Laredo Petroleum, Inc.
Form 10-K
February 27, 2014

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, 2013
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 1800 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 $870.1 million on June 28, 2013, based on $20.56 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 24, 2014: 142,618,804

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2014 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2013, are incorporated by reference into Part III of this report for the year ended December 31, 2013.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

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

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

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

"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.

"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 differs 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, 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 liquid"—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 which 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 acreage 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.
"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.
"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, 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 recent instability and uncertainty in the U.S. and international financial and consumer markets that is adversely affecting the liquidity available to us and our customers and is adversely affecting the demand for commodities, including oil and natural gas;
- the volatility of oil and natural gas prices;
- the possible introduction of regulations that prohibit or restrict our ability to apply hydraulic fracturing to our oil and natural gas wells;
- the possible introduction of regulations that prohibit or restrict our ability to drill new allocation wells;
- 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;
- the availability and costs of drilling and production equipment, labor and oil and natural gas processing and other services;
- drilling and operating risks, including risks related to hydraulic fracturing activities;
- risks related to the geographic concentration of our assets;
- changes in domestic and global demand for oil and natural gas, as well as the continuation of restrictions on the export of domestic crude oil;
- the availability of sufficient pipeline and transportation facilities and gathering and processing capacity;
- changes in the regulatory environment and changes in international, legal, political, administrative or economic conditions;
- our ability to comply with federal, state and local regulatory requirements;
- our ability to execute our strategies, including but not limited to our hedging strategies;
- our ability to recruit and retain the qualified personnel necessary to operate our business;
- evolving industry standards and adverse changes in global economic, political and other conditions;
- restrictions contained in our debt agreements, including our senior secured credit facility and the indentures governing our senior unsecured notes, as well as debt that could be incurred in the future;
- our ability to access additional borrowing capacity under our senior secured credit facility or other means of providing liquidity; and
- our ability to generate sufficient cash to service our indebtedness and to generate future profits.

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. 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 subsidiary, Laredo Midstream Services, LLC, as of the completion of our internal corporate reorganization and thereafter.

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. See Notes A and B in our audited consolidated financial statements included elsewhere in this Annual Report for more information.

All amounts, 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 exploration, development and acquisition of oil and natural gas properties primarily in the Permian region of the United States. The oil and liquids-rich Permian Basin in West Texas 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, 2013, we had assembled 202,084 net acres in the Permian Basin and had total proved reserves, presented on a two-stream basis, of 203,615 MBOE.

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. Following the Anadarko Basin Sale, the percentage of our proved reserves attributable to oil increased to 55% as of December 31, 2013 from 52% prior to such sale.

Our primary exploration and production fairway in the Permian Basin is centered 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 Glasscock, Howard, Reagan, Sterling and Tom Green counties, and is referred to in this Annual Report as the "Permian-Garden City" area. As of December 31, 2013, we held 143,212 net acres in more than 300 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 the Wolfberry interval, comprised of multiple producing formations, including the initial four identified shale zones targeted for horizontal drilling (Upper, Middle and Lower Wolfcamp and Cline shales). From our inception through December 31, 2013, we have drilled and completed 96 horizontal wells in these four target zones, and 818 vertical wells in the Wolfberry interval. We have completed (i.e., the particular well is flowing) 40 horizontal Upper Wolfcamp wells, 13 horizontal Middle Wolfcamp wells, six horizontal Lower Wolfcamp wells and 37 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 25 to 28 stages) as we continue the optimization of our completion techniques.

As illustrated in the following table, as a result of our drilling activity through 2013 coupled with our technical data and well performance, we believe that as of December 31, 2013 we have confirmed the horizontal development potential for the equivalent of 360,000 net acres from the four zones, as well as our entire Permian-Garden City acreage position for vertical development.

	Horizontal development de-risked net acreage as of December 31, 2013
Upper Wolfcamp	80,000
Middle Wolfcamp	80,000
Lower Wolfcamp	73,000
Cline	127,000
Total	360,000

Going forward, we plan to continue drilling and collecting technical data across our Permian-Garden City acreage, as reflected in our 2014 capital drilling budget allocation. As a result, we expect our Permian-Garden City acreage to be the primary driver of our reserves, production and cash flow growth for the foreseeable future.

Laredo was founded in October 2006 by our Chairman and Chief Executive Officer Randy A. 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 and in December 2013, we completed a separate internal corporate reorganization. See "—Corporate history and structure."

Since our inception, we have rapidly grown our reserves, production and cash flow through both our drilling program and strategic acquisitions, including our July 2011 acquisition of Broad Oak. Our net proved reserves were estimated at 203,615 MBOE as of December 31, 2013, of which 35% are classified as proved developed reserves and 55% are attributed to oil reserves. 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 natural gas is included in the wellhead natural gas price. 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, 2013, and average daily production presented on a two-stream basis for the year ended December 31, 2013. Based on estimates in the report prepared by Ryder Scott, we operate wells that represent 98% of the economic value of our proved developed oil and natural gas reserves as of December 31, 2013.

	As of December 31, 2013 Estimated net proved reserves(1)(2)				Producing wells		Year ended December 31, 2013 average daily production(3) (BOE/D)
	MBOE	% of total reserves	% Oil	Net acreage	Gross	Net	
Permian	203,564	99 %	55 %	202,084	1,060	940	24,897
Anadarko Granite Wash(4)	—	— %	— %	—	—	—	4,615
Other Areas(5)	—	— %	— %	—	—	—	1,141
New Ventures(6)	51	1 %	100 %	80,143	1	1	63
Total	203,615	100 %	55 %	282,227	1,061	941	30,716

(1) Our estimated net proved reserves were prepared by Ryder Scott, presented on a two-stream basis as of December 31, 2013 and are based on reference oil and natural gas prices. 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 $93.52 per Bbl for oil and $3.57 per MMBtu for natural gas for the 12 months ended December 31, 2013.

(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, 2013 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 $5.52 per Mcf.

(3) Our average daily production volumes 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.

(4) We sold these assets on August 1, 2013.

(5) We sold these assets on August 1, 2013, which included our acreage in the gas prone Eastern Anadarko (21,000 net acres) and Central Texas Panhandle (43,450 net acres).

(6) On December 20, 2013, we completed the sale of certain properties in the Dalhart Basin, which included 37,000 net acres. The remaining 50,000 net acres that we own in the Dalhart Basin are included in New Ventures. See "—New Ventures."

Our net average daily production for the year ended December 31, 2013 was 30,716 BOE/D, 49% of which was oil and 51% of which was primarily liquids-rich natural gas. Our drilling activity has been and is expected to continue to be focused on oil opportunities in the Permian Basin.

Following the sale of our assets in the Anadarko Basin and Dalhart Basin, we continue to focus on horizontal drilling in the Permian Basin. This Permian Basin horizontal drilling program comprises an extensive, multi-year, multiple-zone inventory of exploratory and development opportunities.

As of December 31, 2013 we had completed 96 gross horizontal Wolfcamp and Cline shale wells in our Permian-Garden City area.

Substantially all of our $1 billion planned capital budget for 2014 is anticipated to be invested in the Permian Basin. We anticipate that we will continue to drill vertical wells for purposes of further delineating our Permian Basin acreage and holding all prospective targeted zones. We are increasingly allocating a greater percentage of both capital and human resources towards our horizontal drilling activity, which generally produces even more attractive economics than our vertical program. Because of the stacked multiple-zone horizontal targets underlying our acreage, we are continuing to refine the optimal geometry relative to well spacing, both vertically and horizontally, 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.

On December 31, 2013 we had a total of 11 operated drilling rigs working on our properties in the Permian-Garden City area, consisting of six rigs drilling vertical wells and five rigs drilling horizontal wells.

We have assembled a multi-year inventory of development drilling and exploitation projects as a result of our early acquisition of technical data, early establishment of significant concentrated acreage positions and successful exploratory drilling.

While our horizontal drilling programs will be focused primarily on developing the four zones already identified in the liquids-rich Wolfcamp and Cline intervals underlying our Permian-Garden City properties, we believe, based on petrophysical analysis, additional potential may exist in both shallower and deeper formations. The testing of these new targeted intervals will be integrated into our drilling program during 2014 and beyond.

We maintain a financial profile that provides operational flexibility. At December 31, 2013, we had $825 million available for borrowings under our Fourth Amended and Restated Credit Agreement (as amended, the "Senior Secured Credit Facility") and total debt of $1.05 billion, of which no amount was outstanding under our Senior Secured Credit Facility. Our total debt, less available cash on the balance sheet, was 1.8 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, 2013. We believe that our operating cash flow and the aforementioned liquidity sources provide us with the capability to implement our planned exploration and development activities as well as the ability to accelerate our capital program, if deemed appropriate. We use 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, we expect to mitigate, but not eliminate, the potential effects of variability in cash flows from operations due to fluctuations in commodity prices.

We carefully assess and monitor many factors in our drilling and exploration projects. Our drilling activities in areas containing extensive historical industry activity have enabled us to determine whether a prospective reservoir underlies our acreage position, and whether it can be defined both vertically and horizontally. We use a number of proven mapping techniques to understand the physical extent of the targeted reservoir. This includes 2D and 3D seismic data, as well as Laredo-owned and historical public well databases (which in the Permian Basin may extend back more than 80 years). We also utilize our laboratory and field derived data from whole cores, sidewall cores, well cuttings, mudlogs and open-hole well logs to understand the petrophysics of the rock characteristics prior to the commencement of any completion operations. Finally, after defining the reservoir, our engineers utilize their technical expertise to develop completion programs that we believe will maximize the amount of hydrocarbons that can be economically recovered. As more wells are completed in the targeted reservoir and additional data becomes available, the process is further refined. Based on these and other factors, 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.

In the Permian-Garden City area, the Wolfberry interval, comprised of multiple producing formations, including the Wolfcamp and Cline shale formations targeted for horizontal drilling in four zones (Upper, Middle and Lower Wolfcamp and Cline shales), is considered a resource play. While the vertical component of the drilling program will continue, our emphasis is now centered on bringing forward the upside potential in the Wolfcamp and Cline shales in our Permian-Garden City acreage through horizontal drilling. As resource plays, the mapping of the gross interval for each of the producing formations underlying a majority of our acreage position is the primary factor in identifying our potential drilling locations. In the general region and immediately around our acreage position, publicly available well data exists from a significant number of vertical wells (in excess of several thousand for the Wolfcamp and Cline shales alone) that allows us to better define the potential areal extent of each of the producing intervals. In addition to the publicly available well data, we have also incorporated our internally generated information from cores, 3D seismic, open-hole logging, production and reservoir engineering data into defining the extent of the targeted formations, the ability of such formations to produce commercial quantities of hydrocarbons, and the viability of the potential locations. We are refining a development plan for a portion of our Permian-Garden City area in order to minimize costs and maximize recoveries and began its implementation in 2013. As of December 31, 2013, we had drilled and completed 10 horizontal wells as a part of our pad drilling program.

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

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., with Laredo Petroleum Holdings, Inc.

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 A. 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 Laredo Petroleum Holdings, Inc. Laredo Petroleum Holdings, Inc. completed an IPO of its common stock on December 20, 2011. As of December 31, 2013, Warburg Pincus owned 49.1% 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 sole remaining wholly-owned subsidiary of Laredo Petroleum, Inc., formerly known as Laredo Gas Services, LLC, changed its name to Laredo Midstream Services, LLC. Laredo Petroleum, Inc., a wholly-owned subsidiary of Laredo Petroleum Holdings, Inc. ("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." The Corporate Reorganization, IPO and Internal Consolidation are discussed in Note A to our audited consolidated financial statements included elsewhere in this Annual Report.

Laredo Petroleum, Inc. is the borrower under our Senior Secured Credit Facility, as well as the issuer of our $550 million 9 1/2% senior unsecured notes due 2019 (the "2019 senior unsecured notes") issued in January and October 2011, our $500 million 7 3/8% senior unsecured notes due 2022 issued in April 2012 (the "2022 senior unsecured notes") and our $450 million 5 5/8% senior unsecured notes due 2022 issued in January 2014 (the "new senior unsecured notes"). We refer to the 2019 senior unsecured notes, the 2022 senior unsecured notes and the new senior unsecured notes collectively as the "senior unsecured notes." Our subsidiary, Laredo Midstream Services, LLC ("Laredo Midstream"), is a guarantor 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:

Grow reserves, production and cash flow.   As of December 31, 2013, we had 143,212 net acres in the Permian-Garden City area. As of such date we believe we have established the economic horizontal potential of 80,000 net acres for horizontal Upper Wolfcamp drilling, 80,000 net acres for horizontal Middle Wolfcamp drilling, 73,000 net acres for Lower Wolfcamp drilling and 127,000 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. We believe the opportunities afforded in our Permian-Garden City area will support consistent, predictable, annual growth in reserves, production and cash flow.

Initiating a development plan for our Permian-Garden City acreage. We believe our Permian-Garden City acreage will be the primary driver of our reserves, production and cash flow growth for the foreseeable future. Based on additional drilling results through December 31, 2013, coupled with our technical data and well performance, we believe we have confirmed the vertical development potential of our entire Permian-Garden City acreage position (utilizing more than 800 vertical wells across our acreage position, of which more than 300 have been drilled through the Wolfcamp, Cline and Atoka formations). The equivalent of 360,000 net acres for commercial horizontal development has been proven from all four targeted zones based on 96 horizontal wells drilled and completed as of December 31, 2013. We further believe this de-risked acreage position provides a multi-year development inventory to support consistent growth of reserves, production and cash flow. We are implementing a systematic pad development drilling program that will allow us to optimize spacing, minimize drainage interference and maximize our frac design. 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. The stacked lateral program (up to four different zones) has been initiated with multiple tests planned in several areas of our acreage in 2014. Our objectives with the stacked lateral program are to optimize the vertical distance between the laterals, minimize interference, enhance frac design and maximize scheduling of rig operations on multi-well pads. The 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 the Middle and Lower Wolfcamp zones in the southern half of the Permian-Garden City acreage. The drilling and testing of other potential zones (i.e., Spraberry and ABW) will likely also be part of the 2014 drilling program. Going

forward, we plan to continue drilling and collecting technical data across our Permian-Garden City acreage position.
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 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 96 completed horizontal wells in all three Wolfcamp zones and the Cline shale zones.
We intend to continue to make upfront investments in technology to understand the geology, geophysics and reservoir parameters of the rock formations that define our exploration and development programs. Through comprehensive coring programs, acquisition and evaluation of high-quality 3D seismic data and advance logging/simulation technologies, we expect to continue to both economically de-risk our remaining property sets to the extent possible before committing to a drilling program, and assist in the evaluation of emerging opportunities.
Enhance returns through prudent capital allocation, optimization of our development program and continued improvements in operational and cost efficiencies. In the current commodity price environment, we have directed our capital spending toward oil and liquids-rich drilling opportunities that 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 initiated a development plan for a portion of our Permian-Garden City area in order to minimize costs and maximize recoveries. 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 vertically and horizontally, 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 to de-risk additional acreage for all zones. Our management team is focused on continuous improvement of our operating practices and has significant experience in successfully converting exploration programs into cost-efficient development projects. We are the operator for 88% of our Permian-Garden City wells which allows 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-year 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. Any transaction we pursue will either generally complement our asset base, provide an anticipated competitive economic proposition relative to our existing opportunities or market conditions, or provide an avenue to accelerate the development of our potentially higher return acreage and maximize the value of the total Company.
Proactively manage risk to limit downside. We continually monitor and control our business and operating risks through various risk management practices, including maintaining a flexible financial profile, making upfront investment in research and development as well as data acquisition, seeking multiple sales outlets, minimizing long-term contracts, maintaining an active commodity hedging program and employing prudent safety and environmental practices.
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-year drilling inventory. From our inception in 2006 through December 31, 2013, we have completed 818 gross vertical and 98 gross horizontal wells with a success rate of 99% in our Permian-Garden City area. The 98 gross horizontal wells are comprised of 96 wells in the Upper, Middle and Lower Wolfcamp and Cline shales and two wells in other zones. Based on our drilling results through December 31, 2013, we believe we had confirmed the economic horizontal development potential of the equivalent of 360,000 net acres from the four zones that includes 80,000 net acres in the Upper Wolfcamp, 80,000 net acres in the Middle Wolfcamp, 73,000 net acres in the Lower Wolfcamp and 127,000 net acres in the Cline shale. We believe these locations provide a multi-year drilling inventory supporting future growth in reserves, production and cash flow.

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 includes 774 square miles of proprietary/licensed 3D seismic (covering 95% of our acreage position), 225 proprietary petrophysical logs (fully core calibrated), and more than 13,500 historical open-hole logs from the general area, as of December 31, 2013. We have also run 96 dipole sonic longs 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. In coordination with a major oil-field consultant, we are in the process of creating a model (utilizing a majority of the data listed above) that we anticipate will assist in developing our Permian-Garden City acreage with the best reservoir characteristics early in the life of the field. Another important objective of the modeling program includes how 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, 2013, based on a report prepared by Ryder Scott. We believe that maintaining operating control permits us to better pursue our strategies of enhancing returns through operational and cost efficiencies and maximizing ultimate hydrocarbon recoveries from mature producing basins 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, has more than 125 miles of pipeline in our natural gas gathering systems in the Permian Basin as of December 31, 2013. These systems and flow lines provide greater operational efficiency and lower price differentials for our natural gas production in our liquids-rich Permian play and enable us to coordinate our activities to connect our wells to market upon completion with minimal days waiting on pipeline. Additionally, on a portion of our production, this provides us with multiple sales outlets through interconnection pipelines, potentially minimizing the risks of both shut-ins awaiting pipeline connection and curtailment of downstream pipelines. We continue to expand this concept by building out our crude oil transportation infrastructure in order to attempt to minimize the risks of shut-in or curtailment. We have constructed crude oil truck stations in Glasscock and Reagan counties, Texas. We have also commenced construction of a crude oil gathering system in Reagan County, Texas.

Financial strength and flexibility. We maintain a financial profile that provides operational flexibility. As of December 31, 2013, we had $825 million available for borrowings under our Senior Secured Credit Facility and total liquidity of $1.0 billion, with no amounts outstanding on our Senior Secured Credit Facility. As of such date, we had $1.05 billion of total debt consisting of two series of senior unsecured notes with maturities in 2019 and 2022. We use derivatives to reduce exposure to fluctuations in the prices of oil and natural gas. By removing a portion of the price volatility associated with future production, we expect to mitigate, but not eliminate, the potential volatility in cash flows from operations due to fluctuations in commodity prices.

Subsequent to December 31, 2013, we issued the new senior unsecured notes that increased our total long-term indebtedness to $1.5 billion and decreased the amount available for borrowings under our Senior Secured Credit Facility to $812.5 million.

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 institutional investor, as well as 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 properties are currently located in the prolific Permian region 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 vertical and horizontal drilling programs. We expect our Permian-Garden City acreage, which is characterized by a high oil content, to be the primary driver of our reserves, production and cash flow growth 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 202,084 net acres as of December 31, 2013, 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 centered 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 and Tom Green counties. As of December 31, 2013, we held

143,212 net acres in more than 300 sections in the Permian-Garden City area with an average working interest of 96% in all Laredo-operated producing wells.

During 2013, we continued to expand our horizontal development program for the Wolfberry and Cline shales. Our results indicate that our acreage in the Permian-Garden City area can be produced horizontally, with even stronger economic results than our vertical program. 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 horizontal targets in the Permian-Garden City area. During 2013, we drilled and completed 36 horizontal wells and now have a total of 96 horizontal wells, confirming production and attractive returns from all four zones. Today, we are continuing our drilling focus on a horizontal development and exploitation program supported by vertical wells that help us define and optimize the horizontal targets.

As of December 31, 2013, our proprietary and industry data includes 774 square miles of proprietary/licensed 3D seismic, 13 whole and more than 335 sidewall cores in the four zones we are currently targeting, providing extensive production and reservoir engineering data. From our analysis of this data, we believe each of these 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 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 analysis, we believe we have confirmed that all three Wolfcamp zones share many similar petrophysical and production attributes.

As of December 31, 2013, we had successfully drilled and completed 40 horizontal wells in the Upper Wolfcamp, 13 horizontal wells in the Middle Wolfcamp and six horizontal wells in the Lower Wolfcamp.

Upper Wolfcamp. As of December 31, 2013, we estimated that 80,000 net acres of our Permian-Garden City area had been de-risked for horizontal Upper Wolfcamp development. In the Upper Wolfcamp, we have identified a facies change progressing from west to east across our acreage, with the shale becoming increasingly carbonate. To date we have drilled and completed more wells in the southern third of our de-risked Upper Wolfcamp acreage, while continuing to explore and develop the entire area.

Middle and Lower Wolfcamp. In the Middle and Lower Wolfcamp, we continue to expand our evaluation efforts across our acreage. Production from our vertical drilling program has confirmed that both the Middle and Lower Wolfcamp zones underlie the majority of our acreage. As with the Upper Wolfcamp, there appears to be a similar facies change in these zones. As of December 31, 2013, we had drilled and completed 13 horizontal wells in the Middle Wolfcamp zone and six horizontal wells in the Lower Wolfcamp zone. As of the same date we estimated that 80,000 net acres in the Middle Wolfcamp and 73,000 net acres in the Lower Wolfcamp had been de-risked for horizontal development. Through the combination of our drilling activities, the initial production results from these wells and our extensive technical database, we will continue our efforts to fully evaluate the potential of both the Middle and Lower Wolfcamp over our whole Permian-Garden City acreage position.

The Cline shale resource play

As of December 31, 2013, we estimated that 127,000 net acres of our Permian-Garden City area had been de-risked for horizontal Cline development. In 2013, we successfully drilled and completed three horizontal wells and now have a total of 37 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

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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.

Other areas

On August 1, 2013 we completed the sale of our assets in the Anadarko Basin in the Texas Panhandle and Western Oklahoma. Included in this sale were 43,450 net acres in the Central Texas Panhandle and 21,000 net acres in the eastern end of the Anadarko Basin, in Caddo, Grady and Comanche counties, Oklahoma.

New Ventures

In addition to our Permian Basin acreage, we continue to evaluate new opportunities in other areas within our core operating regions, which we refer to as our "New Ventures."

The Dalhart Basin is located on the western side of the Texas Panhandle. On December 20, 2013 we completed the sale of 37,000 net acres of our position in the Dalhart Basin. As of December 31, 2013, we held 50,000 net acres in the Dalhart Basin, which is included in New Ventures.

In addition, as of December 31, 2013, we held 29,459 net acres in other New Venture areas.

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 203,615 MBOE as of December 31, 2013, of which 35% were classified as proved developed reserves, and 55% are attributable to oil reserves. The following table presents summary data for each of our core operating areas as of December 31, 2013. Our estimated proved reserves as of December 31, 2013 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."

	As of December 31, 2013		
Area:	Proved reserves (MBOE)	% of total	
Permian Basin	203,564	99	%
New Ventures[1]	51	1	%
Total	203,615	100	%

(1) Includes Dalhart Basin and other New Ventures.

The following table sets forth more information regarding our estimated proved reserves as of December 31, 2013 and 2012. Ryder Scott, our independent reserve engineers, estimated 100% of our proved reserves as of December 31, 2013 and 2012. The reserve estimates as of December 31, 2013 and 2012 were prepared in accordance with the SEC's rules regarding oil and natural gas reserve reporting currently in effect. The information does not give any effect to our commodity hedges.

	As of December 31,	
	2013	2012[1]
Estimated proved reserves:		
Oil and condensate (MBbl)	111,498	98,141
Natural gas (MMcf)	552,702	542,946
Total estimated proved reserves (MBOE)	203,615	188,632
Proved developed producing (MBOE)	67,968	76,777
Proved developed non-producing (MBOE)	3,757	4,713
Proved undeveloped (MBOE)	131,890	107,142
Percent developed	35 %	43 %

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(1) Includes proved reserves attributable to the acreage sold in the Anadarko Basin Sale.

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, 2013 and 2012 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 38 years of practical experience with 30 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 107,142 MBOE as of December 31, 2012 to 131,890 MBOE as of December 31, 2013. During 2013, 5,782 MBOE of proved undeveloped reserves from 25 locations were converted to proved developed reserves. New proved undeveloped reserves of 47,643 MBOE were added during the year, with 96% coming from new horizontal Upper, Middle and Lower Wolfcamp and Cline locations. Negative revisions of 11,944 MBOE were due to the combined effect of removing 174 proved locations and the net effect of redetermining 501 undeveloped locations. The 174 locations that were removed were comprised of vertical Wolfberry and short horizontal laterals. They were replaced with longer 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, 2013 reserves report are $2.2 billion. Based on this report, the capital estimated to be spent in 2014, 2015, 2016, 2017 and 2018 to develop the proved undeveloped reserves is $359 million, $482 million, $558 million, $499 million and $232 million, respectively. All of the proved undeveloped locations are expected to be drilled within a five-year period.

Production, revenues and price history

The following table sets forth information regarding production, revenues and realized prices and production costs for the years ended December 31, 2013, 2012 and 2011. 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."

	For the years ended December 31,		
(unaudited)	2013	2012	2011
Production data:			
Oil (MBbl)	5,487	4,775	3,368
Natural gas (MMcf)	34,348	39,148	31,711
Oil equivalents (MBOE)(1)	11,211	11,300	8,654
Average daily production (BOE/D)(1)	30,716	30,874	23,709
Revenues (in thousands):			
Oil	$494,676	$414,932	$306,481
Natural gas	$170,168	$168,637	$199,774
Average sales prices without hedges:			
Benchmark oil ($/Bbl)(2)	$97.97	$94.20	$95.01
Realized oil ($/Bbl)(3)	$90.16	$86.89	$91.00
Benchmark natural gas ($/MMBtu)(2)	$3.65	$2.80	$4.02
Realized natural gas ($/Mcf)(3)	$4.95	$4.31	$6.30
Average price ($/BOE)	$59.29	$51.65	$58.50
Average sales prices with hedges(4):			
Oil ($/Bbl)	$88.68	$85.59	$88.16
Natural gas ($/Mcf)	$4.98	$4.92	$6.59
Average price ($/BOE)	$58.66	$53.22	$58.47
Average cost per BOE:			
Lease operating expenses	$7.06	$5.96	$5.00
Production and ad valorem taxes	$3.78	$3.33	$3.70
Depletion, depreciation and amortization	$20.87	$21.33	$20.12
General and administrative(5)	$8.00	$5.50	$5.90

(1) The volumes presented for the years ended December 31, 2013, 2012 and 2011 are based on actual results and are not calculated using the rounded numbers in the table above.

(2) 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.

(3) Realized crude oil and natural gas prices are the actual prices realized at the wellhead after all adjustments for natural gas liquids content, quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price at the wellhead.

(4) 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 derivative instruments in accordance with the applicable generally accepted accounting principles in the United States of America (“GAAP”) and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to instruments 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

(5) General and administrative includes non-cash stock-based compensation of $21.4 million, $10.1 million and $6.1 million for the years ended December 31, 2013, 2012 and 2011, respectively. Excluding stock-based compensation from the above metric results in average general and administrative cost per BOE of $6.09, $4.61 and $5.19 for the years ended December 31, 2013, 2012 and 2011, respectively.

Productive wells

The following table sets forth certain information regarding productive wells in each of our core areas as of December 31, 2013. 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 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				Average WI %	
	Gross					
	Vertical	Horizontal	Total	Net		
Permian Basin:						
Operated Permian-Garden City	838	97	935	902	96	%
Non-Operated Permian Garden City	122	1	123	36	29	%
Operated Permian-China Grove[1]	1	1	2	2	99	%
Operated New Ventures[2]	1	—	1	1	95	%
Total	962	99	1,061	941	89	%

(1) Located primarily in Mitchell County, Texas.
(2) Includes Dalhart Basin and other New Ventures.

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own an interest as of December 31, 2013 for each of our core operating areas, including acreage held by production ("HBP"). A majority of our developed acreage is subject to liens securing our Senior Secured Credit Facility.

	Developed acres		Undeveloped acres		Total acres		%	
	Gross	Net	Gross	Net	Gross	Net	HBP	
Permian Basin:								
Permian-Garden City	102,355	93,149	75,968	50,063	178,323	143,212	65	%
Permian-China Grove	478	454	74,737	58,418	75,215	58,872	1	%
New Ventures[1]	640	502	89,495	79,641	90,135	80,143	1	%
Total	103,473	94,105	240,200	188,122	343,673	282,227	33	%

(1) Includes Dalhart Basin and other New Ventures.

Undeveloped acreage expirations

The following table sets forth the gross and net undeveloped acreage in our core operating areas as of December 31, 2013 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.

	2014		2015		2016		2017	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian Basin:								
Permian-Garden City	11,319	10,929	23,596	15,214	5,409	2,515	—	—
Permian-China Grove	21,734	16,692	48,318	38,083	4,686	3,643	—	—
New Ventures[(1)]	39,981	35,825	31,742	26,804	2,741	2,411	10,841	10,714
Total	73,034	63,446	103,656	80,101	12,836	8,569	10,841	10,714

(1) Includes Dalhart Basin and other New Ventures.

Drilling activity

The following table summarizes our drilling activity for the years ended December 31, 2013, 2012 and 2011. 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.

	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	171	127.2	199	183.2	260	233.2
Dry	—	—	—	—	—	—
Total development wells	171	127.2	199	183.2	260	233.2
Exploratory wells:						
Productive	2	2.0	1	1.0	2	1.4
Dry	—	—	1	0.9	—	—
Total exploratory wells	2	2.0	2	1.9	2	1.4

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 to a variety of purchasers 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. 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, 2013, we were committed to deliver the following fixed quantities of production under certain contractual arrangements that specify the delivery of a fixed and determinable quantity.

	Total	2014	2015	2016	2017 and beyond
Oil and condensate (MBbl)	100,314	6,570	9,490	11,802	72,453
Natural gas (MMcf)	70,192	1,170	3,393	4,796	60,833
Total (MBOE)	112,013	6,765	10,055	12,601	82,591

Subsequent to December 31, 2013, we entered into additional agreements to deliver fixed quantities of production. As of February 26, 2014, we were committed to deliver the following fixed quantities of production under certain contractual

arrangements that specify the delivery of a fixed and determinable quantity.

	Total	2014	2015	2016	2017 and beyond
Oil and condensate (MBbl)	131,948	6,570	9,490	14,235	101,653
Natural gas (MMcf)	70,192	1,170	3,393	4,796	60,833
Total (MBOE)	143,646	6,765	10,055	15,034	11,791

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.

Our proved reserves have been sufficient to satisfy our delivery commitments during the three most recent years, and we expect such reserves will continue to satisfy our future commitments. However, should our proved reserves not be sufficient to satisfy our delivery commitments, we can and may use spot market purchases to fulfill the commitments. Based on the current demand for oil and natural gas and the availability of alternate purchasers, 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 I 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 natural 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, 2013, 33% of our leasehold acreage was HBP.

Seasonality

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

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies in our industry that have greater resources than we do, especially in our focus areas. Many of these 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. These companies may be able to pay more for productive properties and exploratory locations or define, 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