Laredo Petroleum, Inc.
Form 10-K
February 26, 2015

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, 2014
or

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

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

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

(918) 513-4570
(Registrant's telephone number, including area code)
Securities Registered Pursuant to Section 12(b) of the Act:

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

Securities Registered Pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes 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. o
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 $2,573.5 million on June 30, 2014, based on $30.98 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 23, 2015: 143,263,488

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2015 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2014, are incorporated by reference into Part III of this report for the year ended December 31, 2014.

Laredo Petroleum, Inc.

Table of Contents

GLOSSARY OF OIL AND NATURAL GAS TERMS

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

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

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

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

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

"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 ("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.

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

"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.

"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 ("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 total 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.
"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 ("PDNP")"—Developed non-producing reserves.
"Proved developed reserves ("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 ("PUD")"—Proved reserves that are expected to be recovered 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 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 oil and natural gas prices;
- changes in domestic and global production, supply and demand for oil and natural gas;
- the continuation of restrictions on the export of domestic crude oil and its potential to cause weakness in domestic pricing;
- 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, coupled with the export limitations noted above and a continuing increase in light sweet crude oil production, 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 adversely affect the demand for commodities, including oil and natural gas;
- 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;
- discovery, estimation, development and replacement of oil and natural gas reserves, including our expectations that estimates of our proved reserves will increase;
- uncertainties about the estimates of our oil and natural gas reserves;
- 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;
- capital requirements for our operations and projects;
- our ability to access additional borrowing capacity under our Senior Secured Credit Facility (as defined below) or other means of providing capital and liquidity;
- our ability to generate sufficient cash to service our indebtedness, fund our capital requirements and to generate future profits;
- 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;
- 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, 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 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. ("Broad Oak"), a Delaware corporation, 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 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. As of December 31, 2014, we had assembled 196,683 net acres in the Permian Basin and had total proved reserves, presented on a two-stream basis, of 247,322 MBOE.

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, and extends approximately 20 miles wide (east/west) and 85 miles long (north/south) in Howard, Glasscock, Reagan, Sterling, Irion and Tom Green counties and is referred to in this Annual Report as the "Permian-Garden City" area. As of December 31, 2014, we held 155,405 net acres in 360 sections in the Permian-Garden City area, with an average working interest of 96% 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, this includes four identified targets for horizontal drilling (Upper, Middle, and Lower Wolfcamp and Cline formations). From our inception in 2006 through December 31, 2014, we have drilled and completed (i.e., the particular well is flowing) 174 horizontal wells in these four target zones and 933 vertical wells in the Wolfberry interval. We have completed 75 horizontal Upper Wolfcamp wells, 31 horizontal Middle Wolfcamp wells, 21 horizontal Lower Wolfcamp wells and 47 horizontal Cline wells. Our horizontal activity since mid-2012 has moved toward drilling longer laterals (typically 7,000 to 7,500 feet) and increased frac density (typically 24 to 29 stages) as we continue the optimization of our completion techniques. As of February 25, 2015, we are drilling five wells in our Permian-Garden City area.

As illustrated in the following table, as a result of our drilling activity through 2014 coupled with our technical data and well performance, we believe that, as of December 31, 2014, we have de-risked the horizontal development potential for the equivalent of 400,000 net acres from these four zones, as well as our entire Permian-Garden City acreage position for vertical development. We consider our acreage to be "de-risked" (i.e., having reduced the risk and uncertainty associated therewith) when we believe we have established the ability to commercially produce from a certain area.

	Horizontal development de-risked net acreage as of December 31, 2014
Upper Wolfcamp	90,000
Middle Wolfcamp	90,000
Lower Wolfcamp	83,000
Cline	137,000
Total	400,000

In addition, in the third quarter of 2014, we successfully drilled our first well in the Canyon formation. It is anticipated that a delineation Canyon well will be drilled in the first quarter of 2015. We plan to continue to gather data and drill additional wells in zones other than our initial four target zones.

In 2015, as reflected in our capital drilling budget, we plan to continue drilling and collecting technical data across our Permian-Garden City acreage. We expect our Permian-Garden City acreage to continue to be the primary driver of our growth in reserves, production and cash flow for the foreseeable future.

Laredo was founded in October 2006 by our Chairman and Chief Executive Officer, Randy Foutch, who was later joined by other members of our management team. Prior to founding Laredo, Mr. Foutch formed, built and sold three private oil and natural gas companies. All of these companies executed the same fundamental business strategy employed by Laredo and created significant economic value through growth in reserves, production and cash flow.

In December 2011, we completed a Corporate Reorganization and IPO (as such terms are defined below). In December 2013, we completed a separate internal corporate reorganization, and in October 2014, we created GCM as a new wholly-owned subsidiary for the primary purpose of holding certain of our mineral interests. See "—Corporate history and structure."

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.

Since our inception, we have grown 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 247,322 MBOE on a two-stream basis as of December 31, 2014, of which 43% are classified as proved developed reserves and 57% are attributed to oil reserves. For all periods prior to January 1, 2015, our reserves and production are 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 is included in the wellhead natural gas price. Effective January 1, 2015, we will report our production volumes on a three-stream basis, which separately reports natural gas liquids 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 two-stream basis, net acreage and producing wells as of December 31, 2014, and average daily production presented on a two-stream basis for the year ended December 31, 2014. Based on estimates in the report prepared by Ryder Scott, we operated wells that represent 98% of the economic value of our proved developed oil and natural gas reserves as of December 31, 2014.

	As of December 31, 2014 Estimated net proved reserves(1)(2)				Producing wells		Year ended December 31, 2014
	MBOE	% of total reserves	% Oil	Net acreage	Gross	Net	average daily production (BOE/D)
Permian Basin	247,313	100 %	57 %	196,683	1,279	1,123	32,128
Other Properties	9	— %	100 %	44,949	1	1	6
Total	247,322	100 %	57 %	241,632	1,280	1,124	32,134

(1) In accordance with applicable rules of the SEC, the reference oil and natural gas prices are derived from the average trailing 12-month index prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the applicable 12-month period), held constant throughout the life of the properties. The reference prices were $91.48 per Bbl for oil and $4.25 per MMBtu for natural gas for the 12 months ended December 31, 2014.

(2) Because our reserves are reported in two streams, the economic value of the natural gas liquids in our natural gas is included in the wellhead natural gas price. The reference prices referred to above that were utilized in the December 31, 2014 reserve report prepared by Ryder Scott are adjusted for natural gas liquids content, quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. The adjusted reference price was $6.39 per Mcf.

Our net average daily production for the year ended December 31, 2014 was 32,134 BOE/D, 59% of which was oil and 41% of which was primarily liquids-rich natural gas.

Reflecting the sharp decline in oil and natural gas prices in the second half of 2014, we reduced our 2015 planned capital program. In connection with the reduced capital program, we approved a capital budget of $525 million for 2015; however, this budget is based on 2014 service cost rates and may be adjusted if service rates decline in 2015. Substantially all of the planned capital budget is anticipated to be invested in the Permian-Garden City area. We intend to continue to drill vertical wells that we believe will provide attractive economics and/or for the purpose of holding prospective targeted zones. Because of the stacked multiple-zone horizontal targets underlying our acreage, we are continuing to refine the optimal geometry relative to horizontal well spacing, lateral placement, completion and production practices. Work to date has included the pad drilling of side-by-side wells within the same zone, stacked lateral wells and extensive reservoir modeling. We are increasingly allocating a greater percentage of both capital and human resources towards our horizontal drilling activity, which generally produces more attractive economics than our vertical program.

In connection with our reduced capital budget, we are decreasing the number of horizontal and vertical drilling rigs working our properties in the Permian-Garden City area. On December 31, 2014, we had a total of nine operated drilling rigs consisting of six rigs drilling horizontal wells and three rigs drilling vertical wells. Our current drilling schedule anticipates that we will drop to two horizontal rigs and one vertical rig by May 1, 2015, and for the entire year of 2015, we expect to average 2.4 horizontal rigs and 1.5 vertical rigs.

While our horizontal drilling program will be focused primarily on developing the four initial zones already identified in the liquids-rich Wolfcamp and Cline intervals underlying our Permian-Garden City area, we believe, based on petrophysical analysis and preliminary drilling results, additional potential may exist in both shallower and deeper formations, including the Spraberry and Canyon. Additional testing of these new targeted intervals, as well as other identified intervals, will continue in 2015, but is not anticipated to be a significant component of our drilling program.

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.

To more efficiently deploy our capital, we anticipate allocating an increased percentage of our reduced capital budget to drilling activities, and we will actively seek to decrease our unit lease operating and general & administrative expenses. On January 20, 2015, we announced the termination of approximately 75 employees Company-wide and the closing of our Dallas, Texas area office. We also released 24 contract personnel. See Note 16.b to our audited consolidated financial statements included elsewhere in this Annual Report. In addition, we anticipate decreases in service costs as a result of the recent commodity price decline.

Laredo has built an extensive proprietary technical database that includes 838 square miles of 3D seismic, 27 microseismic surveys, more than 8,000 open and cased hole logging suites including 120 dipole sonic logs, 3,700 feet of proprietary whole cores in 14 wells, 715 sidewall cores, 56 single zone tests and 42 production logs. Laredo's strategic interest in assembling a rich database is directed at efficiently accelerating the delineation of "de-risked" acreage of resource plays in the Permian-Garden City area and maximizing value creation during the field development phase.

A key component of our reservoir characterization process is internally referred to as the "Earth Model", which represents an 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 three years, covering an area where more than 80 calibrated pre-stack inversion attributes have been extensively developed and tested to determine fundamental controls on reservoir performance. The four major components of the 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 able to develop a relationship to production with an 85% correlation coefficient for the initial four primary targets (Upper Wolfcamp, Middle Wolfcamp, Lower Wolfcamp, and Cline).

We consider the Earth Model a potentially significant tool in planning development wells in laterally and vertically complex geology by optimizing landing points and geo-steering targets while integrating vertical and lateral spacing considerations.

We estimate 90% of our horizontal wells drilled in 2015 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.

Corporate history and structure

Laredo Petroleum Holdings, Inc. was incorporated in August 2011 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 Laredo Petroleum Holdings, Inc. ("Holdings"), with Holdings surviving the merger, was completed on December 19, 2011 (the "Corporate Reorganization"). Laredo Petroleum, LLC was formed in 2007 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., which was founded in 2006 by Randy Foutch, our Chairman and Chief Executive Officer, to acquire, develop and operate oil and natural gas properties in the Permian and Mid-Continent regions of the United States. 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, 2014, Warburg Pincus owned 40.3% 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.

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 Midstream"). 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 audited consolidated financial statements included elsewhere in this Annual Report.

Laredo Petroleum, Inc. is the borrower under our Fourth Amended and Restated Credit Senior Secured Credit Facility (as amended, the "Senior Secured Credit Facility"), as well as the issuer of our $550 million 9 1/2% senior unsecured notes due 2019 (the "2019 Notes") issued in January and October 2011, our $500 million 7 3/8% senior unsecured notes due 2022 issued in April 2012 (the "May 2022 Notes") and our $450 million 5 5/8% senior unsecured notes due 2022 issued in January 2014 (the "January 2022 Notes"). We refer to the 2019 Notes, the May 2022 Notes and the January 2022 Notes collectively as the "Senior Unsecured Notes." Our subsidiaries, Laredo Midstream and GCM, are guarantors of the obligations under our Senior Secured Credit Facility and Senior Unsecured Notes.

Our business strategy

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

Continue to develop our Permian-Garden City acreage. As of December 31, 2014, we had 155,405 net acres in the Permian-Garden City area. As of such date, we believe we have established the economic horizontal potential of 90,000 net acres for horizontal Upper Wolfcamp drilling, 90,000 net acres for horizontal Middle Wolfcamp drilling, 83,000 net acres for Lower Wolfcamp drilling and 137,000 net acres for horizontal Cline drilling. We are continuing to de-risk the remaining acreage for these zones, although at a slower pace than in the past, and in the future will attempt to de-risk acreage for other zones. We anticipate the opportunities afforded in our Permian-Garden City area will support consistent, predictable, annual growth in reserves, production and cash flow.

Our Permian-Garden City acreage will likely be the primary driver of our growth in reserves, production and cash flow for the foreseeable future. We believe we have confirmed the vertical development potential of our entire Permian-Garden City acreage position (utilizing more than 900 vertical wells across our acreage position, of which more than 400 have been drilled through the Wolfcamp, Cline and Atoka formations). Based on 174 horizontal wells drilled and completed as of December 31, 2014, coupled with our technical data and well performance from all four initially targeted zones, we categorize the equivalent of 400,000 net acres as de-risked for commercial horizontal development. We further believe this largely contiguous de-risked acreage position provides a multi-decade development inventory to support consistent growth of reserves, production and cash flow. With the assistance of our expanded infrastructure and midstream capabilities, we are implementing a systematic multi-well pad development drilling program that will enable us to optimize spacing, minimize drainage interference and maximize our frac efficiency. Because of the complexities of developing a field that has multi-dimensional aspects (vertical and horizontal reservoir components), we have drilled and tested side-by-side horizontal wells (same reservoir) with the initial results supporting 660-ft. spacing at or above our internal production estimates. In 2014, we continued to implement our stacked lateral program (up to four different zones) with multiple tests in several areas of our acreage. Our objectives with the stacked lateral program are to optimize the vertical distance between the laterals, minimize interference, enhance frac efficiency and optimize scheduling of rig operations on multi-well pads. We anticipate that these improvements will result in efficiency gains and potentially lead to better rates of return on our wells. Our development plan also calls for having the flexibility to include the de-risking of additional acreage for both the Wolfcamp and the Cline shale intervals while furthering the development of all of our targeted zones in the Permian-Garden City acreage. Going forward, we plan to continue drilling and collecting technical data across our Permian-Garden City acreage position.

Utilize our infrastructure to more efficiently develop our acreage. In conjunction with our development program, Laredo Midstream has built, and is continuing to build, midstream facilities to enhance our production capabilities. Laredo Midstream has constructed crude oil truck stations in Glasscock and Reagan counties, Texas, and for a portion of our production, our system provides us with multiple sales outlets through interconnecting pipelines, potentially minimizing the risks of both shut-ins awaiting pipeline connection and curtailment of downstream pipelines. Laredo Midstream has installed (or is in the process of installing) four production corridors across portions of the Permian-Garden City area to provide for the movement of oil, natural gas and water to and from our drilling and production operations. We anticipate that these corridors will provide the delivery and takeaway capacity necessary to support hundreds of wells to be drilled in these areas. The natural gas lines in these corridors provide for the gathering of produced natural gas, the delivery of natural gas to fuel drilling rigs in the corridor and the high-pressure gas lift for producing wells in the corridor. Similarly, the water lines in the corridor provide for the delivery of fresh water and recycled water to wells for completion on the corridors. In one of our production corridors, Laredo Midstream constructed a water treatment facility that will be used to process flowback and produced water and recycle that water for use in completion operations for the more than 400 wells that can be accommodated by the facilities in this corridor. We believe this will reduce both the fresh water requirements for our operations and the volume of water that must be sent to disposal facilities.

Additionally, through Laredo Midstream and our joint venture entity, Medallion Gathering & Processing, LLC ("Medallion"), a Texas limited liability company, we have built or contributed to the construction of an extensive oil gathering system and pipeline infrastructure spanning more than 220 miles from the Midland Basin to Colorado City, Texas. This network enables us to avoid costs associated with trucking or other transportation options while maintaining our flexibility to sell oil in multiple markets.

Capitalize on technical expertise and database. We are leveraging our operating and technical expertise to further delineate and develop our core acreage positions. We believe that we have de-risked a significant portion of our Permian-Garden City acreage through the utilization of an extensive proprietary technical petrophysical database, a vertical drilling program covering a majority of our core acreage position, numerous vertical single-zone tests in our horizontal targets and the production data from the 174 completed horizontal wells in all three Wolfcamp zones and the Cline shale zones.

We intend to continue to make upfront investments in expanding our technical database only in those areas where the Earth Model indicates additional data is required. Currently, the Earth Model has been completed on approximately the southern third of our Permian-Garden City acreage. It is anticipated that by the end of 2015 a majority of our acreage will be evaluated utilizing this process to some extent. The Earth Model is an evolving workflow that can be re-calibrated as new drilling results, petrophysical data and 3D seismic reprocessing are received over time.

Maintain financial flexibility through continued improvements in operational and cost efficiencies, prudent drilling and measured growth. In the current commodity price environment, we are focused on efficient and prudent capital allocation. We continue to focus on oil and liquids-rich drilling opportunities, which provide attractive returns. We believe by emphasizing our horizontal program, we can increase the efficiency of our resource recovery in the multiple vertically stacked producing horizons on our acreage in our Permian-Garden City area. We are decreasing the number of drilling rigs working our acreage in order to conserve capital and reduce our cash outspend. We are actively seeking to decrease our lease operating and general & administrative expenses. On January 20, 2015, we announced the termination of approximately 75 employees Company-wide and the closing of our Dallas, Texas area office. We also released 24 contract personnel. See Note 16.b to our audited consolidated financial statements included elsewhere in this Annual Report. In addition, based on the current commodity environment, we are actively negotiating lower service cost contracts.

We continue to seek operational efficiencies throughout the Company, including through our development plan. We began implementing this plan in 2013, commencing with a single-zone side-by-side test and vertically stacked horizontal wellbores in multiple zones to test optimal spacing of the laterals, both horizontally and vertically, in the four initial zones targeted for horizontal development. We are now drilling longer laterals and optimizing our completion process to enhance the cost-efficient recovery of our resource potential. In addition, horizontal drilling may be economic in areas where vertical drilling is currently not economical or logistically viable. We will continue to utilize our vertical drilling program where we believe it will result in solid economic returns, hold acreage and/or de-risk additional acreage for all zones. Our management team is focused on continuous improvement of our operating efficiencies and has significant experience in managing development programs during periods of lower commodity prices. We are the operator for 88% of our Permian-Garden City wells, which enables us to more effectively manage operating costs, the pace of development activities, technical applications, the gathering and marketing of our production and capital allocation.

Evaluate and pursue value-enhancing acquisitions, mergers, joint ventures and divestitures. While we believe our multi-decade inventory of potential drilling locations provides us with significant growth opportunities, we continue to evaluate strategically compelling and/or value-enhancing asset acquisitions, mergers, joint ventures and divestitures, including transactions that increase our working interest ownership percentage in areas where we already have leases. As we have previously announced, we have been in discussions with interested parties regarding a potential joint development opportunity involving a portion of our Permian-Garden City acreage. There is no assurance that a transaction will be consummated.

Proactively manage risk to limit downside. We continually monitor and control our business and operating risks through various risk management practices, including employing prudent safety and environmental practices, seeking a flexible financial profile, making upfront investment in research and development as well as data acquisition, seeking multiple sales outlets, minimizing long-term contracts and maintaining an active commodity hedging program.

Our competitive strengths

We have a number of competitive strengths that we believe will help us to successfully execute our business strategy:

Significant de-risked Permian Basin acreage position and multi-decade drilling inventory. From our inception in 2006 through December 31, 2014, we have completed 933 gross vertical and 178 gross horizontal wells with a success rate of 99% in our Permian-Garden City area. The 178 gross horizontal wells are comprised of 174 wells in the Upper, Middle and

Lower Wolfcamp and Cline shales, one well in the Spraberry, one well in the Canyon and two wells in the Strawn. Based on our drilling results through December 31, 2014, we believe we have confirmed the economic horizontal development potential of the equivalent of 400,000 net acres from the four initial zones that includes 90,000 net acres in the Upper Wolfcamp, 90,000 net acres in the Middle Wolfcamp, 83,000 net acres in the Lower Wolfcamp and 137,000 net acres in the Cline shale. We believe these locations provide a multi-decade drilling inventory supporting future growth in reserves, production and cash flow.

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 more than 95% of anticipated production in 2015 with a weighted-average floor price of $80.99 per Bbl, and hedges in place for natural gas and natural gas liquids that represent 63% of anticipated production in 2015 at a weighted-average floor price of $3.00 per MMBtu. For 2016, we have hedges in place for 4.1 million barrels of oil with a weighted-average floor price of $81.84 per Bbl and hedges for natural gas for 18.7 million MMBtu with a weighted-average floor price of $3.00 per MMBtu. Further, at December 31, 2014, for 2017, we had hedges in place for 2.3 million barrels of oil with a weighted-average floor price of $80.00 per barrel. Subsequent to December 31, 2014, we entered into hedges for an additional 365 thousand barrels of oil at a weighted-average floor price of $60.00 per Bbl for 2017. This brings our total 2017 hedged oil volume to 2.6 million barrels with a weighted-average floor price of $77.22. We believe that the price certainty associated with these hedges allows us to better plan and forecast our upcoming capital and operational spending.

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 that define our drilling and development program. We have an extensive library of data applicable to our Permian-Garden City acreage base that, as of December 31, 2014, includes 838 square miles of proprietary/licensed 3D seismic (covering 95% of such acreage position), 303 proprietary petrophysical logs (fully core calibrated), and more than 8,000 historical open and cased hole logs from the general area. We have also run 120 dipole sonic logs, which play a key role in our petrophysical analysis. Approximately 470 square miles of the total 3D seismic coverage has been merged into one volume, allowing for maximum utilization and interpretation of the data set. In addition, membership in an industry core consortium has provided us access to additional petrophysical data across a larger area outside our core Permian-Garden City acreage position. We have utilized this information in the creation of the Earth Model, which we believe will assist us in optimizing our well results. Another important objective of the Earth Model and our information database is to maximize hydrocarbon recovery by utilizing the minimum required number of wells through proper well spacing.

Significant operational control. We operate wells that represent 98% of the economic value of our proved developed reserves as of December 31, 2014, based on a 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 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.

Owned gathering infrastructure. Our wholly-owned subsidiary, Laredo Midstream, owns and operates more than 175 miles of pipeline in our natural gas gathering systems in the Permian Basin as of December 31, 2014. Additionally, through our joint venture with Medallion, we have access to more than 220 miles of oil gathering systems and pipelines connected to Colorado City, Texas. These systems and flowlines 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 days waiting on pipeline. Laredo Midstream has built, and is continuing to build, production corridors on our contiguous acreage position that we believe increase efficiencies in oil and gas takeaway capacity, water supply and field level operations.

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, which is comprised of Laredo management and representatives of Warburg Pincus, our historical institutional investor, as well as other independent individuals, 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 dozens of such companies, including Broad Oak and two previous companies operated by members of our management team.

Focus areas

Our current properties are located in the prolific Permian Basin of the United States, where we leverage our experience and knowledge to identify, exploit and acquire additional upside potential. We have been successful in delivering repeatable results through internally generated horizontal and vertical drilling programs. We expect our Permian-Garden City acreage, which is characterized by a high oil content, to be the primary driver of our growth in reserves, production and cash flow for the foreseeable future.

Permian Basin

The oil and liquids-rich Permian Basin, located in West Texas and Southeastern New Mexico, where we have assembled 196,683 net acres as of December 31, 2014, is one of the most productive onshore oil and natural gas producing regions in the United States. It is characterized by an extensive production history, mature infrastructure, long reserve life and hydrocarbon potential in multiple intervals. Our primary production and exploitation fairway (Permian-Garden City area) is located on the eastern side of the basin 35 miles east of Midland, Texas and extends 20 miles wide (east/west) and 85 miles long (north/south) in Howard, Glasscock, Reagan, Sterling, Irion and Tom Green counties. As of December 31, 2014, we held 155,405 net acres in 360 sections in the Permian-Garden City area with an average working interest of 96% in all Laredo-operated producing wells.

During 2014, we continued to expand our horizontal development program for the Wolfcamp and Cline shales. Our results indicate that our acreage in the Permian-Garden City area can be produced horizontally simultaneously out of multiple zones. Within the Wolfcamp, we have three distinct zones: the Upper, Middle and Lower Wolfcamp shales, which together with the Cline shale provide at least four primary horizontal targets in the Permian-Garden City area. Additional drilling has been done and will continue to determine what other formations, if any, hold economically viable horizontal development opportunities. During 2014, we drilled and completed 78 horizontal wells in our initial four target primary zones and now have a total of 174 horizontal wells, confirming production and attractive returns from all four primary zones. Today, we are continuing our drilling focus on a horizontal development and exploitation program supported by an extensive technical database and the Earth Model that help us to define and optimize the horizontal targets.

As of December 31, 2014, our understanding of the stacked reservoir formations in our Permian-Garden City acreage has been significantly enhanced through the development of the Earth Model. This leads us to believe that each of our four primary zones has the potential to be a stand-alone resource play with significant areal extent, the ability to produce commercial quantities of hydrocarbons and the viability of repeatable well performance from multiple potential locations. Based on our analysis, we also believe the Wolfcamp and Cline shales exhibit similar petrophysical attributes to other large, domestic oil and liquids-rich shale plays, such as the Eagle Ford and Bakken.

The Wolfcamp shale resource play

The Wolfcamp shale continues to be a focus of active drilling by us and the industry and is encountered at depths ranging from 7,000 to 9,000 feet under our Permian-Garden City acreage. We have been able to further define the gross Wolfcamp shale formation into three discernible zones: the Upper, Middle and Lower Wolfcamp. Under our Permian-Garden City acreage, each of these zones ranges in thickness between 300 and 600 feet. Based on our proprietary data and the Earth Model analysis, we believe we have confirmed that all three Wolfcamp zones share many petrophysical attributes and production profiles. Through the utilization of our Earth Model, we have identified both vertical and horizontal petrophysical changes across our acreage that we believe will enable us to develop the potential of each targeted interval in an efficient and cost-effective manner.

As of December 31, 2014, we had successfully drilled and completed 127 Wolfcamp horizontal wells.

Upper Wolfcamp. As of December 31, 2014, we estimated that 90,000 net acres of our Permian-Garden City area had been de-risked for horizontal Upper Wolfcamp development and have drilled and completed 75 horizontal wells.

Middle Wolfcamp. As of December 31, 2014, we estimated that 90,000 net acres of our Permian-Garden City area had been de-risked for horizontal Middle Wolfcamp development and have drilled and completed 31 horizontal wells.

Lower Wolfcamp. As of December 31, 2014, we estimated that 83,000 net acres of our Permian-Garden City area had been de-risked for horizontal Lower Wolfcamp development and have drilled and completed 21 horizontal wells.

The Cline shale resource play

As of December 31, 2014, we estimated that 137,000 net acres of our Permian-Garden City area had been de-risked for horizontal Cline development. In 2014, we successfully drilled and completed ten horizontal wells and now have a total of 47 horizontal wells in the Cline shale.

We first recognized the potential of the Cline shale in 2008, took our first Cline cores in 2009 and drilled our first horizontal well in the formation in early 2010. We are now in the horizontal development phase on this de-risked acreage. We believe the petrophysical data indicates that this is a repeatable economic resource play, and we continue to delineate and define the Cline potential on our remaining Permian-Garden City acreage. Industry activity relative to the Cline shale has also been initiated with several horizontal wells being drilled and/or permitted immediately north and east of our Permian-Garden City acreage position.

The Cline shale is encountered at a depth of 9,000 to 9,500 feet in our Permian-Garden City acreage. Our proprietary petrophysical data indicates that the Cline is a laterally extensive, high-quality, over-pressured source rock with an abundance of oil-prone organic matter and high generation potential. Cline conventional cores contain numerous vertical extension fractures that are partially open, significantly enhancing system permeability across the matrix. Multiple thermal maturity indices show the Cline to be in a "peak liquids" stage in the late oil to early gas/condensate window. As our drilling and data acquisition programs progress, we are beginning to define those areas that show commonality in terms of reservoir type, quality and repeatability.

We continue to evaluate the development opportunities in other formations including the Spraberry, Strawn, Canyon and Atoka/Barnett/Woodford. Utilizing many of the components of our technical database, we drilled and completed our first Canyon well in 2014. The Canyon zone is found at a depth of 8,250 to 9,000 feet and has a gross thickness ranging from 600 to 875 feet across a large portion of our Permian-Garden City acreaege. Our acreage is located structurally "down-dip" from the legacy Canyon Gas Field to the east. We believe that with additional delineation drilling, we may be able to determine that the Canyon zone will add a significant number of drilling locations across a majority of our acreage.

Other Properties

In addition to our Permian-Garden City acreage, we currently hold 44,949 net acres in other areas, including the Dalhart Basin, located on the western side of the Texas Panhandle. We anticipate little or no activity on the other properties in 2015. Approximately 60% of this acreage will expire in 2015 absent drilling or renegotiation of the applicable leases.

Our operations

Estimated proved reserves

Our reserves are reported in two streams: crude oil and liquids-rich natural gas. The economic value of the natural gas liquids in our natural gas is included in the wellhead natural gas price. In this Annual Report, the information with respect to our estimated proved reserves presented below has been prepared by Ryder Scott, our independent reserve engineers, in accordance with the rules and regulations of the SEC applicable to the periods presented.

Our net proved reserves were estimated at 247,322 MBOE on a two-stream basis as of December 31, 2014, of which 43% were classified as proved developed reserves, and 57% are attributable to oil reserves. The following table presents summary data for each of our core operating areas as of December 31, 2014. Our estimated proved reserves as of December 31, 2014 assume our ability to fund the capital costs necessary for their development and are affected by pricing assumptions. In addition, we may not be able to raise the amounts of capital that would be necessary to drill a substantial portion of our proved undeveloped reserves. See "Item 1A. Risk Factors—Risks related to our business—Estimating reserves and future net revenues involves uncertainties. Decreases in oil and natural gas prices, or negative revisions to reserve estimates or assumptions as to future oil and natural gas prices, may lead to decreased earnings, losses or impairment of oil and natural gas assets." Effective January 1, 2015, we will report our production volumes on a three-stream basis, which separately reports natural gas liquids from natural gas and crude oil.

	As of December 31, 2014		
Area:	Proved reserves (MBOE)	% of total	
Permian Basin	247,313	100	%
Other Properties	9	—	%
Total	247,322	100	%

15

The following table sets forth more information regarding our estimated proved reserves as of December 31, 2014 and 2013. Ryder Scott, our independent reserve engineers, estimated 100% of our proved reserves as of December 31, 2014 and 2013. The reserve estimates as of December 31, 2014 and 2013 were prepared in accordance with the SEC's rules regarding oil and natural gas reserve reporting applicable to the periods presented. The information does not give any effect to our commodity hedges.

	As of December 31,	
	2014	2013
Proved developed producing:		
Oil and condensate (MBbl)	53,270	36,019
Natural gas (MMcf)	272,674	191,694
Total proved developed producing (MBOE)	98,715	67,968
Proved developed non-producing:		
Oil and condensate (MBbl)	3,705	1,859
Natural gas (MMcf)	18,819	11,388
Total proved developed non-producing (MBOE)	6,842	3,757
Proved undeveloped:		
Oil and condensate (MBbl)	83,215	73,620
Natural gas (MMcf)	351,301	349,620
Total proved undeveloped (MBOE)	141,765	131,890
Estimated proved reserves:		
Oil and condensate (MBbl)	140,190	111,498
Natural gas (MMcf)	642,794	552,702
Total estimated proved reserves (MBOE)	247,322	203,615
Percent developed	43 %	35 %

Technology used to establish proved reserves. Under the SEC rules, proved reserves are those quantities of oil and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs, and under existing economic conditions, operating methods and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil 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 using pore volume calculations and performance from analogous wells in the surrounding area and 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.

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, 2014 and 2013 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.
Gary B. Smallwood, 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 39 years of practical experience with 31 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. Mr. Smallwood reports directly to our President and Chief Operating Officer. Reserves estimates are reviewed and approved by our senior engineering staff with final approval by our President and Chief Operating Officer and certain other members of our senior management. Our senior management also reviews our independent engineers' reserves estimates and related reports with our senior reservoir engineering staff and other members of our technical staff.

Proved undeveloped reserves

Our proved undeveloped reserves, reported on a two-stream basis, increased from 131,890 MBOE as of December 31, 2013 to 141,765 MBOE as of December 31, 2014. We estimate that we incurred $109 million of costs to convert 5,865 MBOE of proved undeveloped reserves from 22 locations into proved developed reserves in 2014. New proved undeveloped reserves of 41,757 MBOE were added during the year, with 97% coming from new horizontal Upper, Middle and Lower Wolfcamp and Cline locations. Negative revisions to proved undeveloped reserves of 26,017 MBOE were due to the combined effect of removing 226 proved locations and the net effect of redetermining 345 undeveloped locations. The 226 locations that were removed were comprised of 223 vertical Wolfberry and three horizontal laterals to better align with future drilling plans.

Estimated total future development and abandonment costs related to the development of proved undeveloped reserves as shown in our December 31, 2014 reserve report are $2.3 billion. Based on this report, the capital estimated to be spent in 2015, 2016, 2017, 2018 and 2019 to develop the proved undeveloped reserves is $154 million, $302 million, $435 million, $657 million and $746 million, respectively. 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 five-year period. Reserve calculations at any end-of-year period are representative of the Company's development plans at that time. Changes in circumstance, including commodity pricing, oilfield service costs 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, 2014, 2013 and 2012. For these periods our reserves and production are reported in two streams: crude oil and liquids-rich natural gas. The economic value of the natural gas liquids in our liquids-rich natural gas is included in the wellhead natural gas price. For additional information on price calculations, see the information in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

(unaudited)	For the years ended December 31, 2014	2013	2012
Sales volumes:			
Oil (MBbl)	6,901	5,487	4,775
Natural gas (MMcf)(1)	28,965	34,348	39,148
Oil equivalents (MBOE)(2)(3)	11,729	11,211	11,300
Average daily sales volumes (BOE/D)(3)	32,134	30,716	30,874
Revenues (in thousands):			
Oil	$571,620	$494,676	$414,932
Natural gas	$165,583	$170,168	$168,637
Average sales prices without hedges:			
Benchmark oil ($/Bbl)(4)	$93.00	$97.97	$94.20
Oil, realized ($/Bbl)(5)	$82.83	$90.16	$86.89
Benchmark natural gas ($/MMBtu)(4)	$4.41	$3.65	$2.80
Natural gas, realized ($/Mcf)(5)	$5.72	$4.95	$4.31
Average price, realized ($/BOE)(5)	$62.86	$59.29	$51.65
Average sales prices with hedges(6):			
Oil, hedged ($/Bbl)	$85.77	$88.68	$85.59
Natural gas, hedged ($/Mcf)	$5.73	$4.98	$4.92
Average price, hedged ($/BOE)	$64.62	$58.66	$53.22
Average cost per BOE sold:			
Lease operating expenses	$8.23	$7.06	$5.96
Production and ad valorem taxes	$4.29	$3.78	$3.33
Midstream service expense	$0.46	$0.30	$0.23
General and administrative(7)	$9.04	$8.00	$5.50
Depletion, depreciation and amortization	$21.01	$20.87	$21.33

(1) Excludes natural gas produced and consumed in operations of 169 MMcf for the year ended December 31, 2014. There were no comparable amounts for the years ended December 31, 2013 or 2012.

(2) Bbl 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) Benchmark 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. Benchmark natural gas prices are the simple arithmetic average of the last day settlement price for NYMEX natural gas each month for the period indicated.

(5) Realized oil and natural gas prices are the actual prices realized at the wellhead after all adjustments for natural gas liquid content, quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price 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 amount capitalized, of $23.1 million, $21.4 million and $10.1 million for the years ended December 31, 2014, 2013 and 2012, respectively. Excluding stock-based compensation, net of amount capitalized, from the above metric results in general and administrative cost per BOE sold of $7.07, $6.09 and $4.61 for the years ended December 31, 2014, 2013 and 2012, respectively.

Productive wells

The following table sets forth certain information regarding productive wells in each of our core areas as of December 31, 2014. Our wells are classified as oil wells, all of which also produce natural gas, condensate and natural gas liquids. Wells are classified as oil or natural gas wells according to the predominant production stream, except that a well with multiple completions is classified as an oil well if one or more of the completions is an oil completion. We only have two wells that primarily produce gas; however, they both also have completions that produce oil. 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				Average WI %	
	Vertical	Horizontal	Total	Net		
Permian Basin:						
Operated Permian-Garden City	950	179	1,129	1,080	96	%
Non-Operated Permian Garden City	140	10	150	43	29	%
Other Properties	1	—	1	1	95	%
Total	1,091	189	1,280	1,124	88	%

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own an interest as of December 31, 2014 for each of our core operating areas, including acreage held by production ("HBP" in the table below). 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	112,465	102,869	73,762	52,536	186,227	155,405	66	%
Permian-China Grove	478	465	52,237	40,813	52,715	41,278	1	%
Permian Total	112,943	103,334	125,999	93,349	238,942	196,683		
Other Properties	640	502	54,091	44,447	54,731	44,949	1	%
Total	113,583	103,836	180,090	137,796	293,673	241,632	43	%

Undeveloped acreage expirations

The following table sets forth the gross and net undeveloped acreage in our core operating areas as of December 31, 2014 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.

	2015		2016		2017		2018	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian Basin:								
Permian-Garden City	22,915	15,211	8,731	7,057	4,038	1,983	8,068	8,068
Permian-China Grove	47,551	37,168	4,686	3,645	—	—	—	—
Permian Total	70,466	52,379	13,417	10,702	4,038	1,983	8,068	8,068
Other Properties	36,219	26,641	2,741	2,418	10,941	11,096	4,190	4,122
Total	106,685	79,020	16,158	13,120	14,979	13,079	12,258	12,190

Of the total undeveloped acreage identified as expiring over the next three years, approximately 3,165 net acres have PUD reserves on location. These PUD reserves represent approximately 3.7% of the Company's overall PUD reserves. The Company anticipates using lease extensions and drilling to hold the leases associated with these 3,165 net acres. Less than 1% of the net acres of leasehold that were identified as attributable to PUD reserves and potentially expiring in 2014 actually expired. The remainder of such acreage was kept either through lease extensions or drilling.

Drilling activity

The following table summarizes our drilling activity for the years ended December 31, 2014, 2013 and 2012. 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.

	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	219	183.9	171	127.2	199	183.2
Dry	—	—	—	—	—	—
Total development wells	219	183.9	171	127.2	199	183.2
Exploratory wells:						
Productive	2	1.8	2	2.0	1	1.0
Dry	1	1.0	—	—	1	0.9
Total exploratory wells	3	2.8	2	2.0	2	1.9

Marketing and major customers

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

As of December 31, 2014, 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	2015	2016	2017	2018 and after
Crude Oil (MBbl)					
Sales Commitments	30,151	9,180	6,935	8,030	6,006
Transportation Commitments					
Field	108,795	6,059	9,709	13,359	79,668
To U.S. Gulf Coast	36,500	3,060	3,650	3,650	26,140
Natural gas (MMcf)					
Sales Commitments	76,765	8,540	6,474	5,966	55,785
Transportation Commitments	—	—	—	—	—
Total (MBOE)	188,240	19,722	21,373	26,033	121,112

We expect to fulfill our delivery commitments over the next three years with production from our proved reserves. We expect to fulfill our longer-term delivery commitments beyond three years primarily with our proved undeveloped reserves. 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 proved reserves have been equivalent or greater than our delivery commitments during the three most recent years, and we expect such reserves will continue to exceed our future commitments. However, in certain instances, we have used spot market purchases in order to meet commitments in certain locations or due to favorable pricing. We anticipate continuing this practice in the future. Also, if our proved reserves are 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 the loss of any one of our major purchasers would not have a

material adverse effect on our financial condition and results of operations. For information regarding each of our customers that accounted for 10% or more of our oil and natural gas revenues during the last three calendar years, see Note 9 in our audited 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."

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, 2014, 43% of our leasehold 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 available cash. 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 development 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 discharge 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 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, natural gas and natural gas liquids 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, which 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 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 and joint and several liability penalties that could impose liability upon us regardless of fault. 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 of $350 million. 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. It is possible, however, 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 in reportable quantities 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. Although hydraulic fracturing has historically been regulated by state oil and gas commissions, the EPA recently asserted federal regulatory authority over the process under the SDWA's Underground Injection Control ("UIC") Program. 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. Also, the EPA is updating chloride water quality criteria for the protection of aquatic life under the Clean Water Act, which criteria are used by states for establishing acceptable discharge limits. The EPA is expected to release draft criteria in early 2016. 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. On November 3, 2011, the EPA released its Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources. The study will include both analysis of existing data and investigative activities designed to generate future data. The EPA issued a progress report in December 2012, and expects to release a draft report for public comment and peer review in March 2015. In addition, legislation is pending in 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. Finally, on October 20, 2011, the EPA announced its plan to propose federal pre-treatment standards for wastewater generated during the hydraulic fracturing process. Hydraulic fracturing stimulation requires the use of a significant volume of water with some resulting "flowback," as well as "produced water." The EPA asserts that this water may contain radioactive materials and other pollutants and, therefore, may deteriorate drinking water quality if not properly treated before discharge. The Clean Water Act prohibits the discharge of wastewater into federal or state waters. Thus, "flowback" and "produced water" must either be injected into permitted disposal wells, transported to public or private treatment facilities for treatment, or recycled. The EPA asserts that due to some contaminants in hydraulic fracturing wastewater, most treatment facilities are unable to treat the wastewater before introducing it into public waters. If adopted, the new pre-treatment rules will require shale gas operations to pre-treat wastewater before transferring it to treatment facilities. A proposed rule is expected in early 2015. 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.

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. 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. 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 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 disposal well rule amendments became effective November 17, 2014. 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. Furthermore, on May 16, 2013, the United States Department of the Interior ("DOI") issued a revised proposed rule that seeks to require companies operating on federal and Indian lands to (i) publicly disclose the chemicals used in the hydraulic fracturing process; (ii) confirm its wells meet certain construction standards and (iii) establish site plans to manage flowback water. The DOI announced its intent to finalize the rule in 2014, however the final rule remains pending. Under current federal law, there is no requirement for operators to disclose the use of such chemicals, although Laredo has already commenced similar disclosure with state regulators.

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 adopted 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 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. These rules may require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells. 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. The EPA intends to issue revised rules that may be responsive to some of these requests. On September 23, 2013, the EPA finalized the portion of the rule addressing VOC emissions from storage tanks, including a phase-in period and an alternative emissions limit for older tanks. On December 19, 2014, the EPA released final updates and clarifications to the NSPS standards. In addition, on January 14, 2015, the EPA announced a series of steps it plans to take to address methane and smog-forming VOC emissions from the oil and gas industry. 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

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" ("GHGs") and including carbon dioxide and methane, may be contributing to warming of the earth's atmosphere and other climatic changes. In response to such studies, Congress has from time to time considered legislation to reduce emissions of GHGs. One bill approved by the House of Representatives in June 2009, known as the American Clean Energy and Security Act of 2009, would have required an 80% reduction in 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, 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 January 2011, 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 indicates it will undertake a rulemaking action no later than December 31, 2015 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. 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 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 addition, the EPA has continued to adopt GHG regulations of other industries, such as a September 2013 proposed GHG rule that, if finalized, would set NSPS for new coal-fired and natural-gas fired power plants. In December 2014, the EPA published a proposed rule to amend the GHG Reporting Program 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 rule underwent an extended public comment period, which closed on February 24, 2015.

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.

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 that are listed as threatened or endangered and where other species, such as the sage grouse, 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 2013 or 2014.

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

Under the Iran Threat Reduction and Syrian Human Rights Act of 2012 (the "Act"), which added 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 ("EIG") and Santander Asset Management Investment Holdings Limited ("SAMIH"). EIG 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 EIG and SAMIH and its non-U.S. 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 EIG 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 EIG:

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

"On July 2, 2013, the billing information for a subscriber account, or the Subscriber Account was updated to include Seyed Mahmoud Mohaddes, or Mohaddes. On September 16, 2013, the Office of Foreign Assets Control, ("OFAC"), designated Mohaddes as a Specially Designated National, or ("SDN"), pursuant to 31 C.F.R. Part 560.304. On or around September 26, 2014, during a routine compliance scan of new and existing subscriber accounts, EIG discovered that Mohaddes was named as an account contact for the Subscriber Account. EIG promptly suspended the Subscriber Account, locked the domain name IOCUKLTD.COM, which was registered to the Subscriber Account, and reported the domain name to OFAC as potentially the property of a SDN subject to blocking pursuant to Executive Order 13599. Since September 16, 2013, when Mohaddes was added to the SDN list, charges in the total amount of $120.35 were made to the Subscriber Account for web hosting and domain privacy services. EIG has ceased billing for the Subscriber Account. To date, EIG has not received any correspondence from OFAC regarding this matter.

On July 10, 2014, OFAC designated each of Stars Group Holding, or Stars, and Teleserve Plus SAL, or Teleserve, as SDNs under Executive Order 13224, and their property became subject to blocking pursuant to the Global Terrorism Sanctions Regulations, 31 C.F.R. Part 594. On July 15, 2014, as part of EIG's compliance review processes, EIG discovered that the domain names associated with each of Stars, STARSCOM.NET, and Teleserve, TELESERVEPLUS.COM, or collectively, the Stars/Teleserve Domain Names, were registered through EIG's platform. EIG immediately took steps to suspend and lock the Stars/Teleserve Domain Names to prevent them from being transferred or resolving to a website, and EIG promptly reported the Domain Names as potentially blocked property to OFAC. EIG did not generate any revenue from the Stars/Teleserve Domain Names between when they were added to the SDN list on July 10, 2014 and when EIG discovered that they were registered through EIG's platform on July 15, 2014. To date, EIG has not received any correspondence from OFAC regarding the matter.

On July 15, 2014 during a compliance scan of all domain names on one of our platforms, EIG identified the domain name KAHANETZADAK.COM, or (the "Domain Name"), which was listed as an ‘also known as,' or AKA, of the entity Kahane Chai which operates as the American Friends of the United Yeshiva. Kahane Chai was designated as a SDN on November 2, 2001 pursuant to Executive Order 13224. Because the Domain Name was transferred into a customer account of one of EIG's resellers, there was no direct financial transaction between EIG and the registered owner of the Domain Name. The Domain Name was suspended upon EIG's discovering it on EIG's platform, and EIG reported the Domain Name to OFAC as potentially the property of a SDN. To date, EIG have not received any correspondence from OFAC regarding the matter."

As to SAMIH:

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

"Santander UK holds frozen savings and current accounts for three 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 2014. No revenue has been generated by Santander UK on these accounts. The bank account held for one of these customers was closed in the fourth quarter of 2014.

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 2014, total revenue in connection with the mortgage was approximately £2,580 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 accounts have remained frozen during 2014. 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 £250 and net profits in 2014 were negligible relative to the overall profits of Banco Santander, S.A.

In addition, during the third quarter 2014, Santander UK identified two additional customers: a U.K. national designated by the U.S. under the NPWMD sanctions program held a business account. No transactions were made and the account was closed in the fourth quarter of 2014. No revenue or profit has been generated. A second U.K. national designated by the U.S. for reasons of terrorism held a personal current account and a personal credit card account, both of which were closed in the third quarter of 2014. Although transactions took place on the current account during the third quarter of 2014, revenue and profits generated were negligible. No transactions took place on the credit card."

Employees

As of December 31, 2014, we had 420 full-time employees. We also employed a total of 71 contract personnel who assist our full-time employees with respect to specific tasks and perform various field and other services. On January 20, 2015, we announced the closing of our Dallas, Texas area office and the termination of approximately 75 employees Company-wide. We also released 24 contract personnel. See Note 16.b to our audited consolidated financial statements included elsewhere in this Annual Report. 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 that we will be closing our Dallas, Texas area office. We are currently still leasing the office space but are actively exploring alternative arrangements.

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 and natural gas prices are volatile. A continuing and extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments as well as negatively impact our stock price.

The prices we receive for our oil and natural gas production heavily influence our revenue, profitability, access to capital and future rate of growth. Oil 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 and natural gas has been volatile, and this volatility has been evident in the last quarter of 2014 and has continued into the first quarter of 2015. 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, natural gas and NGL;
- the level of global oil, natural gas and NGL exploration and production;
- the level of global oil, natural gas and NGL inventories, in particular due to supply growth from the United States;
- 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 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 and natural gas price and production controls;
- the extent to which U.S. shale producers become "swing producers" adding or subtracting to the world supply totals of oil, natural gas and NGL;
- 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 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, natural gas and NGL prices will 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 and natural gas reserves as existing reserves are depleted. A continuing decrease in oil and natural gas prices could render uneconomic a significant portion of our exploration, development and exploitation projects. This may result in our having to make significant downward adjustments to our estimated proved reserves. Furthermore, under our Senior Secured Credit Facility, scheduled borrowing base redeterminations occur 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. As a result, a substantial or extended decline in oil and natural gas prices may materially and adversely impact our borrowing base in future borrowing base redeterminations, which could trigger repayment obligation 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 and natural gas prices may cause a decline in our stock price.

Drilling for and producing oil 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 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 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 and engineering studies, 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 and natural gas prices, or negative revisions to reserves estimates or assumptions as to future oil and natural gas prices, may lead to decreased earnings, losses or impairment of oil 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 and natural gas prices;
- limited availability of financing or capital at acceptable rates or terms;
- limitations in the market for oil 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.

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 this severe drought, 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 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. 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. 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 process is typically regulated by state oil and gas commissions. The U.S. Environmental Protection Agency (the "EPA"), however, recently asserted federal regulatory authority over hydraulic fracturing under the federal Safe Drinking Water Act's ("SDWA") Underground Injection Control ("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 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 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 draft guidance. Also, the EPA is updating chloride water quality criteria for the protection of aquatic life under the Clean Water Act, which criteria are used by states for establishing acceptable discharge limits. The EPA is expected to release draft criteria in early 2016. 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. On November 3, 2011, the EPA released its Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources. The study will include both analysis of existing data and investigative activities designed to generate future data. The EPA issued a progress report in December 2012, held several technical workshops during 2013, and expects to release a draft report for public comment and peer review in March 2015.

In August 2012, the EPA adopted 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") 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. These rules may require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells by 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. The EPA intends to issue revised rules that may be responsive to some of these requests. On September 23, 2013, the EPA finalized the portion of the rule addressing VOC emissions from storage tanks, including a phase-in period and an alternative emissions limit for older tanks. On December 19, 2014, the EPA released final updates and clarifications to the NSPS standards. In addition, on January 14, 2015, EPA announced a series of steps it plans to take to address methane and smog-forming VOC emissions from the oil and gas industry. 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. 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 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 disposal well rule amendments became effective November 17, 2014. 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. Furthermore, on May 16, 2013, the United States Department of the Interior ("DOI") issued a revised proposed rule that seeks to require companies operating on federal and Indian lands to (i) publicly disclose the chemicals used in the hydraulic fracturing process; (ii) confirm their wells meet certain construction standards and (iii) establish site plans to manage flowback water. The DOI announced its intent to finalize the rule in 2014, however, the final rule remains pending. Under current federal law, there is no requirement for operators to disclose the use of such chemicals, although we have already commenced similar disclosure with state regulators. In addition, legislation is pending in 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. Finally, on October 20, 2011, the EPA announced its plan to propose federal pre-treatment standards for wastewater generated during the hydraulic fracturing process. Hydraulic fracturing stimulation requires the use of a significant volume of water with some resulting "flowback," as well as "produced water." The EPA asserts that this water may contain radioactive materials and other pollutants and, therefore, may deteriorate drinking water quality if not properly treated before discharge. The Clean Water Act prohibits the discharge of wastewater into federal or state waters. Thus, "flowback" and "produced water" must either be injected into permitted disposal wells or transported to public or private treatment facilities for treatment, or recycled. The EPA asserts that due to some contaminants in hydraulic fracturing wastewater, most treatment facilities are unable to properly treat the wastewater before introducing it into public waters. If adopted, the new pre-treatment rules will require shale gas operations to pre-treat wastewater before transferring it to treatment facilities. A proposed rule is expected in early 2015.

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" takes 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 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 disposal well rule amendments become effective November 17, 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 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 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.
Estimating reserves and future net revenues involves uncertainties. Decreases in oil and natural gas prices, or negative revisions to reserve estimates or assumptions as to future oil and natural gas prices, may lead to decreased earnings, losses or impairment of oil 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 and natural gas that cannot be measured in an exact manner. Reserves that are "proved reserves" are those estimated quantities of oil 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 projects for which the extraction of hydrocarbons must have commenced or the operator must be reasonably certain will commence within a reasonable time.
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 many 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 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 2014, negative revisions of 26,017 MBOE were due to the combined effect of removing 226 proved locations and the net effect of redetermining 345 undeveloped locations. The 226 locations that were removed were comprised of 223 vertical Wolfberry and three short horizontal laterals.

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 17.d in our audited consolidated financial statements included elsewhere in this Annual Report.

Also, the substantial decrease in oil and natural gas prices that began in the second half of 2014 and has continued into the first quarter of 2015, if continued or maintained, could have the effect of rendering uneconomic a portion (which could be significant) of our exploration, development and exploitation projects. This would result in our having to make downward adjustments (which could be significant) to our estimated proved reserves.

As a result of the recent commodity price decrease, we may be required to take 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 may be required to write down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. The substantial decrease in oil and natural gas prices that began in the second half of 2014 and which has continued into the first quarter of 2015, if continued or maintained, will have the effect of requiring us to incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken. See Note 2.h to our audited consolidated financial statements included elsewhere in this Annual Report for additional information.

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 and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations, capital contributions, borrowings on our Senior Secured Credit Facility, equity offerings and proceeds from 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 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 financing 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 and natural gas production or reserves and, in some areas, a loss of properties.

Our oil 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 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 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. The current United States restrictions on the export of oil and natural gas increase the possibility of an oversupply in any of the markets into which we sell our products. 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 U.S. If the export limitations noted above continue and light sweet crude oil production 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.

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 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 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 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 owned by the producer. We are active in drilling and producing allocation wells. The RRC has not provided definitive rules on the allocation well permitting process. If the RRC denies or significantly delays the permitting of allocation wells, or if legislation is enacted that negatively impacts the current regulatory 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.

The potential drilling locations for our future wells that we have tentatively identified are scheduled out over many years, making 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 scheduled certain potential drilling locations as an estimation of our future multi-year drilling activities on our existing acreage, our ability to drill and develop these locations depends on a number of uncertainties, including oil 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 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, our actual drilling activities may materially differ from those presently anticipated.

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

Producing oil and natural gas reservoirs generally are 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 decline as those reserves are produced. Our future oil 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.

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 and natural gas, we enter into derivative instrument contracts for a portion of our oil 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 statement of operations gain (loss) on derivatives. Loss (gain) 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. Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

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

In addition, if we are unable to enter into new hedge contracts in the future at favorable pricing and for a sufficient amount of our production, our financial condition and results of operations could be materially adversely affected. 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."

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 and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil 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 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 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 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 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 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 and natural gas produced from our fields, could materially and adversely affect our financial condition and results of operations.
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 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.
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 and natural gas we produce.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases", including carbon dioxide and methane, may be contributing to warming of the earth's atmosphere and other climatic changes. In response to such studies, Congress has from time to time considered legislation to reduce emissions of GHGs. One bill approved by the House of Representatives in June 2009, known as the American Clean Energy and Security Act of 2009, would have required an 80% reduction in 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 January 2011, 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 indicates it will undertake a rulemaking action no later than December 31, 2015 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. 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 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 addition, the EPA has continued to adopt GHG regulations of other industries, such as a September 2013 proposed GHG rule that, if finalized, would set NSPS for new coal-fired and natural-gas fired power plants. In December 2014, the EPA published a proposed rule to amend the GHG Reporting Program to add reporting of greenhouse gas emissions from gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines. The rule is underwent an extended public comment period which closed on February 24, 2015. 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.

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") 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 has 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), establishing an "end-user" exception to the Mandatory Clearing Rule, which we refer to as the "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. In addition, the CFTC and bank regulators re-proposed rules, which we refer to as the "Re-Proposed SD/MSP Margin Rules," which, if adopted, would require that swap dealers and major swap participants receive initial and variation margin on uncleared swaps with financial end-users with material swaps exposures, swap dealers and major swap participants.

We qualify for and will utilize the End-User Exception to the Mandatory Clearing Rule if it is expanded to cover swaps in which we participate, our hedging and other activities are such that we will not be required to post margin under the Re-Proposed SD/MSP Margin Rules, if adopted, 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, if the Re-Proposed SD/MSP Margin Rules are adopted, will be subject to such rule and required to post margin in accordance with such rule in connection with their swaps with other swap dealers and major swap participants. The Dodd-Frank Act, the rules which have been adopted and not vacated, and, to the extent that the Re-Proposed Position Limit Rule and the Re-Proposed SD/MSP Margin Rules are ultimately effected, such proposed rules could significantly increase the cost of our derivative contracts (including through our being required to post collateral), 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. If we reduce our use of derivatives as a result of the Dodd-Frank Act and 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.

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 available for drilling and place us at a competitive disadvantage. For example, as of February 25, 2015 we have $900.0 million 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 $900.0 million elected commitment on our Senior Secured Credit Facility would result in increased annual interest expense of $9.0 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.

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, 2014, substantially 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 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.

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 ($33.8 million as of December 31, 2014) and the sale of our oil and natural gas production ($57.1 million in receivables as of December 31, 2014), which we market to energy marketing companies, refineries and affiliates. Joint interest receivables arise from billing entities who own partial interest 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 and natural gas receivables with several significant customers. The largest purchaser of our oil and natural gas accounted for 36.0% of our total oil and natural gas revenues for the year ended December 31, 2014. See Note 9 to our audited consolidated financial statements included elsewhere in this Annual Report. 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.

Locations that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Locations that we decide to drill that do not yield oil or natural gas in commercially viable quantities will adversely affect our results of operations and financial condition. In this Annual Report, we describe some of our current drilling locations and our plans to explore those drilling locations. Our drilling locations are in various stages of evaluation, ranging from those that are ready to drill to those that will require substantial additional seismic data processing and interpretation before a decision can be made to proceed with the drilling of such locations. There is no way to predict in advance of drilling and testing whether any particular drilling location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will result in successfully locating oil or natural gas in commercial quantities on our prospective acreage.

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 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 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, 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. As a result of our reduced 2015 capital expenditure budget compared to 2014, we have begun releasing drilling rigs as their contracts came close to expiration and incurred related expenses of $0.5 million. 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 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 and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil 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 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, 2014, Warburg Pincus owned 40.3% 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 have limited control over activities on properties we do not operate, which could reduce our production and revenues.

A portion of our business 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, we do not have control over normal operating procedures, expenditures or future development of the underlying properties. 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.

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 which 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 which 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.

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 and natural gas prices and their applicable differentials;
- 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 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 and 2009 of $6.1 million, $192.0 million and $184.5 million, respectively. Our financial statements include deferred tax assets, which require management's judgment when evaluating whether they will be realized. 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 and natural gas reserves and realize our deferred tax assets. 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.

We may incur significant additional amounts of debt.

As of February 25, 2015, we had total long-term indebtedness of $1.9 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.

42

Our debt agreements contain restrictions that will 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.
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. It is unclear whether any of the foregoing changes will actually be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development. Any such 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.
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.

As of December 31, 2014, we had a net operating loss ("NOL") carryforward for federal income tax purposes of approximately $1.0 billion. If we were to experience an "ownership change," as determined under Section 382 of the Internal Revenue 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 NOLs we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate. In general, an ownership change will occur if there is a cumulative increase in our ownership of more than 50 percentage points by one or more "5% shareholders" (as defined in the Internal Revenue Code) at any time during a rolling three-year period.

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 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 your ability to influence corporate matters.
As of December 31, 2014, Warburg Pincus owned 40.3% of our outstanding common stock. Consequently, Warburg Pincus has significant influence over all matters that require approval by our stockholders, including the election of directors and approval of significant corporate transactions. This concentration of ownership limits the ability of other stockholders to influence corporate matters.
Furthermore, conflicts of interest could arise in the future between us, on the one hand, and Warburg Pincus and its affiliates, including its portfolio companies, on the other hand, concerning among other things, potential competitive business activities or business opportunities. Warburg Pincus LLC is a private equity firm that has invested in, among other things, companies in the energy industry. As a result, Warburg Pincus' existing and future portfolio companies which it controls may compete with us for investment or business opportunities. These conflicts of interest may not be resolved in our favor.
We have also renounced our interest in certain business opportunities. Our amended and restated certificate of incorporation provides that, to the fullest extent permitted by applicable law, we renounce any interest or expectancy in any business opportunity, transaction or other matter in which Warburg Pincus or any private fund that it manages or advises, any of their respective officers, directors, partners and employees, and any portfolio company in which such persons or entities have an equity interest (other than us and our subsidiaries) (each, a "specified party") participates or desires or seeks to participate and that involves any aspect of the energy business or industry, even if the opportunity is one that we might reasonably have pursued or had the ability or desire to pursue if granted the opportunity to do so, and no such specified party shall be liable to us for breach of any fiduciary or other duty, as a director or officer or controlling stockholder or otherwise, by reason of the fact that such specified party pursues or acquires any such business opportunity, directs any such business opportunity to another person or fails to present any such business opportunity, or information regarding any such business opportunity, to us. Notwithstanding the foregoing, we do not renounce any interest or expectancy in any business opportunity, transaction or other matter that is offered in writing solely to (i) one of our directors or officers who is not also a specified party or (ii) a specified party who is one of our directors, officers or employees and is offered such business opportunity solely in his or her capacity as our director, officer or employee. By renouncing our interest and expectancy in any business opportunity

that from time to time may be presented to Warburg Pincus and its affiliates, our business and prospects could be adversely affected if attractive business opportunities are procured by such parties for their own benefit rather than for ours.

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

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

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

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

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

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

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

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

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

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

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

Item 3. Legal Proceedings

From time to time, we are subject to various legal proceedings arising in the ordinary course of business, including proceedings for which we have insurance coverage. As of the date hereof, we are not party to any legal proceedings which 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
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
2013:		
Fourth Quarter	$33.52	$25.30
Third Quarter	$30.00	$20.21
Second Quarter	$20.85	$15.95
First Quarter	$20.03	$16.56

On February 25, 2015, the last sale price of our common stock, as reported on the NYSE, was $13.04 per share.

Holders. As of February 23, 2015, there were 59 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 will 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, 2014 - October 31, 2014	4,922	$20.26	—	—
November 1, 2014 - November 30, 2014	1,867	$16.55	—	—
December 1, 2014 - December 31, 2014	3,944	$9.27	—	—

(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, 2014, 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 audited 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, 2014, 2013 and 2012 and the balance sheet data as of December 31, 2014 and 2013 are derived from our audited consolidated financial statements and the notes thereto included elsewhere in this Annual Report. The historical financial data for the years ended December 31, 2011 and 2010 and the balance sheet data as of December 31, 2012, 2011 and 2010 are derived from our audited financial statements not included in this Annual Report.

	For the years ended December 31,				
(in thousands, except per share data)	2014	2013[1]	2012	2011	2010
Statement of operations data[2]:					
Total revenues	$793,885	$665,257	$583,894	$506,347	$239,791
Total costs and expenses	567,499	450,906	411,954	303,827	164,230
Operating income	226,386	214,351	171,940	202,520	75,561
Non operating income (expense), net	203,473	(23,267)	(77,176)	(36,932)	(12,516)
Income from continuing operations before income taxes	429,859	191,084	94,764	165,588	63,045
Income tax (expense) benefit	(164,286)	(74,507)	(33,003)	(59,612)	24,847
Income from continuing operations	265,573	116,577	61,761	105,976	87,892
Income (loss) from discontinued operations, net of tax	—	1,423	(107)	(422)	(1,644)
Net income	$265,573	$118,000	$61,654	$105,554	$86,248
Net income per common share:					
Basic:					
Income from continuing operations	$1.88	$0.88	$0.49	$0.99	
Income (loss) from discontinued operations	—	0.01	—	(0.01)	
Net income per share	$1.88	$0.89	$0.49	$0.98	
Diluted:					
Income from continuing operations	$1.85	$0.87	$0.48	$0.98	
Income (loss) from discontinued operations	—	0.01	—	—	
Net income per share	$1.85	$0.88	$0.48	$0.98	

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

(2) 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.

	As of December 31,				
(in thousands)	2014	2013	2012	2011	2010
Balance sheet data:					
Cash and cash equivalents	$29,321	$198,153	$33,224	$28,002	$31,235
Net property and equipment	3,354,082	2,204,324	2,113,891	1,378,509	809,893
Total assets	3,932,549	2,623,760	2,338,304	1,627,652	1,068,160
Current liabilities	425,025	253,969	262,068	214,361	150,243
Long-term debt	1,801,295	1,051,538	1,216,760	636,961	491,600
Stockholders' equity	1,563,201	1,272,256	831,723	760,013	411,099

	For the years ended December 31,				
(in thousands)	2014	2013(1)	2012	2011	2010
Other financial data:					
Net cash provided by operating activities	$498,277	$364,729	$376,776	$344,076	$157,043
Net cash used in investing activities	(1,406,961)	(329,884)	(940,751)	(706,787)	(460,547)
Net cash provided by financing activities	739,852	130,084	569,197	359,478	319,752

(1) 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 3.e to our audited consolidated financial statements included elsewhere in this Annual Report for additional information.

	For the years ended December 31,				
(in thousands, unaudited)	2014	2013	2012	2011	2010
Adjusted EBITDA(1)	$597,769	$472,166	$443,434	$384,342	$188,568

(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to net income see "—Non-GAAP financial measures and reconciliations" below.

Non-GAAP financial measures and reconciliations

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for interest expense, depletion, depreciation and amortization, impairment of long-lived assets, write-off of debt issuance costs, bad debt expense, gains or losses on disposal of assets, total gains or losses on derivatives, cash settlements of matured commodity derivatives, cash settlements on early terminated commodity derivatives, premiums paid for derivatives that matured during the period, non-cash stock-based compensation and income tax expense or benefit. 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, 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)	2014	2013	2012	2011	2010
Net income	$265,573	$118,000	$61,654	$105,554	$86,248
Plus:					
Interest expense	121,173	100,327	85,572	50,580	18,482
Depletion, depreciation and amortization	246,474	234,571	243,649	176,366	97,411
Impairment of long-lived assets	3,904	—	—	243	—
Write-off of debt issuance costs	124	1,502	—	6,195	—
Bad debt expense	342	653	—	—	—
Loss on disposal of assets, net	3,252	1,508	52	40	30
Gain on derivatives, net	(327,920)	(79,878)	(8,388)	(19,736)	(5,815)
Cash settlements received for matured commodity derivatives, net	28,241	4,046	27,025	3,719	22,701
Cash settlements received for early terminations and modifications of commodity derivatives, net	76,660	6,008	—	—	—
Premiums paid for derivatives that matured during the period[1]	(7,419)	(11,292)	(9,135)	(4,104)	(5,934)
Non-cash stock-based compensation, net of amount capitalized	23,079	21,433	10,056	6,111	1,257
Deferred income tax expense (benefit)	164,286	75,288	32,949	59,374	(25,812)
Adjusted EBITDA	$597,769	$472,166	$443,434	$384,342	$188,568

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

51

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 audited 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 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 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. In December 2013, we completed the Internal Consolidation, which simplified our corporate structure.

Our financial and operating performance for the year ended December 31, 2014 included the following:

- Permian oil and natural gas sales of $737.2 million, compared to $605.2 million for the year ended December 31, 2013;
- Permian average daily sales volumes of 32,134 BOE/D, compared to 24,960 BOE/D for the year ended December 31, 2013;
- Estimated proved reserves of 247,322 MBOE, compared to 203,615 MBOE as of December 31, 2013; and
- Adjusted EBITDA (a non-GAAP financial measure) of $597.8 million, compared to $472.2 million for the year ended December 31, 2013.

Recent developments

Recent drop in oil prices

We review the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC on a quarterly basis. The substantial decrease in oil and natural gas prices that began in the second half of 2014 and has continued into the first quarter of 2015, if continued or maintained, may require us to incur non-cash full cost impairments in the future, which could have a material adverse effect on our results of operations for the periods in which the impairments are incurred.

Potential transaction

As announced previously, we have been in discussions with interested parties regarding a potential joint development opportunity involving, initially, a portion of our northern Permian-Garden City properties, and subsequently expanded to include a portion of our other properties. These discussions are continuing and have centered on terms associated with funding drilling opportunities. There is no assurance as to the form of a potential transaction or that a transaction will be consummated.

Restructuring

Following the recent drop in oil and natural gas prices, in an effort to reduce costs and better position ourselves for ongoing efficient growth, on January 20, 2015, we committed to a company-wide restructuring and reduction in force (the "RIF") that includes (i) the relocation of certain employees in our Dallas, Texas area office to our other existing offices in Tulsa, Oklahoma and Midland, Texas; (ii) closing our Dallas, Texas area office; (iii) a workforce reduction of approximately 75 employees and (iv) the release of 24 contract personnel. The reduction in workforce was communicated to employees on January 20, 2015 and was generally effective immediately. The relocation of our employees and the closing of our Dallas, Texas area office are expected to be completed by June 1, 2015. Our compensation committee approved the RIF and the severance package offered in connection with the RIF. We estimate the first-quarter 2015 financial statement impact to range between $6.0 - $7.0 million.

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 July 12, 2012, we completed the acquisition of additional working interests in certain oil and natural gas properties located in Glasscock County, Texas in the Permian Basin, for a contract price of $20.5 million from a private company, net of closing purchase price adjustments.

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 Permian 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 Permian 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 audited consolidated financial statements included elsewhere in this Annual Report as discontinued operations. See Notes 2.c and 3.e to our audited 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.

Common stock transactions

During the year ended December 31, 2014, Warburg Pincus distributed our common stock pro rata to certain of the Warburg Pincus limited partners. As of February 23, 2015, Warburg Pincus owned 40.4% of our outstanding common stock. The following details the distributions throughout the year ended December 31, 2014:

Date of distribution	Number of shares distributed	Distribution % of Warburg Pincus' holdings of our common stock prior to the distribution	
March 4, 2014	7,035,017	10	%
May 12, 2014	5,097,388	8	%

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, 2014, we had assembled 196,683 net acres in the Permian Basin, of which 155,405 net acres are located in our Permian-Garden City area.

Reserves and pricing

Our results of operations are heavily influenced by commodity prices, which have significantly declined in recent months. Prices for oil and natural gas can fluctuate widely in response to relatively minor changes in the global and regional supply of and demand for oil and natural gas, market uncertainty, economic conditions and a variety of additional factors. Oil prices began to decline in June 2014 and in late November 2014 a rapid decline in oil prices occurred. 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 ability to fund drilling projects, as well as the economic valuation and economic recovery of oil and natural gas reserves.

Ryder Scott, our independent reserve engineers, estimated 100% of our proved reserves, reported on a two-stream basis, as of December 31, 2014, 2013 and 2012. As of December 31, 2014, we had 247,322 MBOE of estimated proved reserves as compared to 203,615 MBOE of estimated proved reserves as of December 31, 2013 and 188,632 MBOE of estimated proved reserves as of December 31, 2012.

Our reserves are reported in two streams: crude oil and liquids-rich natural gas. The economic value of the natural gas liquids in our natural gas is included in the wellhead natural gas price. The unweighted arithmetic average first-day-of-the-month index prices for the prior 12 months were $91.48 per Bbl for oil and $4.25 per MMBtu for natural gas as of December 31, 2014, $93.52 per Bbl for oil and $3.57 per MMBtu for natural gas as of December 31, 2013 and $91.21 per Bbl for oil and $2.63 per MMBtu for natural gas as of December 31, 2012. The prices used to estimate proved reserves for all periods do not include derivative transactions. These prices were held constant throughout the life of the properties and have been adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

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."

Sources of our revenue

Our revenues are primarily derived from the sale of oil 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, 2014, our revenues are comprised of sales of 72% oil, 21% liquids-rich natural gas and 7% purchased oil. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold and/or changes in commodity 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 workover expenses related to our oil and natural gas properties.

Production and ad valorem taxes.   Production taxes are paid on produced oil and natural gas 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 and natural gas revenues. Ad valorem taxes are property taxes based on the value of our reserves attributed to our properties located in Texas.

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 early termination costs incurred for the termination of drilling rigs once drilling has ceased at a well site.
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 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 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 audited 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 audited 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 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 audited consolidated statements of operations as "Loss from equity method investee" and the carrying amount reflected in the audited consolidated balance sheet as "Investment in equity method investee." See Note 14 to our audited 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

55

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.

Write-off of deferred loan 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, 2014, 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.

Results of operations
For the year ended December 31, 2014 as compared to the year ended December 31, 2013, and for the year ended December 31, 2013 as compared to the year ended December 31, 2012
Sales volume, revenue and pricing

The following table sets forth information regarding oil 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,		
(unaudited)	2014	2013	2012
Sales volumes:			
Oil (MBbl)	6,901	5,487	4,775
Natural gas (MMcf)[1]	28,965	34,348	39,148
Oil equivalents (MBOE)[2][3]	11,729	11,211	11,300
Average daily sales volumes (BOE/D)[3]	32,134	30,716	30,874
% Oil	59 %	49 %	42 %
Revenues (in thousands):			
Oil	$571,620	$494,676	$414,932
Natural gas	165,583	170,168	168,637
Total revenues	$737,203	$664,844	$583,569
Average sales prices:			
Oil, realized ($/Bbl)[4]	$82.83	$90.16	$86.89
Natural gas, realized ($/Mcf)[4]	5.72	4.95	4.31
Average price, realized ($/BOE)[4]	62.86	59.29	51.65
Oil, hedged ($/Bbl)[5]	85.77	88.68	85.59
Natural gas, hedged ($/Mcf)[5]	5.73	4.98	4.92
Average price, hedged ($/BOE)[5]	64.62	58.66	53.22

(1) Excludes natural gas produced and consumed in operations of 169 MMcf for the year ended December 31, 2014. There were no comparable amounts for the years ended December 31, 2013 or 2012.
(2) Bbl 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 and natural gas prices are the actual prices realized at the wellhead after all adjustments for natural gas liquid content, quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price 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)	2014	2013	2012
Cash settlements received (paid) for matured commodity derivatives:			
Oil	$26,803	$(149)	$(944)
Natural gas	1,438	4,195	27,969
Total	$28,241	$4,046	$27,025
Premiums paid attributable to contracts that matured during the respective period:			
Oil	$(6,497)	$(7,970)	$(5,278)
Natural gas	(922)	(3,322)	(3,857)
Total	$(7,419)	$(11,292)	$(9,135)

The changes in prices and volumes shown in the oil and natural gas sales volumes, revenue and pricing table above caused the following changes to our oil and natural gas revenue between the years ended December 31, 2012, 2013 and 2014:

(in thousands)	Oil	Natural gas	Total net dollar effect of change
2012 Revenue	$414,932	$168,637	$583,569
Effect of changes in price	17,942	21,982	39,924
Effect of changes in volumes	61,812	(20,688)	41,124
Other	(10)	237	227
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

Oil and natural gas revenues. Our revenues are a function of oil and natural gas production volumes sold and average sales prices received for those volumes. The total increase in oil and natural gas revenues of $72.4 million, or 11%, for the year ended December 31, 2014 as compared to the year ended December 31, 2013 is largely related to a 26% rise in the production volume of oil due to an increased number of rigs in place during the year, along with a 16% increase in natural gas prices realized, which were partially offset by a 16% decrease in natural gas production volumes attributable to the divestiture of our Anadarko Basin assets. The total increase in oil and natural gas revenues of $81.3 million, or 14%, for the year ended December 31, 2013 as compared to the year ended December 31, 2012 is largely due to a 15% increase in oil production in our Permian area and an increase in both oil and natural gas prices realized for the year, which were offset by a decrease in natural gas production volumes attributable to the divestiture of our Anadarko Basin assets and by severe winter weather in the Permian region during the fourth quarter of 2013.

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

	For the years ended December 31,		
(unaudited)	2014	2013	2012
Revenues (in thousands):			
Midstream service revenue	$2,245	$413	$325

Sales of purchased oil	54,437	—	—
Total revenues	$56,682	$413	$325

Midstream service revenue. Our midstream service revenue from operations increased by $1.8 million during the year ended December 31, 2014 as compared to the year ended December 31, 2013 and $0.1 million during the year ended December 31, 2013 as compared to the year ended December 31, 2012. These increases were due to the sale of natural gas, natural gas liquids 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. Our revenues from sales of purchased oil for the year ended ended December 31, 2014 were $54.4 million. During the year ended December 31, 2014, we began purchasing oil from a producer in West Texas, transporting the product on the Bridgetex Pipeline and selling the product to a third party in the Houston market.

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)	2014	2013	2012
Costs and expenses:			
Lease operating expenses	$96,503	$79,136	$67,325
Production and ad valorem taxes	50,312	42,396	37,637
Midstream service expense	5,429	3,368	2,614
Natural gas volume commitment - affiliates	2,552	891	—
Costs of purchased oil	53,967	—	—
Drilling rig fees	527	—	—
General and administrative(1)	106,044	89,696	62,106
Accretion of asset retirement obligations	1,787	1,475	1,200
Depletion, depreciation and amortization	246,474	233,944	241,072
Impairment expense	3,904	—	—
Total costs and expenses	$567,499	$450,906	$411,954
Average costs per BOE sold:			
Lease operating expenses	$8.23	$7.06	$5.96
Production and ad valorem taxes	4.29	3.78	3.33
Midstream service expense	0.46	0.30	0.23
General and administrative(1)	9.04	8.00	5.50
Depletion, depreciation and amortization	21.01	20.87	21.33
Total	$43.03	$40.01	$36.35

(1) General and administrative includes non-cash stock-based compensation, net of amount capitalized, of $23.1 million, $21.4 million and $10.1 million for the years ended December 31, 2014, 2013 and 2012, respectively. Excluding stock-based compensation, net of amount capitalized, from the above metric results in general and administrative cost per BOE sold of $7.07, $6.09 and $4.61 for the years ended December 31, 2014, 2013 and 2012, respectively.

Lease operating 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.

Lease operating expenses, which include workover expenses, increased by $11.8 million, or 18%, compared to a 1% decrease in production, for the year ended December 31, 2013 compared to 2012. On a per-BOE sold basis, lease operating expenses increased in total to $7.06 per BOE sold as of December 31, 2013 from $5.96 per BOE sold as of December 31, 2012. 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 and (ii) the implementation of best practices with respect to workover operations. We expect that these practices will result in longer term well tubing integrity, which should improve overall well performance and production in the long term, in addition to decreasing unit lease expenses as a result of reduced well tubing failures.

Production and ad valorem taxes. 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%. Production taxes are based on and increase in proportion to our oil and natural gas revenue. 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.

Production and ad valorem taxes increased to $42.4 million for the year ended December 31, 2013 from $37.6 million for the year ended December 31, 2012, an increase of $4.8 million, or 13%. This was primarily the result of increased valuations on our Texas properties and an increase in the number of wells included in those valuations as a result of our 2012 and 2013 drilling activity in our Permian and Anadarko Granite Wash areas.

Midstream service expense. Midstream service expenses increased by $2.1 million, or 61%, for the year ended December 31, 2014 compared to 2013, and $0.8 million, or 29%, for the year ended December 31, 2013 compared to 2012, due to the expanded midstream service component of our business.

Costs of purchased oil. Costs of purchased oil for the year ended December 31, 2014 was $54.0 million. These costs include purchasing oil from a producer and transporting the oil on the Bridgetex Pipeline to the Houston market. There were no comparable amounts for the years ended December 31, 2013 and 2012.

General and administrative ("G&A").

The table below shows the changes in the significant components of general and administrative expense for the periods presented:

(in thousands)	Year ended December 31, 2014 compared to 2013	Year ended December 31, 2013 compared to 2012
Changes in G&A:		
Professional fees	$6,851	$(824)
Salaries, benefits and bonuses	6,249	17,493
Charitable contributions	3,106	80
Stock-based compensation, net of amount capitalized[(1)]	1,646	11,377
Performance unit awards	(4,132)	2,936
Production income	(2,217)	(5,837)
Other	4,845	2,365
Total change in G&A	$16,348	$27,590

(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 audited consolidated balance sheets included elsewhere in this Annual Report.

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 fair values of the restricted stock awards issued during 2014 and 2013 were calculated based on the value of our stock price on the date of grant in accordance with GAAP and are being recognized on a straight-line basis over the requisite service period of the awards. The fair values of our non-qualified restricted stock options were determined using a Black-Scholes valuation model in accordance with GAAP and are being recognized on a straight-line basis over the four-year requisite service period of the awards.

Our performance share awards are accounted for as equity awards. The fair value of the performance share awards issued during 2014 was 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 value 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 three-year requisite service period.

Our 2013 and 2012 Performance Unit Awards, which settle in cash, are accounted for as liability awards. The associated expense for these 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 5 to our audited consolidated financial statements included elsewhere in this Annual Report for additional information regarding our stock and performance based compensation.

Year ended December 31, 2013 compared to 2012. G&A expense, excluding stock-based compensation, increased to $68.3 million as of December 31, 2013 from $52.1 million as of December 31, 2012, an increase of $16.2 million, or 31%. The increase is primarily due to $17.5 million in additional salary, benefits and bonuses due to the growth of our business and employee base. Additionally, the issuance of our cash-settled performance unit awards in February 2012 and 2013, which are revalued at the end of each reporting period using a Monte Carlo simulation, accounted for $2.9 million of the total increase. Computer, relocation, aircraft, rent and miscellaneous other expenses also contributed to the increase by $4.4 million due to the growth of our business and employee base. The overall increase in G&A expense was offset by $11.0 million in greater production income, capitalized salary and benefits, billable vehicle expense and lower professional fees, travel costs, production data costs, and legal fees for 2013 as compared to 2012. On a per-BOE basis, G&A expense, excluding stock-based compensation, increased to $6.09 per BOE during the year ended December 31, 2013 from $4.61 per BOE as of December 31, 2012. This increase was a result of the growth in our employee base combined with lower total production growth due to the divestiture of our Anadarko Basin assets.

Stock-based compensation increased to $21.4 million as of December 31, 2013 from $10.1 million as of December 31, 2012, an increase of $11.4 million largely due to the issuance of 1,469,295 restricted stock awards and 1,018,849 non-qualified restricted stock options issued to our employees and non-employee directors during 2013. Additionally, during the year ended December 31, 2013, we accelerated the vestings of certain officers' and employees' restricted stock awards and restricted stock options awards upon retirement or termination of employment due to the Anadarko Basin Sale. These modifications accounted for $4.7 million of the stock-based compensation expense increase over the prior year.

Performance unit award expense increased by $2.9 million at year-end 2013 as compared to the year-end 2012, mainly as a result of the quarterly re-measurement, issuance of a new tranche of performance units during 2013 and the

performance of our stock price relative to the peer groups utilized in the forward-looking Monte Carlo simulation.
During the year ended December 31, 2013, certain officers' performance unit awards were modified to vest upon the officers' retirement in 2013. These performance unit awards were paid in cash at $100.00 per unit totaling $2.1 million.
Depletion, depreciation and amortization ("DD&A"). DD&A was $246.5 million for the year ended December 31, 2014 as compared to $233.9 million for the year ended December 31, 2013 and $241.1 million for the year ended December 31, 2012.

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)	2014	2013	2012
Depletion of evaluated oil and natural gas properties	$237,067	$227,992	$237,130
Depreciation of midstream service assets	4,303	1,510	797
Depreciation and amortization of other fixed assets	5,104	4,442	3,145
Total DD&A	$246,474	$233,944	$241,072
DD&A per BOE sold	$21.01	$20.87	$21.33

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 amortization base during the three months ended December 31, 2014, as management determined that we do not intend to drill this non-core acreage.

The decrease in depletion of evaluated oil and natural gas properties of $9.1 million and $0.64 per BOE for the year ended December 31, 2013 compared to 2012 is mainly a result of the Anadarko Basin Sale.

Impairment expense. Beginning in the fourth quarter of 2014, the Company owned oil line-fill in third-party pipelines, which is accounted for at LCM. For the year ended December 31, 2014, the Company recorded a LCM adjustment of $2.1 million related to its line-fill.

During the year ended December 31, 2014, the Company reduced materials and supplies by $1.8 million in order to reflect the balance at LCM. The Company determined an LCM adjustment was not necessary for materials and supplies during the years ended December 31, 2013 or 2012.

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)	2014	2013	2012
Non-operating income (expense):			
Gain (loss) on derivatives:			
Commodity derivatives, net	$327,920	$79,902	$8,800
Interest rate derivatives, net	—	(24)	(412)
Income (loss) from equity methods investee	(192)	29	—
Interest expense	(121,173)	(100,327)	(85,572)
Interest and other income	294	163	59
Write-off of debt issuance costs	(124)	(1,502)	—
Loss on disposal of assets, net	(3,252)	(1,508)	(51)
Non-operating income (expense), net	$203,473	$(23,267)	$(77,176)

Commodity derivatives. 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, 2014 compared to 2013	Year ended December 31, 2013 compared to 2012
Changes in gain on commodity derivatives, net:		
Fair value of commodity derivatives outstanding	$153,171	$88,073
Early terminations and modifications of commodity derivatives received	70,652	6,008
Cash settlements received for matured commodity derivatives	24,195	(22,979)
Total change in gain on commodity derivatives, net	$248,018	$71,102

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. The increase was partially offset by the cash received for the early settlement in February 2014 of our oil basis swap differential between the Light Louisiana Sweet Argus and the Brent International Petroleum Exchange index oil prices. The year ended December 31, 2013 compared to 2012 increase in fair value of commodity derivatives outstanding is mainly due to our oil basis swap differential between the Light Louisiana Sweet Argus and the Brent International Petroleum Exchange index oil prices, which was entered into during 2013 and was valued at $92.8 million at December 31, 2013.

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. There were no comparable amounts in 2012. Net cash settlements received for matured commodity derivatives are based on the cash settlement prices of our matured commodity derivatives compared to the prices specified in the derivative contracts.

See Notes 2.f, 7 and 8 to our audited 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.

Interest expense and interest rate swaps. Interest expense increased by $20.8 million, or 21%, for the year ended December 31, 2014 compared to 2013, and $14.8 million, or 17%, for the year ended December 31, 2013 compared to 2012. The increase is primarily due to the issuance of the January 2022 Notes in January 2014, which was partially offset by the reduction in 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.

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

(in thousands)	Year ended December 31, 2014 compared to 2013	Year ended December 31, 2013 compared to 2012
Changes in interest expense:		
January 2022 Notes	$23,836	$—
Senior Secured Credit Facility, net of capitalized interest[1]	(2,587)	2,931
Change in net present value of deferred premiums paid for derivatives	(242)	(206)
2019 Notes	(162)	(20)
May 2022 Notes	—	12,189
Other	1	(139)
Total change in interest expense	$20,846	$14,755

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

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 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.

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.

Disposal of assets. Loss on disposal of assets, net increased by $1.7 million for the year ended December 31, 2014 compared to 2013 and $1.5 million for the year ended December 31, 2013 compared to 2012. 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. The 2013 increase over the prior year is largely due to losses sustained from a fire at a truck station on one of our properties and a loss on disposal of a portion of our materials and supplies. These losses were offset by a gain of $3.2 million on the pipeline assets and various other associated property and equipment disposed of in the Anadarko Basin Sale.

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

	For the years ended December 31,		
(in thousands)	2014	2013	2012
Income from continuing operations before income taxes	$429,859	$191,084	$94,764
Income tax expense	(164,286)	(74,507)	(33,003)
Income from continuing operations	$265,573	$116,577	$61,761
Effective tax rate	38%	39%	35%

Our effective tax rate is based on our annual permanent tax differences and annual pre-tax book income. The Company's effective tax rate is affected by recurring permanent differences and by discrete items that may occur in any given year, but are not consistent from year to year. During the year ended December 31, 2014 and December 31, 2013, certain restricted stock awards vested at times when our stock price was lower than the fair value of those restricted stock awards 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 year ended December 31, 2014 and December 31, 2013, certain restricted stock options were exercised. The income tax deduction related to the options' intrinsic value was less than the expense previously recognized for book purposes.

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 a result of these differences in book compensation cost and related tax deduction, the tax impact of these shortfalls decreased by $0.3 million for the year ended December 31, 2014 compared to 2013 and increased by $0.6 million for the year ended December 31, 2013 compared to 2012. There was no tax impact of shortfalls in the year ended December 31, 2012 as all shares vested had a tax basis of zero and no stock options were exercised. For further discussion see Notes 5.a, 5.b and 6 to our audited consolidated financial statements included elsewhere in this Annual Report.

As of December 31, 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 attributable to continuing operations for these respective periods. We expect income tax provisions for future reporting periods will be impacted by these stock compensation tax deduction shortfalls; however, we cannot predict the stock compensation shortfall impact because of dependency upon the future market price of our stock.

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

	For the years ended December 31,		
(in thousands)	2014	2013	2012
Income (loss) from discontinued operations, net of tax	$—	$1,423	$(107)

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. Income (loss) from discontinued operations, net of tax, increased by $1.5 million for the year ended December 31, 2013 compared to 2012. The increases are a result of increased production over time that has attributed to growth in the transportation and gathering income component of our midstream service revenue.

Liquidity and capital resources

Our primary sources of liquidity have been cash flows from operations, proceeds from equity offerings, proceeds from our Senior Unsecured Notes offerings, borrowings under our Senior Secured Credit Facility and proceeds from the Anadarko Basin Sale. We believe cash flows from operations and availability under our Senior Secured Credit Facility provide sufficient liquidity to manage our cash needs, manage our contractual obligations and fund expected capital expenditures. A significant portion of our capital expenditures can be adjusted and managed by us.

As we pursue reserves and production growth in the Permian Basin, we continually consider which financing alternatives, including debt and equity capital resources, joint ventures and asset sales, are available to meet our future financial obligations, planned or accelerated capital expenditures and liquidity requirements. Our primary uses of capital have been for the acquisition, exploration and development of oil and natural gas properties, Laredo Midstream's infrastructure development and investments in Medallion, our equity method investee. Our future ability to grow proved reserves and production will be highly dependent on the capital resources available to us. We continually monitor market conditions and may consider issuing more equity or taking on additional debt if we believe conditions to be favorable.

We continually seek to maintain a financial profile that provides operational flexibility. However, the recent decrease in oil and natural gas prices may have a negative impact on our ability to raise additional capital and/or maintain our desired levels of liquidity. At December 31, 2014, we had $600 million available for borrowings under our Senior Secured Credit Facility and total debt of $1.8 billion, of which $300 million was outstanding under our Senior Secured Credit Facility. Our total 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 measures and reconciliations") for the year ended December 31, 2014. We believe that our operating cash flow and the aforementioned liquidity sources combined with our decreased capital budget for 2015 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. More than 95% of our expected oil production in 2015 is hedged at a weighted-average floor price of $80.99 per Bbl and 63% of our natural gas and natural gas liquids production in 2015 is hedged at a weighted-average floor price of $3.00 per MMBtu. By removing a significant portion of the price volatility associated with future production, we expect to mitigate, but not eliminate, the potential effects of variability in cash flows from operations due to fluctuations in commodity prices.

As of December 31, 2014, we had $300.0 million outstanding under our Senior Secured Credit Facility and $1.5 billion in Senior Unsecured Notes. We had $600.0 million available for borrowings under our Senior Secured Credit Facility and $29.3 million in cash on hand for total available liquidity of $629.3 million as of December 31, 2014. Subsequent to December 31, 2014, we borrowed an additional $135.0 million on our Senior Secured Credit Facility. As of February 24, 2015, we had $1.9 billion in debt outstanding, $465.0 million available for borrowings under our Senior Secured Credit Facility and $7.1 million in cash on hand for total available liquidity of $472.1 million.

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. Please 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)	2014	2013	2012
Net cash provided by operating activities	$498,277	$364,729	$376,776
Net cash used in investing activities	(1,406,961)	(329,884)	(940,751)
Net cash provided by financing activities	739,852	130,084	569,197
Net (decrease) increase in cash and cash equivalents	$(168,832)	$164,929	$5,222

For the years ended December 31, 2013 and 2012, 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 $498.3 million, $364.7 million and $376.8 million for the years ended December 31, 2014, 2013 and 2012, respectively. 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.

The decrease of $12.0 million from 2012 to 2013 is largely due to an increase in our gains on derivatives and various expense items, which were offset by our increased revenues due to production growth driven by our successful drilling program, despite the August 2013 sale of the Anadarko Basin properties as well as increases in the market prices for oil and natural gas.

Our operating cash flows are sensitive to a number of variables, the most significant of which are the variability of oil 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 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.

The decrease of $610.9 million from 2012 to 2013 was largely due to the proceeds we received from the Anadarko Basin Sale as well as decreased capital expenditures for 2013 compared to 2012.

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

	For the years ended December 31,		
(in thousands)	2014	2013	2012
Capital expenditures:			
Acquisitions of oil and natural gas properties	$(6,493)	$(33,710)	$(20,496)
Acquisition of mineral interests	(7,305)	—	—
Oil and natural gas properties	(1,251,757)	(702,349)	(895,312)
Midstream service assets	(60,548)	(24,409)	(16,241)
Other fixed assets	(27,444)	(16,257)	(8,755)
Investment in equity method investee	(55,164)	(3,287)	—
Proceeds from dispositions of capital assets, net of costs	1,750	450,128	53
Net cash used in investing activities	$(1,406,961)	$(329,884)	$(940,751)

Capital expenditure budget

Our board of directors approved a capital expenditure budget of approximately $525.0 million for calendar year 2015, excluding acquisitions. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted.

The amount, timing and allocation of capital expenditures are largely discretionary and within management's control. If oil and natural gas prices decline to levels below our acceptable levels, or costs increase to levels above our acceptable levels, we may choose to defer a portion of our budgeted capital expenditures until later periods in order 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. Additionally, we have been in active discussions with service providers to align service costs with the current decline in commodity prices. 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, 2014, net cash provided by financing activities was the result of our 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.

For the year ended December 31, 2012, net cash provided by financing activities was primarily the result of $500.0 million in gross proceeds from the issuance of our May 2022 Notes on April 27, 2012 and net borrowings on our Senior Secured Credit Facility of $80.0 million. These cash inflows were partially offset by payments of $10.8 million for loan costs.

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

	For the years ended December 31,		
(in thousands)	2014	2013	2012
Borrowings on Senior Secured Credit Facility	$300,000	$230,000	$360,000
Payments on Senior Secured Credit Facility	—	(395,000)	(280,000)
Issuance of January 2022 Notes	450,000	—	—
Issuance of May 2022 Notes	—	—	500,000
Proceeds from issuance of common stock, net of offering costs	—	298,104	—
Proceeds from exercise of employee stock options	1,885	2,050	—
Purchase of treasury stock	(4,242)	(2,083)	—
Payments for debt issuance costs	(7,791)	(2,987)	(10,803)
Net cash provided by financing activities	$739,852	$130,084	$569,197

Debt

As of December 31, 2014, 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, 2014, 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 $900.0 million and $300.0 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 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 and natural gas prices may materially and adversely impact our borrowing base in future borrowing base redeterminations, which could trigger repayment obligation under our Senior Secured Credit Facility to the extent our outstanding loans under the Senior Secured Credit Facility exceed the redetermined borrowing base.

As of December 31, 2014, 2013 and 2012, borrowings outstanding under our Senior Secured Credit Facility totaled $300.0 million, zero and $165.0 million, respectively. As of February 25, 2015, $435.0 million were outstanding under our Senior Secured Credit Facility and the amount available for borrowings was $465.0 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, 2014, 2013 and 2012.
As of December 31, 2014, 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 Internal Revenue 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 $10.0 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, 2014, 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, 2014, 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, 2014.

Senior Unsecured Notes. On January 23, 2014, we completed an offering of $450.0 million aggregate principal amount of 5 5/8% senior unsecured notes due 2022. The January 2022 Notes will mature on January 15, 2022 and bear an interest rate of 5 5/8% per annum, payable semi-annually, in cash in arrears on January 15 and July 15 of each year, commencing July 15, 2014. The January 2022 Notes are guaranteed, jointly and severally, on a senior unsecured basis by Laredo Midstream, GCM and certain of our future restricted subsidiaries. Our January 2022 Notes were issued under and are governed by an indenture dated January 23, 2014 (the "2014 Indenture"), among Laredo and Wells Fargo Bank, National Association, as trustee. The 2014 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 our January 2022 Notes may be accelerated in certain circumstances upon an event of default as set forth in the 2014 Indenture.

On April 27, 2012, we completed an offering of $500.0 million aggregate principal amount of 7 3/8% senior unsecured notes due 2022. 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. Our May 2022 Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by Laredo Midstream, GCM and certain of our future restricted subsidiaries. Our May 2022 Notes were issued under and are governed by an indenture and supplement thereto, each dated April 27, 2012 (collectively, the "2012 Indenture"), among Laredo and Wells Fargo Bank, National Association, as trustee. 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 our May 2022 Notes may be accelerated in certain circumstances upon an event of default as set forth in the 2012 Indenture.

On January 20, 2011 and October 19, 2011, we completed the offerings of $350.0 million principal amount and $200.0 million principal amount, respectively, of 9 1/2% senior unsecured notes due 2019. The 2019 Notes will mature on February 15, 2019 and bear 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. Our 2019 Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by Laredo Midstream, GCM and certain of our future restricted subsidiaries. Our 2019 Notes were issued under and are governed by an indenture dated January 20, 2011, among Laredo and Wells Fargo Bank, National Association, as trustee (the "2011 Indenture"). The 2011 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 our 2019 Notes may be accelerated in certain circumstances upon an event of default as set forth in the 2011 Indenture.

Refer to Note 4 of our audited consolidated financial statements included elsewhere in this Annual Report for further discussion of the January 2022 Notes, May 2022 Notes, 2019 Notes and our Senior Secured Credit Facility.

As of February 25, 2015, we had a total of $1.5 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, 2014:

(in thousands)	Payments due Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
Senior Secured Credit Facility(1)	$—	$—	$300,000	$—	$300,000
Senior Unsecured Notes(2)	114,438	228,875	752,750	1,105,468	2,201,531
Drilling rig commitments(3)	35,924	9,287	—	—	45,211
Derivatives(4)	5,166	4,009	339	—	9,514
Asset retirement obligations(5)	1,156	1,937	1,193	27,912	32,198
Office and equipment leases(6)	2,477	6,319	5,540	9,509	23,845
Performance unit liability awards(7)	2,738	2,313	—	—	5,051
Capital contribution commitment to equity method investee(8)	18,359	—	—	—	18,359
Total	$180,258	$252,740	$1,059,822	$1,142,889	$2,635,709

(1) Includes outstanding principal amount at December 31, 2014. 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, 2014, 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, 2014, we had several drilling rigs under term contracts which expire during 2015 and 2016. Any other rig performing work for us is doing so on a well-by-well basis and therefore can be released without penalty at the conclusion of drilling on the current well. Therefore, drilling obligations on well-by-well rigs have not been included in the table above. 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 audited consolidated financial statements as incurred. See Note 10.c to our audited consolidated financial statements included elsewhere in this Annual Report for additional discussion of our drilling contract commitments.

(4) Represents payments due for deferred premiums on our commodity hedging contracts.

(5) 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 audited consolidated financial statements included elsewhere in this Annual Report.

(6) See Note 10.a to our audited consolidated financial statements included elsewhere in this Annual Report for a description of lease obligations.

(7) Represents cash awards that were granted on February 3, 2012 and February 15, 2013 under the 2011 Omnibus Equity Incentive Plan. The February 3, 2012 performance awards were paid in January 2015. The payout of the February 15, 2013 Performance Awards is dependent upon our relative total shareholder return performance against a set of peers and will be paid out, if at all, in 2016. See Note 5.e to our audited consolidated financial statements included elsewhere in this Annual Report for additional discussion of our performance units.

(8) See Note 14 to our audited consolidated financial statements included elsewhere in this Annual Report for a discussion of our equity method investee. See Note 16.c to our audited consolidated financial statements included elsewhere in this Annual Report for further information regarding a capital call that occurred after December 31, 2014.

Critical accounting policies and estimates

The discussion and analysis of our financial condition and results of operations are based upon our audited 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 audited consolidated financial statements. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our audited 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) revenue recognition, (iv) fair value of assets acquired and liabilities assumed in an acquisition, (v) impairment of oil and natural gas properties, (vi) asset retirement obligations, (vii) valuation of derivatives and deferred premiums, (viii) valuation of stock-based compensation and performance unit compensation and (ix) estimation of income taxes. 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, 2014. See Note 2.b to our audited 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 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 and natural gas reserves and associated future net cash flows. The SEC has defined proved reserves as the estimated quantities of oil 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.

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 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 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.

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 Note 14 to our audited consolidated financial statements included elsewhere in this Annual Report for a discussion of our unconsolidated VIE.

Impairment of oil and natural gas properties

We review the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues less estimated future expenditures to be incurred in developing and producing the evaluated reserves, less any related income tax effects. For the years ended December 31, 2014, 2013 and 2012, the result 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.

Asset retirement obligations

In accordance with the Financial Accounting Standard Board's (the "FASB") authoritative guidance on 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 audited 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 audited 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 date of grant. 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. Beginning in the first quarter of 2012, we utilized 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 audited 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 5 of our audited 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 date of grant 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 will be settled in cash at the end of the requisite service period 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 audited consolidated statements of operations with the corresponding liabilities recorded in the "Other current liabilities" and "Other noncurrent liabilities" line items of our audited consolidated balance sheets.

As there are inherent uncertainties related to the factors and our judgment in applying them to the fair value determinations, there is risk that the recorded performance unit awards may not accurately reflect the amount ultimately earned by the member of management. Refer to Note 5 of our audited 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. The fair value of the performance share awards issued during 2014 was 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 value 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 three-year requisite service period.

Income taxes

As of December 31, 2014, and 2013, we had a deferred tax liability of $176.9 million and $12.7 million, respectively. As part of the process of preparing the audited 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 audited 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 audited 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 evaluated 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.

During 2014, in evaluating whether it was more-likely-than-not that our deferred tax asset was recoverable from future net income, we considered our strong earnings history for the current and most recent two years.

We also determined through our analysis that our net operating loss carry-forward deferred tax asset was recoverable over future years and that we had no net operating losses expiring prior to 2026. In performing our analysis, we used inputs from third-party sources, which came primarily from our reserve reports that were independently estimated by a third party engineer. Based on our forecasted results from multiple analyses, as of December 31, 2014 and 2013, future taxable income from our oil and natural gas reserves is expected to be sufficient to utilize the entire net operating loss carry-forward in approximately eight to twelve years. We believe this analysis provides significant positive evidence that is objectively verifiable, as it uses three-year historical operating results to predict future taxable income. We considered all applicable tax deductions in our analysis which were substantially known and were not subject to significant estimates.

As of December 31, 2014, we had charitable contribution carry-forwards of $3.6 million, which will begin to expire in 2015. The utilization of charitable contributions for any tax year is limited to 10% of taxable income without regard to charitable contributions, net operating losses, and dividend received deductions. A corporation is permitted to carry-over to the five succeeding tax years contributions that exceeded the 10% limitation, but deductions in those years are also subject to the maximum limitation. Based on our analysis, we do not believe it is more-likely-than-not that we will utilize the carry-forward in its entirety before expiration, therefore, a full valuation allowance of $1.3 million has been recorded against the related deferred tax asset.

Based on our analysis, we determined as of December 31, 2014 that given the proper weight of the positive evidence noted above, it was more-likely-than-not that our deferred tax asset would be recovered with the exception of the deferred tax asset related to the charitable contribution carry-over.

We will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods. If our assumptions regarding forecasted production, pricing and margins are not achieved by amounts in excess of our sensitivity analysis, it may have a significant impact on the corresponding taxable income which may require a valuation allowance to be recorded against our deferred tax assets at that time.

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, 2014 and 2013, 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.

Recent accounting pronouncements

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, 2016, including interim periods within that reporting period. We are currently evaluating this standard and our existing revenue recognition policies to determine what impact this guidance will have on our audited consolidated financial statements upon adoption.

In April 2014, the FASB issued guidance on reporting discontinued operations and disclosures of disposals of components of an entity. The guidance changes the criteria for reporting discontinued operations, including raising the threshold for a disposal to qualify as discontinued operations. The guidance also requires entities to provide additional disclosure about discontinued operations as well as disposal transactions that do not meet the discontinued operations criteria. The pronouncement is effective for annual and interim periods beginning after December 15, 2014. Early adoption is permitted for disposals or for assets classified as held for sale that have not been reported in previously issued financial statements. We elected to early adopt this guidance in the second quarter of 2014 on a prospective basis, and the adoption did not have an effect on our audited consolidated financial statements.

In July 2013, the FASB issued guidance on the presentation of an unrecognized tax benefit when a net operating loss carry-forward, a similar tax loss or a tax credit carry-forward exists. The guidance requires an unrecognized tax benefit, or a portion of an unrecognized tax benefit, to be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carry-forward, a similar tax loss or a tax credit carry-forward except when (i) a net operating loss carry-forward, a similar tax loss or a tax credit carry-forward is not available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position, or (ii) the tax law of the applicable jurisdiction does not require the entity to use, and the entity does not intend to use, the deferred tax asset for such purpose. In those situations the unrecognized tax benefit should be presented in the financial statements as a liability and should not be combined with deferred tax assets. We adopted this guidance on January 1, 2014, and the adoption did not have an effect on our audited consolidated financial statements.

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, 2012 through the year ended December 31, 2014. 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, which are included in "—Obligations and commitments."

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 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 and natural gas prices, we use commodity derivatives, such as collars, swaps and puts to hedge price risk associated with a significant portion of our anticipated oil and natural gas production. By removing a majority 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 value of our commodity derivatives using an independent third-party valuation and recognize the associated gain or loss in our audited 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, 2014, 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	$234,272	$397,596

As of December 31, 2014 and 2013, the fair values of our open derivatives contracts were $312.3 million and $82.1 million, respectively. Refer to Notes 7 and 8 of our audited 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, 2014, we had $300.0 million outstanding on our Senior Secured Credit Facility. Our 2019 Notes, January 2022 Notes and May 2022 Notes bear fixed interest rates and we had $550.0 million (excluding the remaining premium of $1.3 million), $450.0 million and $500.0 million outstanding, respectively, as of December 31, 2014, as shown in the table below.

	Expected maturity date						
(in millions except for interest rates)	2015	2016	2017	2018	2019	Thereafter	Total
2019 Notes - fixed rate	$—	$—	$—	$—	$550.0	$—	$550.0
Average interest rate	— %	— %	— %	— %	9.500 %	— %	9.500 %
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 %
Senior Secured Credit Facility - variable rate	$—	$—	$—	$300.0	$—	$—	$300.0
Average interest rate	— %	— %	— %	1.790 %	— %	— %	1.790 %

Counterparty and customer credit risk

Our principal exposures to credit risk are through (i) receivables from derivatives ($312.4 million as of December 31, 2014), (ii) receivables resulting from the sale of our oil and natural gas production ($57.1 million as of December 31, 2014), which we market to energy marketing companies and refineries, (iii) joint interest receivables ($33.8 million as of December 31, 2014) and (iv) receivables from midstream product sales ($18.9 million as of December 31, 2014).

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

We have entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of our derivative counterparties, who also are or were 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 9 of our audited 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.

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, 2014 at the reasonable assurance level.

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.

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, 2014, 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, 2014.

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, 2014. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2014, 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, 2014, 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, 2014, 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, 2014, and our report dated February 26, 2015 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP
Tulsa, Oklahoma
February 26, 2015

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Information regarding our Code of Conduct and Business Ethics, Code of Ethics For Senior Financial Officers and Corporate Governance Guidelines for our principal executive officer and principal financial and accounting officer are described in "Item 1. Business" in this Annual Report. Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 10 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2014.

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, 2014.

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, 2014.

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, 2014.

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, 2014.

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	Amended and Restated Bylaws of Laredo Petroleum Holdings, Inc. (incorporated by reference to Exhibit 3.2 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
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.
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.
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.
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	Purchase and Sale Agreement, dated May 20, 2013, by and between Laredo Petroleum, Inc., Laredo Petroleum Texas, LLC, Laredo Gas Services, LLC and EnerVest Energy Institutional Fund XII-WIB, L.P., EnerVest Energy Institutional Fund XII-WIC, L.P., EnerVest Energy Institutional Fund XII-A, L.P., EnerVest Energy Institutional Fund XIII-A, L.P., EnerVest Energy Institutional Fund XIII-WIB, L.P., EnerVest Energy Institutional Fund XIII-WIC, L.P. and EnerVest Operating, L.L.C. (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on August 1, 2013).
10.5	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).
10.6#	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).
10.7#	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).
10.8#	

	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).
10.9#	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.3 of Laredo's Quarterly Report on Form 10-Q (File No. 001-35380) filed on August 9, 2012).
10.10#	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).
10.11#	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).
10.12	Laredo Petroleum Holdings, Inc. Change in Control Executive Severance Plan Certificate (incorporated by reference to Exhibit 10.7 of Laredo's Registration Statement on Form S-1/A (File No. 333-176439) filed on November 14, 2011).
10.13#	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.
10.14*	Non-Exclusive Aircraft Lease Agreement, dated January 1, 2015 between Lariat Ranch, LLC and Laredo Petroleum, Inc.
10.15	Registration Rights Agreement, dated as of January 23, 2014, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC and the initial purchasers (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on January 24, 2014).

Exhibit Number	Description
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 26, 2015	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)	2/26/2015
/s/ Richard C. Buterbaugh Richard C. Buterbaugh	Executive Vice President and Chief Financial Officer (principal financial officer)	2/26/2015
/s/ Michael T. Beyer Michael T. Beyer	Vice President - Controller and Chief Accounting Officer (principal accounting officer)	2/26/2015
/s/ Jay P. Still Jay P. Still	Director, President and Chief Operating Officer	2/26/2015
/s/ Peter R. Kagan Peter R. Kagan	Director	2/26/2015
/s/ James R. Levy James R. Levy	Director	2/26/2015
/s/ B.Z. (Bill) Parker B.Z. (Bill) Parker	Director	2/26/2015
/s/ Pamela S. Pierce Pamela S. Pierce	Director	2/26/2015
/s/ Ambassador Francis Rooney Ambassador Francis Rooney	Director	2/26/2015
/s/ Dr. Myles W. Scoggins Dr. Myles W. Scoggins	Director	2/26/2015
/s/ Edmund P. Segner, III Edmund P. Segner, III	Director	2/26/2015
/s/ Donald D. Wolf Donald D. Wolf	Director	2/26/2015

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2014 and 2013, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2014. 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, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2014, 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 26, 2015, expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP
Tulsa, Oklahoma
February 26, 2015

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

	December 31, 2014	2013
Assets		
Current assets:		
Cash and cash equivalents	$29,321	$198,153
Accounts receivable, net	126,929	77,318
Derivatives	194,601	15,806
Deferred income taxes	—	3,634
Other current assets	14,402	12,698
Total current assets	365,253	307,609
Property and equipment:		
Oil and natural gas properties, full cost method:		
Evaluated properties	4,446,781	3,276,578
Unevaluated properties not being amortized	342,731	208,085
Midstream service assets	117,052	51,704
Other fixed assets	56,165	32,832
Total property and equipment	4,962,729	3,569,199
Less accumulated depletion, depreciation, amortization and impairment	(1,608,647)	(1,364,875)
Net property and equipment	3,354,082	2,204,324
Derivatives	117,788	79,726
Debt issuance cost, net	28,463	25,933
Investment in equity method investee	58,288	5,913
Other assets, net	8,675	255
Total assets	$3,932,549	$2,623,760
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable	$39,008	$16,002
Accrued payable - affiliates	3,443	3,489
Undistributed revenue and royalties	65,438	35,124
Accrued capital expenditures	148,241	116,328
Derivatives	115	10,795
Deferred income taxes	71,191	—
Other current liabilities	97,589	72,231
Total current liabilities	425,025	253,969
Long-term debt	1,801,295	1,051,538
Derivatives	—	2,680
Deferred income taxes	105,754	16,293
Asset retirement obligations	31,042	21,478
Other noncurrent liabilities	6,232	5,546
Total liabilities	2,369,348	1,351,504
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $0.01 par value, 50,000,000 shares authorized and zero issued at December 31, 2014 and 2013	—	—
Common stock, $0.01 par value, 450,000,000 shares authorized, and 143,686,491 and 142,671,436 issued, at December 31, 2014 and 2013, respectively	1,437	1,427

Additional paid-in capital	1,309,171	1,283,809
Retained earnings (accumulated deficit)	252,593	(12,980)
Total stockholders' equity	1,563,201	1,272,256
Total liabilities and stockholders' equity	$3,932,549	$2,623,760

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,		
	2014	2013	2012
Revenues:			
Oil and natural gas sales	$737,203	$664,844	$583,569
Midstream service revenue	2,245	413	325
Sales of purchased oil	54,437	—	—
Total revenues	793,885	665,257	583,894
Costs and expenses:			
Lease operating expenses	96,503	79,136	67,325
Production and ad valorem taxes	50,312	42,396	37,637
Midstream service expense	5,429	3,368	2,614
Natural gas volume commitment - affiliates	2,552	891	—
Costs of purchased oil	53,967	—	—
Drilling rig fees	527	—	—
General and administrative	106,044	89,696	62,106
Accretion of asset retirement obligations	1,787	1,475	1,200
Depletion, depreciation and amortization	246,474	233,944	241,072
Impairment expense	3,904	—	—
Total costs and expenses	567,499	450,906	411,954
Operating income	226,386	214,351	171,940
Non-operating income (expense):			
Gain (loss) on derivatives:			
Commodity derivatives, net	327,920	79,902	8,800
Interest rate derivatives, net	—	(24)	(412)
Income (loss) from equity method investee	(192)	29	—
Interest expense	(121,173)	(100,327)	(85,572)
Interest and other income	294	163	59
Write-off of debt issuance costs	(124)	(1,502)	—
Loss on disposal of assets, net	(3,252)	(1,508)	(51)
Non-operating income (expense), net	203,473	(23,267)	(77,176)
Income from continuing operations before income taxes	429,859	191,084	94,764
Income tax expense:			
Deferred	(164,286)	(74,507)	(33,003)
Total income tax expense	(164,286)	(74,507)	(33,003)
Income from continuing operations	265,573	116,577	61,761
Income (loss) from discontinued operations, net of tax	—	1,423	(107)
Net income	$265,573	$118,000	$61,654
Net income per common share:			
Basic:			
Income from continuing operations	$1.88	$0.88	$0.49
Income (loss) from discontinued operations, net of tax	—	0.01	—
Net income per share	$1.88	$0.89	$0.49
Diluted:			
Income from continuing operations	$1.85	$0.87	$0.48
Income (loss) from discontinued operations, net of tax	—	0.01	—
Net income per share	$1.85	$0.88	$0.48

Weighted-average common shares outstanding:			
Basic	141,312	132,490	126,957
Diluted	143,554	134,378	128,171

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)		Retained earnings (accumulated deficit)	Total
	Shares	Amount		Shares	Amount		
Balance, December 31, 2011	127,617	$1,276	$951,375	8	$(4)	$ (192,634)	$760,013
Restricted stock awards	932	9	(9)	—	—	—	—
Restricted stock forfeitures	(251)	(2)	2	—	—	—	—
Stock-based compensation	—	—	10,056	—	—	—	10,056
Net income	—	—	—	—	—	61,654	61,654
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

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,		
	2014	2013	2012
Cash flows from operating activities:			
Net income	$265,573	$118,000	$61,654
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred income tax expense	164,286	75,288	32,949
Depletion, depreciation and amortization	246,474	234,571	243,649
Bad debt expense	342	653	—
Impairment expense	3,904	—	—
Non-cash stock-based compensation, net of amount capitalized	23,079	21,433	10,056
Accretion of asset retirement obligations	1,787	1,475	1,200
Mark-to-market on derivatives:			
Gain on derivatives, net	(327,920)	(79,878)	(8,388)
Cash settlements received for matured derivatives, net	28,241	3,745	24,910
Cash settlements received for early terminations and modifications of derivatives, net	76,660	6,008	—
Change in net present value of deferred premiums paid for derivatives	220	462	668
Cash premiums paid for derivatives	(7,419)	(10,277)	(6,118)
Amortization of debt issuance costs	5,137	5,023	4,816
Write-off of debt issuance costs	124	1,502	—
Amortization of October 2011 Notes premium	(243)	(222)	(202)
Loss on disposal of assets, net	3,252	1,508	52
Cash settlement of performance unit awards	—	(2,080)	—
Other	838	(37)	19
(Increase) decrease in accounts receivable	(49,953)	6,825	(9,705)
Increase in other assets	(16,688)	(7,438)	(414)
Increase (decrease) in accounts payable	23,006	(32,581)	2,665
Increase (decrease) in undistributed revenues and royalties	30,314	(941)	9,221
Increase in other accrued liabilities	23,837	16,458	7,849
Increase in other noncurrent liabilities	2,825	499	98
Increase in fair value of performance unit awards	601	4,733	1,797
Net cash provided by operating activities	498,277	364,729	376,776
Cash flows from investing activities:			
Capital expenditures:			
Acquisitions of oil and natural gas properties	(6,493)	(33,710)	(20,496)
Acquisition of mineral interests	(7,305)	—	—
Oil and natural gas properties	(1,251,757)	(702,349)	(895,312)
Midstream service assets	(60,548)	(24,409)	(16,241)
Other fixed assets	(27,444)	(16,257)	(8,755)
Investment in equity method investee	(55,164)	(3,287)	—
Proceeds from dispositions of capital assets, net of costs	1,750	450,128	53
Net cash used in investing activities	(1,406,961)	(329,884)	(940,751)
Cash flows from financing activities:			
Borrowings on Senior Secured Credit Facility	300,000	230,000	360,000
Payments on Senior Secured Credit Facility	—	(395,000)	(280,000)

Issuance of January 2022 Notes	450,000	—	—
Issuance of May 2022 Notes	—	—	500,000
Proceeds from issuance of common stock, net of offering costs	—	298,104	—
Proceeds from exercise of employee stock options	1,885	2,050	—
Purchase of treasury stock	(4,242)	(2,083)	—
Payments for debt issuance costs	(7,791)	(2,987)	(10,803)
Net cash provided by financing activities	739,852	130,084	569,197
Net (decrease) increase in cash and cash equivalents	(168,832)	164,929	5,222
Cash and cash equivalents, beginning of period	198,153	33,224	28,002
Cash and cash equivalents, end of period	$29,321	$198,153	$33,224

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

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

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 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 ("Laredo Midstream"). 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 Laredo Midstream (together, the "Guarantors") guarantee all of Laredo's debt instruments.

In these notes, the "Company," (i) when used in the present tense, prospectively or as of December 31, 2014, refers to Laredo, Laredo Midstream and GCM collectively; (ii) when used for historical periods from December 31, 2013 to October 23, 2014, refers to Laredo and Laredo Midstream collectively; (iii) when used for historical periods from December 19, 2011 to December 30, 2013, refers to Laredo and its subsidiaries, collectively; and (iv) when used for historical periods prior to December 19, 2011 refers to Laredo LLC, Laredo Inc 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.

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 Company uses the equity method of accounting to record its net interests when the Company holds 20% to 50% of the voting rights and/or has the ability to exercise significant influence but does not control the entity. Under the equity method, the Company's proportionate share of the investee's net income (loss) is included in the consolidated statements of operations. See Note 14 for additional discussion of the Company's equity-method investment. The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). All material intercompany transactions and account balances have been eliminated in the consolidation of accounts. The Company reports as one business segment, which explores for, develops and produces oil and natural gas. Unless otherwise indicated, the information in these notes relates to the Company's continuing operations.

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 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

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

in an acquisition and (viii) fair values of commodity derivatives, interest rate 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 2014 presentation. These reclassifications had no impact to previously reported total assets, total liabilities, net income, stockholders' equity or cash flows. See Note 3.f for a discussion regarding discontinued operations.

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 9).

e. Accounts receivable

The Company sells oil and natural gas to various customers and participates with other parties in the drilling, completion and operation of oil and natural gas wells. Joint interest, oil and natural gas sales and purchased oil and other product sales receivables related to these operations are generally unsecured. Accounts receivable for joint interest billings are recorded as amounts billed to customers less an allowance for doubtful accounts.

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.

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

(in thousands)	2014	2013
Oil and natural gas sales	$57,070	$57,647
Joint operations, net[1]	33,808	16,629
Purchased oil and other product sales	18,917	—
Other	17,134	3,042
Total	$126,929	$77,318

(1) Accounts receivable for joint operations are presented net of an allowance for doubtful accounts of $0.8 million and $0.7 million as of December 31, 2014 and 2013, 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 primarily in the form of collars, swaps, puts and basis swaps. In addition, in prior periods the Company entered into interest rate derivatives.

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

Derivatives are recorded at fair value and are included net on the consolidated balance sheets as assets or liabilities. The Company nets the fair value of derivatives by counterparty on the accompanying consolidated balance sheets where the right of offset exists. The Company determines the fair value of its derivatives 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 7 and 8).

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 Note 7).

g. Other current liabilities

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

(in thousands)	2014	2013
Accrued interest payable	$37,689	$25,885
Lease operating expense payable	11,963	10,637
Accrued compensation and benefits	13,034	16,711
Other accrued liabilities	34,903	18,998
Total other current liabilities	$97,589	$72,231

h. Oil and natural gas properties

The Company uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of finding oil and natural gas are capitalized and amortized on a composite units of production method based on proved oil 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 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 amortization base until the properties associated with these costs are evaluated. Approximately $342.7 million and $208.1 million of such costs were excluded from the amortization base as of December 31, 2014 and 2013, respectively. The amortization base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values. Total accumulated depletion for oil and natural gas properties was $1.6 billion and $1.3 billion for the years ended December 31, 2014 and 2013, respectively. Depletion expense for oil and natural gas properties was $237.1 million, $228.0 million and $237.1 million for the years ended December 31, 2014, 2013 and 2012, respectively. There were no impairments recorded for the years ended December 31, 2014, 2013 and 2012. Depletion per barrel of oil equivalent for the Company's oil and natural gas properties was $20.21, $20.34 and $20.98 for the years ended December 31, 2014, 2013 and 2012, 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 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 amortization.
The full cost ceiling is based principally on the estimated future net cash flows from proved oil and natural gas properties discounted at 10%. Full cost 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, unless prices were defined by contractual arrangements, to calculate the discounted future revenues. In the event the unamortized cost of evaluated oil and

natural gas properties being amortized exceeds the full cost ceiling, as defined by the Securities and Exchange Commission ("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.

As of December 31, 2014, the full cost ceiling value of the Company's reserves was calculated based on the unweighted arithmetic average first-day-of-the-month price for the 12-months ended December 31, 2014 of $4.25 per MMBtu for natural gas, adjusted by area for energy content, transportation fees, and regional price differentials, and the unweighted arithmetic average first-day-of-the-month price for the 12-months ended December 31, 2014 of $91.48 per barrel for oil, adjusted by area for energy content, transportation fees, and regional price differentials. Using these prices, the Company's net book value of evaluated oil and natural gas properties did not exceed the full cost ceiling amount as of December 31, 2014. Changes in prices, production rates, levels of reserves, future development costs, and other factors will determine the Company's actual full cost ceiling test calculation and impairment analysis in future periods.

As of December 31, 2013, the full cost ceiling value of the Company's reserves was calculated based on the unweighted arithmetic average first-day-of-the-month price for the 12-months ended December 31, 2013 of $3.57 per MMBtu for natural gas, adjusted by area for energy content, transportation fees, and regional price differentials, and the unweighted arithmetic average first-day-of-the-month price for the 12-months ended December 31, 2013 of $93.52 per barrel for oil, adjusted by area for energy content, transportation fees, and regional price differentials. Using these prices, the Company's net book value of evaluated oil and natural gas properties did not exceed the full cost ceiling amount as of December 31, 2013.

As of December 31, 2012, the full cost ceiling value of the Company's reserves was calculated based on the unweighted arithmetic average first-day-of-the-month price for the 12-months ended December 31, 2012 of $2.63 per MMBtu for natural gas, adjusted by area for energy content, transportation fees, and regional price differentials, and the unweighted arithmetic average first-day-of-the-month price for the 12-months ended December 31, 2012 of $91.21 per barrel for oil, adjusted by area for energy content, transportation fees, and regional price differentials. Using these prices, the Company's net book value of evaluated oil and natural gas properties did not exceed the full cost ceiling amount as of December 31, 2012.

i. 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 accumulated depreciation. 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 and amortization are removed from the accounts and any gain or loss is recognized in "Non-operating income (expense)" in the consolidated statements of operations. Depreciation expense from continuing operations for midstream service assets was $4.3 million, $1.5 million and $0.8 million for the years ended December 31, 2014, 2013 and 2012, respectively.

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

(in thousands)	2014	2013
Midstream service assets	$117,052	$51,704
Less accumulated depreciation	(8,590)	(4,404)
Total, net	$108,462	$47,300

j. Other fixed assets

Other fixed assets are recorded at cost net of accumulated 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 "Non-operating income (expense)" in the consolidated statements of operations. Depreciation and amortization expense from continuing operations for other fixed assets was \$5.1 million, \$4.4 million and \$3.1 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

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

(in thousands)	2014	2013
Computer hardware and software	$13,495	$11,370
Vehicles	7,802	4,542
Leasehold improvements	6,867	3,520
Aircraft	4,952	4,952
Production equipment	2,577	403
Furniture and fixtures	1,750	1,342
Other	5,490	2,565
Depreciable total	42,933	28,694
Less accumulated depreciation and amortization	(13,820)	(11,156)
Depreciable total, net	29,113	17,538
Land	13,232	4,138
Total, net	$42,345	$21,676

k. 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, 2014 or 2013.

l. 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. 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 $28.5 million and $25.9 million, net of accumulated amortization of $19.4 million and $14.2 million, as of December 31, 2014 and 2013, respectively.

As a result of changes in the borrowing base of the Senior Secured Credit Facility due to the issuance of the January 2022 Notes, the Company wrote-off $0.1 million of debt issuance costs during the year ended December 31, 2014. 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. No debt issuance costs were written off in the year ended December 31, 2012. See Notes 4 and 3 for definition of and information regarding the Senior Secured Credit Facility, the January 2022 Notes and the Anadarko Basin Sale (defined below), respectively.

Future amortization expense of debt issuance costs as of December 31, 2014 is as follows:

(in thousands)	
2015	$5,295
2016	5,361
2017	5,433
2018	5,222
2019	2,110
Thereafter	5,042
Total	$28,463

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

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 based on the reserve life per well, (iii) estimated remaining life of midstream service assets, (iv) estimated removal and/or remediation costs for 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 for continuing and discontinued operations as of December 31:

(in thousands)	2014	2013
Liability at beginning of year	$21,743	$21,505
Liabilities added due to acquisitions, drilling, midstream service asset construction and other	6,370	2,709
Accretion expense	1,787	1,475
Liabilities settled upon plugging and abandonment	(450)	(226)
Liabilities removed due to sale of property	—	(7,801)
Revision of estimates	2,748	4,081
Liability at end of year	$32,198	$21,743

n. Fair value measurements

The carrying amounts reported in the consolidated balance sheets for cash and cash equivalents, accounts receivable, prepaid expenses, accounts payable, undistributed revenue and royalties and other accrued assets and liabilities approximate their fair values. See Note 4 for fair value disclosures related to the Company's debt obligations. The Company carries its derivatives at fair value. See Note 7 and Note 8 for details regarding the fair value of the Company's derivatives.

o. Treasury stock

The Company acquires treasury stock, which is recorded at cost, to satisfy tax withholding obligations for Laredo's employees that arise upon the lapse of restrictions on restricted stock. Upon acquisition, this treasury stock is retired.

p. Revenue recognition

Oil and natural gas revenues are recorded using the sales method. Under this method, the Company recognizes revenues based on actual volumes of oil 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,

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

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, 2014 or 2013. 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. General and administrative expense

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)	2014	2013	2012
Fees received for the operation of jointly-owned oil and natural gas properties	$3,265	$3,398	$2,335

r. Compensation awards

Stock-based compensation expense is recognized in "General and administrative" in the Company's consolidated statements of operations over the awards' vesting periods and is based on their grant date fair value. The Company utilizes the closing stock price on the date of grant, 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 5 for further discussion regarding the restricted stock awards, restricted stock option awards, performance share awards and performance unit awards.

s. Income taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating losses and tax credit carry-forwards. Under this method, deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income 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 6 for detail of amounts recorded in the consolidated financial statements.
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, 2014, 2013 or 2012.

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

t. 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 are comprised of equipment used in developing oil and natural gas properties and are included in "Other current assets" and "Other assets, net" on the consolidated balance sheets. They are carried at the lower of cost or market ("LCM"). During the year ended December 31, 2014, the Company reduced materials and supplies by $1.8 million in order to reflect the balance at LCM. The adjustment is included in "Impairment expense" in the consolidated statements of operations. The Company determined an LCM adjustment was not necessary for materials and supplies during the years ended December 31, 2013 or 2012.

Pipelines in which we have a minimum volume of product in the system to enable the system to operate is known as line-fill, and is generally not available to be withdrawn from the system until the expiration of the contract. Beginning in 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 year ended December 31, 2014, the Company recorded an LCM adjustment of $2.1 million related to its line-fill, which is included in "Impairment expense" in the consolidated statements of operations.

u. Supplemental cash flow disclosure information 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)	2014	2013	2012
Cash paid for interest, net of $150, $255 and $627 of capitalized interest, respectively	$104,936	$95,622	$74,638

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)	2014	2013	2012
Change in accrued capital expenditures	$31,913	$(5,284)	$30,590
Change in accrued capital contribution to equity method investee	$(2,597)	$2,597	$—
Capitalized asset retirement cost	$9,118	$6,790	$7,379
Capitalized stock-based compensation	$4,650	$—	$—
Equity issued in connection with acquisition	$—	$3,029	$—

Note 3—Acquisitions and divestitures

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.

F-14

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

a. 2014 acquisition of leasehold interests
During the year ended December 31, 2014, the Company completed a material acquisition of leasehold interests totaling 8,156 net acres in the Midland Basin, primarily within the Company's core development area, for $192.5 million. The acquisition was accounted for as an acquisition of assets.
b. 2014 acquisition of mineral interests
On February 25, 2014, the Company completed the acquisition of the mineral interests underlying 278 net acres in Glasscock County, Texas in the Permian Basin for $7.3 million. These mineral interests entitle the Company to receive royalty interests on all production from this acreage with no additional future capital or operating expenses required. As such, the acquisition was accounted for as an acquisition of assets.
c. 2014 acquisitions of evaluated and unevaluated oil and natural gas properties
On June 11, 2014, the Company completed the acquisition of evaluated and unevaluated oil and natural gas properties, totaling 460 net acres, located in Reagan County, Texas for $4.7 million, net of closing adjustments. On June 23, 2014, the Company 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. The results of operations prior to June 2014 do not include results from these acquisitions.
d. 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.
e. 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 periods presented:

	For the years ended December 31,	
(in thousands)	2013	2012
Revenues	$59,631	$84,616
Expenses[(1)]	46,357	89,602

(1) Expenses include lease operating expense, production and ad valorem tax expense, accretion expense and depletion, depreciation and amortization expense.

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.

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

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

	For the years ended December 31,	
(in thousands)	2013	2012
Revenues:		
Midstream service revenue	$4,020	$4,186
Total revenues from discontinued operations	4,020	4,186
Cost and expenses:		
Midstream service expense, net	1,189	1,769
Depreciation and amortization	627	2,577
Total costs and expenses from discontinued operations	1,816	4,346
Non-operating expense, net	—	(1)
Income (loss) from discontinued operations before income tax	2,204	(161)
Income tax (expense) benefit	(781)	54
Income (loss) from discontinued operations	$1,423	$(107)

f. Summary of 2013 and 2012 business combinations

The following presents the Company's 2013 and 2012 business combination activities. 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.

(in thousands)	Accounting treatment	Cash consideration	Common stock issued[2]
September 6, 2013 acquisition of evaluated and unevaluated oil and natural gas properties[1]	Acquisition method	$ 33,710	$3,029
July 12, 2012 acquisition of evaluated and unevaluated oil and natural gas properties	Acquisition method	$ 20,496	$—

(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"). Subject to 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 8.

Note 4—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)	2014	2013	2012
Cash payments for interest	$105,086	$95,877	$75,265
Amortization of debt issuance costs and other adjustments	4,433	4,926	4,940
Change in accrued interest	11,804	(221)	5,994
Interest costs incurred	121,323	100,582	86,199

Less capitalized interest	(150)	(255)	(627)
Total interest expense	$121,173	$100,327	$85,572

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

b. January 2022 Notes

On January 23, 2014, the Company completed an offering of $450.0 million in aggregate principal amount of 5 5/8% senior unsecured notes due 2022 (the "January 2022 Notes"), and entered into an Indenture (the "Indenture") among Laredo, Laredo Midstream 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, jointly and severally, on a senior unsecured basis by Laredo Midstream, GCM and certain of the Company's future restricted subsidiaries, subject to certain automatic customary releases, including the sale, disposition, or transfer of all of the capital stock or of all or substantially all of the assets of a subsidiary guarantor to one or more persons that are not the Company or a restricted subsidiary, exercise of legal defeasance or covenant defeasance options or satisfaction and discharge of the Indenture, designation of a subsidiary guarantor as a non-guarantor restricted subsidiary or as an unrestricted subsidiary in accordance with the Indenture, release from guarantee under the Senior Secured Credit Facility, or liquidation or dissolution (collectively, the "Releases").

The January 2022 Notes were issued pursuant to the 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.

In connection with the closing of the offering of the January 2022 Notes, the Company entered into a registration rights agreement with the several initial purchasers named in the registration rights agreement, pursuant to which the Company filed a registration statement with the Securities and Exchange Commission ("SEC") that became effective with respect to an offer to exchange the January 2022 Notes for substantially identical notes (other than with respect to restrictions on transfer or any increase in annual interest rate) that are registered under the Securities Act. The offer to exchange the January 2022 Notes for substantially identical notes registered under the Securities Act was launched on April 22, 2014 with all notes exchanged on May 22, 2014.

c. May 2022 Notes

On April 27, 2012, the Company completed an offering of $500.0 million in aggregate principal amount of 7 3/8% senior unsecured notes due 2022 (the "May 2022 Notes"). The May 2022 Notes 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, jointly and severally, on a senior unsecured basis by Laredo Midstream, GCM 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

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

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. Furthermore, before May 1, 2015, Laredo may, at any time or from time to time, redeem up to 35% of the aggregate principal amount of the May 2022 Notes with the net proceeds of a public or private equity offering at a redemption price of 107.375% of the principal amount of the May 2022 Notes, plus any accrued and unpaid interest to the date of redemption, if at least 65% of the aggregate principal amount of the May 2022 Notes issued under the 2012 Indenture remains outstanding immediately after such redemption and the redemption occurs within 180 days of the closing date of such equity offering. Laredo may also be required to make an offer to purchase the May 2022 Notes upon a change of control triggering event.

d. 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 "2019 Notes"). The 2019 Notes will mature on February 15, 2019 and bear 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 2019 Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by Laredo Midstream, GCM and certain of the Company's future restricted subsidiaries, subject to certain Releases.

The 2019 Notes were issued under and are 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 dividends or similar restricted payments, the undertaking of transactions with Laredo's unrestricted affiliates and limitations on asset sales. Indebtedness under the 2019 Notes may be accelerated in certain circumstances upon an event of default as set forth in the Indenture.

Laredo has the option to redeem the 2019 Notes, in whole or in part, at the redemption prices (expressed as percentages of principal amount) of 104.750% for the 12-month period beginning on February 15, 2015, 102.375% for the 12-month period beginning on February 15, 2016 and 100.000% for the 12-month period beginning on February 15, 2017 and at any time thereafter, together with accrued and unpaid interest, if any, to the date of redemption. Laredo may also be required to make an offer to purchase the 2019 Notes upon a change of control triggering event.

e. Senior Secured Credit Facility

As of December 31, 2014, 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 $900.0 million with $300.0 million outstanding and was subject to an interest rate of 1.94%. The borrowing base is subject to a semi-annual redetermination 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 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;

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

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, 2014 or 2013.

f. Fair value of debt

The following table presents the carrying amounts and fair values of the Company's debt instruments for the periods presented:

(in thousands)	December 31, 2014 Carrying value	December 31, 2014 Fair value	December 31, 2013 Carrying value	December 31, 2013 Fair value
2019 Notes[1]	$551,295	$550,000	$551,538	$615,313
January 2022 Notes	450,000	396,014	—	—
May 2022 Notes	500,000	467,529	500,000	549,375
Senior Secured Credit Facility	300,000	300,279	—	—
Total value of debt	$1,801,295	$1,713,822	$1,051,538	$1,164,688

(1) The carrying value of the 2019 Notes includes the October Notes unamortized bond premium of $1.3 million and $1.5 million as of December 31, 2014 and 2013, respectively.

The fair values of the debt outstanding on the 2019 Notes, the January 2022 Notes and the May 2022 Notes were determined using the December 31, 2014 and 2013 quoted market price (Level 1) for each respective instrument. The fair value of the outstanding debt on the Senior Secured Credit Facility as of December 31, 2014 was estimated utilizing pricing models for similar instruments (Level 2). See Note 8 for information about fair value hierarchy levels.

Note 5—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.

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, 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 date of the grant and (v) fully on the third anniversary date of the grant. Restricted stock awards granted to non-employee directors vest fully on the first anniversary date of the grant.

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

The following table reflects the outstanding restricted stock awards for the years ended December 31, 2014, 2013 and 2012:

(in thousands, except for weighted-average grant date fair values)	Restricted stock awards	Weighted-average grant date fair value (per award)
Outstanding at December 31, 2011	911	$ 1.14
Granted	932	$ 22.90
Forfeited	(251)	$ 15.61
Vested[1]	(397)	$ 1.03
Outstanding at December 31, 2012	1,195	$ 15.06
Granted	1,469	$ 18.17
Forfeited	(229)	$ 18.47
Vested[2]	(636)	$ 18.69
Outstanding at December 31, 2013	1,799	$ 19.17
Granted	1,234	$ 25.68
Forfeited	(148)	$ 22.56
Vested[2]	(680)	$ 19.13
Outstanding at December 31, 2014	2,205	$ 22.63

(1) Vestings in the year ended December 31, 2012 related to restricted stock awards converted in the Corporate Reorganization. Such shares have a tax basis of zero to the grantee and therefore result in no tax benefit to the Company.

(2) 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 6 for additional discussion regarding the tax impact of vested restricted stock awards.

For grants after the IPO, the Company utilizes the closing stock price on the date of grant to determine the fair value of service vesting restricted stock awards. As of December 31, 2014, unrecognized stock-based compensation expense related to restricted stock awards was $27.6 million. Such cost is expected to be recognized over a weighted-average period of 1.46 years.

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

b. Restricted stock option awards

Restricted stock options awards granted under the LTIP vest and are exercisable in four equal installments on each of the four anniversaries of the date of the grant. The following table reflects the stock option award activity for the years ended December 31, 2014, 2013 and 2012:

(in thousands, except for weighted-average exercise price and contractual term)	Restricted stock option awards	Weighted-average exercise price (per option)	Weighted-average remaining contractual term (years)
Outstanding at December 31, 2011	—	$ —	—
Granted	603	$ 24.11	10
Forfeited	(144)	$ 24.11	10
Outstanding at December 31, 2012	459	$ 24.11	10
Granted	1,019	$ 17.34	9.13
Exercised[(1)]	(104)	$ 20.79	8.75
Expired or canceled	(12)	$ 24.11	—
Forfeited	(133)	$ 19.88	—
Outstanding at December 31, 2013	1,229	$ 19.32	8.82
Granted	336	$ 25.60	9.16
Exercised[(1)]	(95)	$ 19.93	7.73
Expired or canceled	(30)	$ 21.15	—
Forfeited	(73)	$ 19.68	—
Outstanding at December 31, 2014	1,367	$ 20.76	8.17
Vested and exercisable at end of period[(2)]	324	$ 20.29	7.68
Vested, exercisable, and expected to vest at end of period[(3)]	1,336	$ 20.76	8.16

(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 6 for additional discussion regarding the tax impact of exercised stock option awards.

(2) The vested and exercisable options as of December 31, 2014 had no aggregate intrinsic value.

(3) The vested, exercisable and expected to vest options as of December 31, 2014 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, 2014, unrecognized stock-based compensation related to restricted option awards was $8.2 million. Such cost is expected to be recognized over a weighted-average period of 2.32 years.

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

The assumptions used to estimate the fair value of restricted stock options granted are as follows:

	February 27, 2014		February 15, 2013		February 3, 2012	
Risk-free interest rate[(1)]	1.88	%	1.19	%	1.14	%
Expected option life[(2)]	6.25 years		6.25 years		6.25 years	
Expected volatility[(3)]	53.21	%	58.89	%	59.98	%
Fair value per stock option	$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, matching 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 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, 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 in order to determine the fair value of these awards at the date of grant. The Company has determined the Performance Share Awards are equity awards and is recognizing the associated expense on a straight-line basis over the three-year requisite service period of the awards. These awards will be settled in stock at the end of the requisite service period based on the achievement of certain performance criteria.

The 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. During the year ended December 31, 2014, 271,667 performance shares were awarded and all remain outstanding at December 31, 2014. As of December 31, 2014, unrecognized stock-based compensation related to the Performance Share Awards was $5.4 million. Such cost is expected to be recognized over a weighted-average period of 2.16 years.

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

The assumptions used to estimate the fair value of the Performance Share Awards are as follows:

Risk-free rate[(1)]	0.63	%
Dividend yield	—	%
Expected volatility[(2)]	38.21	%
Laredo stock closing price as of February 27, 2014	$25.60	
Fair value per performance share	$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)	2014	2013	2012
Restricted stock award compensation	$21,982	$17,084	$8,496
Restricted stock option award compensation	3,639	4,349	1,560
Restricted performance share award compensation	2,108	—	—
Total stock-based compensation	27,729	21,433	10,056
Less amounts capitalized in oil and natural gas properties	(4,650)	—	—
Net stock-based compensation expense	$23,079	$21,433	$10,056

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 ("2013 Performance Unit Awards") and on February 3, 2012 ("2012 Performance Unit Awards") are subject to a combination of market and service vesting criteria. A Monte Carlo simulation prepared by an independent third party was utilized in order to determine the fair values of these awards at the date of grant 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 is based on the volatility of the Company's stock price and the stock price volatilities of a group of peer companies that have been determined to be most representative of the Company's expected volatility. These awards are accounted for as liability awards as they will be settled in cash at the end of the requisite service period based on the achievement of certain performance criteria. The liability and related compensation expense of these awards for each period 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. As there are inherent uncertainties related to these factors and the Company's judgment in applying them to the fair value determinations, there is risk that the recorded performance unit compensation may not accurately reflect the amount ultimately earned by the members of management.

The 2013 Performance Unit Awards have a performance period of January 1, 2013 to December 31, 2015 and are expected to be paid in the first quarter of 2016 if the performance criteria are met. The 2012 Performance Unit Awards had a performance period of January 1, 2012 to December 31, 2014 and were paid at $100 per unit in the first quarter of 2015. There were no performance unit awards issued or outstanding during the year ended December 31, 2011.

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

The following table reflects the outstanding performance unit awards for the periods presented:

(in thousands)	2013 Performance Unit Awards	2012 Performance Unit Awards (2)
Outstanding at December 31, 2011	—	—
Granted	—	49
Forfeited	—	(2)
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	—

(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 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 assumptions used to estimate the fair value of the 2013 Performance Unit Awards as of December 31, 2014 are as follows:

Risk-free rate(1)	0.25	%
Dividend yield	—	%
Expected volatility(2)	64.76	%
Laredo closing price as of December 31, 2014	$10.35	

(1) The risk-free rate uses the one-year zero-coupon yield derived from the Treasury Constant Maturities yield curve.

(2) The expected volatility is calculated using daily stock returns based on the one year historical volatility for LPI.

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 fair value of the 2012 Performance Unit Awards as of December 31, 2012 was $5.4 million.

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

	For the years ended December 31,		
(in thousands)	2014	2013	2012
2013 Performance Unit Award compensation expense	$409	$2,863	$—
2012 Performance Unit Award compensation expense	192	1,870	1,797
Total performance unit award compensation expense	$601	$4,733	$1,797

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" in the consolidated balance sheets. As there are inherent uncertainties related to the factors and the Company's judgment in applying them to the fair value determination of the 2013 Performance Unit Awards, there is risk that the recorded performance unit compensation may not accurately reflect the amount ultimately earned by the members of management.

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

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)	2014	2013	2012
Contributions	$2,202	$1,886	$1,293

Note 6—Income taxes

The Company uses an asset and liability approach for financial accounting and for reporting income tax. Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes.

The Company is subject to corporate income taxes and the Texas franchise tax. Income tax expense attributable to income from continuing operations for the periods presented consisted of the following:

	For the years ended December 31,		
(in thousands)	2014	2013	2012
Current taxes:			
Federal	$—	$—	$—
State	—	—	—
Deferred taxes:			
Federal	(147,445)	(64,034)	(31,390)
State	(16,841)	(10,473)	(1,613)
Income tax expense	$(164,286)	$(74,507)	$(33,003)

The following presents the comprehensive provision for income taxes for the periods presented:

	For the years ended December 31,		
(in thousands)	2014	2013	2012
Comprehensive provision for income taxes allocable to:			
Continuing operations	$(164,286)	$(74,507)	$(33,003)
Discontinued operations	—	(781)	54
Comprehensive provision for income taxes	$(164,286)	$(75,288)	$(32,949)

Income tax expense attributable to income from continuing operations before income taxes differed from amounts computed by applying the applicable federal income tax rate of 35% for the year ended December 31, 2014 and 34% for the

F-25

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

years ended December 31, 2013 and 2012 to pre-tax earnings as a result of the following:

	For the years ended December 31,		
(in thousands)	2014	2013	2012
Income tax expense computed by applying the statutory rate	$(150,450)	$(64,969)	$(32,219)
State income tax, net of federal tax benefit and increase in valuation allowance	(11,099)	(7,532)	(102)
Non-deductible stock-based compensation	(509)	(1,070)	(1,177)
Stock-based compensation tax deficiency	(266)	(559)	—
Change in deferred tax valuation allowance	(1,139)	(63)	583
Other items	(823)	(314)	(88)
Income tax expense	$(164,286)	$(74,507)	$(33,003)

The effective tax rate for the Company's continuing operations was 38%, 39% and 35% for the years ended December 31, 2014, 2013 and 2012, respectively. The Company's effective tax rate is affected by recurring permanent differences and by discrete items that may occur in any given year, but are not consistent from year to year.
The impact of significant discrete items is separately recognized in the year in which they 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 date of grant. 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 date of grant 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, 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 taxable vestings of stock awards or the exercise of stock options during the year ended December 31, 2012. 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 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)	2014	2013	2012
Vesting of restricted stock	$112	$425	$—
Exercise of restricted stock options	158	150	—
Tax impact of shortfalls	$270	$575	$—

Significant components of the Company's deferred tax liabilities as of December 31 are as follows:

(in thousands)	2014	2013
Oil and natural gas properties, midstream service assets and other fixed assets	$(424,712)	$(278,735)
Net operating loss carry-forward	353,724	284,890
Derivatives	(121,365)	(30,859)
Stock-based compensation	10,718	6,578
Accrued bonus	3,256	3,740
Capitalized interest	3,049	2,099
Other	(316)	(240)
Gross deferred tax liability	(175,646)	(12,527)
Valuation allowance	(1,299)	(132)
Net deferred tax liability	$(176,945)	$(12,659)

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

Net deferred tax assets and liabilities were classified in the consolidated balance sheets as of December 31 as follows:

(in thousands)	2014	2013
Deferred tax asset	$—	$3,634
Deferred tax liability	(176,945)	(16,293)
Net deferred tax liability	$(176,945)	$(12,659)

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

The following presents the Company's federal net operating loss carry-forwards and their applicable expiration dates as of December 31, 2014:

(in thousands)	
2026	$2,741
2027	38,651
2028	228,661
2029	101,932
2030	82,948
Thereafter	549,892
Total	$1,004,825

The Company had federal net operating loss carry-forwards totaling $1.0 billion and state of Oklahoma net operating loss carry-forwards totaling $92.7 million as of December 31, 2014. These carry-forwards begin expiring in 2026 and continue through 2034, as presented in the table above. As of December 31, 2014, the Company believes the federal and state of Oklahoma net operating loss carry-forwards are 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 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 its oil and natural gas reserves (including the timing of those cash flows), the reversal of deferred tax liabilities recorded as of December 31, 2014, 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, 2014, 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, 2014, a full valuation allowance of $1.3 million was recorded against the deferred tax asset related to the Company's charitable contribution carry-forward of $3.6 million.

The Company filed its 2013 federal and Oklahoma income tax returns during the year ended December 31, 2014. As a result, the Company recognized an aggregate expense from tax return related items, which is a discrete item, of $0.6 million for the year ended December 31, 2014 and is included in income tax expense attributable to continuing operations for the period. The tax expense impact of the prior-year return to provision true-up was $2.4 million for year ended December 31, 2013. There was no comparative amount for the year ended December 31, 2012.

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 2011 through 2014 remain open and subject to examination by federal tax authorities and/or the tax authorities in Oklahoma, Texas and Louisiana, which are the jurisdictions where the Company has or had operations. The Company's 2011 federal income tax return is currently under examination. 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.

Note 7—Derivatives

a. Commodity derivatives

The Company engages in derivative transactions such as collars, swaps and puts to hedge price risks due to unfavorable changes in oil and natural gas prices related to its oil and natural gas production. As of December 31, 2014, the Company had 31 open derivative contracts with financial institutions which extend from January 2015 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 respective "Gain (loss) on derivatives" amounts.

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 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 put transaction has an established floor price. The Company pays the counterparty a premium in order 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.

During the first quarter of 2014, the Company unwound a physical commodity contract and the associated oil basis swap financial derivative contract which 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

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

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

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)	2014	2013	2012
Cash settlements received for matured commodity derivatives	$28,241	$4,046	$27,025
Cash settlements paid for matured interest rate swaps	—	(301)	(2,115)
Early terminations and modification of commodity derivatives received[1]	76,660	6,008	—
Cash settlements received for derivatives, net	$104,901	$9,753	$24,910

(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 modifications of commodity derivative contracts.

The following table summarizes open positions as of December 31, 2014, and represents, as of such date, derivatives in place through December 2017 on annual production volumes:

	Year 2015	Year 2016	Year 2017
Oil positions[1]:			
Puts:			
Hedged volume (Bbl)	456,000	—	—
Weighted-average price ($/Bbl)	$75.00	$—	$—
Swaps:			
Hedged volume (Bbl)	672,000	1,573,800	—
Weighted-average price ($/Bbl)	$96.56	$84.82	$—
Collars:			
Hedged volume (Bbl)	6,557,020	2,556,000	2,263,000
Weighted-average floor price ($/Bbl)	$79.81	$80.00	$80.00
Weighted-average ceiling price ($/Bbl)	$95.40	$93.77	$100.00
Totals:			
Total volume hedged with ceiling price (Bbl)	7,229,020	4,129,800	2,263,000
Weighted-average ceiling price ($/Bbl)	$95.51	$90.36	$100.00
Total volume hedged with floor price (Bbl)	7,685,020	4,129,800	2,263,000
Weighted-average floor price ($/Bbl)	$80.99	$81.84	$80.00
Natural gas positions[2]:			
Collars:			
Hedged volume (MMBtu)	28,600,000	18,666,000	—
Weighted-average floor price ($/MMBtu)	$3.00	$3.00	$—
Weighted-average ceiling price ($/MMBtu)	$5.96	$5.60	$—

(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, 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 8.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 or originally were participants in the 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 8—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, 2014, 2013 or 2012.

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

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 December 31, 2014 and 2013:

(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

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

(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, 2013:						
Assets						
Current:						
Oil derivatives	$—	$24,784	$—	$24,784	$(7,911)	$16,873
Natural gas derivatives	—	166	—	166	(235)	(69)
Oil deferred premiums	—	—	—	—	(537)	(537)
Natural gas deferred premiums	—	—	—	—	(461)	(461)
Noncurrent:						
Oil derivatives	$—	$115,712	$—	$115,712	$(35,593)	$80,119
Natural gas derivatives	—	491	—	491	(411)	80
Oil deferred premiums	—	—	—	—	—	—
Natural gas deferred premiums	—	—	—	—	(473)	(473)
Liabilities						
Current:						
Oil derivatives	$—	$(11,782)	$—	$(11,782)	$7,911	$(3,871)
Natural gas derivatives	—	(302)	—	(302)	235	(67)
Oil deferred premiums	—	—	(6,942)	(6,942)	537	(6,405)
Natural gas deferred premiums	—	—	(913)	(913)	461	(452)
Noncurrent:						
Oil derivatives	$—	$(33,948)	$—	$(33,948)	$35,593	$1,645
Natural gas derivatives	—	(380)	—	(380)	411	31
Oil deferred premiums	—	—	(4,146)	(4,146)	—	(4,146)
Natural gas deferred premiums	—	—	(683)	(683)	473	(210)
Net derivative position	$—	$94,741	$(12,684)	$82,057	$—	$82,057

These items are included in "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 which 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.

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

The following table presents actual cash payments required for deferred premium contracts in place as of December 31, 2014, and for the calendar years following:

(in thousands)	
2015	$5,166
2016	358
2017	3,651
2018	339
Total	$9,514

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)	2014	2013	2012
Balance of Level 3 at beginning of period	$(12,684)	$(24,709)	$(18,868)
Change in net present value of deferred premiums for derivatives	(220)	(462)	(668)
Total purchases and settlements:			
Purchases	(3,800)	—	(11,291)
Settlements[(1)]	7,419	12,487	6,118
Balance of Level 3 at end of period	$(9,285)	$(12,684)	$(24,709)

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

See Note 2.t for discussion of the Company's impairment of line-fill and materials and supplies in the year ended December 31, 2014.

Note 9—Credit risk

The Company's oil 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. 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 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 Note 7 for additional information regarding the Company's derivatives.

For the year ended December 31, 2014, the Company had two customers that accounted for 36.0% and 13.7% of total oil and natural gas sales, with each customer accounting for 16.4% and 22.5%, respectively, of oil and natural gas sales accounts receivable, and three other customers accounting for 13.5%, 12.5% and 11.6% of oil 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

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

for 28.3%, 11.7% and 11.7% of total oil 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. For the year ended December 31, 2012, the Company had three customers that accounted for 34.0%, 12.3% and 10.0% of total oil and natural gas sales. 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. As of December 31, 2013, the Company had four partners whose joint operations accounts receivable accounted for 16.0%, 14.1%, 13.1% and 10.9% of the Company's total joint operations accounts receivable.

For the year ended December 31, 2014, the Company had one customer that accounted for 100% 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 years ended December 31, 2013 and 2012 and correspondingly, there was no purchased oil and other product sales receivable as of December 31, 2013.

The Company's cash balances are insured by the FDIC up to $250,000 per bank. The Company had a cash balance on deposit with certain banks as of December 31, 2014, which exceeded the balance insured by the FDIC in the amount of $56.8 million. Management believes that the risk of loss is mitigated by the banks' reputation and financial position.

Related-party transactions

The Company has a gathering and processing arrangement with affiliates of Targa Resources, Inc. ("Targa"). Warburg Pincus IX, a major stockholder of Laredo, and other affiliates of Warburg Pincus LLC, held material investment interests in Targa until May 2013. One of Laredo's directors is on the board of directors of affiliates of Targa. The following table summarizes the net oil and natural gas sales (oil and natural gas sales less production taxes) received from Targa and included in the consolidated statements of operation for the periods presented:

	For the years ended December 31,		
(in thousands)	2014	2013	2012
Net oil and natural gas sales	$96,100	$74,245	$71,916

The following table summarizes the amounts included in oil and natural gas sales receivable from Targa in the consolidated balance sheets for the periods presented:

	December 31,	
(in thousands)	2014	2013
Oil and natural gas sales receivable	$12,869	$9,064

Note 10—Commitments and contingencies

a. Lease commitments

The Company leases equipment and office space under operating leases expiring on various dates through 2027. Minimum annual lease commitments as of December 31, 2014 for the calendar years presented are:

(in thousands)	
2015	$2,477
2016	3,095
2017	3,224
2018	3,141
2019	2,399
Thereafter	9,509
Total	$23,845

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

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

	For the years ended December 31,		
(in thousands)	2014	2013	2012
Rent expense	$3,042	$1,923	$1,339

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

b. Litigation

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

c. Drilling contracts

The Company has committed to drilling contracts with various third parties in order to complete its various drilling projects. The contracts contain early termination clauses that require the Company to potentially pay penalties to the third party should the Company cease drilling efforts. These penalties would negatively impact the Company's financial statements upon early contract termination, especially if a significant number of such contracts were terminated early in their respective terms. In the fourth quarter, the Company announced a reduced 2015 capital expenditure budget compared to 2014. As a result of this budget decrease, the Company began releasing rigs as drilling contracts came close to expiration and incurred charges of $0.5 million which are 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, 2013 or 2012. Future commitments of $45.2 million as of December 31, 2014 are not recorded in the accompanying consolidated balance sheets. Management does not currently anticipate the early termination of any existing contracts in 2015 which would result in a substantial penalty.

d. Federal and state regulations

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

e. Other commitments

See Note 14 for discussion regarding commitments to the Company's non-consolidated variable interest entity ("VIE").

Note 11—Follow-on 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 "Follow-on 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, commissions, and offering expenses as a result of the Follow-on Offering. The Company did not receive any proceeds from either of the sales of shares of Laredo's common stock by the Selling Stockholders. There were no comparable stock offerings in the years ended December 31, 2014 or 2012.

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

Note 12—Net income per share

Basic net income per share is computed by dividing net income by the weighted-average number of common shares outstanding for the period. Diluted net income 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, 2014, the Performance Share Awards' total shareholder return was below their agreement's payout threshold, and therefore, the Performance Share Awards were excluded from the calculation of diluted net income per share.

The effects of the Company's 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, 2013 and 2012, 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 exceeds the average stock price during the period and, therefore, the inclusion of these outstanding options would have been anti-dilutive.

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

	For the years ended December 31,		
(in thousands, except for per share data)	2014	2013	2012
Net income (numerator):			
Income from continuing operations—basic and diluted	$265,573	$116,577	$61,761
Income (loss) from discontinued operations, net of tax—basic and diluted	—	1,423	(107)
Net income—basic and diluted	$265,573	$118,000	$61,654
Weighted-average common shares outstanding (denominator):			
Weighted-average common shares outstanding—basic (1)	141,312	132,490	126,957
Non-vested restricted stock awards	2,242	1,888	1,214
Weighted-average common shares outstanding—diluted	143,554	134,378	128,171
Net income per share:			
Basic:			
Income from continuing operations	$1.88	$0.88	$0.49
Income from discontinued operations, net of tax	—	0.01	—
Net income per share	$1.88	$0.89	$0.49
Diluted:			
Income from continuing operations	$1.85	$0.87	$0.48
Income from discontinued operations, net of tax	—	0.01	—
Net income per share	$1.85	$0.88	$0.48

(1) 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 has been computed taking into account the Follow-on Offering.

Note 13—Recently issued accounting standards

In May 2014, the Financial Accounting Standards Board ("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, 2016, 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.

In April 2014, the FASB issued guidance on reporting discontinued operations and disclosures of disposals of components of an entity. The guidance changes the criteria for reporting discontinued operations, including raising the threshold for a disposal to qualify as discontinued operations. The guidance also requires entities to provide additional disclosure about discontinued operations as well as disposal transactions that do not meet the discontinued operations criteria. The pronouncement is effective for annual and interim periods beginning after December 15, 2014. Early adoption is permitted for disposals or for assets classified as held for sale that have not been reported in previously issued financial statements. The Company elected to early adopt this guidance in the second quarter of 2014 on a prospective basis, and the adoption did not have an effect on its consolidated financial statements.

In July 2013, the FASB issued guidance on the presentation of an unrecognized tax benefit when a net operating loss carry-forward, a similar tax loss or a tax credit carry-forward exists. The guidance requires an unrecognized tax benefit, or a portion of an unrecognized tax benefit, to be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carry-forward, a similar tax loss or a tax credit carry-forward except when (i) a net operating loss carry-forward, a similar tax loss or a tax credit carry-forward is not available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position, or (ii) the tax law of the applicable jurisdiction does not require the entity to use, and the entity does not intend to use, the deferred tax asset for such purpose. In those situations the unrecognized tax benefit should be presented in the financial statements as a liability and should not be combined with deferred tax assets. The Company adopted this guidance on January 1, 2014, and the adoption did not have an effect on its consolidated financial statements.

Note 14—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.

Laredo Midstream contributed $55.2 million and $3.3 million during the years ended December 31, 2014 and 2013, respectively, to Medallion Gathering & Processing, LLC, a Texas limited liability company formed on October 12, 2012, and its wholly-owned subsidiaries (together "Medallion"). Laredo Midstream holds 49% of Medallion ownership units. Medallion was established for the purpose of developing midstream solutions and providing midstream infrastructure to bring discovered oil and natural gas to market. Laredo Midstream 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 operation and business decisions. The Company has determined that Medallion is a VIE. However, Laredo Midstream is not considered to be the primary beneficiary of the VIE because Laredo Midstream 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."

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

During the year ended December 31, 2014, Medallion completed the construction of its pipeline from Garden City, Texas to Colorado City, Texas and an extension from Medallion's Garden City Station to Midland and Upton counties, Texas. As of December 31, 2014, Laredo Midstream has committed to fund an estimated $18.4 million to Medallion. See Note 16.c for further information regarding a capital call that occurred after December 31, 2014.
As of December 31, 2014, the Company recorded a payable of $3.4 million related to its minimum volume commitment to Medallion. As of December 31, 2013, the Company recorded a capital contribution payable of $2.6 million related to the fourth quarter cash requirements of the project and a payable of $0.9 million related to its minimum volume commitment to Medallion. These payables are reported on the consolidated balance sheets as "Accrued payable - affiliates." The corresponding expense is reported on the consolidated statements of operations in the "Natural gas volume commitment - affiliates" line item.

Note 15—Subsidiary guarantee

Laredo and the Guarantors have fully and unconditionally guaranteed the 2019 Notes, the January 2022 Notes, the May 2022 Notes and the Senior Secured Credit Facility, subject to the Releases. In accordance with practices accepted by the SEC, Laredo has prepared condensed consolidating financial statements in order 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, 2014 and 2013, and condensed consolidating statements of operations and condensed consolidating statements of cash flows each for the years ended December 31, 2014, 2013 and 2012, 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 Laredo Midstream and for GCM are recorded on Laredo's statements of financial position, statements of operations and statements of cash flow 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 Laredo Midstream at historical cost.

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	150,430	4,496	—	154,926
Total assets	$3,898,216	$197,915	$(163,582)	$3,932,549
Accounts payable	$38,453	$555	$—	$39,008
Other current liabilities	354,217	31,800	—	386,017
Other long-term liabilities	140,817	2,211	—	143,028
Long-term debt	1,801,295	—	—	1,801,295
Stockholders' equity	1,563,434	163,349	(163,582)	1,563,201
Total liabilities and stockholders' equity	$3,898,216	$197,915	$(163,582)	$3,932,549

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

Condensed consolidating balance sheet
December 31, 2013

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Accounts receivable, net	$77,318	$—	$—	$77,318
Other current assets	230,291	—	—	230,291
Total oil and natural gas properties, net	2,135,348	—	—	2,135,348
Total midstream service assets, net	5,802	41,498	—	47,300
Total other fixed assets, net	21,676	—	—	21,676
Investment in subsidiaries and equity method investee	36,666	5,913	(36,666)	5,913
Total other long-term assets	105,914	—	—	105,914
Total assets	$2,613,015	$47,411	$(36,666)	$2,623,760
Accounts payable	$12,216	$3,786	$—	$16,002
Other current liabilities	231,008	6,959	—	237,967
Other long-term liabilities	45,997	—	—	45,997
Long-term debt	1,051,538	—	—	1,051,538
Stockholders' equity	1,272,256	36,666	(36,666)	1,272,256
Total liabilities and stockholders' equity	$2,613,015	$47,411	$(36,666)	$2,623,760

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, net	(120,879)	—	—	(120,879)
Other, net	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, net	(100,164)	—	—	(100,164)
Other, net	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

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

Condensed consolidating statement of operations
For the year ended December 31, 2012

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total operating revenues	$583,759	$10,285	$(10,150)	$583,894
Total operating costs and expenses	418,745	3,359	(10,150)	411,954
Income from operations	165,014	6,926	—	171,940
Interest expense, net	(85,513)	—	—	(85,513)
Other, net	18,143	—	(9,806)	8,337
Income from continuing operations before income tax	97,644	6,926	(9,806)	94,764
Income tax expense	(33,003)	—	—	(33,003)
Income from continuing operations	64,641	6,926	(9,806)	61,761
Income (loss) from discontinued operations, net of tax	(2,987)	2,880	—	(107)
Net income	$61,654	$9,806	$(9,806)	$61,654

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

Laredo Petroleum, Inc.
Notes to the consolidated financial statements
December 31, 2014, 2013 and 2012

Condensed consolidating statement of cash flows
For the year ended December 31, 2012

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Net cash flows provided by operating activities	$373,362	$13,219	$(9,805)	$376,776
Change in investments between affiliates	(12,827)	3,022	9,805	—
Capital expenditures and other	(924,510)	(16,241)	—	(940,751)
Net cash flows provided by financing activities	569,197	—	—	569,197
Net increase in cash and cash equivalents	5,222	—	—	5,222
Cash and cash equivalents at beginning of period	28,002	—	—	28,002
Cash and cash equivalents at end of period	$33,224	$—	$—	$33,224

Note 16—Subsequent events

a. Senior Secured Credit Facility

On January 8, January 15, February 5 and February 12, 2015, the Company borrowed $20.0 million, $45.0 million, $15.0 million and $55.0 million on the Senior Secured Credit Facility, respectively. The outstanding balance under the Senior Secured Credit Facility was $435.0 million at February 25, 2015.

b. Restructuring

Following the recent drop in oil and natural gas prices, in an effort to reduce costs and better position the Company for ongoing efficient growth, on January 20, 2015, the Company committed to a company-wide restructuring and reduction in force (the "RIF") that includes (i) the relocation of certain employees in the Company's Dallas, Texas area office to the Company's other existing offices in Tulsa, Oklahoma and Midland, Texas; (ii) closing our Dallas, Texas area office; (iii) a workforce reduction of approximately 75 employees and (iv) the release of 24 contract personnel. The reduction in workforce was communicated to employees on January 20, 2015 and was generally effective immediately. The relocation of Company employees and the closing of the Company's Dallas, Texas area office are expected to be completed by June 1, 2015. The Company's compensation committee approved the RIF and the severance package offered in connection with the RIF.

c. Medallion capital call

On February 17, 2015, the Company received a capital call from Medallion totaling $14.5 million, which represents Laredo Midstream'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.

d. New commodity derivative contracts

Subsequent to December 31, 2014, the Company entered into the following new commodity derivative contracts:

	Aggregate volumes	Swap Price	Floor Price	Ceiling Price	Contract period
Oil (volumes in Bbl)					
Price collar[(1)]	365,000	$—	$60.00	$80.00	January 2017 - December 2017
Basis swaps[(2)]	3,060,000	$(1.95)	$—	$—	March 2015 - December 2015

(1) The associated commodity derivative will be settled based on the WTI NYMEX index oil price. There is a $1.0 million deferred premium associated with this contract.

(2) The associated oil basis swaps will be settled on the differential between the West Texas Intermediate Argus Americas Crude Midland index oil price and the WTI NYMEX index oil price.

Laredo Petroleum, Inc.
Supplemental oil and natural gas disclosures
December 31, 2014, 2013 and 2012

Note 17—Supplemental oil and natural gas disclosures
a. Costs incurred in oil and natural gas property acquisition, exploration and development activities
Costs incurred in the acquisition, exploration and development of oil and natural gas assets are presented below for the periods presented:

	For the years ended December 31,		
(in thousands)	2014	2013	2012
Property acquisition costs:			
Evaluated	$3,873	$9,652	$16,925
Unevaluated	9,925	27,087	3,693
Exploration(1)	242,284	48,763	93,266
Development costs(2)	1,049,317	654,452	839,118
Total costs incurred	$1,305,399	$739,954	$953,002

(1) The Company acquired significant leasehold interests during the year ended December 31, 2014.
(2) The costs incurred for oil and natural gas development activities include $6.9 million, $6.8 million and $7.4 million in asset retirement obligations for the years ended December 31, 2014, 2013 and 2012, respectively.

b. Capitalized oil and natural gas costs
Aggregate capitalized costs related to oil and natural gas production activities with applicable accumulated depletion, depreciation and impairment are presented below for the periods presented:

	For the years ended December 31,		
(in thousands)	2014	2013	2012
Capitalized costs:			
Evaluated properties	$4,446,781	$3,276,578	$2,993,266
Unevaluated properties	342,731	208,085	159,946
	4,789,512	3,484,663	3,153,212
Less accumulated depletion, depreciation and impairment	(1,586,237)	(1,349,315)	(1,121,273)
Net capitalized costs	$3,203,275	$2,135,348	$2,031,939

The following table shows a summary of the oil and natural gas property costs not being amortized as of December 31, 2014, by year in which such costs were incurred:

(in thousands)	2014	2013	2012	2011 and prior	Total
Unevaluated properties	$260,955	$47,095	$24,373	$10,308	$342,731

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

Laredo Petroleum, Inc.
Supplemental oil and natural gas disclosures
December 31, 2014, 2013 and 2012

c. Results of oil and natural gas producing activities

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

	For the years ended December 31,		
(in thousands)	2014	2013	2012
Revenues:			
Oil and natural gas sales	$737,203	$664,844	$583,569
Production costs:			
Lease operating expenses	96,503	79,136	67,325
Production and ad valorem taxes	50,312	42,396	37,637
	146,815	121,532	104,962
Other costs:			
Depletion and depreciation	237,067	227,992	237,130
Accretion of asset retirement obligation	1,721	1,475	1,200
Income tax expense[(1)]	126,576	112,984	83,686
Results of operations	$225,024	$200,861	$156,591

---

(1) Income tax expense above is computed utilizing the statutory rate.

d. Net proved oil 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, 2014, 2013 and 2012. In accordance with SEC regulations, reserves as of December 31, 2014, 2013 and 2012 were estimated using the unweighted arithmetic average first-day-of-the-month price for the preceding 12-month period. The Company's reserves are reported in two streams; crude oil and natural gas. The economic value of the natural gas liquids in the Company's natural gas is included in the wellhead natural gas price. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and natural gas properties. Accordingly, the estimates may change as future information becomes available.

The following table provides an analysis of the change in estimated quantities of oil and natural gas reserves, all of which are located within the United States, for the periods presented.

	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

Laredo Petroleum, Inc.
Supplemental oil and natural gas disclosures
December 31, 2014, 2013 and 2012

	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
Sales 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

	Year ended December 31, 2012		
	Oil (MBbl)	Gas (MMcf)	MBOE
Proved developed and undeveloped reserves:			
Beginning of year	56,267	601,117	156,453
Revisions of previous estimates	(12,396)	(260,651)	(55,837)
Extensions, discoveries and other additions	57,391	232,418	96,127
Purchases of reserves in place	1,654	9,210	3,189
Production	(4,775)	(39,148)	(11,300)
End of year	98,141	542,946	188,632
Proved developed reserves:			
Beginning of year	21,762	248,598	63,195
End of year	33,316	289,045	81,490
Proved undeveloped reserves:			
Beginning of year	34,505	352,519	93,258
End of year	64,825	253,901	107,142

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. The oil and natural gas reference prices used in computing the Company's reserves as of December 31, 2014 were $91.48 per barrel of oil and $4.25 per MMBtu of natural gas before price differentials.

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

Laredo Petroleum, Inc.
Supplemental oil and natural gas disclosures
December 31, 2014, 2013 and 2012

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. The oil and natural gas reference prices used in computing the Company's reserves as of December 31, 2013 were $93.52 per barrel of oil and $3.57 per MMBtu of natural gas before price differentials.

For the year ended December 31, 2012, the Company's negative revision of 55,837 MBOE of previous estimated quantities is primarily attributable to the removal of 50,845 MBOE due to lower natural gas prices and increased development costs for vertical Granite Wash locations in the Anadarko Basin and shallow Wolfberry vertical locations in the Permian Basin. Due to these factors, these locations became economically unattractive to develop and were replaced by new horizontal and/or oil development opportunities. The balance of the negative revision of 4,993 MBOE is due to a combination of performance, pricing and other changes. Extensions, discoveries and other additions of 96,127 MBOE during the year ended December 31, 2012, consist of 26,235 MBOE primarily from the drilling of new wells during the year and 69,892 MBOE from new proved undeveloped locations added during the year, which increased the Company's proved reserves. The latter consists of 67,200 MBOE attributable to 317 locations in our Permian Basin play and 2,692 MBOE attributable to six locations in our Anadarko Granite Wash play. Purchases of minerals in place added 3,189 MBOE from acquisition of proved reserves in the Permian Basin. The oil and natural gas reference prices used in computing the Company's reserves as of December 31, 2012 were $91.21 per barrel of oil and $2.63 per MMBtu of natural gas before price differentials.

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 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, 2014, 2013 and 2012 are based on the unweighted arithmetic average first-day-of-the-month price for the preceding 12-month period. Estimated future production of proved reserves and estimated future production and development costs of proved reserves are based on current costs and economic conditions. 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 and natural gas reserves, less the tax basis of the Company's oil and natural gas properties. Reference prices used, before differentials were applied, were $91.48, $93.52 and $91.21 per Bbl of oil and $4.25, $3.57 and $2.63 per MMBtu for December 31, 2014, 2013 and 2012, respectively. All wellhead prices are held flat over the forecast period for all reserve categories. The estimated future net cash flows are then discounted at a rate of 10%.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is as follows for the periods presented:

	For the years ended December 31,		
(in thousands)	2014	2013	2012
Future cash inflows	$16,663,685	$13,337,798	$11,636,926
Future production costs	(3,616,775)	(3,059,368)	(3,163,371)
Future development costs	(2,471,985)	(2,250,950)	(2,252,559)
Future income tax expenses	(2,827,763)	(2,150,983)	(1,433,373)
Future net cash flows	7,747,162	5,876,497	4,787,623
10% discount for estimated timing of cash flows	(4,500,434)	(3,554,293)	(2,910,167)
Standardized measure of discounted future net cash flows	$3,246,728	$2,322,204	$1,877,456

In the foregoing determination of future cash inflows, sales prices used for oil and natural gas for December 31, 2014, 2013 and 2012 were estimated using the average price during the 12-month period, determined as the unweighted arithmetic average first-day-of-the-month price for each month. Prices were adjusted by lease for quality, transportation fees and regional price differentials. Future costs of developing and producing the proved oil and natural gas reserves reported at the end of each year shown were based on costs determined at each such year-end, assuming the continuation of existing economic conditions.

Laredo Petroleum, Inc.
Supplemental oil and natural gas disclosures
December 31, 2014, 2013 and 2012

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, costs and prices as of the measurement date are used in the determinations, and no value may be assigned to probable or possible reserves.
Changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows for the periods presented:

	For the years ended December 31,		
(in thousands)	2014	2013	2012
Standardized measure of discounted future net cash flows, beginning of year	$2,322,204	$1,877,456	$1,400,859
Changes in the year resulting from:			
Sales, less production costs	(590,388)	(543,312)	(478,607)
Revisions of previous quantity estimates	(320,275)	(190,961)	(631,693)
Extensions, discoveries and other additions	1,340,022	1,166,481	1,287,952
Net change in prices and production costs	145,740	313,947	194,921
Changes in estimated future development costs	(22,961)	921	(3,917)
Previously estimated development costs incurred during the period	92,135	89,396	137,510
Purchases of reserves in place	6,100	7,604	25,041
Divestitures of reserves in place	—	(239,148)	—
Accretion of discount	305,325	234,852	176,996
Net change in income taxes	(266,757)	(259,991)	(101,955)
Timing differences and other	235,583	(135,041)	(129,651)
Standardized measure of discounted future net cash flows, end of year	$3,246,728	$2,322,204	$1,877,456

Estimates of economically recoverable oil 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 and natural gas may differ materially from the amounts estimated.

Laredo Petroleum, Inc.
Supplemental quarterly financial data
December 31, 2014 and 2013

Note 18—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, 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

	Year ended December 31, 2013			
(in thousands, except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$163,705	$177,296	$170,840	$153,416
Operating income	44,505	57,414	57,420	55,012
Net income	1,409	35,812	12,543	68,236
Net income per common share:				
Basic	$0.01	$0.28	$0.09	$0.48
Diluted	$0.01	$0.27	$0.09	$0.48