z. (Bill) Parker B.Z. (Bill) Parker	Director	2/17/2016
/s/ Pamela S. Pierce Pamela S. Pierce	Director	2/17/2016
/s/ Ambassador Francis Rooney Ambassador Francis Rooney	Director	2/17/2016
/s/ Dr. Myles W. Scoggins Dr. Myles W. Scoggins	Director	2/17/2016
/s/ Edmund P. Segner III Edmund P. Segner, III	Director	2/17/2016
/s/ Donald D. Wolf Donald D. Wolf	Director	2/17/2016

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Laredo Petroleum, Inc.

We have audited the accompanying consolidated balance sheets of Laredo Petroleum, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Laredo Petroleum, Inc. and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 14 to the consolidated financial statements, the Company has changed its method of presentation for deferred income taxes in 2015 and 2014 due to the adoption of FASB Accounting Standards Update No. 2015-17 – Balance Sheet Classification of Deferred Taxes. Additionally, as discussed in Note 14 to the consolidated financial statements, the Company has changed its method of presentation for debt issuance costs in 2015 and 2014 due to the adoption of FASB Accounting Standards Update No. 2015-03 – Simplifying the Presentation of Debt Issuance Costs.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, 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 17, 2016, expressed an unqualified opinion.

/s/ GRANT THORNTON LLP
Tulsa, Oklahoma
February 17, 2016

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

	December 31, 2015	2014
Assets		
Current assets:		
Cash and cash equivalents	$31,154	$29,321
Accounts receivable, net	87,699	126,929
Derivatives	198,805	194,601
Other current assets	14,574	14,402
Total current assets	332,232	365,253
Property and equipment:		
Oil and natural gas properties, full cost method:		
Evaluated properties	5,103,635	4,446,781
Unevaluated properties not being depleted	140,299	342,731
Less accumulated depletion and impairment	(4,218,942)	(1,586,237)
Oil and natural gas properties, net	1,024,992	3,203,275
Midstream service assets, net	131,725	108,462
Other fixed assets, net	43,538	42,345
Property and equipment, net	1,200,255	3,354,082
Derivatives	77,443	117,788
Investment in equity method investee	192,524	58,288
Other assets, net	10,833	15,290
Total assets	$1,813,287	$3,910,701
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable	$14,181	$39,008
Undistributed revenue and royalties	34,540	65,438
Accrued capital expenditures	61,872	148,241
Derivatives	—	115
Other current liabilities	106,222	101,032
Total current liabilities	216,815	353,834
Long-term debt, net	1,416,226	1,779,447
Deferred income taxes, net	—	176,945
Asset retirement obligations	44,759	31,042
Other noncurrent liabilities	4,040	6,232
Total liabilities	1,681,840	2,347,500
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $0.01 par value, 50,000,000 shares authorized and zero issued at December 31, 2015 and 2014	—	—
Common stock, $0.01 par value, 450,000,000 shares authorized, and 213,808,003 and 143,686,491 issued, at December 31, 2015 and 2014, respectively	2,138	1,437
Additional paid-in capital	2,086,652	1,309,171
(Accumulated deficit) retained earnings	(1,957,343)	252,593
Total stockholders' equity	131,447	1,563,201
Total liabilities and stockholders' equity	$1,813,287	$3,910,701

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

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

	For the years ended December 31,		
	2015	2014	2013
Revenues:			
Oil, NGL and natural gas sales	$431,734	$737,203	$664,844
Midstream service revenues	6,548	2,245	413
Sales of purchased oil	168,358	54,437	—
Total revenues	606,640	793,885	665,257
Costs and expenses:			
Lease operating expenses	108,341	96,503	79,136
Production and ad valorem taxes	32,892	50,312	42,396
Midstream service expenses	5,846	5,429	3,368
Minimum volume commitments	5,235	2,552	891
Costs of purchased oil	174,338	53,967	—
Drilling rig fees	—	527	—
General and administrative	90,425	106,044	89,696
Restructuring expenses	6,042	—	—
Accretion of asset retirement obligations	2,423	1,787	1,475
Depletion, depreciation and amortization	277,724	246,474	233,944
Impairment expense	2,374,888	3,904	—
Total costs and expenses	3,078,154	567,499	450,906
Operating income (loss)	(2,471,514)	226,386	214,351
Non-operating income (expense):			
Gain (loss) on derivatives:			
Commodity derivatives, net	214,291	327,920	79,902
Interest rate derivatives, net	—	—	(24)
Income (loss) from equity method investee	6,799	(192)	29
Interest expense	(103,219)	(121,173)	(100,327)
Interest and other income	426	294	163
Loss on early redemption of debt	(31,537)	—	—
Write-off of debt issuance costs	—	(124)	(1,502)
Loss on disposal of assets, net	(2,127)	(3,252)	(1,508)
Non-operating income (expense), net	84,633	203,473	(23,267)
Income (loss) from continuing operations before income taxes	(2,386,881)	429,859	191,084
Income tax benefit (expense):			
Deferred	176,945	(164,286)	(74,507)
Total income tax benefit (expense)	176,945	(164,286)	(74,507)
Income (loss) from continuing operations	(2,209,936)	265,573	116,577
Income from discontinued operations, net of tax	—	—	1,423
Net income (loss)	$(2,209,936)	$265,573	$118,000
Net income (loss) per common share:			
Basic:			
Income (loss) from continuing operations	$(11.10)	$1.88	$0.88
Income from discontinued operations, net of tax	—	—	0.01
Net income (loss) per share	$(11.10)	$1.88	$0.89
Diluted:			
Income (loss) from continuing operations	$(11.10)	$1.85	$0.87

Income from discontinued operations, net of tax	—	—	0.01
Net income (loss) per share	$(11.10)	$1.85	$0.88
Weighted-average common shares outstanding:			
Basic	199,158	141,312	132,490
Diluted	199,158	143,554	134,378

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

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

	Common Stock		Additional paid-in capital	Treasury Stock (at cost)		(Accumulated deficit) retained earnings	Total
	Shares	Amount		Shares	Amount		
Balance, December 31, 2012	128,298	$1,283	$961,424	8	$(4)	$(130,980)	$831,723
Restricted stock awards	1,469	15	(15)	—	—	—	—
Restricted stock forfeitures	(229)	(2)	2	—	—	—	—
Vested restricted stock exchanged for tax withholding	—	—	—	95	(2,083)	—	(2,083)
Retirement of treasury stock	(95)	(1)	(2,086)	(103)	2,087	—	—
Exercise of employee stock options	104	1	2,049	—	—	—	2,050
Equity issuance, net of offering costs	13,000	130	297,974	—	—	—	298,104
Equity issued for acquisition, net of offering costs	124	1	3,028	—	—	—	3,029
Stock-based compensation	—	—	21,433	—	—	—	21,433
Net income	—	—	—	—	—	118,000	118,000
Balance, December 31, 2013	142,671	1,427	1,283,809	—	—	(12,980)	1,272,256
Restricted stock awards	1,234	12	(12)	—	—	—	—
Restricted stock forfeitures	(148)	(1)	1	—	—	—	—
Vested restricted stock exchanged for tax withholding	—	—	—	166	(4,242)	—	(4,242)
Retirement of treasury stock	(166)	(2)	(4,240)	(166)	4,242	—	—
Exercise of employee stock options	95	1	1,884	—	—	—	1,885
Stock-based compensation	—	—	27,729	—	—	—	27,729
Net income	—	—	—	—	—	265,573	265,573
Balance, December 31, 2014	143,686	1,437	1,309,171	—	—	252,593	1,563,201
Restricted stock awards	1,902	19	(19)	—	—	—	—
Restricted stock forfeitures	(553)	(6)	6	—	—	—	—
Vested restricted stock exchanged for tax	—	—	—	227	(2,811)	—	(2,811)

withholding							
Retirement of treasury stock	(227)	(2)	(2,809)	(227)	2,811	—	—
Equity issuance, net of offering costs	69,000	690	753,473	—	—	—	754,163
Stock-based compensation	—	—	26,830	—	—	—	26,830
Net loss	—	—	—	—	—	(2,209,936)	(2,209,936)
Balance, December 31, 2015	213,808	$2,138	$2,086,652	—	$—	$(1,957,343)	$131,447

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

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

	For the years ended December 31,		
	2015	2014	2013
Cash flows from operating activities:			
Net income (loss)	$(2,209,936)	$265,573	$118,000
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred income tax (benefit) expense	(176,945)	164,286	75,288
Depletion, depreciation and amortization	277,724	246,474	234,571
Impairment expense	2,374,888	3,904	—
Loss on early redemption of debt	31,537	—	—
Bad debt expense	255	342	653
Non-cash stock-based compensation, net of amounts capitalized	24,509	23,079	21,433
Accretion of asset retirement obligations	2,423	1,787	1,475
Mark-to-market on derivatives:			
Gain on derivatives, net	(214,291)	(327,920)	(79,878)
Cash settlements received for matured derivatives, net	255,281	28,241	3,745
Cash settlements received for early terminations and modification of derivatives, net	—	76,660	6,008
Change in net present value of deferred premiums paid for derivatives	203	220	462
Cash premiums paid for derivatives	(5,167)	(7,419)	(10,277)
Amortization of debt issuance costs	4,727	5,137	5,023
Write-off of debt issuance costs	—	124	1,502
Loss on disposal of assets, net	2,127	3,252	1,508
(Income) loss on equity method investee	(6,799)	192	(29)
Cash settlement of performance unit awards	(2,738)	—	(2,080)
Other, net	4	403	(230)
Decrease (increase) in accounts receivable	38,975	(49,953)	6,825
Increase in other assets	(2,309)	(16,688)	(7,438)
(Decrease) increase in accounts payable	(24,827)	23,006	(32,581)
(Decrease) increase in undistributed revenues and royalties	(30,898)	30,314	(941)
(Decrease) increase in other accrued liabilities	(26,996)	23,837	16,458
Increase in other noncurrent liabilities	119	2,825	499
Increase in fair value of performance unit awards	4,081	601	4,733
Net cash provided by operating activities	315,947	498,277	364,729
Cash flows from investing activities:			
Capital expenditures:			
Acquisitions of oil and natural gas properties	—	(6,493)	(33,710)
Acquisition of mineral interests	—	(7,305)	—
Oil and natural gas properties	(588,017)	(1,251,757)	(702,349)
Midstream service assets	(35,459)	(60,548)	(24,409)
Other fixed assets	(9,125)	(27,444)	(16,257)
Investment in equity method investee	(99,855)	(55,164)	(3,287)
Proceeds from dispositions of capital assets, net of costs	64,949	1,750	450,128
Net cash used in investing activities	(667,507)	(1,406,961)	(329,884)
Cash flows from financing activities:			
Borrowings on Senior Secured Credit Facility	310,000	300,000	230,000

Payments on Senior Secured Credit Facility	(475,000)	—	(395,000)
Issuance of March 2023 Notes	350,000	—	—
Issuance of January 2022 Notes	—	450,000	—
Redemption of January 2019 Notes	(576,200)	—	—
Proceeds from issuance of common stock, net of offering costs	754,163	—	298,104
Purchase of treasury stock	(2,811)	(4,242)	(2,083)
Proceeds from exercise of employee stock options	—	1,885	2,050
Payments for debt issuance costs	(6,759)	(7,791)	(2,987)
Net cash provided by financing activities	353,393	739,852	130,084
Net increase (decrease) in cash and cash equivalents	1,833	(168,832)	164,929
Cash and cash equivalents, beginning of period	29,321	198,153	33,224
Cash and cash equivalents, end of period	$31,154	$29,321	$198,153

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

Laredo Petroleum, Inc.
Notes to the consolidated financial statements

Note 1—Organization

The Company (defined below) is an independent energy company focused on the acquisition, exploration and development of oil and natural gas properties, and the transportation of oil and natural gas from such properties, primarily in the Permian Basin in West Texas. On August 1, 2013, the Company sold its properties in the Mid-Continent region of the United States (as further described below).

Laredo Petroleum, Inc. ("Laredo"), formerly known as Laredo Petroleum Holdings, Inc., was formed pursuant to the laws of the State of Delaware on August 12, 2011 for purposes of a Corporate Reorganization (defined below) and initial public offering of its common stock (the "IPO"). On December 19, 2011, Laredo Petroleum, LLC ("Laredo LLC"), a Delaware limited liability company, was merged with and into Laredo, with Laredo surviving the merger (the "Corporate Reorganization"). As a holding company, Laredo's management operations were conducted through its wholly-owned subsidiary, Laredo Petroleum, Inc. ("Laredo Inc."), a Delaware corporation, and Laredo Inc's subsidiaries, Laredo Petroleum Texas, LLC ("Laredo Texas"), a Texas limited liability company, Laredo Gas Services, LLC ("Laredo Gas"), a Delaware limited liability company, and Laredo Petroleum—Dallas, Inc. ("Laredo Dallas"), a Delaware corporation.

Effective December 31, 2013, an internal corporate reorganization was completed, which simplified the corporate structure. Two of Laredo Inc.'s subsidiaries, Laredo Texas and Laredo Dallas, were merged with and into Laredo Inc. The sole remaining wholly-owned subsidiary of Laredo Inc. at the time of the internal corporate reorganization, Laredo Gas, changed its name to Laredo Midstream Services, LLC ("LMS"). Laredo Inc. merged with and into Laredo with Laredo surviving and changing its name to "Laredo Petroleum, Inc." (the events described in this paragraph collectively, the "Internal Consolidation").

On October 24, 2014, Laredo formed Garden City Minerals, LLC ("GCM"), a Delaware limited liability company, for the purpose of holding its mineral interests. GCM is wholly owned by Laredo. GCM and LMS (together, the "Guarantors") guarantee all of Laredo's debt instruments.

In these notes, the "Company," (i) when used in the present tense, prospectively or from October 24, 2014, refers to Laredo, LMS and GCM collectively; (ii) when used for historical periods from December 31, 2013 to October 23, 2014, refers to Laredo and LMS collectively; and (iii) when used for historical periods from December 19, 2011 to December 30, 2013, refers to Laredo and its subsidiaries, collectively, unless the context indicates otherwise. All amounts, dollars and percentages presented in these consolidated financial statements and the related notes are rounded and therefore approximate.

The Company operates in two business segments, which are (i) exploration and production and (ii) midstream and marketing. The exploration and production segment is engaged in the acquisition, exploration and development of oil and natural gas properties primarily in the Permian Basin in West Texas. The midstream and marketing segment provides Laredo's exploration and production segment and certain third parties with (i) products and services that need to be delivered by midstream infrastructure, including oil and natural gas gathering services as well as rig fuel, natural gas lift and water in and around Laredo's primary production corridors, (ii) water takeaway in and around Laredo's primary production corridors and (iii) oil and natural gas takeaway optionality in the field coupled with firm service commitments to maximize Laredo's oil, natural gas liquids ("NGL") and natural gas revenues.

Note 2—Basis of presentation and significant accounting policies

a. Basis of presentation

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

the investee's net income (loss) is included in the consolidated statements of operations. See Note 15 for additional discussion of the Company's equity method investment.

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

The preparation of the accompanying consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions about future events. These estimates and the underlying assumptions affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements

and the reported amounts of revenues and expenses during the reporting period. Although management believes these estimates are reasonable, actual results could differ.

Significant estimates include, but are not limited to, (i) estimates of the Company's reserves of oil, NGL and natural gas, (ii) future cash flows from oil and natural gas properties, (iii) depletion, depreciation and amortization, (iv) asset retirement obligations, (v) stock-based compensation, (vi) deferred income taxes, (vii) fair value of assets acquired and liabilities assumed in an acquisition and (viii) fair values of commodity derivatives, commodity deferred premiums and performance unit awards. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. 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 2015 presentation. These reclassifications had no impact to previously reported net income, stockholders' equity or cash flows. See Notes 7 and 14 for discussion regarding reclassifications related to the Company's early adoption of new guidance related to the classification of income taxes. See Notes 2.k, 5.h and 14 for discussion regarding the Company's early adoption of new guidance related to the presentation of deferred loan costs.

d. Cash and cash equivalents

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

e. Accounts receivable

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

Joint interest operations amounts are considered past due after 30 days. The Company determines joint interest operations accounts receivable allowances based on management's assessment of the creditworthiness of the joint interest owners. Additionally, as the operator of the majority of its wells, the Company has the ability to realize the receivables through netting of anticipated future production revenues. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses, current receivables aging and existing industry and economic data. The Company reviews its allowance for doubtful accounts quarterly. Past due amounts greater than 90 days and over a specified amount are reviewed individually for collectability. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential for recovery is remote.

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

(in thousands)	2015	2014
Matured derivatives	$27,469	$16,098
Oil, NGL and natural gas sales	25,582	57,070
Joint operations, net[(1)]	21,375	33,808
Purchased oil and other product sales	11,775	18,917
Other	1,498	1,036
Total	$87,699	$126,929

(1) Accounts receivable for joint operations are presented net of an allowance for doubtful accounts of $0.2 million and $0.8 million as of December 31, 2015 and 2014, respectively.

f. Derivatives

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

Derivatives are recorded at fair value and are presented on a net basis on the consolidated balance sheets as assets or liabilities. The Company nets the fair value of derivatives by counterparty where the right of offset exists. The Company determines the fair value of its derivatives by utilizing pricing models for substantially similar instruments. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. See Note 9 for discussion regarding the fair value of the Company's derivatives. The Company's derivatives were not designated as hedges for accounting purposes for any of the periods presented. Accordingly, the changes in fair value are recognized in the consolidated statements of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities. See Notes 8 and 9 for discussion regarding the Company's commodity derivatives.

g. Oil and natural gas properties

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

The Company computes the provision for depletion of oil and natural gas properties using the units of production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the depletion base until the properties associated with these costs are evaluated. Approximately $140.3 million and $342.7 million of such costs were excluded from the depletion base as of December 31, 2015 and 2014, respectively. The depletion base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values. Total accumulated depletion and impairment for oil and natural gas properties was $4.2 billion and $1.6 billion for the years ended December 31, 2015 and 2014, respectively. Depletion expense for oil and natural gas properties was $263.7 million, $237.1 million and $228.0 million for the years ended December 31, 2015, 2014 and 2013, respectively. Depletion per barrel of oil equivalent for the Company's oil and natural gas properties was $16.13, $20.21 and $20.34 for the years ended December 31, 2015, 2014 and 2013, respectively.

The Company excludes the costs directly associated with acquisition and evaluation of unevaluated properties from the depletion calculation until it is determined whether or not proved reserves can be assigned to the properties. The Company capitalizes a portion of its interest costs on its unevaluated properties. Capitalized interest becomes a part of the cost of the unevaluated properties and is subject to depletion when proved reserves can be assigned to the associated properties. All items

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classified as unevaluated property are assessed on a quarterly basis for possible impairment or reduction in value. The assessment includes consideration of the following factors, among others: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of evaluated reserves and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion.

The full cost ceiling is based principally on the estimated future net revenues from proved oil and natural gas properties discounted at 10%. Per the Securities and Exchange Commission ("SEC") guidelines, companies are required to use the unweighted arithmetic average first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period before differentials ("Benchmark Prices"). The Benchmark Prices are then adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead ("Realized Prices"). The Realized Prices are utilized to calculate the discounted future net revenues in the full cost ceiling calculation.

In the event the unamortized cost of evaluated oil and natural gas properties being amortized 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, Realized Prices and the corresponding non-cash full cost ceiling impairments recorded as of the periods presented:

	For the quarters ended				For the years ended[1]	
	December 31, 2015	September 30, 2015	June 30, 2015	March 31, 2015	December 31, 2014	December 31, 2013
Benchmark Prices						
Oil ($/Bbl)	$46.79	$55.73	$68.17	$79.21	$91.48	$93.52
NGL ($/Bbl)	18.75	21.87	26.73	31.25	—	—
Natural gas ($/MMBtu)	2.47	2.89	3.22	3.73	4.25	3.57
Realized Prices						
Oil ($/Bbl)	45.58	54.28	66.68	77.72	89.57	92.26
NGL ($/Bbl)	12.50	15.25	19.56	23.75	—	—
Natural gas ($/Mcf)	1.89	2.30	2.62	3.09	6.39	5.52
Non-cash full cost ceiling impairment (in thousands)	$975,011	$906,420	$488,046	$—	$—	$—

(1) For periods prior to January 1, 2015, the Company presented reserves for oil and natural gas, which combined NGL with the natural gas stream, and did not separately report NGL. This change impacts the comparability of 2015 with prior periods.

Full cost ceiling impairment expense for the year ended December 31, 2015 in the consolidated statements of operations was $2.4 billion. The amount is included in the "Impairment expense" line item in the consolidated statements of operations and in the financial information provided for the Company's exploration and production segment presented in Note 17.

h. Midstream service assets

Midstream service assets 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. The oil and natural gas pipeline gathering assets, related equipment, oil delivery stations and water storage and treatment facilities are recorded at cost, net of impairment. See Note 2.m for discussion regarding midstream service asset retirement cost. Depreciation of assets is recorded using the straight-line method based on estimated useful lives of 10 to 20 years, as applicable. Expenditures for significant betterments or renewals, which extend the useful lives of existing fixed assets, are capitalized and depreciated. Upon retirement or disposition, the cost and related accumulated depreciation are

removed from the accounts and any gain or loss is recognized in "Loss on disposal of assets, net" in the consolidated statements of operations. Depreciation expense from continuing operations for midstream service assets was $7.5 million, $4.3 million and $1.5 million for the years ended December 31, 2015, 2014 and 2013, respectively.

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

(in thousands)	2015	2014
Midstream service assets	$147,811	$117,052
Less accumulated depreciation	(16,086)	(8,590)
Total, net	$131,725	$108,462

i. Other fixed assets

Other fixed assets are recorded at cost and are subject to depreciation and amortization. Land is recorded at cost and is not subject to depreciation. Depreciation and amortization of other fixed assets is provided using the straight-line method based on estimated useful lives of three to ten years, as applicable. Leasehold improvements are capitalized and amortized over the shorter of the estimated useful lives of the assets or the terms of the related leases. Expenditures for significant betterments or renewals, which extend the useful lives of existing fixed assets, are capitalized and depreciated. Upon retirement or disposition, the cost and related accumulated depreciation and amortization are removed from the accounts and any gain or loss is recognized in "Loss on disposal of assets, net" in the consolidated statements of operations. Depreciation and amortization expense from continuing operations for other fixed assets was $6.5 million, $5.1 million and $4.4 million for the years ended December 31, 2015, 2014 and 2013, respectively.

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

(in thousands)	2015	2014
Computer hardware and software	$12,148	$13,495
Vehicles	9,266	7,802
Leasehold improvements	7,710	6,867
Real estate and buildings	7,618	4,908
Aircraft	4,952	4,952
Other	5,105	4,909
Depreciable total	46,799	42,933
Less accumulated depreciation and amortization	(18,169)	(13,820)
Depreciable total, net	28,630	29,113
Land	14,908	13,232
Total, net	$43,538	$42,345

j. Long-lived assets, materials and supplies and line-fill

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

Materials and supplies used in developing oil and natural gas properties and midstream service assets are carried at the lower of cost or market ("LCM") and are included in "Other current assets" and "Other assets, net" on the consolidated balance sheets. The market price for materials and supplies is determined utilizing the Company's recent prices paid to acquire materials. During the years ended December 31, 2015 and 2014, the Company reduced materials and supplies by $2.8 million and $1.8 million, respectively, in order to reflect the balance at LCM. These adjustments are included in "Impairment expense" in the consolidated statements of operations and as "Impairment expense" for the Company's exploration and production segment presented in Note 17. The Company determined an LCM adjustment was not necessary for materials and supplies during the year ended December 31, 2013.

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

price differentials (Level 2). For the years ended December 31, 2015 and 2014, the Company recorded LCM adjustments of $1.3 million and $2.1 million, respectively, related to its line-fill, which is included in "Impairment expense" in the consolidated statements of operations and as "Impairment expense" for the Company's midstream and marketing segment presented in Note 17.

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For the year ended December 31, 2015, the Company recorded an impairment, based on an internally developed cash flow model, of $1.3 million related to its compressed natural gas station. This amount is included in "Impairment expense" in the consolidated statements of operations and as "Impairment expense" for the Company's midstream and marketing segment presented in Note 17. There were no comparable impairments recorded for the years ended December 31, 2014 or 2013.

k. Debt issuance costs

Debt issuance fees, which are recorded at cost, net of amortization, are amortized over the life of the respective debt agreements utilizing the effective interest and straight-line methods. The Company capitalized $6.8 million of debt issuance costs during the year ended December 31, 2015 mainly as a result of the issuance of the March 2023 Notes (as defined below). The Company capitalized $7.8 million of debt issuance costs during the year ended December 31, 2014 mainly as a result of the issuance of the January 2022 Notes (as defined below). The Company capitalized $3.0 million of debt issuance costs during the year ended December 31, 2013. The Company had total debt issuance costs of $23.9 million and $28.5 million, net of accumulated amortization of $17.0 million and $19.4 million, as of December 31, 2015 and 2014, respectively.

The Company wrote-off approximately $6.6 million of debt issuance costs during the year ended December 31, 2015 as a result of the early redemption of the January 2019 Notes (as defined below), which is included in the consolidated statements of operations in the "Loss on early redemption of debt" line item. During the year ended December 31, 2014, $0.1 million of debt issuance costs were written-off as a result of changes in the borrowing base of the Senior Secured Credit Facility (as defined below) due to the issuance of the January 2022 Notes. During the year ended December 31, 2013, $1.5 million of debt issuance costs were written off as a result of changes in the borrowing base of the Senior Secured Credit Facility due to the Anadarko Basin Sale (as defined below). Debt issuance costs written-off during the years ended December 31, 2014 and 2013 are included in the consolidated statements of operations in the "Write-off of debt issuance costs" line item. See Notes 4.d, 5.b, 5.c, 5.e and 5.f for definition of and information regarding the Anadarko Basin Sale, March 2023 Notes, January 2022 Notes, January 2019 Notes and Senior Secured Credit Facility, respectively.

During the year ended December 31, 2015, the Company early-adopted new guidance that seeks to simplify the presentation of debt issuance costs and has applied its provisions retrospectively. The adoption of this standard resulted in $18.8 million and $21.8 million of unamortized debt issuance costs related to the Company's senior unsecured notes being presented in "Long-term debt, net" rather than the past presentation in "Other assets, net" within its consolidated balance sheets as of December 31, 2015 and December 31, 2014, respectively. Other than this reclassification of the December 31, 2014 amount, the adoption of this standard did not have an impact on the Company's consolidated financial statements. Debt issuance costs related to the Senior Secured Credit Facility remain presented in "Other assets, net" on the Company's consolidated balance sheets. See Notes 5.h and 14 for additional discussion of debt issuance costs.

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

(in thousands)	December 31, 2015
2016	$4,503
2017	4,575
2018	4,349
2019	2,915
2020	3,005
Thereafter	4,585
Total	$23,932

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l. Other current liabilities

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

(in thousands)	2015	2014
Capital contribution payable to equity method investee[1]	$27,583	$—
Accrued interest payable	24,208	37,689
Accrued compensation and benefits	14,342	13,034
Lease operating expense payable	13,205	11,963
Costs of purchased oil	12,189	20,114
Other accrued liabilities	14,695	18,232
Total other current liabilities	$106,222	$101,032

(1) See Notes 15, 16 and 19.b for additional discussion regarding our equity method investee.

m. Asset retirement obligations

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

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

The Company is obligated by contractual and regulatory requirements to remove certain pipeline and gas gathering assets and perform other remediation of the sites where such pipeline and gas 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 gas gathering assets in the periods in which settlement dates are reasonably determinable.

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

(in thousands)	2015	2014
Liability at beginning of year	$32,198	$21,743
Liabilities added due to acquisitions, drilling, midstream service asset construction and other	2,236	6,370
Accretion expense	2,423	1,787
Liabilities settled upon plugging and abandonment	(146)	(450)
Liabilities removed due to sale of property	(2,005)	—
Revision of estimates[1]	11,600	2,748
Liability at end of year	$46,306	$32,198

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

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n. Fair value measurements

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

o. Treasury stock

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

p. Revenue recognition

Oil, NGL and natural gas revenues are recorded using the sales method. Under this method, the Company recognizes revenues based on actual volumes of oil, NGL and natural gas sold to purchasers. For natural gas sales, the Company and other joint interest owners may sell more or less than their entitlement share of the volumes produced. Under the sales method, when a working interest owner has overproduced in excess of its share of remaining estimated reserves, the overproduced party recognizes the excessive imbalance as a liability. If the underproduced working interest owner determines that an overproduced owner's share of remaining net reserves is insufficient to settle the imbalance, the underproduced owner recognizes a receivable, net of any allowance from the overproduced working interest owner. The Company is also subject to natural gas pipeline imbalances, which are recorded as accounts receivable or payable at values consistent with contractual arrangements with the owner of the pipeline. The Company did not have any producer or pipeline imbalance positions as of December 31, 2015 or 2014. During the year ended December 31, 2013, the majority of the Company's natural gas producer imbalance positions were transferred to a buyer in connection with the Anadarko Basin Sale (defined below). Prior to their disposition, the value of net overproduced positions arising during the year ended December 31, 2013, which increased oil and natural gas sales, was $0.03 million.

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

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

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

The following amounts have been recorded for the periods presented:

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Fees received for the operation of jointly-owned oil and natural gas properties	$3,125	$3,265	$3,398

r. Compensation awards

Stock-based compensation expense, net of amounts capitalized, is included in "General and administrative" in the Company's consolidated statements of operations over the awards' vesting periods and is based on the awards' grant date fair value. The Company utilizes the closing stock price on the grant date, less an expected forfeiture rate, to determine the fair value of service vesting restricted stock awards and a Black-Scholes pricing model to determine the fair values of service vesting restricted stock option awards. The Company utilizes a Monte Carlo simulation prepared by an independent third party to determine the fair values of the performance share awards and performance unit awards. On January 1, 2014, the Company began capitalizing a portion of stock-based compensation for employees who are directly involved in the acquisition, exploration and development of its oil and natural gas properties into the full cost pool. Capitalized stock-based compensation is included as an addition to "Oil and natural gas properties" in

the consolidated balance sheets. See Note 6 for further discussion regarding the restricted stock awards, restricted stock option awards, performance share awards and performance unit awards.

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s. Income taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating losses and tax credit carry-forwards. Under this method, deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income (loss) in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is determined 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. See Note 7 for detail of amounts recorded in the consolidated financial statements and discussion regarding the valuation allowance taken in 2015.

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, 2015, 2014 or 2013.

t. Environmental

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, among other things, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed in the period incurred. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. Management believes no materially significant liabilities of this nature existed as of December 31, 2015 or 2014.

u. Supplemental disclosures of cash flow and non-cash investing and financing information

The following table summarizes the supplemental disclosure of cash flow information for the periods presented:

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Cash paid for interest, net of $236, $150 and $255 of capitalized interest, respectively	$112,457	$104,936	$95,622

The following presents the supplemental disclosure of non-cash investing and financing information for the periods presented:

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Change in accrued capital expenditures	$(86,369)	$31,913	$(5,284)
Change in accrued capital contribution to equity method investee	27,583	(2,597)	2,597
Capitalized asset retirement cost	13,836	9,118	6,790
Capitalized stock-based compensation	2,321	4,650	—
Equity issued in connection with acquisition	—	—	3,029

Note 3—Equity offerings

a. March 2015 Equity Offering

On March 5, 2015, the Company completed the sale of 69,000,000 shares of Laredo's common stock at a price to the public of $11.05 per share (the "March 2015 Equity Offering"). The Company received net proceeds of $754.2

million, after underwriting discounts and commissions and offering expenses, from the March 2015 Equity Offering. Entities affiliated with Warburg Pincus LLC ("Warburg Pincus") purchased 29,800,000 shares in the March 2015 Equity Offering, following which

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Warburg Pincus owned 41.0% of Laredo's common stock. There were no comparative offerings of the Company's stock during the year ended December 31, 2014.

b. August 2013 Equity Offering

On August 19, 2013, Laredo, together with certain affiliates of Warburg Pincus and members of the Company's management (together with Warburg Pincus, the "Selling Stockholders") completed the sale of (i) 13,000,000 shares of Laredo's common stock by Laredo and (ii) 3,000,000 shares of Laredo's common stock by the Selling Stockholders, at a price to the public of $23.75 per share ($22.9781 per share, net of underwriting discounts) (the "August 2013 Equity Offering"). On August 27, 2013, certain of the Selling Stockholders sold an additional 1,577,583 shares of Laredo's common stock pursuant to the option to purchase additional shares of Laredo's common stock granted to the associated underwriters. The Company received net proceeds of $298.1 million, after underwriting discounts and commissions and offering expenses, from the August 2013 Equity Offering. The Company did not receive any proceeds from either of the sales of shares of Laredo's common stock by the Selling Stockholders.

Note 4—Acquisitions and divestitures

a. 2015 Divestiture of non-strategic assets

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

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

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

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Oil, NGL and natural gas sales	$5,138	$19,337	$24,187
Expenses[1]	5,791	11,082	11,826

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

b. Summary of 2014 and 2013 acquisitions

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

The Company makes various assumptions in estimating the fair values of assets acquired and liabilities assumed. The most significant assumptions relate to the estimated fair values of evaluated and unevaluated oil and natural gas properties. The fair value of these properties are measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted-average cost of capital rate. The market-based weighted-average cost of capital rate is subjected 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 probable and possible reserves are reduced by additional risk-weighting factors.

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The following table presents the Company's 2014 and 2013 acquisitions. For further discussion of the estimates of fair value of the acquired assets and liabilities of these acquisitions, see Note C in the Company's 2013 Annual Report on Form 10-K and Note 3 in the Company's 2014 Annual Report on Form 10-K.

(in thousands)	Accounting treatment	Cash consideration	Common stock issued[2]
August 28, 2014 acquisition of leasehold interests	Acquisition of assets	$192,484	$—
June 23, 2014 acquisition of evaluated and unevaluated oil and natural gas properties	Acquisition method	1,800	—
June 11, 2014 acquisition of evaluated and unevaluated oil and natural gas properties	Acquisition method	4,693	—
February 25, 2014 acquisition of mineral interests	Acquisition of assets	7,305	—
September 6, 2013 acquisition of evaluated and unevaluated oil and natural gas properties[1]	Acquisition method	33,710	3,029

(1) The fair value of the acquired assets and liabilities were allocated in the following manner: $9.7 million to evaluated properties, $27.1 million to unevaluated properties, $0.2 million to other assets and $0.2 million to other liabilities.

(2) In accordance with the acquisition agreement, on September 6, 2013, Laredo issued 123,803 restricted shares of its common stock to the sellers (the "Acquisition Shares"). In accordance with federal securities laws, the Acquisition Shares were restricted from trading on public markets for six months from the acquisition date. For accounting purposes, the fair value of the Acquisition Shares was determined in accordance with GAAP by adjusting the closing price of $26.21 per share of Laredo's common stock on September 6, 2013 for a discount for lack of marketability. The discount of 6.64% was determined utilizing an Asian put option model, which includes an assumption of the estimated volatility of Laredo's common stock. This assumption represents a Level 3 input under the fair value hierarchy, as described in Note 9.

c. 2013 divestiture of Dalhart Basin acreage

On December 20, 2013, the Company completed the sale of 37,000 net acres and one producing property in the Dalhart Basin for $20.4 million, subject to customary closing adjustments.

d. 2013 divestiture of Anadarko assets

On August 1, 2013, the Company completed the sale of its oil and natural gas properties, associated pipeline assets and various other associated property and equipment in the Anadarko Granite Wash, Central Texas Panhandle and the Eastern Anadarko Basin (the "Anadarko Basin Sale") to certain affiliates of EnerVest, Ltd. (collectively, "EnerVest") and certain other third parties in connection with the exercise of such third parties' preferential rights associated with the oil and gas assets. The purchase price consisted of $400.0 million from EnerVest and $38.0 million from the third parties. Approximately $388.0 million of the purchase price, excluding closing adjustments, was allocated to oil and natural gas properties pursuant to to the rules governing full cost accounting. After transaction costs and adjustments at closing reflecting an economic effective date of April 1, 2013, the net proceeds were $428.3 million, net of working capital adjustments.

Effective at closing, the operations and cash flows of these properties were eliminated from the ongoing operations of the Company and the Company does not have continuing involvement in the operations of these properties. The results of operations of the oil and natural gas properties that are a component of the Anadarko Basin Sale are not presented as discontinued operations pursuant to the rules governing full cost accounting for oil and natural gas properties.

The following table presents revenues and expenses of the oil and natural gas properties that are a component of the Anadarko Basin Sale included in the accompanying consolidated statements of operations for the period presented:

(in thousands)	For the year ended December 31, 2013
Revenues	$59,631
Expenses[1]	46,357

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

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The results of operations of the associated pipeline assets and various other associated property and equipment ("Pipeline Assets") are presented as results of discontinued operations, net of tax in these consolidated financial statements. Accordingly, the Company has reclassified the financial results and the related notes for all prior periods presented to reflect these operations as discontinued. As a result of the sale of the Pipeline Assets, a gain of $3.2 million was recognized in the consolidated statements of operations in the line item "Loss on disposal of assets, net" during the year ended December 31, 2013.

The following represents operating results from discontinued operations for the period presented:

(in thousands)	For the year ended December 31, 2013
Revenues:	
Midstream service revenue	$4,020
Total revenues from discontinued operations	4,020
Cost and expenses:	
Midstream service expense, net	1,189
Depreciation and amortization	627
Total costs and expenses from discontinued operations	1,816
Non-operating expense, net	—
Income (loss) from discontinued operations before income tax	2,204
Income tax (expense) benefit	(781)
Income (loss) from discontinued operations	$1,423

Note 5—Debt

a. Interest expense

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

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Cash payments for interest	$112,693	$105,086	$95,877
Amortization of debt issuance costs and other adjustments	4,243	4,433	4,926
Change in accrued interest	(13,481)	11,804	(221)
Interest costs incurred	103,455	121,323	100,582
Less capitalized interest	(236)	(150)	(255)
Total interest expense	$103,219	$121,173	$100,327

b. March 2023 Notes

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

The March 2023 Notes were offered and sold pursuant to a prospectus supplement dated March 4, 2015 and the base prospectus dated March 22, 2013, relating to the Company's effective shelf registration statement on Form S-3 (File No. 333-187479). The Company received net proceeds of $343.6 million from the offering, after deducting the underwriters'

discount and the estimated outstanding offering expenses. In April 2015, the Company used the proceeds of the offering to fund a portion of the Company's redemption of the January 2019 Notes (as defined below). See Note 5.e for additional discussion of this early redemption.

The Company may redeem, at its option, all or part of the March 2023 Notes at any time on or after March 15, 2018, at the applicable redemption price plus accrued and unpaid interest to, but not including, the date of redemption. Further, before March 15, 2018, the Company may on one or more occasions redeem up to 35% of the aggregate principal amount of the March 2023 Notes in an amount not exceeding the net proceeds from one or more private or public equity offerings at a redemption price of 106.25% of the principal amount of the March 2023 Notes, plus accrued and unpaid interest to the date of redemption, if at least 65% of the aggregate principal amount of the March 2023 Notes remains outstanding immediately after such redemption and the redemption occurs within 180 days of the closing date of each such equity offering. If a change of control occurs prior to March 15, 2016, the Company may redeem all, but not less than all, of the March 2023 Notes at a redemption price equal to 110% of the principal amount of the March 2023 Notes plus any accrued and unpaid interest to, but not including, the date of redemption.

c. January 2022 Notes

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

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

Laredo will have the option to redeem all or part of the January 2022 Notes at any time on and after January 15, 2017, at the applicable redemption price plus accrued and unpaid interest to the date of redemption. In addition, the Company may redeem, at its option, all or part of the January 2022 Notes at any time prior to January 15, 2017 at a redemption price equal to 100% of the principal amount of the January 2022 Notes redeemed plus the applicable premium and accrued and unpaid interest and additional interest, if any, to the date of redemption. Further, before January 15, 2017, the Company may on one or more occasions redeem up to 35% of the aggregate principal amount of the January 2022 Notes in an amount not exceeding the net proceeds from one or more private or public equity offerings at a redemption price of 105.625% of the principal amount of the January 2022 Notes, plus accrued and unpaid interest to the date of redemption, if at least 65% of the aggregate principal amount of the January 2022 Notes remains outstanding immediately after such redemption and the redemption occurs within 180 days of the closing date of each such equity offering.

d. May 2022 Notes

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

The May 2022 Notes were issued under, and are governed by, an indenture and supplement thereto, each dated April 27, 2012 (collectively, and as further supplemented, the "2012 Indenture"), among Laredo Inc, Wells Fargo Bank,

National Association, as trustee, and the guarantors named therein. The 2012 Indenture contains customary terms, events of default and covenants relating to, among other things, the incurrence of debt, the payment of dividends or similar restricted payments, entering into transactions with affiliates and limitations on asset sales. Indebtedness under the May 2022 Notes may be accelerated in certain circumstances upon an event of default as set forth in the 2012 Indenture.

Laredo will have the option to redeem the May 2022 Notes, in whole or in part, at any time on or after May 1, 2017, at the redemption prices (expressed as percentages of principal amount) of 103.688% for the 12-month period beginning on May 1, 2017, 102.458% for the 12-month period beginning on May 1, 2018, 101.229% for the 12-month period beginning on May 1, 2019 and 100.000% beginning on May 1, 2020 and at any time thereafter, together with any accrued and unpaid interest, if any,

to the date of redemption. In addition, before May 1, 2017, Laredo may redeem all or any part of the May 2022 Notes at a redemption price equal to the sum of the principal amount thereof, plus a make-whole premium at the redemption date, plus accrued and unpaid interest, if any, to the redemption date. Laredo may also be required to make an offer to purchase the May 2022 Notes upon a change of control triggering event.

e. January 2019 Notes

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

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

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

f. Senior Secured Credit Facility

As of December 31, 2015, the Fourth Amended and Restated Credit Agreement (as amended, the "Senior Secured Credit Facility"), which matures November 4, 2018, had a maximum credit amount of $2.0 billion, a borrowing base of $1.15 billion and an aggregate elected commitment of $1.0 billion with $135.0 million outstanding and was subject to an interest rate of 1.90%. The borrowing base is subject to a semi-annual redetermination occurring each May 1 and November 1 based on the financial institutions' evaluation of the Company's oil and natural gas reserves. As defined in the Senior Secured Credit Facility, (i) the Adjusted Base Rate advances under the facility bear interest payable quarterly at an Adjusted Base Rate plus applicable margin, which ranges from 0.5% to 1.5% and (ii) the Eurodollar advances under the facility bear interest, at the Company's election, at the end of one-month, two-month, three-month, six-month or, to the extent available, 12-month interest periods (and in the case of six-month and 12-month interest periods, every three months prior to the end of such interest period) at an Adjusted London Interbank Offered Rate plus an applicable margin, which ranges from 1.5% to 2.5%, based on the ratio of outstanding revolving credit to the total commitment under the Senior Secured Credit Facility. Laredo is also required to pay an annual commitment fee on the unused portion of the financial institutions' commitment of 0.375% to 0.5%, based on the ratio of outstanding revolving credit to the total commitment under the Senior Secured Credit Facility.

The Senior Secured Credit Facility is secured by a first-priority lien on Laredo and the Guarantor's assets and stock, including oil, NGL and natural gas properties, constituting at least 80% of the present value of the Company's evaluated reserves. Further, the Company is subject to various financial and non-financial ratios on a consolidated basis, including a current ratio at the end of each calendar quarter, of not less than 1.00 to 1.00. As defined by the Senior Secured Credit Facility, the current ratio represents the ratio of current assets to current liabilities, inclusive of available capacity and exclusive of current balances associated with derivative positions. Additionally, at the end of each calendar quarter, the Company must maintain a ratio of (I) its consolidated net income (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 all non-cash income ("EBITDAX"), as defined in the Senior Secured Credit Facility, to (II) the sum of 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 Senior Secured Credit Facility contains both financial and non-financial covenants and the Company was in compliance with these covenants for all periods presented.

Additionally, the Senior Secured Credit Facility provides for the issuance of letters of credit, limited to the lesser of total capacity or $20.0 million. No letters of credit were outstanding as of December 31, 2015 or 2014.

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g. Fair value of debt

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

	December 31, 2015		December 31, 2014	
(in thousands)	Long-term debt	Fair value	Long-term debt	Fair value
January 2019 Notes[1]	$—	$—	$551,295	$550,000
January 2022 Notes	450,000	388,301	450,000	396,014
May 2022 Notes	500,000	460,000	500,000	467,529
March 2023 Notes	350,000	301,000	—	—
Senior Secured Credit Facility	135,000	134,993	300,000	300,279
Total value of debt	$1,435,000	$1,284,294	$1,801,295	$1,713,822

(1) The long-term debt amount includes the October Notes' unamortized bond premium of $1.3 million as of December 31, 2014.

The fair values of the debt outstanding on the January 2019 Notes, the January 2022 Notes, the May 2022 Notes and the March 2023 Notes were determined using the December 31, 2015 and 2014 quoted market price (Level 1) for each respective instrument. The fair values of the outstanding debt on the Senior Secured Credit Facility as of December 31, 2015 and 2014 were estimated utilizing pricing models for similar instruments (Level 2). See Note 9 for information about fair value hierarchy levels.

h. Debt issuance costs

The following tables summarize the net presentation of the Company's long-term debt and debt issuance cost on the consolidated balance sheets as of the periods presented:

	December 31, 2015			December 31, 2014		
(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 2019 Notes[1]	$—	$—	$—	$551,295	$(7,031)	$544,264
January 2022 Notes	450,000	(5,939)	444,061	450,000	(6,916)	443,084
May 2022 Notes	500,000	(7,066)	492,934	500,000	(7,901)	492,099
March 2023 Notes	350,000	(5,769)	344,231	—	—	—
Senior Secured Credit Facility[2]	135,000	—	135,000	300,000	—	300,000
Total	$1,435,000	$(18,774)	$1,416,226	$1,801,295	$(21,848)	$1,779,447

(1) The long-term debt amount includes the October Notes' unamortized bond premium of $1.3 million as of December 31, 2014.

(2) Debt issuance costs related to our Senior Secured Credit Facility are recorded in "Other assets, net" on the consolidated balance sheets.

Note 6—Employee compensation

The Company has a Long-Term Incentive Plan (the "LTIP"), which provides for the granting of incentive awards in the form of restricted stock awards, restricted stock option awards, performance share awards, performance unit awards and other awards. The LTIP provides for the issuance of 10.0 million shares.

The Company recognizes the fair value of stock-based compensation awards expected to vest over the requisite service period as a charge against earnings, net of amounts capitalized. The Company's stock-based compensation awards are accounted for as equity instruments and its performance unit awards are accounted for as liability awards. Stock-based compensation is included in "General and administrative" in the consolidated statements of operations.

On January 1, 2014, the Company began capitalizing a portion of stock-based compensation for employees who are directly involved in the acquisition, exploration and development of oil and natural gas properties into the full cost pool. Capitalized stock-based compensation is included as an addition to "Oil and natural gas properties" in the consolidated balance sheets.

Laredo Petroleum, Inc.
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a. Restricted stock awards

All restricted stock awards are treated as issued and outstanding in the accompanying consolidated financial statements. Per the award agreement terms, if an employee terminates employment prior to the restriction lapse date, for reasons other than death and disability, the awarded shares are forfeited and canceled and are no longer considered issued and outstanding. If the employee's termination of employment is by reason of death or disability, all of the holder's restricted stock will automatically vest. Restricted stock awards granted to officers and employees vest in a variety of vesting schedules including (i) 20% at the grant date and then 20% annually thereafter, (ii) 33%, 33% and 34% per year beginning on the first anniversary date of the grant, (iii) 50% in year two and 50% in year three, (iv) fully on the first anniversary of the grant date and (v) fully on the third anniversary of the grant date. Restricted stock awards granted to non-employee directors vest fully on the first anniversary of the grant date.

The following table reflects the outstanding restricted stock awards for the years ended December 31, 2015, 2014 and 2013:

(in thousands, except for weighted-average grant date fair values)	Restricted stock awards	Weighted-average grant date fair value (per award)
Outstanding as of December 31, 2012	1,195	$ 15.06
Granted	1,469	$ 18.17
Forfeited	(229)	$ 18.47
Vested[1]	(636)	$ 18.69
Outstanding as of December 31, 2013	1,799	$ 19.17
Granted	1,234	$ 25.68
Forfeited	(148)	$ 22.56
Vested[1]	(680)	$ 19.13
Outstanding as of December 31, 2014	2,205	$ 22.63
Granted	1,902	$ 11.98
Forfeited	(553)	$ 20.48
Vested[1]	(1,015)	$ 22.32
Outstanding as of December 31, 2015	2,539	$ 15.26

(1) The vesting of certain restricted stock awards could result in federal and state income tax expense or benefit related to the difference between the market price of the common stock at the date of vesting and the date of grant. See Note 7 for additional discussion regarding the tax impact of vested restricted stock awards.

The Company utilizes the closing stock price on the grant date to determine the fair value of service vesting restricted stock awards. As of December 31, 2015, unrecognized stock-based compensation related to the restricted stock awards expected to vest was $21.6 million. Such cost is expected to be recognized over a weighted-average period of 1.74 years.

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b. Restricted stock option awards

Restricted stock option awards granted under the LTIP vest and are exercisable in four equal installments on each of the four anniversaries of the grant date. The following table reflects the stock option award activity for the years ended December 31, 2015, 2014 and 2013:

(in thousands, except for weighted-average price and contractual term)	Restricted stock option awards	Weighted-average price (per option)	Weighted-average remaining contractual term (years)
Outstanding as of December 31, 2012	459	$ 24.11	10
Granted	1,019	$ 17.34	
Exercised[1]	(104)	$ 20.79	
Expired or canceled	(12)	$ 24.11	
Forfeited	(133)	$ 19.88	
Outstanding as of December 31, 2013	1,229	$ 19.32	8.82
Granted	336	$ 25.60	
Exercised[1]	(95)	$ 19.93	
Expired or canceled	(30)	$ 21.15	
Forfeited	(73)	$ 19.68	
Outstanding as of December 31, 2014	1,367	$ 20.76	8.17
Granted	632	$ 11.93	
Exercised	—	$ —	
Expired or canceled	(82)	$ 19.92	
Forfeited	(139)	$ 18.17	
Outstanding as of December 31, 2015	1,778	$ 17.86	7.91
Vested and exercisable at end of period[2]	545	$ 20.77	6.94
Expected to vest at end of period[3]	1,219	$ 16.51	8.34

(1) The exercise of stock option awards could result in federal and state income tax expense or benefits related to the difference between the fair value of the stock option award at the date of grant and the intrinsic value of the stock option award when exercised. See Note 7 for additional discussion regarding the tax impact of exercised stock option awards.

(2) The vested and exercisable options as of December 31, 2015 had no aggregate intrinsic value.

(3) The restricted stock options expected to vest as of December 31, 2015 had no aggregate intrinsic value.

The Company utilizes the Black-Scholes option pricing model to determine the fair value of restricted stock option awards and is recognizing the associated expense on a straight-line basis over the four-year requisite service period of the awards. Determining the fair value of equity-based awards requires judgment, including estimating the expected term that stock option awards will be outstanding prior to exercise and the associated volatility. As of December 31, 2015, unrecognized stock-based compensation related to restricted stock option awards expected to vest was $7.0 million. Such cost is expected to be recognized over a weighted-average period of 2.35 years.

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Notes to the consolidated financial statements

The assumptions used to estimate the fair value of restricted stock options granted are as follows:

	February 27, 2015	February 27, 2014	February 15, 2013	February 3, 2012
Risk-free interest rate[1]	1.70 %	1.88 %	1.19 %	1.14 %
Expected option life[2]	6.25 years	6.25 years	6.25 years	6.25 years
Expected volatility[3]	52.59 %	53.21 %	58.89 %	59.98 %
Fair value per stock option	$6.15	$13.41	$9.67	$13.52

(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 option.

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

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

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

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

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

c. Performance share awards

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

The 2015 Performance Share Awards have a performance period of January 1, 2015 to December 31, 2017 and any shares earned under such awards are expected to be issued in the first quarter of 2018 if the performance criteria are met. During the year ended December 31, 2015, the Company granted 602,501 2015 Performance Share Awards and

all remain outstanding as of December 31, 2015. The 271,667 outstanding 2014 Performance Share Awards have a performance period of January 1, 2014 to December 31, 2016 and any shares earned under such awards are expected to be issued in the first quarter of 2017 if the performance criteria are met. No 2014 Performance Share Awards were forfeited during the years ended December 31, 2015 or 2014.

As of December 31, 2015, unrecognized stock-based compensation related to the 2015 Performance Share Awards and the 2014 Performance Share Awards was $9.9 million. Such cost is expected to be recognized over a weighted-average period of 1.86 years.

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The assumptions used to estimate the fair value of the Performance Share Awards granted are as follows:

	February 27, 2015	February 27, 2014
Risk-free rate[1]	0.95 %	0.63 %
Dividend yield	— %	— %
Expected volatility[2]	53.78 %	38.21 %
Laredo stock closing price as of the grant date	$11.93	$25.60
Fair value per performance share	$16.23	$28.56

(1) The risk-free rate was derived using a zero-coupon yield derived from the Treasury Constant Maturities yield curve on the grant date.

(2) The Company utilized a peer historical look-back, weighted with the Company's own volatility, to develop the expected volatility.

d. Stock-based compensation award expense

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

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Restricted stock award compensation	$17,534	$21,982	$17,084
Restricted stock option award compensation	4,074	3,639	4,349
Restricted performance share award compensation	5,222	2,108	—
Total stock-based compensation, gross	26,830	27,729	21,433
Less amounts capitalized in oil and natural gas properties	(2,321)	(4,650)	—
Total stock-based compensation, net of amounts capitalized	$24,509	$23,079	$21,433

During the year ended December 31, 2013, two officers' and 20 employees' restricted stock awards and restricted option awards were modified to vest upon the officers' or the employees' retirement or in connection with the employees' termination of employment as a result of the Anadarko Basin Sale. The incremental compensation cost resulting from these modifications recognized during the year ended December 31, 2013 was $4.7 million.

e. Performance unit awards

The performance unit awards issued to management on February 15, 2013 (the "2013 Performance Unit Awards") and on February 3, 2012 (the "2012 Performance Unit Awards") were subject to a combination of market and service vesting criteria. These awards were accounted for as liability awards as they were settled in cash at the end of the requisite service period based on the achievement of certain performance criteria. A Monte Carlo simulation prepared by an independent third party was utilized to determine the fair values of these awards at the grant date and to re-measure the fair values at the end of each reporting period until settlement in accordance with GAAP. The volatility criteria utilized in the Monte Carlo simulation was based on the volatility of the Company's stock price and the stock price volatilities of a group of peer companies defined in each respective award agreement. The liability and related compensation expense of these awards for each period was recognized by dividing the fair value of the total liability by the requisite service period and recording the pro rata share for the period for which service had already been provided.

The 2013 Performance Unit Awards had a performance period of January 1, 2013 to December 31, 2015 and, as their performance criteria were satisfied, they were paid at $143.75 per unit during the first quarter of 2016. The 2012 Performance Unit Awards had a performance period of January 1, 2012 to December 31, 2014 and, as their performance criteria were satisfied, they were paid at $100 per unit during the first quarter of 2015.

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The following table reflects the outstanding performance unit awards for the periods presented:

(in thousands)	2013 Performance Unit Awards[2]	2012 Performance Unit Awards [3]
Outstanding at December 31, 2012	—	47
Granted	58	—
Forfeited	(4)	(9)
Vested[1]	(10)	(11)
Outstanding at December 31, 2013	44	27
Vested	—	(27)
Outstanding at December 31, 2014	44	—
Vested	(44)	—
Outstanding at December 31, 2015	—	—

(1) During the year ended December 31, 2013, certain officers' performance unit awards were modified to vest upon the officers' retirement in 2013. The cash payments for these performance unit awards were paid at $100.00 per unit.

(2) The 2013 Performance Unit Awards' performance period ended December 31, 2015. Their market and service criteria were met and accordingly they were paid at $143.75 per unit in the first quarter of 2016.

(3) The 2012 Performance Unit Awards' performance period ended December 31, 2014. Their market and service criteria were met and accordingly they were paid at $100.00 per unit in the first quarter of 2015.

The liability related to the 2013 Performance Unit Awards as of December 31, 2015 was $6.4 million and represents the cash payment made in the first quarter of 2016. The fair value of the 2013 Performance Unit Awards as of December 31, 2014 was $3.5 million. The liability related to the 2012 Performance Unit Awards as of December 31, 2014 was $2.7 million and represents the cash payment made in the first quarter of 2015. The fair values of the 2013 Performance Unit Awards and 2012 Performance Unit Awards as of December 31, 2013 were $5.7 million and $3.8 million, respectively.

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

	For the years ended December 31,		
(in thousands)	2015	2014	2013
2013 Performance Unit Award compensation expense	$4,081	$409	$2,863
2012 Performance Unit Award compensation expense	—	192	1,870
Total performance unit award compensation expense	$4,081	$601	$4,733

Compensation expense for the 2012 Performance Unit Awards and the 2013 Performance Unit Awards is recognized in "General and administrative" in the Company's consolidated statements of operations, and the corresponding liabilities are included in "Other current liabilities" and "Other noncurrent liabilities" on the consolidated balance sheets.

f. Defined contribution plan

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

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

	For the years ended December 31,		
(in thousands)	2015	2014	2013

Contributions	$1,847	$2,202	$1,886

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Note 7—Income taxes

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

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

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Current taxes:			
Federal	$—	$—	$—
State	—	—	—
Deferred taxes:			
Federal	152,590	(147,445)	(64,034)
State	24,355	(16,841)	(10,473)
Income tax benefit (expense)	$176,945	$(164,286)	$(74,507)

The following presents the comprehensive benefit (expense) for income taxes for the periods presented:

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Comprehensive benefit (expense) for income taxes allocable to:			
Continuing operations	$176,945	$(164,286)	$(74,507)
Discontinued operations	—	—	(781)
Comprehensive benefit (expense) for income taxes	$176,945	$(164,286)	$(75,288)

Income tax benefit (expense) attributable to income (loss) from continuing operations before income taxes differed from amounts computed by applying the applicable federal income tax rate of 35% for the years ended December 31, 2015 and 2014 and 34% for the year ended December 31, 2013 to pre-tax earnings as a result of the following:

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Income tax benefit (expense) computed by applying the statutory rate	$835,408	$(150,450)	$(64,969)
State income tax, net of federal tax benefit and increase in valuation allowance	13,975	(11,099)	(7,532)
Non-deductible stock-based compensation	(256)	(509)	(1,070)
Stock-based compensation tax deficiency	(3,274)	(266)	(559)
Increase in deferred tax valuation allowance	(668,702)	(1,139)	(63)
Other items	(206)	(823)	(314)
Income tax benefit (expense)	$176,945	$(164,286)	$(74,507)

The effective tax rate for the Company's continuing operations was 7%, 38% and 39% for the years ended December 31, 2015, 2014 and 2013, respectively. The Company's effective tax rate is affected by changes in valuation allowances, recurring permanent differences and by discrete items that may occur in any given year, but are not consistent from year to year.

A valuation allowance is established to reduce deferred tax assets if it is determined that it is more likely than not that the related tax benefit will not be realized. On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realizability of the deferred tax assets and adjusts the amount of such allowances, if necessary. During 2015, in evaluating whether it was more likely than not that the Company’s net

deferred tax assets were realized through future net income, management considered all available positive and negative evidence, including (i) its earnings history, (ii) its ability to recover net operating loss carry-forwards, (iii) the existence of significant proved oil and natural gas reserves, (iv) its ability to use tax planning strategies, (v) its current price protection utilizing oil and natural gas

hedges, (vi) its future revenue and operating cost projections and (vii) the current market prices for oil and natural gas. Based on all the evidence available, during the year ended December 31, 2015, management determined it was more likely than not that the net deferred tax assets were not realizable, therefore a valuation allowance of $676.0 million was recorded.

The impact of significant discrete items is separately recognized in the year in which the discrete items occur. The vesting of certain restricted stock awards could result in federal and state income tax expense or benefits related to the difference between the market price of the common stock at the date of vesting and the grant date. The exercise of stock option awards could result in federal and state income tax expense or benefits related to the difference between the fair value of the stock option at the grant date and the intrinsic value of the stock option when exercised. The tax impact resulting from vestings of restricted stock awards and exercise of option awards are discrete items. During the years ended December 31, 2015, 2014 and 2013, certain shares related to restricted stock awards vested at times when the Company's stock price was lower than the fair value of those shares at the time of grant. As a result, the income tax deduction related to such shares is less than the expense previously recognized for book purposes. During the years ended December 31, 2014 and 2013, certain restricted stock options were exercised. There were no comparable exercise of stock options during the year ended December 31, 2015. The income tax deduction related to the intrinsic value of the options was less than the expense previously recognized for book purposes. In accordance with GAAP, such shortfalls reduce additional paid-in capital to the extent windfall tax benefits have been previously recognized. However, the Company has not previously recognized any windfall tax benefits. Therefore, such shortfalls are included in income tax benefit (expense) attributable to continuing operations.

The following table presents the tax impact of these shortfalls for the periods presented:

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Vesting of restricted stock	$3,334	$112	$425
Exercise of restricted stock options	—	158	150
Tax expense due to shortfalls	$3,334	$270	$575

Significant components of the Company's net deferred tax liability as of December 31 are as follows:

(in thousands)	2015	2014
Oil and natural gas properties, midstream service assets and other fixed assets	$306,997	$(424,712)
Net operating loss carry-forward	479,022	353,724
Derivatives	(98,675)	(121,365)
Stock-based compensation	11,597	10,718
Equity method investee	(31,711)	(2,331)
Accrued bonus	4,763	3,256
Capitalized interest	2,525	3,049
Materials and supplies impairment	1,647	642
Other	1,173	1,373
Net deferred tax asset (liability) before valuation allowance	677,338	(175,646)
Valuation allowance	(677,338)	(1,299)
Net deferred tax asset (liability)	$—	$(176,945)

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Deferred tax assets and liabilities were classified in the consolidated balance sheets as of December 31 are as follows:

(in thousands)	2015	2014[1]	Offset[1]	2014 new presentation[1]
Deferred tax asset	$—	$—	$—	$ —
Deferred tax liability:				
Current	—	(71,191)	71,191	—
Noncurrent	—	(105,754)	(71,191)	(176,945)
Deferred tax liability	$—	$(176,945)	$—	$ (176,945)
Net deferred tax liability	$—	$(176,945)	$—	$ (176,945)

(1) See Note 14 for discussion regarding the new guidance early adopted by the Company that resulted in a balance sheet reclassification of the deferred tax liability from current to noncurrent for the year ended December 31, 2014.

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

(in thousands)	December 31, 2015
2026	$2,741
2027	38,651
2028	228,661
2029	101,932
2030	80,963
Thereafter	915,642
Total	$1,368,590

The Company had federal net operating loss carry-forwards totaling $1.4 billion and state of Oklahoma net operating loss carry-forwards totaling $40.9 million as of December 31, 2015. These carry-forwards begin expiring in 2026. As of December 31, 2015, the Company believes a portion of the net operating loss carry-forwards are not fully realizable. The Company considered all available evidence, both positive and negative, in determining whether, based on the weight of that evidence, a valuation allowance was needed. Such consideration included projected future cash flows from its oil and natural gas reserves (including the timing of those cash flows), the reversal of deferred tax liabilities recorded as of December 31, 2015, the Company's ability to capitalize intangible drilling costs, rather than expensing these costs in order to prevent an operating loss carry-forward from expiring unused, and future projections of Oklahoma sourced income.

The Company's federal and state operating loss carry-forwards include windfall tax deductions from vestings of certain restricted stock awards and stock option exercises that were not recorded in the Company's income tax provision. The amount of windfall tax benefit recognized in additional paid-in capital is limited to the amount of benefit realized currently in income taxes payable. As of December 31, 2015, the Company had suspended additional paid-in capital credits of $4.5 million related to windfall tax deductions. Upon realization of the net operating loss carry-forwards from such windfall tax deductions, the Company would record a benefit of up to $4.5 million in additional paid-in capital.

The Company maintains a valuation allowance to reduce certain deferred tax assets to amounts that are more likely than not to be realized. As of December 31, 2015, a valuation allowance of $677.3 million has been recorded against the deferred tax asset.

Prior to the Internal Consolidation, the Company and its subsidiaries filed a federal corporate income tax return on a consolidated basis. Following the Internal Consolidation, the surviving entities file a single return. The Company's income tax returns for the years 2012 through 2015 remain open and subject to examination by federal tax authorities and/or the tax authorities in Oklahoma and Texas, which are the jurisdictions where the Company has or had operations. Additionally, the statute of limitations for examination of federal net operating loss carry-forwards

typically does not begin to run until the year the attribute is utilized in a tax return.

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Note 8—Derivatives

a. Commodity derivatives

The Company engages in derivative transactions such as puts, swaps, collars and basis swaps to hedge price risks due to unfavorable changes in oil and natural gas prices related to its production. As of December 31, 2015, the Company had 18 open derivative contracts with financial institutions that extend from January 2016 to December 2017. None of these contracts were designated as hedges for accounting purposes. The contracts are recorded at fair value on the consolidated balance sheets and gains and losses are recognized in current period earnings. Gains and losses on derivatives are reported on the consolidated statements of operations in the "Gain (loss) on derivatives" line items.

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

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

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

Each basis swap transaction has an established fixed basis differential corresponding to two index prices. Depending on the difference of the two 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.

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

During the year ended December 31, 2013, the following commodity derivative contracts were transferred to a buyer in connection with the Anadarko Basin Sale:

	Aggregate volumes	Swap price	Contract period
Natural gas (volumes in MMBtu):			
Swap	2,386,800	$4.31	August 2013 - December 2013
Swap	3,978,500	$4.36	January 2014 - December 2014

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The following commodity derivative contracts were unwound in connection with the Anadarko Basin Sale during the year ended December 31, 2013:

	Aggregate volumes	Floor price	Ceiling price	Contract period
Natural gas (volumes in MMBtu):				
Price collar	2,200,000	$4.00	$7.05	September 2013 - December 2013
Put	2,200,000	$4.00	$—	September 2013 - December 2013
Price collar	3,480,000	$4.00	$7.00	January 2014 - December 2014
Price collar	1,800,000	$4.00	$7.05	January 2014 - December 2014
Price collar	1,680,000	$4.00	$7.05	January 2014 - December 2014
Price collar	1,560,000	$3.00	$5.50	January 2014 - December 2014
Price collar	2,520,000	$3.00	$6.00	January 2015 - December 2015
Price collar	2,400,000	$3.00	$6.00	January 2015 - December 2015
Price collar	2,400,000	$3.00	$6.00	January 2015 - December 2015

The following represents cash settlements received (paid) for matured derivatives and for early terminations and modifications of derivatives for the periods presented:

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Cash settlements received for matured commodity derivatives	$255,281	$28,241	$4,046
Cash settlements paid for matured interest rate swaps	—	—	(301)
Early terminations and modification of commodity derivatives received[(1)]	—	76,660	6,008
Cash settlements received for derivatives, net	$255,281	$104,901	$9,753

(1) During the year ended December 31, 2013, the Company received $6.0 million, net of $2.2 million in deferred premiums in settlements from early terminations and modification of commodity derivative contracts.

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The following table summarizes open positions as of December 31, 2015, and represents, as of such date, derivatives in place through December 2017 on annual production volumes:

	Year 2016	Year 2017
Oil positions:[1]		
Puts:		
Hedged volume (Bbl)	1,296,000	—
Weighted-average price ($/Bbl)	$45.00	$—
Swaps:		
Hedged volume (Bbl)	1,573,800	—
Weighted-average price ($/Bbl)	$84.82	$—
Collars:		
Hedged volume (Bbl)	3,654,000	2,628,000
Weighted-average floor price ($/Bbl)	$73.99	$77.22
Weighted-average ceiling price ($/Bbl)	$89.63	$97.22
Totals:		
Total volume hedged with floor price (Bbl)	6,523,800	2,628,000
Weighted-average floor price ($/Bbl)	$70.84	$77.22
Total volume hedged with ceiling price (Bbl)	5,227,800	2,628,000
Weighted-average ceiling price ($/Bbl)	$88.18	$97.22
Natural gas positions:[2]		
Collars:		
Hedged volume (MMBtu)	18,666,000	5,475,000
Weighted-average floor price ($/MMBtu)	$3.00	$3.00
Weighted-average ceiling price ($/MMBtu)	$5.60	$4.00

(1) Oil derivatives are settled based on the average of the daily settlement prices for the First Nearby Month of the West Texas Intermediate NYMEX Light Sweet Crude Oil Futures Contract for each NYMEX Trading Day during each month ("WTI NYMEX").

(2) Natural gas derivatives are settled based on the Inside FERC index price for West Texas Waha for the calculation period.

b. Interest rate derivatives

The Company is exposed to market risk for changes in interest rates related to any drawn amount on its Senior Secured Credit Facility. In prior periods, interest rate derivative agreements were used to manage a portion of the exposure related to changing interest rates by converting floating-rate debt to fixed-rate debt. If the London Interbank Offered Rate ("LIBOR") was lower than the fixed rate in the contract, the Company was required to pay the counterparties the difference, and conversely, the counterparties were required to pay the Company if LIBOR was higher than the fixed rate in the contract. The Company did not designate the interest rate derivatives as cash flow hedges; therefore, the changes in fair value of these instruments were recorded in current earnings. In prior years, the Company had one interest rate swap and one interest rate cap outstanding for a notional amount of $100.0 million with fixed pay rates of 1.11% and 3.00%, respectively, until their expiration in September 2013. No interest rate derivatives were in place as of December 31, 2015 or 2014.

c. Balance sheet presentation

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

By using derivatives to hedge exposures to changes in commodity prices and interest rates, the Company exposes itself to credit risk and market risk. For the Company, market risk is the exposure to changes in the market price of oil and natural gas, which are subject to fluctuations from a variety of factors, including changes in supply and demand. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, thereby creating credit risk. The Company's counterparties are participants in the

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Senior Secured Credit Facility, which is secured by the Company's oil and natural gas reserves; therefore, the Company is not required to post any collateral. The Company does not require collateral from its derivative counterparties. The Company minimizes the credit risk in derivatives by: (i) limiting its exposure to any single counterparty, (ii) entering into derivatives only with counterparties that meet the Company's minimum credit quality standard or have a guarantee from an affiliate that meets the Company's minimum credit quality standard and (iii) monitoring the creditworthiness of the Company's counterparties on an ongoing basis.

Note 9—Fair value measurements

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

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

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

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

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

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

When the inputs used to measure fair value fall within different levels of the hierarchy in a liquid environment, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measurement in its entirety. The Company conducts a review of fair value hierarchy classifications on an annual basis. Changes in the observability of valuation inputs may result in a reclassification for certain financial assets or liabilities. Transfers between fair value hierarchy levels are recognized and reported in the period in which the transfer occurred. No transfers between fair value hierarchy levels occurred during the years ended December 31, 2015, 2014 or 2013.

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

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

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(in thousands)	Level 1	Level 2	Level 3	Total gross fair value	Amounts offset	Net fair value presented on the consolidated balance sheets
As of December 31, 2014:						
Assets						
Current:						
Oil derivatives	$—	$190,303	$—	$190,303	$—	$190,303
Natural gas derivatives	—	9,647	—	9,647	—	9,647
Oil deferred premiums	—	—	—	—	(4,653)	(4,653)
Natural gas deferred premiums	—	—	—	—	(696)	(696)
Noncurrent:						
Oil derivatives	$—	$117,963	$—	$117,963	$—	$117,963
Natural gas derivatives	—	3,646	—	3,646	—	3,646
Oil deferred premiums	—	—	—	—	(3,821)	(3,821)
Natural gas deferred premiums	—	—	—	—	—	—
Liabilities						
Current:						
Oil derivatives	$—	$—	$—	$—	$—	$—
Natural gas derivatives	—	—	—	—	—	—
Oil deferred premiums	—	—	(4,768)	(4,768)	4,653	(115)
Natural gas deferred premiums	—	—	(696)	(696)	696	—
Noncurrent:						
Oil derivatives	$—	$—	$—	$—	$—	$—
Natural gas derivatives	—	—	—	—	—	—
Oil deferred premiums	—	—	(3,821)	(3,821)	3,821	—
Natural gas deferred premiums	—	—	—	—	—	—
Net derivative position	$—	$321,559	$(9,285)	$312,274	$—	$312,274

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

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

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

(in thousands)	December 31, 2015
2016	$8,629
2017	5,796
2018	426
Total	$14,851

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

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Balance of Level 3 at beginning of period	$(9,285)	$(12,684)	$(24,709)
Change in net present value of deferred premiums for derivatives	(203)	(220)	(462)
Total purchases and settlements:			
Purchases	(10,298)	(3,800)	—
Settlements[1]	5,167	7,419	12,487
Balance of Level 3 at end of period	$(14,619)	$(9,285)	$(12,684)

(1) The settlement amount for the year ended December 31, 2013 includes $2.2 million in deferred premiums which were settled net with the early terminated contracts from which they derive.

b. Fair value measurement on a nonrecurring basis

The Company accounts for the impairment of long-lived assets, if any, at fair value on a nonrecurring basis. For purposes of fair value measurement, it was determined that the impairment of long-lived assets is classified as Level 3, based on the use of internally developed cash flow models. See Note 2.j for discussion of the Company's impairment of line-fill, materials and supplies and other fixed assets for the periods presented.

The accounting policies for impairment of oil and natural gas properties are discussed in Note 2.g. Significant inputs included in the calculation of discounted cash flows used in the impairment analysis include the Company's estimate of operating and development costs, anticipated production of evaluated reserves and other relevant data. See Note 2.g for discussion regarding the prices used in the calculation of discounted cash flows and the Company's second, third and fourth-quarter 2015 full cost ceiling impairments.

Note 10—Net income (loss) per share

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

The effects of the Company's then outstanding restricted stock options that were granted in February 2014 to purchase 336,140 shares of common stock at $25.60 per share and in February 2012 to purchase 280,626 shares of common stock at $24.11 per share were excluded from the calculation of diluted net income per share for each of the years ended December 31, 2014 and 2013, because the exercise prices of these options were greater than the average market price during the period, and, therefore, the inclusion of these outstanding options would have been anti-dilutive.

The effect of the Company's outstanding restricted stock options that were granted in February 2013 to purchase 750,338 shares of common stock at $17.34 per share was excluded from the calculation of diluted net income per share for the years ended December 31, 2014 and 2013, because, utilizing the treasury method, the sum of the assumed proceeds exceeded the average stock price during the period and, therefore, the inclusion of these outstanding options would have been anti-dilutive. For the year ended December 31, 2014, the 2014 Performance Share Awards' total shareholder return was below their agreement's payout threshold, and therefore the 2014 Performance Share Awards were excluded from the calculation of diluted net income per share. There were no outstanding performance

share awards in 2013.

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

	For the years ended December 31,		
(in thousands, except for per share data)	2015	2014	2013
Net income (loss) (numerator):			
Income (loss) from continuing operations—basic and diluted	$(2,209,936)	$265,573	$116,577
Income from discontinued operations, net of tax—basic and diluted	—	—	1,423
Net income (loss)—basic and diluted	$(2,209,936)	$265,573	$118,000
Weighted-average common shares outstanding (denominator):			
Weighted-average common shares outstanding—basic[1]	199,158	141,312	132,490
Non-vested restricted stock awards	—	2,242	1,888
Weighted-average common shares outstanding—diluted	199,158	143,554	134,378
Net income (loss) per share:			
Basic:			
Income (loss) from continuing operations	$(11.10)	$1.88	$0.88
Income from discontinued operations, net of tax	—	—	0.01
Net income (loss) per share	$(11.10)	$1.88	$0.89
Diluted:			
Income (loss) from continuing operations	$(11.10)	$1.85	$0.87
Income from discontinued operations, net of tax	—	—	0.01
Net income (loss) per share	$(11.10)	$1.85	$0.88

(1) For the year ended December 31, 2015, weighted-average common shares outstanding used in the computation of basic and diluted net loss per share attributable to stockholders was computed taking into account the March 2015 Equity Offering. For the year ended December 31, 2013, weighted-average common shares outstanding used in the computation of basic and diluted net income per share attributable to stockholders was computed taking into account the August 2013 Equity Offering.

Note 11—Credit risk

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

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

For the year ended December 31, 2015, the Company had two customers that accounted for 37.5% and 20.3% of total oil, NGL and natural gas sales, with each customer accounting for 35.3% and 23.7%, respectively, of oil, NGL and natural gas sales accounts receivable, and two other customers accounting for 18.5% and 10.7% of oil, NGL and natural gas sales accounts receivable as of December 31, 2015. For the year ended December 31, 2014, the Company had two customers that accounted for 36.0% and 13.7% of total oil, NGL and natural gas sales, with each customer

accounting for 16.4% and 22.5%, respectively, of oil, NGL and natural gas sales accounts receivable, and three other customers accounting for 13.5%, 12.5% and 11.6% of oil, NGL and natural gas sales accounts receivable as of December 31, 2014. For the year ended December 31, 2013, the Company had three customers that accounted for 28.3%, 11.7% and 11.7% of total oil, NGL and natural gas sales, with two of the three

customers accounting for 36.0% and 15.7% of oil and natural gas sales accounts receivable as of December 31, 2013. These customers and percentages reported are related to the Company's exploration and production segment, see Note 17.

As of December 31, 2015, the Company had two partners whose joint operations accounts receivable accounted for 18.9% and 17.1% of the Company's total joint operations accounts receivable. As of December 31, 2014, the Company had two partners whose joint operations accounts receivable accounted for 20.5% and 13.2% of the Company's total joint operations accounts receivable. These customers and percentages reported are related to the Company's exploration and production segment, see Note 17.

For the year ended December 31, 2015, the Company had one customer that accounted for 100.0% of total sales of purchased oil, with the same customer accounting for 99.6% of purchased oil and other product sales receivable as of December 31, 2015. For the year ended December 31, 2014, the Company had one customer that accounted for 100.0% of total sales of purchased oil, with the same customer accounting for 97.3% of purchased oil and other product sales receivable as of December 31, 2014. There were no comparable sales of purchased oil for the year ended December 31, 2013 and correspondingly, there was no purchased oil and other product sales receivable as of December 31, 2013. The customer and percentages reported relate to the Company's midstream and marketing segment, see Note 17.

The Company's cash balances are insured by the FDIC up to $250,000 per bank. The Company had cash balances on deposit with certain banks as of December 31, 2015, which exceeded the balance insured by the FDIC in the amount of $51.3 million. Management believes that the risk of loss is mitigated by the banks' reputation and financial position.

Note 12—Commitments and contingencies

a. Lease commitments

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

(in thousands)	December 31, 2015
2016	$3,087
2017	3,244
2018	3,160
2019	2,408
2020	1,294
Thereafter	8,217
Total	$21,410

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

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Rent expense	$2,880	$3,042	$1,923

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

b. Litigation

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

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c. Drilling contracts

The Company has committed to drilling contracts with various third parties to complete its various drilling projects. The contracts contain early termination clauses that require the Company to potentially pay penalties to third parties should the Company cease drilling efforts. These penalties would negatively impact the Company's financial statements upon early contract termination, especially if a significant number of such contracts were terminated early in their respective terms. In the fourth quarter of 2014, the Company announced a reduced 2015 capital expenditure budget compared to 2014. As a result, the Company began releasing rigs as drilling contracts came close to expiration and incurred charges of $0.5 million which were recorded for the year ended December 31, 2014 on the consolidated statements of operations as "Drilling rig fees." No comparable amounts were recorded in the years ended December 31, 2015 or 2013. Future commitments of $10.3 million as of December 31, 2015 are not recorded in the accompanying consolidated balance sheets. Management does not currently anticipate the early termination of any existing contracts in 2016 that would result in a substantial penalty.

d. Firm sale and transportation commitments

The Company has committed to deliver for sale or transportation fixed volumes under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. If not fulfilled, the Company is subject to minimal volume penalties. These commitments are normal and customary for the Company's business. Future commitments of $425.7 million as of December 31, 2015 are not recorded in the accompanying consolidated balance sheets. The Company's production has been equivalent or greater than its delivery commitments during the three most recent years, and management expects such production will continue to exceed the Company's future commitments. However, in certain instances, the Company has used spot market purchases to meet its commitments in certain locations or due to favorable pricing. Management anticipates continuing this practice in the future. Also, if production is not sufficient to satisfy the Company's delivery commitments, the Company can and may use spot market purchases to fulfill the commitments.

e. Federal and state regulations

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

f. Other commitments

See Notes 2.u, 16.a and 19.b for the amount of and discussion regarding outstanding commitments to the Company's non-consolidated variable interest entity ("VIE").

Note 13—Restructuring

Following the fourth-quarter 2014 drop in oil prices, in an effort to reduce costs and to better position the Company for ongoing efficient growth, on January 20, 2015, the Company executed a company-wide restructuring and reduction in force (the "RIF") that included (i) the relocation of certain employees from the Company's Dallas, Texas area office to the Company's other existing offices in Tulsa, Oklahoma and Midland, Texas; (ii) closing the Company's Dallas, Texas area office; (iii) a workforce reduction of approximately 75 employees and (iv) the release of 24 contract personnel. The RIF was communicated to employees on January 20, 2015 and was generally effective immediately. The Company's compensation committee approved the RIF and the related severance package. The Company incurred $6.0 million in expenses during the year ended December 31, 2015 related to the RIF. There were no comparative amounts recorded in the years ended December 31, 2014 or 2013.

Note 14—Recently issued accounting standards

In November 2015, the Financial Accounting Standards Board ("FASB") issued new guidance in Topic 740, Income Taxes, which seeks to simplify the presentation of deferred income taxes. The amendments in this update require that deferred tax liabilities and assets be classified as noncurrent in a classified statement of financial position. For public business entities, the amendments in this update are effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Earlier application is permitted as of the beginning of an interim or annual reporting period. The amendments in this update may be applied either prospectively to all deferred tax liabilities and assets or retrospectively to all periods presented. The Company has early-adopted this standard as of December 31, 2015, and

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has applied its provisions retrospectively. The adoption of this standard resulted in the reclassification of deferred income taxes from the current liabilities "Deferred income taxes" to the noncurrent liabilities "Deferred income taxes" within the consolidated balance sheets.

The changes to the line items in the consolidated balance sheets as of the previously reported interim periods, as if this standard had been adopted in first-quarter 2015, are presented below:

(in thousands)	September 30, 2015	June 30, 2015	March 31, 2015	December 31, 2014
Noncurrent assets:				
Decrease in deferred income taxes	$(68,069)	$(45,089)	$—	$—
Decrease in total assets	(68,069)	(45,089)	—	—
Current liabilities:				
Decrease in deferred income taxes	$(68,069)	$(45,089)	$(73,753)	$(71,191)
Decrease in total current liabilities	(68,069)	(45,089)	(73,753)	(71,191)
Noncurrent liabilities:				
Increase in deferred income taxes	$—	$—	$73,753	$71,191
Decrease in total liabilities	(68,069)	(45,089)	—	—

See Note 7 for additional discussion of the December 31, 2014 consolidated balance sheet presentation reclassification.

In July 2015, the FASB issued new guidance in Topic 330, Inventory, which seeks to simplify the measurement of inventory. The amendments in this update apply to inventory that is measured using all methods excluding last-in, first-out and the retail inventory method. The main substantive provision of this guidance is for an entity to change the subsequent measurement of inventory, within the scope of this guidance, from LCM to the lower of cost and net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. The amendments in this update are effective for annual reporting periods beginning after December 15, 2016, including interim periods within those fiscal years and should be applied prospectively with earlier application permitted as of the beginning of an interim or annual reporting period. The Company is currently evaluating the impact this guidance will have on its consolidated financial statements upon adoption of this standard.

In April 2015, the FASB issued new guidance in Subtopic 835-30, Interest-Imputation of Interest, which seeks to simplify the presentation of debt issuance costs. These amendments require that debt issuance costs related to a recognized debt liability be presented in an entity's balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this guidance. Entities should apply the amendments on a retrospective basis, wherein the balance sheet of each individual period presented should be adjusted to reflect the period-specific effects of applying the new guidance. The Company has early-adopted this standard as of September 30, 2015, and has applied its provisions retrospectively. The adoption of this standard resulted in the reclassification of (i) the unamortized debt issuance costs related to the Company's senior unsecured notes from noncurrent assets "Debt issuance costs, net" to noncurrent liabilities "Long-term debt, net" and (ii) the unamortized debt issuance costs related to the Company's Senior Secured Credit Facility from noncurrent assets "Debt issuance costs, net" to noncurrent assets "Other assets, net" within the consolidated balance sheets. See Notes 2.k and 5.h for additional discussion of debt issuance costs.

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The changes to the line items in the consolidated balance sheets as of the previously reported interim periods, as if this standard had been adopted in first-quarter 2015, are presented below:

(in thousands)	June 30, 2015	March 31, 2015	December 31, 2014
Noncurrent assets:			
Decrease in debt issuance costs, net	$(26,158)	$(33,513)	$(28,463)
Increase in other assets, net	6,068	6,873	6,615
Decrease in total assets	(20,090)	(26,640)	(21,848)
Noncurrent liabilities:			
Decrease in long-term debt, net	$(20,090)	$(26,640)	$(21,848)
Decrease in total liabilities	(20,090)	(26,640)	(21,848)

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

Note 15—Variable interest entity

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

LMS contributed $99.9 million and $55.2 million during the years ended December 31, 2015 and 2014, respectively, to Medallion Gathering & Processing, LLC, a Texas limited liability company formed on October 12, 2012, and its wholly-owned subsidiaries (together, "Medallion"). See Note 19.b for discussion regarding a contribution made to Medallion subsequent to December 31, 2015.

LMS holds 49% of Medallion ownership units. Medallion was established for the purpose of developing midstream solutions and providing midstream infrastructure to bring oil, NGL and natural gas to market. LMS and the other 51% interest-holder have agreed that the voting rights of Medallion, the profit and loss sharing, and the additional capital contribution requirements shall be equal to the ownership unit percentage held. Additionally, Medallion requires a super-majority vote of 75% for all key operating and business decisions. The Company has determined that Medallion

is a VIE. However, LMS is not considered to be the primary beneficiary of the VIE because LMS does not have the power to direct the activities that most significantly affect Medallion's economic performance. As such, Medallion is accounted for under the equity method of accounting with the Company's proportionate share of Medallion's net income (loss) reflected in the consolidated statements of operations as "Income (loss) from equity method investee" and the carrying amount reflected in the consolidated balance sheets as "Investment in equity method investee."

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

During the year ended December 31, 2015, the Company negotiated a buyout of a minimum volume commitment to Medallion, which was related to natural gas gathering infrastructure Medallion constructed on acreage that the Company does not plan to develop. The portion of the buyout that was related to the Company's minimum volume commitment for future periods was $3.0 million and is included in the consolidated statements of operations in the line item "Minimum volume commitments" for the period in which the buyout was settled. See Note 16.a for discussion of items included in the consolidated financial statements related to Medallion.

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

	For the years ended December 31,		
(in thousands)	2015[3]	2014	2013
Total revenues	$34,288	$4,623	$892
Gross profit[1]	29,826	4,623	892
Income (loss) from continuing operations	13,821	(333)	54
Net income (loss)[2]	13,821	(333)	54

(1) Medallion's pipeline did not become operational until 2015, accordingly no costs of good sold were recorded for the years ended December 31, 2014 and 2013.

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

(3) Medallion's consolidated statement of operations for the year ended December 31, 2015 was unaudited as of February 17, 2016.

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

	December 31,	
(in thousands)	2015[1]	2014
Assets:		
Current assets	$78,411	$25,777
Noncurrent assets	329,956	112,753
Total assets	$408,367	$138,530
Liabilities:		
Current liabilities	$15,461	$19,522
Noncurrent liabilities	—	—
Total liabilities	$15,461	$19,522

(1) Medallion's consolidated balance sheet as of December 31, 2015 was unaudited as of February 17, 2016.

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Note 16—Related Parties

a. Medallion

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

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Midstream service revenues	$487	$—	$—
Minimum volume commitments	5,235	2,552	891
Interest and other income	158	—	—

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

	December 31,	
(in thousands)	2015	2014
Accounts receivable, net	$1,163	$—
Other assets, net[1]	1,025	1,110
Other current liabilities[2]	27,583	3,443

(1) Amounts included in "Other assets, net" above represent LMS owned line-fill in Medallion's pipeline.

(2) Amounts included in "Other current liabilities" above for the year ended December 31, 2015 represents LMS's capital contribution payable to Medallion, of which a portion was paid subsequent to December 31, 2015. "Other current liabilities" above for the year ended December 31, 2014 represents LMS's minimum volume commitment payable to Medallion. See Note 15 for additional discussion of Medallion and Note 19.b for additional discussion of the subsequent payment to Medallion.

b. Targa Resources Corp.

The Company has a gathering and processing arrangement with affiliates of Targa Resources Corp. ("Targa"). One of Laredo's directors was on the board of directors of Targa until May 18, 2015.

The following table summarizes the oil, NGL and natural gas sales and midstream service revenues received from Targa and included in the consolidated statements of operations for the periods presented:

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Oil, NGL and natural gas sales	$99,992	$96,100	$74,245
Midstream service revenues	590	—	—

The following table summarizes the amounts included in accounts receivable, net from Targa in the consolidated balance sheets as of the periods presented:

	December 31,	
(in thousands)	2015	2014
Accounts receivable, net	$6,097	$12,869

c. Archrock Partners, L.P.

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

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

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Lease operating expenses	$1,477	$975	$51

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

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Capital expenditures:			
Oil and natural gas properties	$—	$57	$—
Midstream service assets	64	833	—

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

	December 31,	
(in thousands)	2015	2014
Accounts payable	$13	$—

d. Helmerich & Payne, Inc.

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

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

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Capital expenditures:			
Oil and natural gas properties	$2,434	$9,518	$9,943

Note 17—Segments

Since the beginning of 2015, the Company has presented financial results by segment to highlight the growing value of its midstream and marketing segment and the midstream and marketing segment's interest in Medallion, as Medallion's third-party revenues have increased.

The Company operates in two business segments, which are (i) exploration and production and (ii) midstream and marketing. The exploration and production segment is engaged in the acquisition, exploration and development of oil and natural gas properties. The midstream and marketing segment provides Laredo's exploration and production segment and certain third parties with (i) products and services that need to be delivered by midstream infrastructure, including oil and natural gas gathering services as well as rig fuel, natural gas lift and water in and around Laredo's primary production corridors, (ii) water takeaway in and around Laredo's primary production corridors and (iii) oil and natural gas takeaway optionality in the field coupled with firm service commitments to maximize Laredo's oil, NGL and natural gas revenues.

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

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(in thousands)	Exploration and production	Midstream and marketing	Eliminations	Consolidated company
Year ended December 31, 2015:				
Oil, NGL and natural gas sales	$432,711	$1,692	$(2,669)	$431,734
Midstream service revenues	—	27,965	(21,417)	6,548
Sales of purchased oil	—	168,358	—	168,358
Total revenues	432,711	198,015	(24,086)	606,640
Lease operating expenses, including production tax	151,918	—	(10,685)	141,233
Midstream service expenses, including minimum volume commitments	4,399	18,393	(11,711)	11,081
Costs of purchased oil	—	174,338	—	174,338
General and administrative[1]	82,251	8,174	—	90,425
Depletion, depreciation and amortization[2]	269,631	8,093	—	277,724
Impairment expense	2,372,296	2,592	—	2,374,888
Other operating costs and expenses[3]	8,123	342	—	8,465
Operating loss	$(2,455,907)	$(13,917)	$(1,690)	$(2,471,514)
Other financial information:				
Income from equity method investee	$—	$6,799	$—	$6,799
Interest expense[4]	$(98,040)	$(5,179)	$—	$(103,219)
Loss on early redemption of debt[5]	$(30,056)	$(1,481)	$—	$(31,537)
Income tax benefit[6]	$171,952	$4,993	$—	$176,945
Capital expenditures	$(597,086)	$(35,515)	$—	$(632,601)
Gross property and equipment[8]	$5,302,716	$345,183	$(1,923)	$5,645,976
Year ended December 31, 2014:				
Oil, NGL and natural gas sales	$738,455	$1,660	$(2,912)	$737,203
Midstream service revenues	—	7,838	(5,593)	2,245
Sales of purchased oil	—	54,437	—	54,437
Total revenues	738,455	63,935	(8,505)	793,885
Lease operating expenses, including production tax	153,427	—	(6,612)	146,815
Midstream service expenses, including minimum volume commitments	—	9,641	(1,660)	7,981
Costs of purchased oil	—	53,967	—	53,967
General and administrative[1]	99,075	6,969	—	106,044
Depletion, depreciation and amortization[2]	241,834	4,640	—	246,474
Impairment expense	1,802	2,102	—	3,904
Other operating costs and expenses[3]	2,248	66	—	2,314
Operating income (loss)	$240,069	$(13,450)	$(233)	$226,386
Other financial information:				
Loss from equity method investee	$—	$(192)	$—	$(192)
Interest expense[4]	$(117,560)	$(3,613)	$—	$(121,173)
Income tax (expense) benefit[6]	$(170,551)	$6,265	$—	$(164,286)
Capital expenditures[7]	$(1,279,142)	$(60,607)	$—	$(1,339,749)
Gross property and equipment[8]	$4,841,895	$179,355	$(233)	$5,021,017
Year ended December 31, 2013:				

Oil, NGL and natural gas sales	$664,844	$—	$—	$664,844
Midstream service revenues	328	8,824	(8,739)	413
Total revenues	665,172	8,824	(8,739)	665,257
Lease operating expenses, including production tax	130,152	—	(8,620)	121,532
Midstream service expenses, including minimum volume commitments	2,807	1,571	(119)	4,259
General and administrative[1]	86,951	2,745	—	89,696
Depletion, depreciation and amortization[2]	231,703	2,241	—	233,944
Other operating costs and expenses[3]	1,475	—	—	1,475
Operating income	$212,084	$2,267	$—	$214,351
Other financial information:				
Income from equity method investee	$—	$29	$—	$29
Interest expense[4]	$(98,680)	$(1,647)	$—	$(100,327)
Income tax expense[6]	$(73,476)	$(1,031)	$—	$(74,507)
Capital expenditures[7]	$(718,606)	$(24,409)	$—	$(743,015)
Gross property and equipment[8]	$3,516,406	$58,706	$—	$3,575,112

(1) General and administrative costs were allocated based on the number of employees in the respective segment for the years ended December 31, 2015, 2014 and 2013. Certain components of general and administrative costs were not allocated and were based on actual costs for each segment, which primarily consisted of payroll, deferred

compensation and vehicle costs for the years ended December 31, 2015 and 2014 and payroll and deferred compensation for the year ended December 31, 2013. Costs associated with land and geology were not allocated to the midstream and marketing segment for the years ended December 31, 2015, 2014 and 2013.

(2) Depletion, depreciation and amortization were based on actual costs for each segment with the exception of the allocation of depreciation of other fixed assets, which was based on the number of employees in the respective segment for the years ended December 31, 2015, 2014 and 2013.

(3) Other operating costs and expenses include restructuring expense and accretion of asset retirement obligations for the year ended December 31, 2015, accretion of asset retirement obligations and drilling rig fees for the year ended December 31, 2014 and accretion of asset retirement obligations for the year ended December 31, 2013. These expenses are based on actual costs and are not allocated.

(4) Interest expense was allocated to the exploration and production segment based on gross property and equipment for the years ended December 31, 2015, 2014 and 2013 and allocated to the midstream and marketing segment based on gross property and equipment and life-to-date contributions to the Company's equity method investee for the years ended December 31, 2015, 2014 and 2013.

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

(6) Income tax benefit or expense for the midstream and marketing segment was calculated by multiplying income (loss) from continuing operations before income taxes by 36% for the years ended December 31, 2015, 2014 and 2013.

(7) Capital expenditures exclude acquisition of oil and natural gas properties and acquisition of mineral interests for the year ended December 31, 2014 and excludes acquisitions of oil and natural gas properties for the year ended December 31, 2013.

(8) Gross property and equipment for the midstream and marketing segment includes investment in equity method investee totaling $192.5 million, $58.3 million and $5.9 million as of December 31, 2015, 2014 and 2013, respectively. Other fixed assets were allocated based on the number of employees in the respective segment as of December 31, 2015, 2014 and 2013.

Note 18—Subsidiary guarantors

The Guarantors have fully and unconditionally guaranteed the January 2022 Notes, the May 2022 Notes, the March 2023 Notes and the Senior Secured Credit Facility (and had guaranteed the January 2019 Notes until the Redemption Date), subject to the Releases. In accordance with practices accepted by the SEC, Laredo has prepared condensed consolidating financial statements to quantify the assets, results of operations and cash flows of such subsidiaries as subsidiary guarantors. The following condensed consolidating balance sheets as of December 31, 2015 and 2014, and condensed consolidating statements of operations and condensed consolidating statements of cash flows each for the years ended December 31, 2015, 2014 and 2013, present financial information for Laredo on a stand-alone basis (carrying any investment in subsidiaries under the equity method), financial information for the subsidiary guarantors on a stand-alone basis (carrying any investment in subsidiaries under the equity method), and the consolidation and elimination entries necessary to arrive at the information for the Company on a condensed consolidated basis. Deferred income taxes for LMS and for GCM are recorded on Laredo's statements of financial position, statements of operations and statements of cash flows as they are disregarded entities for income tax purposes. Laredo and the Guarantors are not restricted from making intercompany distributions to each other. During the year ended December 31, 2014, certain midstream service assets were transferred from Laredo to LMS at historical cost.

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Notes to the consolidated financial statements

Condensed consolidating balance sheet
December 31, 2015

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

Condensed consolidating balance sheet
December 31, 2014

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Accounts receivable, net	$107,860	$19,069	$—	$126,929
Other current assets	238,300	24	—	238,324
Total oil and natural gas properties, net	3,196,231	7,277	(233)	3,203,275
Total midstream service assets, net	—	108,462	—	108,462
Total other fixed assets, net	42,046	299	—	42,345
Investment in subsidiaries and equity method investee	163,349	58,288	(163,349)	58,288
Total other long-term assets	128,582	4,496	—	133,078
Total assets	$3,876,368	$197,915	$(163,582)	$3,910,701
Accounts payable	$38,453	$555	$—	$39,008
Other current liabilities	283,026	31,800	—	314,826
Long-term debt, net	1,779,447	—	—	1,779,447
Other long-term liabilities	212,008	2,211	—	214,219
Stockholders' equity	1,563,434	163,349	(163,582)	1,563,201
Total liabilities and stockholders' equity	$3,876,368	$197,915	$(163,582)	$3,910,701

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

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

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

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

Condensed consolidating statement of operations
For the year ended December 31, 2013

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total operating revenues	$665,172	$8,824	$ (8,739)	$665,257
Total operating costs and expenses	455,972	3,673	(8,739)	450,906
Income from operations	209,200	5,151	—	214,351
Interest expense and other, net	(100,164)	—	—	(100,164)
Other non-operating income	84,861	2,268	(10,232)	76,897
Income from continuing operations before income tax	193,897	7,419	(10,232)	191,084
Income tax expense	(74,507)	—	—	(74,507)
Income from continuing operations	119,390	7,419	(10,232)	116,577
Income (loss) from discontinued operations, net of tax	(1,390)	2,813	—	1,423
Net income	$118,000	$10,232	$ (10,232)	$118,000

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

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

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

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

Condensed consolidating statement of cash flows
For the year ended December 31, 2013

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Net cash flows provided by operating activities	$359,198	$15,763	$(10,232)	$364,729
Change in investments between affiliates	23,986	(34,218)	10,232	—
Capital expenditures and other	(348,339)	18,455	—	(329,884)
Net cash flows provided by financing activities	130,084	—	—	130,084
Net increase in cash and cash equivalents	164,929	—	—	164,929
Cash and cash equivalents at beginning of period	33,224	—	—	33,224
Cash and cash equivalents at end of period	$198,153	$—	$—	$198,153

Note 19—Subsequent events

a. Senior Secured Credit Facility

On January 14, 2016, the Company borrowed $35.0 million on the Senior Secured Credit Facility. The outstanding balance under the Senior Secured Credit Facility was $170.0 million at February 16, 2016.

b. Medallion capital call

On January 15 and February 16, 2016, the Company made additional capital contributions to Medallion of $12.7 million and $8.3 million, respectively, which represent LMS's remaining commitment for the extension from Medallion's Garden City Station to Midland and Upton counties, Texas and a portion of the commitment for the southern extension from Medallion's Reagan Station further into Reagan County, Texas.

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c. New commodity derivative contracts

Subsequent to December 31, 2015, the Company entered into the following new commodity derivative contracts:

	Aggregate volumes	Floor price	Contract period
Natural gas (volumes in MMBtu):[1]			
Put	8,040,000	$2.50	January 2017 - December 2017
Put	8,220,000	$2.50	January 2018 - December 2018

(1) The associated commodity derivatives will be settled based on the Inside FERC index price for West Texas Waha. There are $4.3 million in deferred premiums associated with these contracts.

Note 20—Supplemental oil, NGL and natural gas disclosures

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

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

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Property acquisition costs:			
Evaluated	$—	$3,873	$9,652
Unevaluated	—	9,925	27,087
Exploration[1]	20,697	242,284	48,763
Development costs[2]	500,577	1,049,317	654,452
Total costs incurred	$521,274	$1,305,399	$739,954

(1) The Company acquired significant leasehold interests during the year ended December 31, 2014.

(2) The costs incurred for oil, NGL and natural gas development activities include $13.4 million, $6.9 million and $6.8 million in asset retirement obligations for the years ended December 31, 2015, 2014 and 2013, respectively.

b. Capitalized oil, NGL and natural gas costs

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

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Capitalized costs:			
Evaluated properties	$5,103,635	$4,446,781	$3,276,578
Unevaluated properties not being depleted	140,299	342,731	208,085
	5,243,934	4,789,512	3,484,663
Less accumulated depletion and impairment	(4,218,942)	(1,586,237)	(1,349,315)
Net capitalized costs	$1,024,992	$3,203,275	$2,135,348

The following table shows a summary of the oil, NGL and natural gas property costs not being depleted as of December 31, 2015, by year in which such costs were incurred:

(in thousands)	2015	2014	2013	2012 and prior	Total
Unevaluated properties not being depleted	$12,640	$110,955	$9,293	$7,411	$140,299

Unevaluated properties, which are not subject to depletion, are not individually significant and consist of costs for acquiring oil, NGL and natural gas leaseholds where no evaluated reserves have been identified, including costs of wells being

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evaluated. The evaluation process associated with these properties has not been completed and therefore, the Company is unable to estimate when these costs will be included in the depletion calculation.

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

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

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Revenues:			
Oil, NGL and natural gas sales	$431,734	$737,203	$664,844
Production costs:			
Lease operating expenses	108,341	96,503	79,136
Production and ad valorem taxes	32,892	50,312	42,396
	141,233	146,815	121,532
Other costs:			
Depletion	263,666	237,067	227,992
Accretion of asset retirement obligations	2,236	1,721	1,475
Impairment expense	2,369,477	—	—
Income tax (benefit) expense[(1)]	(164,141)	126,576	112,984
Results of operations	$(2,180,737)	$225,024	$200,861

(1) During the year ended December 31, 2015, the Company recorded a valuation allowance against its deferred tax assets related to its oil, NGL and natural gas producing activities. Accordingly, for the year ended December 31, 2015, income tax benefit is computed utilizing the Company's effective rate of 7%, which reflects tax deductions and tax credits and allowances relating to the oil, NGL and natural gas producing activities that are reflected in the Company's consolidated income tax benefit for the period. For the years ended December 31, 2014 and 2013, income tax expense is computed utilizing the statutory rate.

d. Net proved oil, NGL and natural gas reserves - (unaudited)

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, 2015, 2014 and 2013. In accordance with SEC regulations, reserves as of December 31, 2015, 2014 and 2013 were estimated using the Realized Prices (which are the Benchmark Prices adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead), see Note 2.g. The Company's reserves as of December 31, 2015 are reported in three streams: oil, NGL and natural gas. The Company's reserves as of December 31, 2014 and 2013 are reported in two streams: oil and liquids-rich natural gas with the economic value of the NGLs in the Company's natural gas included in the wellhead natural gas price. This change impacts the comparability of 2015 with prior periods. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil, NGL and natural gas properties. Accordingly, the estimates may change as future information becomes available.

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The following tables provide an analysis of the changes in estimated reserve quantities of oil, NGL and natural gas for the year ended December 31, 2015 and of oil and liquids-rich natural gas for the years ended December 31, 2014 and 2013, all of which are located within the United States.

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

(1) The positive NGL revisions of previous estimates and the negative natural gas revisions of previous estimates include the impact of the Company's conversion to three-stream production. For periods prior to January 1, 2015, the Company presented its reserves for oil and natural gas, which combined NGL with the natural gas stream, and did not separately report NGL. This change impacts the comparability to prior periods.

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

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	Year ended December 31, 2013		
	Oil (MBbl)	Gas (MMcf)	MBOE
Proved developed and undeveloped reserves:			
Beginning of year	98,141	542,946	188,632
Revisions of previous estimates	(17,956)	15,710	(15,338)
Extensions, discoveries and other additions	37,850	192,229	69,888
Purchases of reserves in place	170	1,454	412
Sale of reserves in place	(1,220)	(165,289)	(28,768)
Production	(5,487)	(34,348)	(11,211)
End of year	111,498	552,702	203,615
Proved developed reserves:			
Beginning of year	33,316	289,045	81,490
End of year	37,878	203,082	71,725
Proved undeveloped reserves:			
Beginning of year	64,825	253,901	107,142
End of year	73,620	349,620	131,890

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

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

For the year ended December 31, 2013, the Company's negative revision of 15,338 MBOE of previously estimated quantities is primarily attributable to the removal of 11,944 MBOE due to the combined effect of the removal of 174 proved undeveloped locations and the net effect of reinterpreting 501 undeveloped locations. The 174 locations that were removed were comprised of vertical Wolfberry and short horizontal laterals which were replaced with longer horizontal laterals to better align with future drilling plans. The remaining 3,394 MBOE of the negative revision is due to a combination of pricing, performance and other changes. Extensions, discoveries and other additions of 69,888 MBOE during the year ended December 31, 2013, consisted of 22,245 MBOE primarily from the drilling of new wells during the year and 47,643 MBOE from new proved undeveloped locations added during the year. The latter consists of 45,510 MBOE attributable to 85 horizontal locations in the Permian Basin. Purchases of minerals in place added 412 MBOE from acquisition of proved reserves in the Permian Basin.

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e. Standardized measure of discounted future net cash flows - (unaudited)

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, 2015, 2014 and 2013 are based on the Realized Prices, which reflect adjustments to the Benchmark Prices for gravity, quality, local conditions, fuel and shrinkage and/or distance from market. All Realized Prices are held flat over the forecast period for all reserve categories in calculating the discounted future net revenues. Any effect from the Company's commodity hedges is excluded. In accordance with SEC regulations, the proved reserves were anticipated to be economically producible from the "as of date" forward based on existing economic conditions, including prices and costs at which economic producibility from a reservoir was determined. These costs, held flat over the forecast period, include development costs, operating costs, ad valorem and production taxes and abandonment costs after salvage. Future income tax expenses are computed using the appropriate year-end statutory tax rates applied to the future pretax net cash flows from proved oil, NGL and natural gas reserves, less the tax basis of the Company's oil, NGL and natural gas properties. The estimated future net cash flows are then discounted at a rate of 10%. The Company's net book value of evaluated oil, NGL and natural gas properties exceeded the full cost ceiling amount as of June 30, 2015, September 30, 2015 and December 31, 2015. See Note 2.g for discussion of the Benchmark Prices, Realized Prices and the corresponding non-cash full cost ceiling impairments recorded.

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

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Future cash inflows	$3,269,184	$16,663,685	$13,337,798
Future production costs	(1,321,471)	(3,616,775)	(3,059,368)
Future development costs	(376,701)	(2,471,985)	(2,250,950)
Future income tax expenses	—	(2,827,763)	(2,150,983)
Future net cash flows	1,571,012	7,747,162	5,876,497
10% discount for estimated timing of cash flows	(740,265)	(4,500,434)	(3,554,293)
Standardized measure of discounted future net cash flows	$830,747	$3,246,728	$2,322,204

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.

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

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Standardized measure of discounted future net cash flows, beginning of year	$3,246,728	$2,322,204	$1,877,456
Changes in the year resulting from:			
Sales, less production costs	(290,501)	(590,388)	(543,312)
Revisions of previous quantity estimates	(2,444,322)	(320,275)	(190,961)
Extensions, discoveries and other additions	192,979	1,340,022	1,166,481
Net change in prices and production costs	(1,495,144)	145,740	313,947
Changes in estimated future development costs	(2,974)	(22,961)	921
Previously estimated development costs incurred during the period	162,237	92,135	89,396
Purchases of reserves in place	—	6,100	7,604
Divestitures of reserves in place	(29,149)	—	(239,148)
Accretion of discount	424,453	305,325	234,852
Net change in income taxes	997,805	(266,757)	(259,991)
Timing differences and other	68,635	235,583	(135,041)
Standardized measure of discounted future net cash flows, end of year	$830,747	$3,246,728	$2,322,204

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 from continuing operations by quarter for the periods presented are as follows:

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

	Year ended December 31, 2014			
(in thousands, except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$173,310	$183,044	$200,241	$237,290
Operating income	60,038	64,561	69,164	32,623
Net income (loss)	(213)	(18,899)	83,407	201,278
Net income (loss) per common share:				
Basic	$—	$(0.13)	$0.59	$1.42
Diluted	$—	$(0.13)	$0.58	$1.40